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Market Surveillance Panel Report 35

MONITORING REPORT ON THE IESO-ADMINISTERED ELECTRICITY MARKETS

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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 35th Market Surveillance Panel Monitoring Report published since market opening in 2002. The report includes a discussion of current issues that the Panel recommends be addressed (Chapter 3). The report also notes recent electricity sector events (Chapter 1), as well as events in the monitoring period May 1, 2020 to October 31, 2020 – referred to as the Summer 2020 Period (Chapter 2 and Appendix A).

This Monitoring Report is broken down into three chapters and an appendix:

- Chapter 1: Market Developments
- Chapter 2: Analysis of Anomalous Market Outcomes
- Chapter 3: Matters to Report in the Ontario Electricity Marketplace
- Appendix A: Market Outcomes for the Summer 2020 Period

Chapter 1: Market Developments

Five recent market developments are considered noteworthy: an upcoming inaugural report by the IESO's Market Assessment and Compliance Division on compliance and enforcement activities since market opening; the IESO's capacity procurement plans in the context of engagements on resource adequacy; the government-led review of Ontario's Long-Term Energy Planning framework; a Market Rule amendment which addresses certain Panel recommendations on Congestion Management Settlement Credit (CMSC) payments to dispatchable loads; and an IESO pilot program for auction-based procurement of Energy Efficiency.

Chapter 2: Analysis of Anomalous Market Outcomes

This Chapter deals with events in the Summer 2020 Period that exceed predefined thresholds established to identify outcomes considered anomalous and therefore potentially significant for the IESO-Administered Markets.

Two events are examined in detail. First, on July 9 and 10, 2020 a nuclear generator outage caused by an IESO error contributed to higher energy prices amid peak summer demand. The first non-test Hourly Demand Response (HDR) activations occurred on those days. The second event is a price spike that occurred on August 15, 2020.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

The performance of HDR resources has been disappointing in both test activations and most recently during emergency activation in July 2020.

The Panel believes that the current non-performance penalties for HDR are insufficient to encourage dispatch compliance. Further, the design of payments and penalties incentivizes resources to overstate their capacity when offering into auctions. The Panel recommends adjustments to the Capacity Auction's payments and penalties to improve resource performance.

Recommendation 3-1

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.

<u>Recommendation 3-2:</u>

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.

Carbon pricing – a market-based approach to greenhouse gas reductions – has now been in effect in Ontario for several years and has been assumed to be integrated into the offers made into the energy market. However, the IESO is weakening the carbon price signal in the electricity market by repaying a significant portion of the carbon price to gas-fired generators with out-of-market reimbursements under the Real-Time Generation Cost Guarantee (GCG) program. These carbon cost reimbursements undermine the market-based incentives put in place by government. In July 2021, the federal government announced that it has updated the minimum national standards (federal benchmark) to ensure provincial government measures "do not weaken the price signal".[1,2] To improve the efficiency of the electricity market and the effectiveness of the carbon price, the IESO should cease reimbursements to gas generators of carbon cost payments.

<u>Recommendation 3-3:</u>

The IESO should immediately cease reimbursements to gas generators of carbon cost payments.

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[1] See the federal government's news release "Government of Canada confirms ambitious new greenhouse gas emissions reduction target", July 12, 2021:

https://www.canada.ca/en/environment-climate-change/news/2021/07/government-of-canada-confirms-ambitious-new-greenhouse-gas-emissions-reduction-target.html

[2] See the federal government's webpage "Additional information on the federal carbon pollution pricing benchmark":

https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html

Recommendation 3-4:

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.

Recommendation 3-5:

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 Panel continues to monitor capacity procurements in the electricity sector. Market efficiency is best served by competitive procurements whenever possible. Several non-competitive procurements are currently underway without sufficient consideration for competition or transparency. If the IESO's Resource Adequacy Framework successfully achieves open, transparent, competitive and needs-based capacity procurement, the Panel expects that non-competitive procurement will become unnecessary. Until that time, the Panel makes two recommendations to enhance transparency.

Recommendation 3-6:

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).

Recommendation 3-7:

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 Panel recently provided input to the government-led review of Long-Term Energy Planning, recommending that non-electricity costs and benefits be identified and separated from system costs and benefits, and that revenue collection for non-electricity costs be established outside of ratepayer funding. In any event, the separation of system costs and benefits from non-electricity costs and benefits would facilitate the inclusion of projects that have multiple benefits in competitive processes by only considering electricity system costs in competitive comparisons.

Recommendation 3-8:

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.

Chapter 1: Market Developments

This chapter contains an update on recent developments related to the IESO-Administered Markets since the previous Monitoring Report was published in February 2021.

1.1.1 Transparency of Market Enforcement Activities

The market rules currently limit the IESO's ability to make public information relating to the activities of the IESO's Market Assessment and Compliance Division regarding enforcement activities. Publication of enforcement-related information can further the goal of fostering compliance with the market rules and North American reliability standards and deter future non-compliance. It can also enable Market Participants to better understand what types of behaviour may be viewed as non-compliant. Market rule amendments that would allow for greater transparency into MACD's enforcement activities would benefit all Market Participants and electricity consumers.

The Panel is aware that MACD will soon release an inaugural Update Report which will speak to MACD's mandate and its compliance-enabling and enforcement activities from market opening to the present. The Panel views the aggregate reporting of MACD's activities as a positive first step in enhancing compliance-related transparency for the IESO-Administered Markets.

1.1.2 Resource Adequacy Update

The IESO's recent engagements on resource adequacy are focused on gathering stakeholder input on its strategy to acquire resources to meet electricity system capacity needs.

The engagement session held on March 22, 2021 included a discussion of the purpose and goals of the IESO's Capacity Auction, following the first auction in December 2020 that secured 992 MW, mostly from Demand Response (DR). The Panel submitted comments focused on the proposed Capacity Auction enhancements and specifically the issue of resource performance.[3] The Panel commented that the Capacity Auction's rules and processes for testing, qualification, payments, and charges should be assessed on an integrated basis to discourage inefficient outcomes, unnecessary costs and reliability issues.

The IESO has released the first Annual Acquisition Report, which sets the summer and winter capacity targets for the December 2021 Capacity Auction, announces upcoming RFPs for medium- and long-term commitment lengths, and discusses five non-competitive procurements (discussed further in Section 3.3 of this report).[4] Proposals have also been developed for methodologies to calculate the Unforced Capacity of various resource types for future Capacity Auctions and other procurements.[5]

1.1.3 Long-Term Energy Planning Framework Review

On January 27, 2021, the Ministry of Energy, Northern Development and Mines posted a proposal on the Environmental Registry of Ontario website seeking input on long-term energy planning in Ontario, specifically reviewing the roles and responsibilities of technical agencies and regulators in Ontario's electricity sector. The Panel has submitted comments on this topic and supports mandating the IESO to continue to identify system needs through long-term planning, and the OEB to have oversight of the IESO's processes to identify system needs and concomitant procurement methodologies as well as strengthening and clarifying accountabilities.

[3] See the Panel's comments for the March 22, 2021 Resource Adequacy engagement: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210414-market-surveillance-panel.ashx

[4] See the IESO's Annual Acquisition Report, dated July 2021, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2021.ashx

[5] See the IESO's Resource Adequacy stakeholder engagement presentation, dated July 22, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210722-presentation.ashx

1.1.4 CMSC Recovery from Dispatchable Loads

On March 10, 2021, the IESO Board approved a Market Rule amendment that enables the recovery of Congestion Management Settlement Credit (CMSC) payments from dispatchable loads when those payments are a result of actions taken to prevent endangering the safety of any person, equipment damage, or the violation of any applicable law (i.e. SEAL). The Market Rule amendment allows the IESO to recover CMSC payments when a dispatchable load facility makes a SEAL claim and is either unable to follow IESO dispatch instructions or is constrained by the IESO at the request of the dispatchable load.

This Market Rule amendment aligns with two previous recommendations by the Panel: Recommendation 3-1 from the Panel's 2018 Monitoring Report 29 published March 2018, and the Panel's recommendation in its CMSC Investigations Report published February 2015.[6]

1.1.5 Energy Efficiency Auction Pilot

The IESO held an Energy Efficiency auction pilot on March 22-23, 2021. The purpose of the pilot is to procure demand reduction from energy efficiency and load-shifting projects during peak demand periods, with a pilot budget of $5 million. The IESO will apply the lessons from the pilot to inform future IESO energy efficiency programs and procurement initiatives.[7] The auction cleared 7.4 MW of energy reductions for the daily peak hours of Winter 2022/2023 and 6.6 MW for Summer 2023.[8]

[6] For more information on the Panel's previous discussion on CMSC paid to dispatchable loads see the Panel's Monitoring Report 29 published March 2018 and the Panel's Investigation Report relating to CMSC payments made to two market participants, dated, February 2015:

https://www.oeb.ca/sites/default/files/msp-monitoring-report-20180322.pdf and

https://www.oeb.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf

[7] For more information on the IESO's specific learning objectives for the Energy Efficiency Auction Pilot, see: https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Energy-Efficiency-Auction-Pilot

[8] The EE pilot defines Winter 2022/2023 as the period from November 1, 2022 to February 28, 2023, whereas Summer 2023 is defined as the period from June 1, 2023 to August 31, 2023.

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter provides data and analysis of the 6-month monitoring period from May 1, 2020 to October 31, 2020, referred to as the Summer 2020 Period.

A primary responsibility of the Panel is to monitor for anomalies in the market.[9] Since market inception, the Panel has identified metrics to aid in identifying market anomalies. Over time, monitoring of these metrics has provided the Panel with a consistent dataset to compare both short- and long-term trends.[10,11] The Panel uses thresholds, described below, to identify statistical outliers that warrant additional analysis. Any instance where a threshold is exceeded and the price or payment does not reflect the underlying supply and demand conditions is considered an anomalous market outcome.

Anomalous event thresholds are defined for: energy prices, Congestion Management Settlement Credit (CMSC) payments, Operating Reserve (OR) payments and Intertie Offer Guarantee (IOG) payments. The energy price thresholds are Hourly Ontario Energy Prices (HOEP) greater than $200/MWh, or less than or equal to $0/MWh.[12] The CMSC threshold is

[9] See the Ontario Energy Board (OEB) Bylaw #2, Article 4: "The Panel shall monitor, evaluate and analyse activities related to the IESO-Administered Markets and the conduct of market participants with a view to: (a) identifying inappropriate or anomalous market conduct by a market participant, including unilateral or interdependent behaviour […]", available at: https://www.oeb.ca/sites/default/files/OEB-bylaw-2-20201002.pdf

[10] The $200/MWh HOEP threshold has remained in place since market open. For more information, see the Panel's Monitoring Report 1 published October 2002, page 70: "For purposes of this report, we have arbitrarily selected $200/MWh to define our "high-price" cases. The $200 threshold is more than three times the average HOEP for the four-month period. It also exceeds what is generally known to be the incremental costs of the highest cost fossil generating units in the province.", available at: https://www.oeb.ca/documents/msp/panel_mspreport_imoadministered_071002.pdf

[11] The $200/MWh HOEP threshold represented the "upper 1%" of the HOEP from May 2002-October 2003, as stated in the Panel's Monitoring Report 3 published December 2003, page 56: https://www.oeb.ca/documents/msp/panel_mspreport_imoadministered_171203.pdf

[12] 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 retail Regulated Price Plan (RPP), except for those who have entered into a retail contract. A new MCP is set every five minutes.

any payment that exceeds $1 million/day or $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 or $500,000/hour. These payments are recovered from Ontario consumers and exporters through uplift charges.

2.1 Threshold Analysis

To provide context to the market price thresholds, Figure 2-1 and Table 2-1 present recent price trends for the median, top 5%, top 0.5%, and maximum HOEP from Summer 2018 through Summer 2020. During the Summer 2020 Period, there were four hours where the HOEP exceeded $200/MWh while there were none during the Summer 2019 Period and six hours during the Summer 2018 Period. The number of hours when the HOEP was less than or equal to $0/MWh decreased to 15% of hours (662 hours) in the Summer 2020 monitoring Period from 29% of all hours during the Summer 2019 Period (1,281 hours), a decline of approximately 50%. In general, this decline can be explained by higher loads brought on by higher temperatures in Summer 2020 as compared to Summer 2019.

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

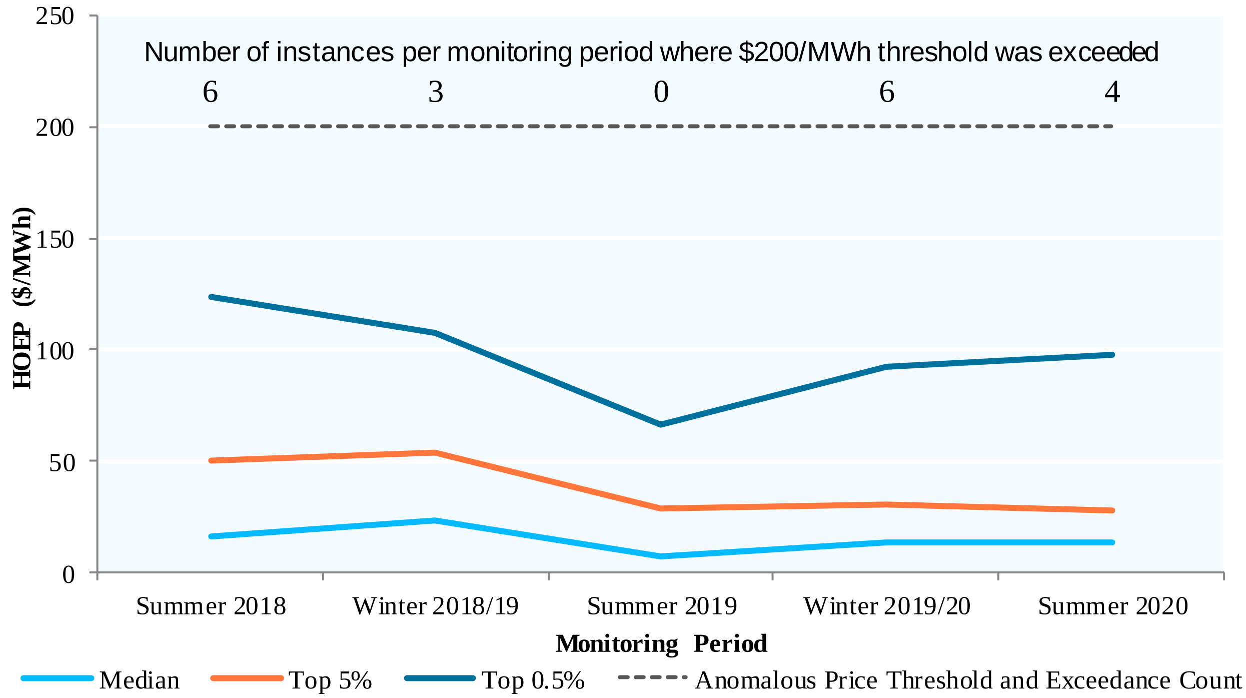


Figure 2-1 above displays the median, top 5% (95 percentile) and top 0.5% (99.5 percentile) of the HOEP for the last 5 periods (Summer 2018 to Summer 2020). Additionally, at the top of the figure the numbers of hours above the $200/MWh threshold are shown.

Table 2-1: Summary of HOEP Percentiles Summer 2018 to Summer 2020, 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)
Summer 2018	$16	$21	$51	$124	$296	687	6	4,416
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**

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

Table 2-2 presents a comparison of CMSC, OR and IOG average payments and the number of hours thresholds were exceeded during Summer 2020 (May 1, 2020 to October 31, 2020). This is presented alongside the corresponding 6-month Summer 2019 monitoring period from the year prior (May 1, 2019 to October 31, 2019).[13]

Table 2-2: Summary of Threshold Exceedances for the Summer 2019 Period and 2020 Period

Payments Threshold	Summer 2019 (May to Oct 2019)		**Summer 2020 (May to Oct 2020)**	
	Average Payment	Threshold Exceedances	**Average Payment**	**Threshold Exceedances**
Daily Energy CMSC	~$267,000/day	6 instances >$1 million/day	**~$246,000/day**	**4 instances >$1 million/day**
Hourly Energy CMSC	~$11,100/hour	0 instances >$500,000/hour	**~$10,200/hour**	**0 instances >$500,000/hour**
Hourly OR	~$9,800/hour	3 instances >$100,000/hour	**$4,700/hour**	**6 instances >$100,000/hour**
Daily IOG	~$32,100/day	0 instances >$1 million/day	**~$75,000/day**	**1 instance >$1 million/day**
Hourly IOG	~$1,300/hour	0 instances >$500,000/hour	**~$3,100/hour**	**0 instances >$500,000/hour**

The table above shows the average prices and number of hours CMSC, OR and IOG were exceeded during the Summer 2020 and the Summer 2019 (Summer is defined as May 1 to October 31) periods. This considers CMSC net payment after any applicable claw backs.

The total CMSC paid in Summer 2020 was $45 million. The average CMSC payment was approximately $246,000/day, a decrease from Summer 2019. The Summer 2019 CMSC payment was $49 million (an average of approximately $267,000/day).[14] The number of days when CMSC was greater than $1 million/day decreased to four days in the Summer 2020 Period from six days in the Summer 2019 Period. There were no instances in the

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

[14] For comparison, total HOEP in the Summer 2020 period was $955 million which is approximately $5 million/day.

Summer 2020 Period where CMSC exceeded the $500,000/hour threshold, which was also the case in the Summer 2019 Period.

The total OR payment in Summer 2020 was $21 million (average of approximately $4,700/hour). This amounted to less than half the OR payment for Summer 2019 of $43 million (average of approximately $9,800/hour). There were six instances where OR payments surpassed the $100,000/hour threshold in the Summer 2020 Period, an increase of 50% as compared to the Summer 2019 Period.

The total IOG payment in Summer 2020 was $14 million (average of approximately $75,000/day), an increase from Summer 2019 of $6 million (average of approximately $32,100/day). There was one instance in the current monitoring period where the IOG payment surpassed the $1 million/day monitoring threshold. This threshold was not exceeded in the Summer 2019 Period.

Table 2-3 below presents the dates and, where applicable, time when the threshold exceedances occurred during the Summer 2020 Period. Table 2-4 provides a summary of the main causes for the HOEP and OR thresholds being exceeded.

Table 2-3: Date and Time of Threshold Exceedances for the Summer 2020 Period

High HOEP	High OR	Daily CMSC	Hourly CMSC	Daily IOG	Hourly IOG
	May 10 | HE 20		No Events		No Events
	May 14 | HE 17				
May 23 | HE 21	May 23 | HE 21				
Jun 7 | HE 18	Jun 7 | HE 18				
Jul 9 | HE 16		Jul 9			
	Jul 19 | HE 12				
		Jul 27			
		Aug 12			
Aug 15 | HE 16	Aug 15 | HE 16				
		Aug 24			
				Sept 28	

The table above shows the date and, where applicable, time (Hour Ending, HE) when thresholds were exceeded during the period from May 2020 to Oct 2020. 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.

2.1.1 Energy Prices and OR Payments Above Threshold

Factors contributing to high HOEP also contribute to upward pressure on OR prices, which leads to higher OR payments.[15] The Panel has determined that two events are considered anomalous and therefore warrant detailed analysis, as noted in the July 9, 2020 and August 15, 2020 descriptions in Table 2-4 below. This analysis is further discussed in Section 2.2.

Table 2-4: Causes of High HOEP and OR Payments for the Summer 2020 Period

Event Date	Event Hour Ending	HOEP ($/MWh)	OR ($/hour)	Main Causes
May 10	20	$117	**$102,609**	- Over forecasted variable generation. - OR shortfall.
May 14	17	$167	**$129,701**	- Over forecasted variable generation. - OR shortfall.
May 23	21	**$320**	**$237,152**	- Over forecasted variable generation. - Under forecasted demand. - OR shortfall throughout hour. - Unavailable hydroelectric generators.
Jun 7	18	**$381**	**$404,264**	- Over forecasted variable generation. - Under forecasted demand. - OR shortfall.
Jul 9	16	**$203**	$59,628	- Supply shortfall due to nuclear unit removed from service. - Discussed in detail in Section 2.2.
Jul 19	12	$139	**$112,035**	- Over forecasted variable generation
Aug 15	16	**$207**	**$158,533**	-Under forecasted demand. - OR shortfall. - Unavailable hydroelectric generators. - Gas generator derate and outage. - Discussed in detail in Section 2.2.

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. In instances when these figures are included in this table that have not exceeded their relevant threshold, it is done so to give context to the figures that did exceed the threshold in the same hour.

[15] 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 market 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 in order to find the schedule that meets the required demand while minimizing the cost.

2.1.2 CMSC Payments Above Threshold

CMSC payments are out-of-market uplift payments, which in principle are made to compensate generators or loads when they are instructed to diverge from their economically optimal level of generation or consumption.[16] In principle, CMSC is paid when the IESO's dispatch instructions to these resources differ from the dispatch instructions that they would have received had system constraints not been present. The following is a review of the CMSC payments associated with the threshold exceedances that were identified in Table 2-2. All four instances of the CMSC threshold being exceeded involved the IESO constraining on the same generator – highlighted here as anomalous events since this is a consistent out-of-market action taken by the IESO that does not reflect the underlying supply and demand conditions.

On July 9, 2020, a large nuclear unit was shut down due to an IESO error.[17] This loss of supply, combined with the highest Ontario demand of 2020, contributed to several market impacts including the only instance in the monitoring period when both HOEP and CMSC exceeded their daily thresholds simultaneously. The HOEP reached $203/MWh in hour ending (HE) 16 and CMSC payments totaled $1 million on this day. A majority of the CMSC payments – approximately $0.6 million – were paid to the same generator. This generator was

[16] Although generators and dispatchable loads make up proportionally higher payments towards CMSC, 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.

[17] The IESO self-reported this incident as described in this update, dated October 8, 2020, available at: https://www.ieso.ca/Sector-Participants/IESO-News/2020/10/Assessment-of-Operational-Incident-on-July-9-2020

constrained on to minimize risk of units not being available on the following day.[18] This event is examined in detail in Section 2.2.

On July 27, 2020, the IESO's forecasting tool was unable to narrow the forecast for when a storm would reach Ontario. The humidex was expected to exceed 40°C on this day. This was the third day of high heat and humidity. The storm was forecasted to bring up to 30-50 mm of rain in Southwestern Ontario and up to 100 km/h winds with hail in the Northeast. In HE 2, the IESO noted that wind generation was forecasted to ramp down by 1,000 MW in Southwestern and Eastern Ontario due to the moving storm front. In this instance, the IESO did not enable its flexibility solution and instead constrained on multiple generators in HE 2. On this day, $1.1 million of CMSC was paid. The vast majority – $0.8 million – was paid to the same generator that was constrained on on July 9, 2020.

On August 12, 2020, $1.2 million of CMSC was paid, of which $0.9 million was paid to the same generator that was constrained on on July 27, 2020 and July 9, 2020. On this day, the heat and humidity were expected to cause a humidex in excess of 35°C. It was the third consecutive day of high temperatures. Peak demand was forecasted to be 800 MW higher than the previous day. Additionally, wind had ramped down and was scheduled to be 1,000 MW less over peak than it was on the previous day. Furthermore, Ontario was scheduling 2,000 MW of imports.

On August 24, 2020, demand was expected to be greater than 23,500 MW with severe thunderstorms forecasted throughout southern Ontario. Additionally, a nuclear unit was de-rated by 100 MW due to an equipment problem. As a result, multiple generators were constrained on for reliability which caused the CMSC daily threshold to be exceeded on

[18] As detailed in the July 9, 2020 IESO control room operator log. Upon investigation, the IESO also noted that the generator was constrained on to 1) ensure reserve requirements could be met, as 400 MW of voltage reduction Control Action Operating Reserve had been scheduled; 2) help manage Area Control Error, which was negative at the time; and 3) to provide more spare energy on the system, as very little was available prior to constraining the unit on.

August 24, 2020. Total CMSC was $1.3 million with the vast majority – $0.9 million – paid to the same generator that was constrained on on July 9, 2020, July 27, 2020 and August 12, 2020.

The Panel has previously expressed concerns about frequent out-of-market actions relating to system needs that the IESO refers to as "system flexibility".[19] During July and August 2020, the IESO constrained on the same generating station on seven days – citing either "flexibility" or "spare energy" – while the IESO's flexibility solution was not used in any of the above-noted instances.[20] This is an example of the lack of clarity regarding the application of the IESO's "flexibility" solution and the continued use of out-of-market actions.[21] The Panel has previously recommended that the IESO give further consideration to improving how the need for additional system flexibility is addressed, and expects the IESO to work towards reducing the number of instances when out-of-market actions are taken to address a flexibility need.[22] The IESO has indicated that a review will be conducted one year after the implementation of the Market Renewal Program.[23] The Panel will continue to monitor such consistent out-of-market

[19] In 2016, the IESO identified a need for greater flexibility to address increased forecast uncertainty in wind and solar resources that had been handled through the use of out-of-market actions only. The IESO's solution is to procure a predetermined amount (200 MW) of additional Operational Reserve (OR) with the intention of scheduling a generator(s) to come online that otherwise would not be committed. This can enable additional generation to start that would otherwise not have started as a result of the normal dispatch schedule. The solution has not been used consistently. For more information, see the Panel's Monitoring Report 32 published July 2020: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

[20] Spare energy is a measure of available online capacity over and above dispatch and OR that is spinning but not producing energy. It is potentially available to address an unexpected supply gap. Spare energy is forecasted based on the pre-dispatch constrained gas resource schedules.

[21] As noted by the IESO, scheduling Flex OR would not have provided spare energy through additional unit commitments on these days as all available non-quickstart resources had schedules while unscheduled non-quick start resources were either 1) grid incapable, 2) out of service; 3) did not have offers; or 4) offered at/close to the Maximum Market Clearing Price

[22] This recommendation was made in the Panel's Monitoring Report 32 published July 2020: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

[23] Per the IESO Annual OEB Status Update Report (Period January 2016 – December 2020): https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-assessment/Annual-OEB-Status-Update-Report.ashx

actions with the intention of recommending market-based solutions that would more efficiently address reliability.

2.1.3 IOG Payments Above Threshold

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. The following is a review of the IOG payment that exceeded the threshold, as identified in Table 2-2 above.

On September 28, 2020, an equipment issue on the Beauharnois intertie led to the IESO de-rating the capacity of the intertie from 390 MW to 310 MW. The capacity was further de-rated to 230 MW due to Hydro-Québec[24] reporting that the earlier Ontario restriction created a restriction in Québec which required a configuration change. The restrictions on the Beauharnois intertie led to import congestion in HE 16 to HE 19. The Beauharnois Intertie Zonal Prices (IZPs) in these hours dropped to extreme negative values of -$2,000/MWh. This is the price payable by importers for every megawatt-hour of imported energy. On this day the

[24] For convenience, this report refers simply to Hydro-Québec. HQ Energy Marketing Inc., a wholly-owned subsidiary of Hydro-Québec, is the registered market participant (intertie trader) in the IESO-Administered Markets.

IESO paid out significant DA-IOG payments to Hydro-Québec, the overwhelming majority of which was paid for HE 16 to HE 19.[25]

The Panel has noted a consistent pattern of increased imports scheduled day-ahead and high IOG payments to Hydro-Québec since 2017, when the IESO's seven-year electricity trade agreement with Hydro-Québec took effect. The Panel has reported on this issue in its previous monitoring reports, including in greater detail in Monitoring Report 31 published December 2019.[26] The Panel will consider a more thorough examination of high IOG payments and their causes in future monitoring reports.

2.2 Detailed Review of Anomalous Outcomes

This section provides additional details about two anomalous events that the Panel believes warrant further discussion.

2.2.1 Details of Events on July 9 and 10, 2020

The highest Ontario demand of the year occurred on July 9, 2020. As well, there were several major generator outages, one occurring as a result of operator error, all leading to tight supply conditions and the high HOEP as noted in Section 2.1. The IESO also took control actions to manage the supply/demand balance, including the first ever emergency operating state activation of Hourly Demand Response (HDR).[27]

[25] This issue was most recently discussed in the Panel's Monitoring Report 34 published February 2021: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202101.pdf; and the Panel's Monitoring Report 33 published December 2020: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf

[26] Monitoring Report 31 published December 2019: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

[27] The first emergency activation of HDR was discussed in the Panel's Monitoring Report 34 published February 2021, pages 5-6: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202101.pdf

Background

Hourly demand on July 9 was as much as 3,300 MW greater than on a typical business day that July. Ontario demand for July 9 and 10, 2020 is shown in Figure 2-2.

Figure 2-2: Ontario Demand for July 9 and 10, 2020

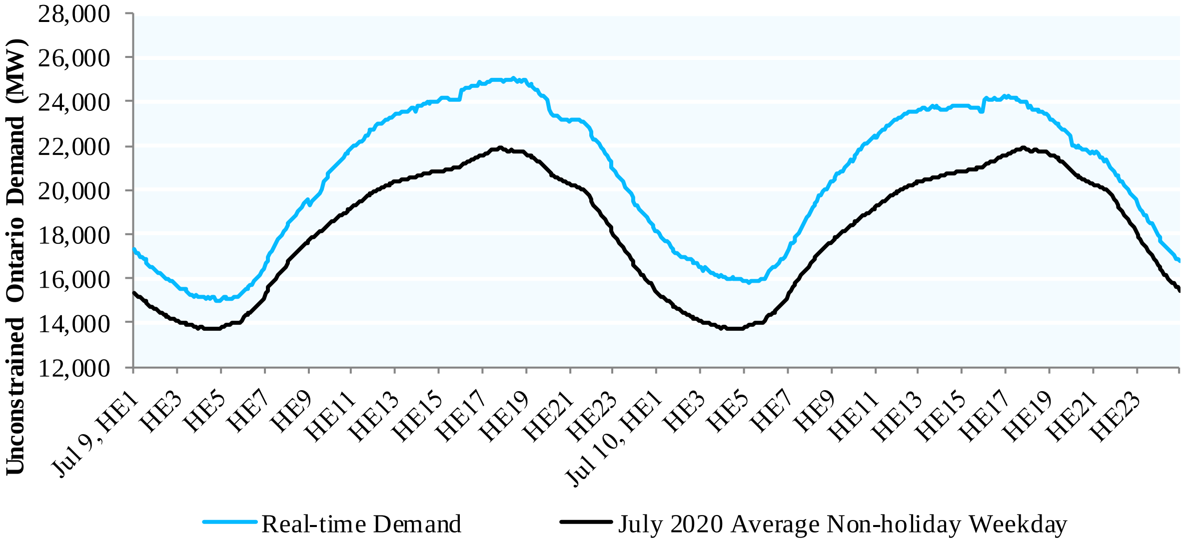


Figure 2-2 details the Ontario demand in the unconstrained sequence for July 9 and 10, 2020.

In addition, more capacity than usual (mainly gas and nuclear generators) experienced outages and de-rates. In Hour Ending (HE) 9 on July 9, a unit at the Bruce Nuclear Generating Station (approximately 800 MW) was forced out of service as a result of an error by the IESO when they incorrectly selected an option in an area transmission system remedial action scheme. The shutdown activated a reactor safety system requiring that unit to remain out of service for 55 hours. Approximately two hours after the initial shutdown, the IESO issued an Energy Emergency Alert 1 (EEA-1), which, according to their procedures, indicates that all available generating resources were, or were expected to be, in use.[28] As load diminished,

[28] For more information, see Market Manual 7.1: IESO Controlled Grid Operating Procedures, Appendix B: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/system-operations/so-SystemsOperations.ashx

system conditions improved overnight. However, with the Bruce unit still out of service on July 10, the IESO issued another EEA-1 in HE 11. Generator outages for July 9, 2020 and 10, 2020 are shown in Figure 2-3.

Figure 2-3: Generator Outages for July 9 and 10, 2020

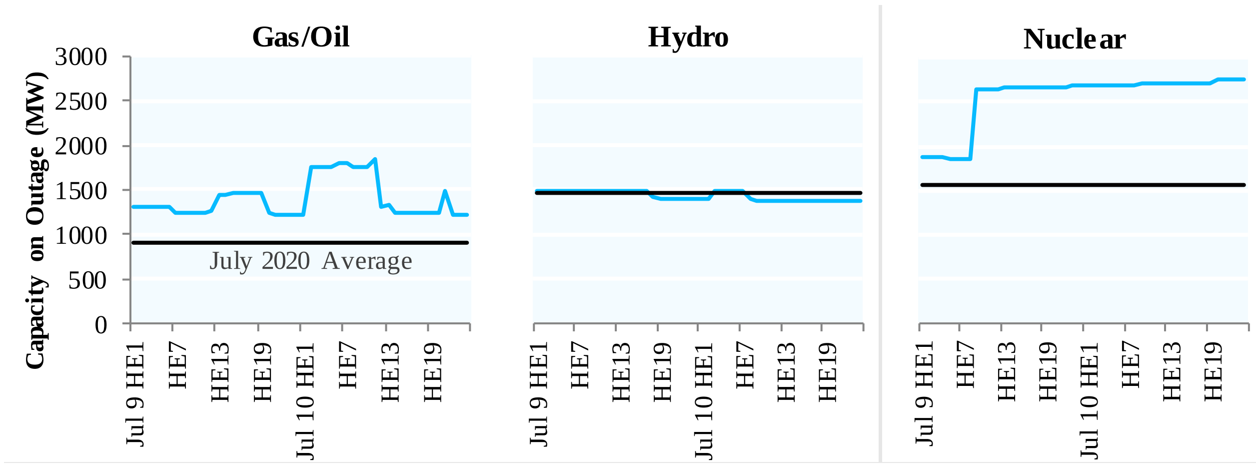


Figure 2-3 details the generator outages by fuel type for gas/oil, hydro and nuclear resources on July 9 and 10, 2020.

Bruce Generator Outage

The IESO proactively reported the Bruce incident and its market impact on its website.[29] According to the IESO's analysis, "market payments to suppliers increased by an estimated $17 million" and "there was no increase to system costs as a whole". The IESO also stated that the change in the HOEP caused an estimated $2 million increase in costs for Class A customers and $2 million decrease in costs for Class B customers.

In discussions with the Panel, the IESO indicated that their market impact assessment was based on a simulation of how the outage had affected the HOEP, which is an outcome of the unconstrained sequence of the Dispatch Scheduling and Optimization (DSO). While this

[29] See the IESO's Market Impact Assessment of the Bruce incident, dated October 8, 2020: https://www.ieso.ca/Sector-Participants/IESO-News/2020/10/Assessment-of-Operational-Incident-on-July-9-2020

approach is reasonable for estimating the market impact, it does not support the statement that system costs did not increase. The Panel has identified two shortcomings with the IESO's methodology.

First, the analysis depends on a simplified assumption that, for contracted and rate-regulated generators, "the resources dispatched up to manage the outage would have received the same amount of payments whether through market revenues or via Global Adjustment (GA), given their inverse relationship".[30] This assumption is not always valid. Total payments to contracted generators can vary depending on how those generators are dispatched. If more gas resources were dispatched on to replace the energy that would have been delivered by the Bruce unit had the IESO error not triggered it off, there would be higher total costs for gas generation. The IESO has not demonstrated that any increase in gas contract payments would be offset by reductions in other parts of the GA.

The IESO's analysis also does not include any assessment of out-of-market control actions. The HDR activations on July 9 and 10 led to net activation payments of approximately $5 million, which would likely not have been necessary if Bruce G1 had been in service. The capacity of the Bruce unit that was forced out of service is nearly twice the size of the HDR delivered during the supply shortage but the IESO argues that "it is not possible to determine with certainty whether the activation of HDR on these days can be directly attributed to the outage" and has confirmed that "no analysis was done on the costs of other out-of-market actions".

In summary, an IESO error led to an outage of one of the largest units in the province – a reduction of nearly 800 MW – that lasted more than two days. The IESO publicly reported the incident, noting the market impact but claiming that there was no increase in total system costs as a whole. The Panel believes there was not sufficient analysis to reach this conclusion. In

[30] Quotations are from an explanation provided to the Panel by the IESO.

fact, the assumptions used by the IESO in their assessment excluded any factor that would have impacted total system costs.

Given the complexity of the electricity market and generator contracts, it can be challenging to calculate the cost impact of specific events. However, greater transparency in how these calculations are made would enhance their credibility. Market and system cost impacts should generally be explained with a reasonable level of detail accepting that estimates will have a range of uncertainty.

Emergency Operating State Control Actions

The IESO has broad discretion to take control actions when needed to maintain reliability. Certain actions, like constraining generation on or off or scheduling additional operating reserve for flexibility, can affect market outcomes and system costs. The Panel supports using market mechanisms whenever possible to reduce the need for control actions. When control actions are necessary, the rationale should be clear and the action should be reasonably predictable to Market Participants and should not go beyond the specific reliability need.

One of the IESO's market manuals sets out a list of control actions to be used when the system is facing a risk of supply deficiency.[31] The manual lists the actions in the order they would likely be used, from relatively minor actions for lower-risk situations to voltage reductions and rolling blackouts in extreme cases. Emergency operating state HDR activations fall in the middle of the list. Although the ordering is not a guarantee, it does signal to Market Participants that periods of supply scarcity may occur. Resources which bid or offer at high prices, like HDR, might be particularly interested in understanding how prices will be affected by emergency operating state control actions.

[31] For more information, see Market Manual 7.1: IESO Controlled Grid Operating Procedures, Appendix B: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/system-operations/so-SystemsOperations.ashx

The manual shows HDR activations among ten control actions that "can be used only if the 30-minute operating reserve shortfall is forecasted to last beyond four hours".[32] In an emergency operating state, the IESO may take several actions before calling on HDR resources including allowing 30-minute operating reserve to fall short of requirements for up to four hours. There was no operating reserve shortfall identified in the forecast on either July 9, 2020 or July 10, 2020 when the decisions to activate HDR were made. The IESO chose to activate HDR instead of the other, less costly options available because HDR requires approximately two and a half hours of advance notice before the dispatch hour.

HDR Activations and Performance

HDR resources were acquired on the basis that they would be available and used to maintain the reliability of the electricity system. The HDR resources that are acquired in the Demand Response (DR) auction and its replacement, the Capacity Auction, have an obligation to bid their resources into the energy market at full capacity, but it is recognized that in real-time, operational variations may occur. The IESO is expected to monitor those bids and as reliability needs arise, may call on HDR resources to be activated to maintain reliability. The Panel has observed behaviours of concern in both the IESO's management of that resource and the performance of the resources themselves.

On July 9, a miscommunication within the IESO resulted in only a portion (~450 MW) of the available HDR resources being activated for four hours starting in Hour Ending (HE) 16. Once the error was caught and corrected the remaining HDR resources (~150 MW) were activated for four hours starting in HE 18. The two four-hour activations spanned HE 16 to HE 21. Assuming the IESO needed and intended to activate all 600 MW starting in HE 16, the actual activation fell short for two hours. Under different circumstances, the staggered activation could have led to shortfalls in HE 16 and 17. While the IESO was able to quickly address the

[32] The manual also makes clear that "the IESO may initiate control actions at any point in the table depending on the specific circumstances and conditions of the IESO or external control area. In addition, the IESO may alter the order in which the control actions are implemented to respond to reliability concerns."

issue to prevent reoccurrence, it is concerning that HDR resources that were acquired and paid for by the customers to provide reliability were mishandled this way.

The performance of HDR resources on July 9 and 10, 2020 is further examined in Section 3.1.4.

2.2.2 Details of the August 15, 2020 Price Spike

On August 15, 2020, supply outages and demand forecast error in HE 16 required resources to ramp up in real-time; however, generation units that should have been available for dispatch were initially claimed to be unavailable. Certain units had submitted offers for intervals in this hour, and became economical for dispatch due to high prices.[33] When contacted by the IESO in HE 16, the generator stated that they did not think they were able to run the units that were offered. The IESO asked the generator to submit a derate for the units due to their unavailability. Subsequently, the generator dispatched the units after discussion with their local management.

Background

On August 15, 2020, the Hourly Ontario Energy Price (HOEP) spiked to $207/MWh and Operating Reserve (OR) spiked at $176/MWh during HE 16. The price spike occurred primarily between interval 7 and interval 12 in HE 16. OR payments reached $158,533 during this hour, which surpassed the Panel's threshold of $100,000/hour.

In HE 14, a nuclear unit was removed from service, resulting in a large loss of supply. Shared Activation of Reserve (SAR) was activated for four intervals until HE 16. Due to the "high prices" after the large loss of supply, the IESO manually constrained on two gas units, which were still loading to their Minimum Loading Point (MLP) in interval 5 of HE 16. Another

[33] As noted in the IESO control room log on August 15, 2020.

355 MW of capacity was lost due to forced outages and derates of gas units starting in interval 7 of HE 16. Moreover, demand was running 150 MW higher than forecast during this hour.

Figure 2-4: HOEP and OR for August 15, 2020

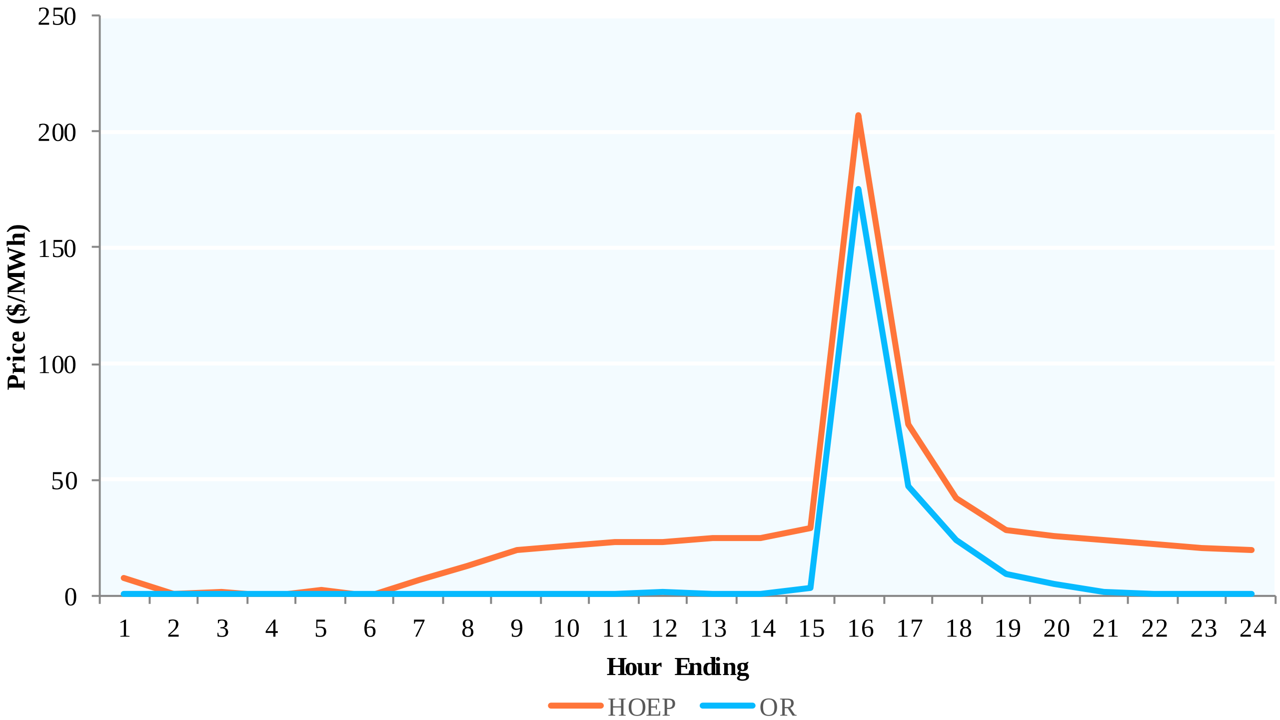


Figure 2-4 above shows the hourly price of the HOEP and OR on August 15, 2020. It details the spike in price in HE 16.

Market Participant Obligations

A generator had submitted offers for their units in HE 16, however they claimed that they were unable to run the units when they became economical for dispatch. The generator eventually did dispatch the units. The generator was reminded by the IESO that Market Participants are obligated to provide energy into the system in amounts consistent with their offer. All Market Participants have an obligation under the Market Rules to submit offers and bids that are consistent with their units' actual capabilities at the time.

Market Participants that submit offers and bids that are inconsistent with their capabilities at the time are in violation of Market Rules. When this energy is not delivered, the time available to take corrective action is reduced and reliability could be compromised. These offers and bids displace other resources higher in the price stack that are capable of meeting their dispatch instructions. This behaviour can result in negative impacts on reliability and inefficiencies in the market. The Panel will continue to monitor instances where Market Participants may be submitting offers and bids that are inconsistent with their actual capabilities, to promote compliance with the Market Rules.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

In this chapter, the Panel summarizes market design deficiencies or concerns related to Market Participant conduct or activities of the IESO that affect the efficient operation of the IESO-Administered Markets. To improve market efficiency, the Panel makes eight recommendations relating variously to Demand Response (DR) performance, the IESO's Real-Time Generation Cost Guarantee (GCG) program and carbon pricing, and non-competitive procurements.

3.1 Demand Response Performance

3.1.1 Introduction

DR is an electricity resource that works by reducing specific loads when dispatch instructions are issued, usually during periods of high prices or tight supply. DR is viewed as a cost-effective alternative to new generation for meeting reliability needs. In Ontario's market, DR can be provided by dispatchable loads or Hourly Demand Response (HDR) resources. To date, approximately 75% of DR participation is from HDR resources, with the remainder from dispatchable loads. Dispatchable loads participate in the energy market in a similar manner to dispatchable generators, according to a price-based dispatch schedule every five minutes. HDR is dispatched on an hourly basis with at least two hours of advance notice. Dispatchable loads are most often industrial facilities connected to the transmission system, while HDR can be provided by large facilities or aggregators of small distribution-connected loads. DR resources compete in annual auctions for capacity obligations, which are commitments to offer (or, for demand-side resources, bid) an amount of capacity into the energy market during a specified period. The capacity obligation is intended to recognize the value of capacity and provide certainty that capacity resources including DR will contribute to reliability when needed.

Resources with a capacity obligation earn payments for offering/bidding as required, and risk penalties (i.e. charges) for failing to provide the capacity when needed. The penalties introduced in the DR auction – and inherited by the Capacity Auction – provide an inadequate disincentive against failing to deliver on capacity obligations. Insufficient penalties may have led to the poor performance when the IESO activated HDR resources on July 9 and 10, 2020.

The following Section 3.1.2 discusses how the IESO's handling of HDR has changed over time, and Section 3.1.3 outlines the rules for HDR's participation in the energy market. Section 3.1.4 covers the performance of HDR when it has been activated, and Section 3.1.5 discusses why the penalties are inadequate. Finally, Section 3.1.6 includes the Panel's recommendations in the context of recent developments relating to the IESO's Capacity Auction.

3.1.2 Background

DR and Capacity Auctions

The IESO has acquired DR through an annual auction mechanism since 2015. The DR Auction was originally intended as a competitive mechanism for procuring resources to meet a government-mandated DR target that would substantially reduce peak demand.[34] Ultimately the auction did not deliver any peak demand reductions and the IESO then shifted the focus to meeting much more limited future capacity needs with DR.

The DR auction was intended as a first step towards an integrated capacity auction for DR and generating resources. Development of this integrated auction, which began in 2017, was hindered by a series of false starts and concerted opposition from stakeholders. The history of the Capacity Auction is discussed in the Panel's Monitoring Report 33.[35]

[34] See the IESO's presentation "Developing a Market Renewal Workplan", dated April 19, 2016, slides 7-8: https://web.archive.org/web/20200927210059/http://www.ieso.ca/-/media/files/ieso/document-library/engage/me/me-20160419-developing-a-workplan.pdf?la=en

[35] See the Panel's Monitoring Report 33, published December 2020, Section 3.1.2: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf

The IESO's first Capacity Auction, in December 2020, was largely an expansion of the DR auction to include participation by certain other resources. It inherited many key design elements from the DR Auction, including the testing procedures and penalties discussed in Section 3.1.3.

The cost to ratepayers of the first five DR auctions in 2015 through 2019 was approximately $180 million.[36] The DR Auctions never demonstrated their value, mainly because of fundamental flaws in the dispatch process discussed below, but in part because they were conducted during a period of capacity surplus.[37] This system capacity surplus is now shrinking due to forecast demand growth and nuclear generation outages required for refurbishments. According to the 2020 Annual Planning Outlook (APO), capacity needs may emerge in 2022.[38]

Evolution of HDR Dispatch

The Panel's Monitoring Report 28, released May 2017, assessed the DR Auction in detail.[39] This assessment concluded that, given the design of the program rules, there was virtually no chance that HDR resources would ever be economically activated. At the time, the program rules required shadow prices to exceed the HDR resource's bid price for four consecutive

[36] Total of all DR Auction payments and penalties for DR Auction Charge Type numbers 1314 through 1320.

[37] Based on the annual Long-Term Reliability Assessments for 2015 to 2019 (published by the North American Electric Reliability Corporation), the only DR auction that may have been necessary to meet a resource need was in 2015, for the Summer 2016 season. Long-Term Reliability Assessments are available at: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

[38] See the IESO's Annual Planning Outlook report published December 2020, Section 3.2: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Dec2020.ashx

[39] See the Panel's Monitoring Report 28 published May 2017, Section 3.2: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf

hours, three hours ahead of the activation hour.[40] Nearly all HDR resources routinely bid at the highest allowable value – $1,999/MWh.

HDR resources were never activated under those program rules because Ontario's energy market never had the required high and sustained shadow prices. High pre-dispatch shadow prices can signal to the IESO that there is not much additional capacity available and that it may become difficult to maintain the supply/demand balance if there are unforeseen events. To mitigate this risk, the IESO will typically begin to take out-of-market actions pre-emptively before pre-dispatch prices are allowed to reach $2,000/MWh.

The Panel's Monitoring Report 28, published May 2017, also outlined the Panel's concerns regarding the need, suitability and cost-effectiveness of DR procurements for Ontario's system at the time. The resulting recommendation was:[41]

> *"The IESO should reassess the value provided by the capacity procured through its Demand Response auction in light of Ontario's surplus capacity conditions, as well as the stated preference of the government and the IESO (through its Market Renewal initiative) for technology-neutral procurement at least cost."*

All of the Panel's previous concerns remain valid in 2021.

Since the publication of the Panel's Monitoring Report 28 in May 2017, the IESO has modified the rules for HDR, but not in a way that has led to any material change in the outcome.

[40] Shadow prices are produced by the constrained mode of the IESO's dispatch algorithm and are used to determine the dispatch instructions sent to resources. They are not used to settle resource payments. Unlike unconstrained prices, shadow prices take into account transmission congestion and may vary by location within the province. In some cases, shadow prices exceed the maximum market clearing price of $2,000/MWh.

[41] See the Panel's Monitoring Report 28 published May 2017, Recommendation 4-2, page 106: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf

In the 2018 DR Auction, the IESO made minor changes to the economic activation mechanism intended to increase the likelihood that HDR would be activated. Program rules were amended such that the pre-dispatch shadow prices would trigger an activation if they exceeded an HDR resource's bid for only a single hour, instead of four consecutive hours.[42] As of June 2021, there have been two economic HDR activations under these revised rules. Both occurred only because shadow prices at the relevant HDR resources' locations were high due to unusual local factors. With the economic HDR activation process seldom leading to HDR utilization, the IESO constructed a separate mechanism for HDR activations. In 2018, HDR was added to the Emergency Operating State Control Action (EOSCA) list, allowing the IESO to activate HDR resources "out-of-market" for reliability.[43]

HDR resources activated using the new EOSCA mechanism receive separate out-of-market payments for activation. EOSCA activation payments are based on HDR resources' bids in the energy market so they incentivize HDR resources to continue bidding at the highest possible price. The decision to activate HDR resources under EOSCA is unrelated to the Capacity Auction rules and is an out-of-market action largely based on the IESO's judgement. The IESO used this emergency activation mechanism for the first time on July 9 and 10, 2020 (See Section 2.2.1).

[42] See the associated Market Rule Amendment Proposal "MR-00433-R00: Notification and Activation of Hourly Demand Response", approved by the IESO Board August 29, 2018: https://www.ieso.ca/-/media/Files/IESO/Document-Library/mr-amendments/mr2018/MR-00433-R00-Notification-Activation-Hourly-Demand-Response-v5-0.ashx

[43] The Market Manual changes were effective May 1, 2018 and the IESO Board approved related clarifications to the Market Rules in August 2018. For more information, see Market Rule Amendment Proposal "MR-00433-R01: Hourly Demand Response to the EOSCA List" approved by the IESO Board August 29, 2018: https://www.ieso.ca/-/media/Files/IESO/Document-Library/mr-amendments/mr2018/MR-00433-R01-Hourly-Demand-Response-EOSCA-v5-0.ashx

The emergency activation mechanism changed expectations about how HDR would be used. High energy market prices would no longer be required for an activation. By July 2019, the IESO had taken the position that HDR was intended only as an emergency resource for very rare events. In 2020, the IESO's stated objective for HDR evolved to "[providing] capacity to maintain reliability during times of localized or global system stress".[44]

The IESO's introduction of emergency activations was a tacit admission that the original design of the HDR program would seldom, if ever, dispatch HDR when it was needed for reliability.

Looking forward, the IESO has undertaken to modify the procurement of HDR resources in the Capacity Auction to improve its usefulness as an emergency resource. There may be opportunities for HDR resources to provide value in the operating reserve market, beyond their current role as an emergency capacity resource.[45] However, high HDR bid prices ensure that economic activations will remain highly unlikely without further rule changes. The Panel has also identified deficiencies in the design of non-performance penalties that may affect the performance of HDR both as an emergency capacity resource and as a provider of operating reserve.

[44] See the DR Working Group Presentation, dated December 3, 2020: https://www.ieso.ca/-/media/Files/IESO/Document-Library/working-group/demand-response/drwg-20201203-presentation.ashx

[45] For example, see the Expanding Participation in Operating Reserve (OR) and Energy engagement, dated August 12, 2020: https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Expanding-Participation-in-Operating-Reserve-and-Energy

3.1.3 HDR Characteristics

All resources which clear the Capacity Auction, including HDR, receive payments for their capacity and may be subject to certain charges based on their behaviour.[46] The two HDR payments and five HDR charges are detailed in the sections below. Details are also provided on how HDR resources are activated and tested, and how their performance is measured.

HDR Payments

Two payments are available for HDR resources with a capacity obligation.

- **Availability Payment:** Availability payments are earned for each hour in the availability window (i.e. a predefined set of hours each business day) during the obligation period.[47] Total availability payments for the period are calculated as the Capacity Auction clearing price ($/MW-day) multiplied by the resource's committed capacity and the business days in the period. Table 3-1 shows the total potential availability payments from the 2019 DR Auction, assuming all cleared capacity maintained its obligation.
- **Out-of-Market Activation Payment:** HDR resources can receive out-of-market activation payments for test activations and activations leading up to or during an emergency operating state. The price for test activations is a fixed amount currently set

[46] The payments and charges discussed in this section are listed as Charge Type Number 1314 through 1320 in the IESO Charge Types and Equations document, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/imo-charge-types-and-equations.ashx

[47] There are two seasonal obligations periods for a DR auction or Capacity Auction with different availability windows. The Summer obligation period is from May 1 to October 31 and the Winter obligation period is from November 1 to April 30. The Summer availability window is from HE 13 to HE 21 and the Winter availability window is from HE 17 to HE 21.

at $250/MWh. The price for emergency activations is effectively a bid price guarantee.[48] For a four-hour activation, an HDR resource bidding at $1,999/MWh benefits nearly $8,000/MW through the combination of avoided energy purchases and the out-of-market activation payment. Prior to the December 2020 auction, the out-of-market payment applied to all energy curtailed, even if the curtailment by the HDR resource unilaterally exceeded the amount that was activated by the IESO. A market manual amendment has since capped the out-of-market payment such that it does not apply to over-delivery.[49]

Table 3-1: Example of Potential Availability Payments from the 2019 DR Auction

Quantity	Summer 2020	Winter 2020/21
Total Capacity Cleared (MW)	779.8	798
Weighted Average Clearing Price ($/MW-day)	257.96	212.87
Total Daily Availability Payment ($ millions/day)	0.20	0.17
Business Days	126	123
Total Availability Payment ($ millions)	25.3	20.9

Table 3-1 demonstrates how availability payments would be calculated for the 2019 DR Auction, assuming no changes in the amount of capacity with an obligation. Note that the actual availability payments differ from this example calculation due to buy-outs and other factors.

[48] The payment is based on the difference between an HDR resource's bid price and the Hourly Ontario Energy Prices (HOEP). For example, if a resource has bid at $1,999/MWh and HOEP is $100/MWh, the out-of-market activation payments will provide $1,899/MWh. For a load which is exposed to the HOEP, the total benefit in $/MWh of reducing load is the sum of avoided market payments for energy (charged at HOEP) and the out-of-market activation payment.

[49] For more information on HDR payments, see Market Manual 5.5, Section 1.6.26.2, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/se-rtestatements.ashx

For more information on the market manual amendment, see the DR Working Group Presentation, dated October 8, 2020: https://www.ieso.ca/-/media/Files/IESO/Document-Library/working-group/demand-response/drwg-20201008-presentation.ashx

HDR Charges

There are five charges specific to the Capacity Auction that may potentially be assessed against HDR resources. Four charges are considered non-performance charges: the availability charge, the dispatch charge, the capacity charge, and the administration charge. One other charge is for reducing or eliminating a capacity obligation through a “buy-out”.

- **Availability Charge:** Capacity resources are liable for an availability charge for each hour in the obligation period when they fail to bid their capacity obligation in the IESO’s real-time energy market. The charge is calculated as the product of the bid shortfall in megawatts, the hourly auction clearing price, and a non-performance factor ranging between one and two depending on the month.[50]
- **Dispatch Charge:** The dispatch charge is applied when an HDR resource is dispatched and does not perform within a 15% deadband for any form of activation.[51] In other words, a dispatch charge will apply if a resource delivers (or lowers load by) less than 85% of the amount that is activated for any of the five-minute intervals during an hour of activation. The dispatch charge is calculated similarly to the availability charge, except the scheduled (i.e. activated) HDR quantity is used instead of the bid shortfall.

[50] The monthly capacity non-performance factors are used in the formulas for the availability charge, the dispatch charge, and the buy-out charge. The factors are higher in the months which typically have higher peak demands. See Market Manual 12, Section 6.1, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/capacity-auction/Capacity-Auction.ashx

[51] HDR is subject to a 15% deadband regardless of resource size. There is also a separate dispatch compliance deadband for other resources which can range from 2% to 100% depending on size. It is used to determine whether a dispatchable facility is considered compliant with dispatch instructions but it is not associated with an automatic penalty. For more information on the dispatch compliance deadband, see the Market Rule Interpretation Bulletin "IMO_MKRI_0001: Compliance with Dispatch Instructions Issued to Dispatchable Facilities", published June 29, 2009: https://www.ieso.ca/-/media/Files/IESO/Document-Library/mr-interpret-bulletin/ib_IMO_MKRI_0001.ashx

Residential HDR resources are exempt from the dispatch charge, although no residential HDR is currently registered in the IESO-administered markets.

- **Capacity Charge:** The capacity charge is assessed when a resource fails to deliver at least 80% of its capacity obligation. The charge was applied to all activations for the December 2019 Auction (including the Summer 2020 obligation period) but has now been limited to test activations since the December 2020 Auction. The capacity charge is equal to the total availability payments for one month. However, it is capped at one charge per month.
- **Administration Charge:** The administration charge is applied for late data submissions following an activation or for failed data audits. It is equal to the total availability payments for one month.[52]
- **Buy-Out Charge:** Participants can apply to buy-out their capacity at any time, paying the buy-out charge to reduce or eliminate their capacity obligation.

The availability charge can encourage a resource to offer/bid consistently with its capacity obligation as the Market Rules require, but the charge does not consider the resource's performance when activated. Section 3.1.5 discusses the insufficiency of capacity charges and dispatch charges to encourage compliance with obligations. As shown in Table 3-2, if a summer resource ignores a four-hour activation during a peak month where the non-performance factor is at its highest, the total dispatch charge will be only 0.7% of that resource's total availability payments for the season. This is an insignificant consequence for total failure to perform the core function of a DR resource. Although the capacity charge is larger than the dispatch charge, it now applies only to test activations.

[52] When the administration charge is applied, there is no data recorded for a resource's performance. Other non-performance charges may be applied in addition to the administration charge as a result.

Table 3-2: Example of Capacity and Dispatch Charge Calculation

Line	Quantity	Amount	Formula
A	Summer 2020 Business Days	125	
B	Availability Hours per Day	9	
C	Auction Clearing Price ($/MW-day)	250	
D	Hourly Auction Clearing Price ($/MWh)	27.78	C / B
E	July 2020 Business Days	21	
F	July Non-Performance Factor	2	
G	Activation Duration (hours)	4	
H	Availability Payment for Summer 2020 ($/MW)	31,250	A * C
I	Capacity Charge, per failure ($/MW)	5,250	E * C
J	Dispatch Charge, per failure ($/MW)	222	D * F * G
K	**Capacity Charge, as a % of Availability Payment**	**16.8%**	**I / H**
L	**Dispatch Charge, as a % of Availability Payment**	**0.7%**	**J / H**

Table 3-2 summarizes how the capacity and dispatch charges are calculated for an HDR resource with a hypothetical $250/MW-day auction clearing price in the Summer 2020 obligation period.

Activation and Testing

HDR resources can be activated only if they first receive a standby notice for the day. A standby notice is automatically sent if any pre-dispatch shadow prices in the HDR resource's availability window exceed $100/MWh before the 06:07 pre-dispatch run.[53] HDR resources can also be manually placed on standby in preparation for a test activation or emergency operating state. For all forms of activation, an activation notice is sent approximately two and a half hours

[53] See Market Manual 9.3 Section 4.11.2: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/day-ahead-commitment/OperationDACP.pdf

before the operating hour (real-time hour in which they are expected to provide load reduction). For test activations, HDR resources are also notified the day before the test.[54]

In principle, testing allows an HDR resource to demonstrate that its offered capability to reduce load is actually backed by such load reduction capability when requested/activated in real-time. Testing is particularly important for HDR resources, as compared to conventional generation resources. An HDR resource is unlikely to be dispatched economically and can expect to be activated for reliability only when the system approaches an emergency operating state.[55] Emergency activations are rare; in the six obligation periods since this form of activation was introduced, they have been used only in one: Summer 2020. Consequently, HDR tests could be the only occasion in a given Capacity Auction obligation period when HDR resources are activated.

Participants can be tested up to two times in each 6-month obligation period for four hours. If the resource performs well on the first test, the second test can be waived and/or the test duration reduced to one hour.

Performance Measurement

There are two kinds of HDR. Physical HDR is revenue metered by the IESO and virtual HDR is not, typically because the associated load is connected to the distribution system. Residential HDR would be considered virtual, while commercial and industrial (C&I) HDR may be physical or virtual.

[54] For more information on HDR testing procedures, see Market Manual 12 Section 5.3.3, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/capacity-auction/Capacity-Auction.ashx

[55] See the Panel's Monitoring Report 28 published May 2017, Section 3.2: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf

HDR performance is measured relative to a “baseline”, which is an estimate of what demand would have been if the activation had not occurred. For C&I HDR, baselines are calculated using demand in the business days prior to the activation and an “in-day adjustment”. For residential HDR, the baseline is from a subset of residences that are not activated (i.e. the “control” group).[56]

The lack of telemetry for virtual HDR creates some challenges. The IESO relies on real-time data from generators and loads to operate the system, but does not have real-time data on virtual HDR. Data for virtual HDR evaluation is provided by the resources themselves several weeks after activations occur.

3.1.4 Historical HDR Performance

July 2020 Emergency Activations

As discussed in Section 2.2.1, the Panel is concerned by the performance of Hourly HDR resources during the first two emergency activations on July 9 and 10, 2020. In aggregate, HDR resources were able to reduce their real-time load by 82% of the total HDR load reduction called for during this period. However, the performance across individual resources was highly variable (see Figure 3-1).

All resources are expected to follow their dispatch instructions. Performance is judged using a 15% deadband, meaning that a resource is considered to have fulfilled its obligation if it reduces load by at least 85% and at most 115% of its total activated load reduction. Of all the HDR capacity activated, more than half (55%) failed to provide even 85% of their activated load reduction. A smaller number of resources (14%) over-delivered, some by as much as

[56] For more on the baseline methodology, including the in-day adjustment for C&I HDR, see Market Manual 5.5 Section 1.6.26.3.1. The IESO has also launched a review of the HDR baseline methodology in the Resource Adequacy Engagement, dated April 22, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210422-presentation.ashx

200%. HDR over-delivery is not beneficial in electricity markets, as it represents an unanticipated drop in demand and can cause operational problems.

This performance makes clear – in the only non-test activation of HDR for the purpose for which they were acquired (initially as capacity and later for emergencies) – that there are serious questions regarding the value and effectiveness of HDR in contributing to reliability.

Figure 3-1: Distribution of HDR Performance (Energy Delivered/Activated) for July 9 and 10, 2020

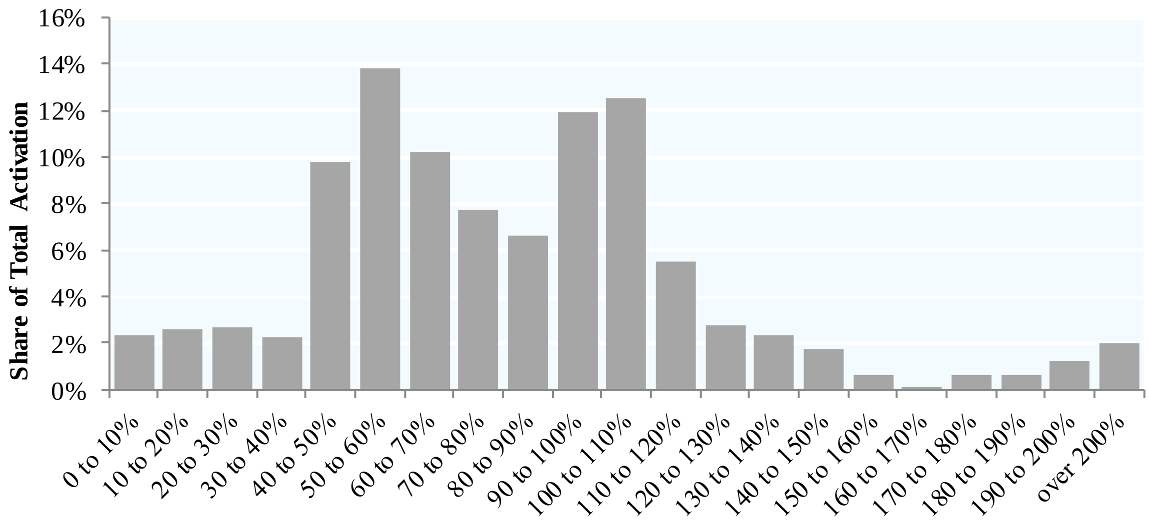


Figure 3-1 shows the distribution of performance for all HDR resources activated on July 9 and 10, 2020. The bins represent energy delivered compared to energy activated, with bins below 100% indicating under-delivery and bins above 100% indicating over-delivery. The height of each bar is share of the 4,500 MWh of HDR activated on July 9 and 10 that resulted in that level of performance.

The absolute capacity provided by HDR remained in the range of 450 to 470 MW for both days (see Figure 3-2).

Figure 3-2: HDR Performance for July 9 and 10, 2020

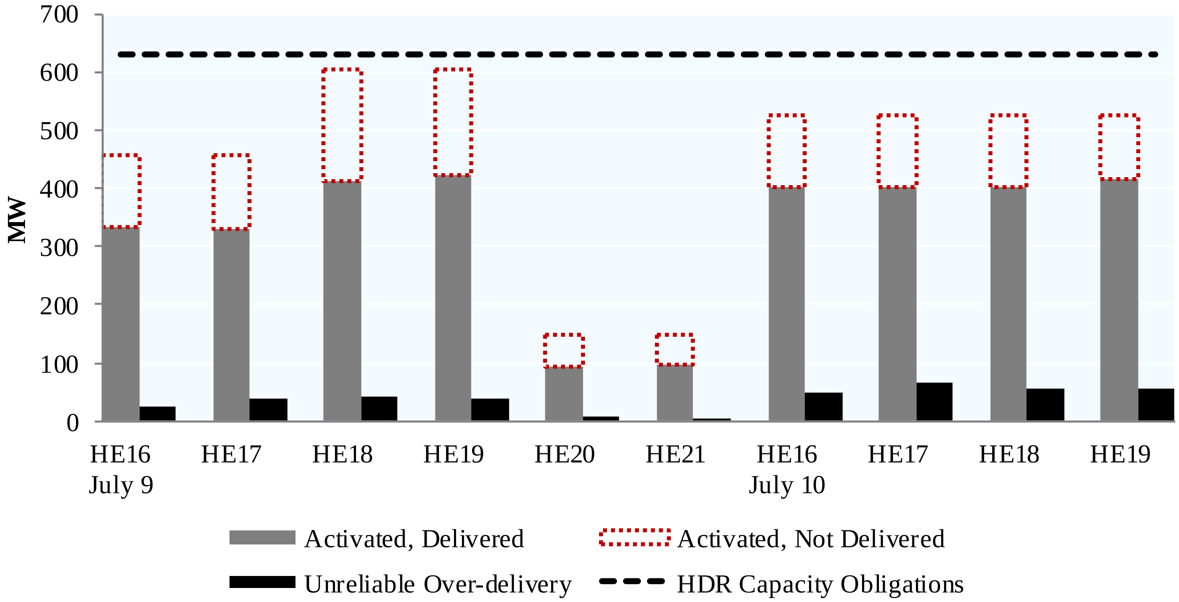


Figure 3-2 charts HDR performance (MW) for the hours it was activated on July 9 and 10, 2020. Of the HDR capacity activated, some was not delivered. Separately, some of the delivered HDR capacity was provided in excess of a resource's activated amount. HDR Capacity Obligations is the total amount of capacity that held an obligation at the time of the activations. HDR resources are obliged to bid, in real-time, into the energy market consistently with the conditions that they submitted and were accepted in the Capacity Auction. They then must follow IESO dispatch if that capacity is activated.

There were complications with bid behaviour shortly after activation notices were sent on July 9, 2020. Once these notices were issued, some participants attempted to change their bids during the mandatory window.[57] On July 10, 2020, more participants reduced their bids before receiving an activation notice so the total activation was only 525.8 MW. Later in the day, with more bid reductions and forced HDR outages reported, the expected amount of demand reduction from HDR (i.e. activated amount net of post-activation changes) had fallen to 487.5 MW.

[57] HDR resources and dispatchable loads cannot submit outages to the IESO's systems. Instead, these resources report outages and derates by modifying their bid quantities.

The bid reductions on July 10 shown in Figure 3-3 and Figure 3-4 created the appearance of improved performance because a smaller amount of HDR was activated. HDR resources received availability charges (i.e. penalties) for failing to bid their capacity obligation into the market.

Figure 3-3: Average Final Bids for Resources Receiving Activation Payments

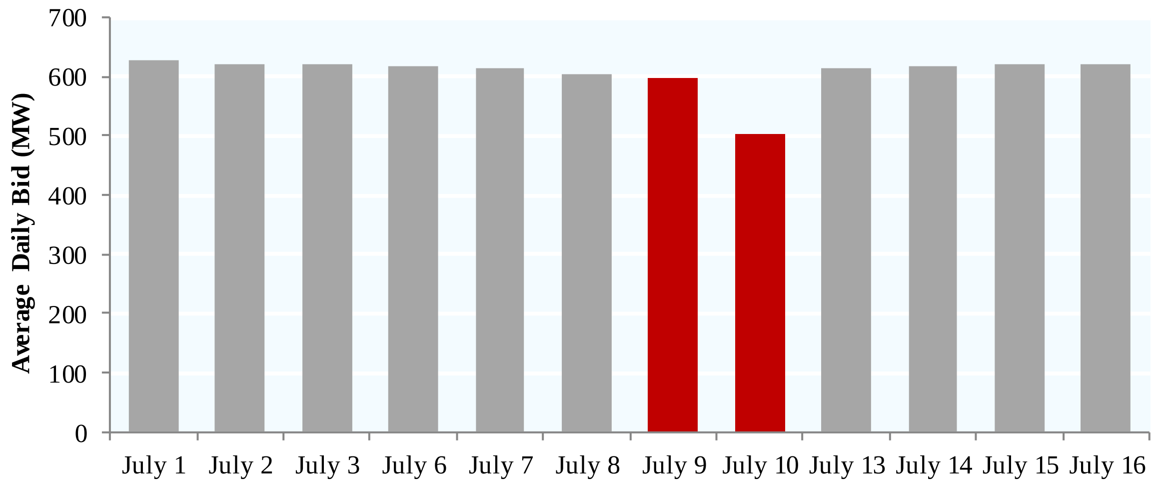


Figure 3-3 shows the average daily bids for the HDR resources which received activation payments on July 9 or July 10.

The December 2019 Capacity Auction cleared approximately 740 MW of HDR for the Summer 2020 commitment period. From April to June 2020, several HDR resources submitted notices of Force Majeure due to the pandemic or bought out their capacity obligations. The remaining HDR that was engaged in July 2020 was approximately 630 MW.[58] HDR bids were expected to be of that magnitude, except for various operational constraints. Figure 3-3 illustrates that for the days before and after July 9 and 10, HDR bids averaged about 620 MW. However, their bids dropped by about 20 MW on July 9, 2020 and 110 MW on July 10, 2020. These bid reductions appear to have been made to avoid activation or to signal unplanned

[58] Force Majeure notices are listed here: https://www.ieso.ca/en/sector-participants/market-operations/markets-and-related-programs/demand-response-auction

outages. While HDR is subject to an availability charge for failing to bid an amount equal to their capacity obligation, a resource that was expected to be available through best efforts, at a certain level, seems to have become unavailable shortly after it was notified that it would be needed.

Figure 3-4: Timeline of HDR Bids and Activation Notices, July 8 to 10, 2020

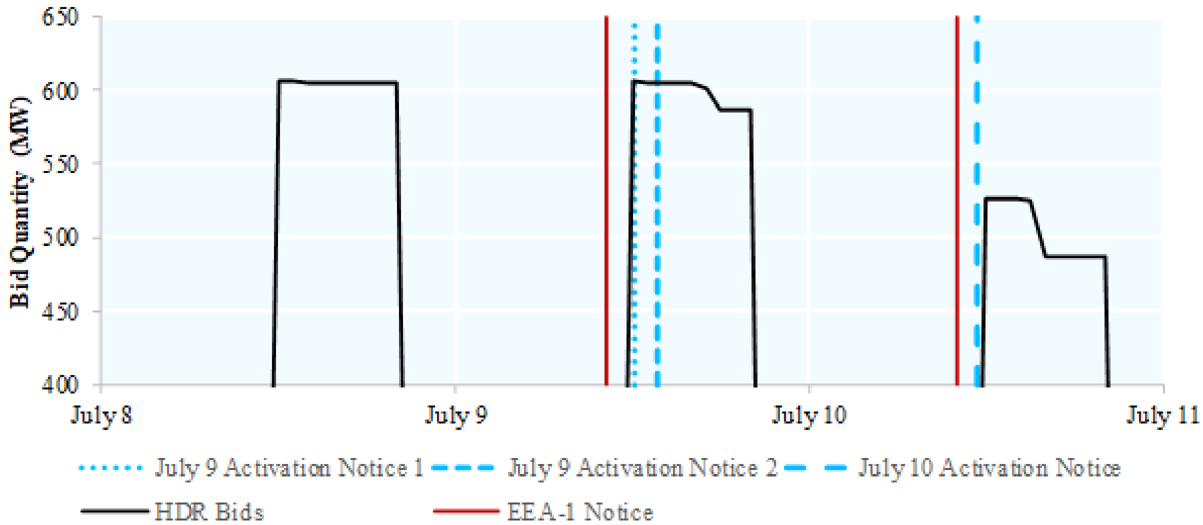


Figure 3-4 shows the timing of Energy Emergency Alert 1 (EEA-1) notices and HDR activation notices on July 9 and 10, 2020 and the hourly bids for the HDR resources which received activation payments.

In addition, delays in data submission and collection were so long that they delayed the analysis in this report. Although meter data was due on August 24, 2020, the July 2020 activation data was not fully complete until late December 2020.

Test Activations

The poor HDR performance observed on July 9 and 10, 2020 was consistent with historical test results, which have been disappointing since the DR auction started procuring HDR resources (see Table 3-3). Many HDR resources consistently incur dispatch charges, indicating that they did not maintain a load reduction within 15% of their dispatch instruction for the duration of their activations. Total activated load reduction compared to scheduled real-time load reduction (Total Energy vs Scheduled Energy row in Table 3-3) can appear satisfactory, but that is misleading. On July 10, 2020, some HDR resources did not bid their full capacity obligation, which reduced the amount of energy curtailment they would be activated to deliver. For all activations, aggregate HDR performance masks the unpredictable mix of over- and under-delivery by individual resources. As discussed in the next section, real-time compensation for emergency activations provides a substantial incentive to over-deliver.

Table 3-3: HDR Performance for 2018/2019 Summer Tests and July 2020 Emergency Activations[59]

Metric	Test Activations, Summers 2016-2018	Test Activations, Summer 2019	Emergency Activation, July 9, 2020	Emergency Activation, July 10, 2020
Assessed Dispatch Charge	60%	39%	70%	55%
Assessed Capacity Charge	43%	23%	61%	
Total Energy vs Schedule	81%	91%	77%	93%

Table 3-3 shows the share of HDR resources which received the dispatch charge and capacity charge, as well as the aggregate amount of energy delivered compared to the amount that was scheduled to be delivered. Results are presented for historical test activations and the first two emergency activations.

Despite the poor test results, the IESO did not make any substantial change to participants' incentives and penalties. A Q3 2019 "review of DR operational processes" recommended "conducting follow up with DR participants to determine root-cause of failed tests".[60] The

[59] The figures for the capacity charge on July 9, 2020 and July 10, 2020 were presented at the DR Working Group meeting dated October 2020, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/working-group/demand-response/drwg-20201008-presentation.ashx

Note that the capacity charge is capped at one charge per month. Other figures for July 2020 were provided to the Panel separately by the IESO. Aggregate historical test results were presented at the DR Working Group meeting dated February 2020, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/working-group/demand-response/drwg-20200225-presentation.ashx

[60] For more information, see the DR Working Group meeting, dated February 2020: https://www.ieso.ca/-/media/Files/IESO/Document-Library/working-group/demand-response/drwg-20200225-presentation.ashx

review led to changes in oversight and documentation, but it is not apparent that these changes led to improvements in performance.

Although the IESO has not yet addressed poor DR performance through penalties or changes to the Capacity Auction, IESO planning documents now appear to recognize and model performance problems related to DR resources. The Annual Planning Outlook (APO) released in December 2020 had greatly reduced DR capacity (and consequently HDR resource capacity) contributions: 56% in the summer and 66% in the winter.[61] The methodology document states that "monthly demand-response capacity is equal to the capacity obligation from the most recent auction, de-rated by historical performance during testing".[62] This is a welcome step toward reducing the gap between HDR promise and its performance.

The IESO has only recently begun to consider DR performance in the Capacity Auction with a proposed Qualified Capacity process (see Section 3.1.6). This appears to be a first step toward ensuring that actual performance will meet expectations when the HDR resources are activated. However, it does not appear that the IESO plans to act on any of these changes until 2022 at the earliest and, as stated above, it is very unlikely any economic activations will actually occur pursuant to the auction until the relevant dispatch rules are reformed.

3.1.5 Insufficient Penalties

The Panel believes that the relatively poor performance for the first emergency activations in Summer 2020 can be explained in part by the limited consequences for failure. Two automatic non-performance penalties apply to all resources participating in a DR (now Capacity) Auction: the dispatch charge, which applies to all activations, and the capacity charge, which applies

[61] See the IESO's APO "Supply, Adequacy and Energy Module Data", dated December 2020: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Supply-Adequacy-Energy-Outlook-Module-Data.ashx

[62] See the IESO's APO "Resource Adequacy and Energy Assessment Methodology", dated December 2020: https://ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Resource-Adequacy-Energy-Assessment-Methodology.ashx

only to test activations. However, these penalties appear to be too small compared to a resource's availability payments to deter under-delivery by HDR resources when activated.

The current non-performance penalties do not provide a meaningful incentive for participants to improve their performance.

1. **Financial Incentive to Overstate Capacity:** HDR resources can earn more from the auction by overstating their capability (thereby increasing their availability payments) and paying the resulting performance penalties, if necessary. Table 3-4 demonstrates the incentive to inflate true HDR capability. It shows that, even with the maximum of two test activations, a hypothetical resource is better off inflating its true capability and receiving additional availability payments (Case 2) than by truthfully representing its capability in the Capacity Auction (Case 1).

Table 3-4: Increased Net Payments for Overstated Capacity Compared to Actual Capacity

Quantity	Case 1 (actual capacity)	Case 2 (overstated capacity)
True Capability (MW)	1	1
Claimed Capability (MW)	1	2
Test Performance	100%	50%
Capacity Charge ($)	0	21,000
Dispatch Charge ($)	0	889
Availability Payments ($)	31,250	62,500
Net Payments ($)	31,250	40,611

Assumptions for Table 3-4 are: Summer obligation period, $250/MW-day auction clearing price, two capacity tests with four-hour duration, tests occurring in months with 21 business days and a non-performance factor of 2.0, and no non-test activations.

2. **Virtually No Penalty for Ignoring Dispatch:** The only automatic consequence of failing a non-test activation is the dispatch charge. Table 3-2 shows that the dispatch charge for a four-hour activation is at most 0.7% of the season's total availability payments. For residential HDR resources, which are exempt from the dispatch charge, there appear to be no consequences at all for failing a non-test activation.

Table 3-5 shows the total payments and penalties to all DR auction resources for the Summer 2020 obligation period, excluding the administration charge and the buy-out charge. It shows the relatively small cost of penalties compared to the total availability payments. Table 3-5 also highlights the magnitude of the activation payments made in July 2020. The activation payments were almost 75% greater than the July availability payment.

Table 3-5: Summer 2020 Availability Payments, Activation Payments and Selected Charges

Month	Availability Payment ($millions)	Activation Payment ($millions)	Availability Charge ($millions)	Dispatch Charge ($millions)	Capacity Charge ($millions)
May	3.8	-	-0.3	-	-
June	4.0	-	-0.3	-	-
July	4.1	7.1	-0.4	-0.1	-1.8
August	3.8	-	-0.6	-	-
September	4.0	-	-0.2	-	-
October	4.0	-	-0.2	-	-

Table 3-5 provides the total amount paid or charged to DR Auction participants for the Summer 2020 obligation period for charge code types 1314, 1315, 1317, 1318, and 1320.

DR resources received net payments of $26.2 million for the Summer 2020 obligation period. The resources received $30.9 million in availability and activation payments while only being subject to $4.7 million in penalties. Despite HDR resource's poor performance, only $2 million of penalties (the dispatch charge and capacity charge) was related to performance during activations.

Since the Summer 2020 period, HDR payments and penalties have been adjusted. The capacity charge no longer applies to economic or emergency operating state activations, further reducing the penalty for failing to follow dispatch instructions in situations where HDR is needed for reliability.

There was, however, an improvement in out-of-market activation payment following the high payments in July 2020. At the time, the payment applied to all energy curtailed by the HDR resource. This could encourage over-delivery, leading to high activation costs for the IESO and difficulty controlling supply and demand balance. Starting with the December 2020 Capacity Auction, the out-of-market activation payment will no longer compensate over-delivery.

3.1.6 Capacity Auction Considerations

Many HDR resources fall short of their capacity obligations and a smaller number have substantially over-delivered (see Figure 3-1). The low dependability of HDR reduces the overall efficiency of the new Capacity Auction, particularly as HDR resources are now able to compete with reliable generators and imports for the same capacity obligations.

In the ongoing Resource Adequacy engagement, the IESO has begun to develop a Qualified Capacity process to conduct the auction on an Unforced Capacity (UCAP) basis. The process aims to equalize the contribution of different resources and resource types and to "ensure alignment between planning assessment and the auction in terms of UCAP calculations".[63] Several enhancements were also proposed to improve the performance of Capacity Auction resources. These include "(eliminating) payments for over-delivery of capacity", "(updating) charges to incent better performance", and "(introducing) stronger future consequences for continued poor performance".

[63] See the IESO's stakeholder engagement presentation, dated March 22, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210322-presentation.ashx

The Panel supports these proposals and the transition to UCAP. The IESO's previous efforts at Capacity Auction design have been marked by slow progress, reversed decisions, and setbacks. The resource performance enhancements currently contemplated, including the Qualified Capacity process, are long overdue. Unfortunately, it appears that the 2021 Capacity Auction will continue to overvalue HDR to the detriment of ratepayers and competing resources. The Panel urges the IESO to address Qualified Capacity without delay. However, unless the dispatch rules are reformed, these changes will not create any value for HDR other than as an emergency resource.

Implementing the changes that are proposed will require carefully balancing different priorities. The IESO has proposed a methodology to calculate UCAP for HDR based on performance in the previous year.[64] The incentive from this calculation methodology would supplement other mechanisms like penalties and compliance investigations which can be triggered after a non-performance event. Of the ex post options, structural solutions like penalties can more quickly and effectively apply to numerous diverse participants without requiring the IESO to perform resource-intensive investigations into non-performance.

Additionally, penalties should be large enough to incentivize good performance, but not so large that they discourage resources from participation. Well-targeted penalties will apply most heavily to poor-performers without affecting those resources which can reliably meet their obligations.

Recommendation 3-1

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

[64] See the IESO's stakeholder engagement presentation, dated July 22, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210722-presentation.ashx

capacity payments net of penalties reflect each resource's ability to deliver capacity when dispatched.

One of the central issues with the current payments and penalties for HDR and other Capacity Auction participants is the opportunity to increase net payments by intentionally overstating a resource's capacity (Table 3-4). From the perspective of a participant, expected earnings should be maximized when the participant offers their own best estimate of their resource's capability.

Recommendation 3-2:

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.

3.2 IESO's GCG Program and Carbon Pricing

In an effort to reduce greenhouse gas (GHG) emissions, both the federal and provincial governments have developed market-based incentives for the electricity sector. Carbon pricing – a market-based approach to greenhouse gas reductions – has now been in effect in Ontario for several years and has been assumed to be integrated into the offers made into the energy market. However, the IESO is weakening the carbon price signal in the electricity market by repaying a significant portion of the carbon price to gas-fired generators with out-of-market reimbursements under the Real-Time Generation Cost Guarantee (GCG) program. These carbon cost reimbursements from the IESO undermine the market-based incentives put in place by government. In July 2021, the federal government announced that it has updated the minimum national standards (federal benchmark) to ensure that provincial government measures "do not weaken the price signal, for example by giving instant rebates that are tied to the amount of carbon price paid or by explicitly reducing fuel taxes in order to offset the carbon price".[65,66] To improve the efficiency of the electricity market and the effectiveness of the carbon price, the IESO should cease reimbursements to gas generators of carbon cost payments.

3.2.1 Background – GCG Program

The GCG program has paid nearly $1 billion dollars to non-quick start gas generators since 2003 to maintain system reliability, yet 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

[65] See the federal government's news release "Government of Canada confirms ambitious new greenhouse gas emissions reduction target", dated July 12, 2021: https://www.canada.ca/en/environment-climate-change/news/2021/07/government-of-canada-confirms-ambitious-new-greenhouse-gas-emissions-reduction-target.html

[66] See the federal government's webpage "Additional information on the federal carbon pollution pricing benchmark": https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html

alternatives could achieve the reliability objectives at less cost.[67,68] The Panel's Monitoring Report 27, published November 2016, concluded that the GCG program was only required in 1% of committed hours to meet real-time domestic demand and operating reserve.[69] Since 2010, the Panel has made 13 recommendations relating to the GCG program in Monitoring Reports, including recommendations for reducing the cost of the program should its retention be justified, the majority of which remain unaddressed. Problems with the GCG program were also highlighted by the Office of the Auditor General in 2017.[70] No significant improvements have been made to the program since that report and, despite the potential for nearer-term benefits to ratepayers, the IESO remains unwilling to make changes prior to the now-delayed Market Renewal (anticipated November 2023).

The majority of gas-fired generators in Ontario are "non-quick start" generators that require several hours to ramp up to a level where they would be available to respond to dispatch. The GCG program guarantees recovery of incremental costs incurred during this startup period, such as fuel, and operating and maintenance costs, for non-quick start generators.[71] These non-quick start gas generators consume fuel while they warm up, emitting GHG emissions while not producing energy, and then emit at higher rates during the rest of the startup period

[67] The GCG program, also known as the Spare Generation On Line (SGOL) program was initiated in 2003. Approximately $0.9 billion has been paid out by the IESO under charge type 183 (Generation Cost Guarantee Recovery Debit), since 2004.

[68] 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.

[69] See the Panel's Monitoring Report 27 published November 2016: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf

[70] See the Auditor General's 2017 Annual Report Volume 1, Chapter 3: Reports on Value-for-Money Audits, Section 3.06 Independent Electricity System Operator – Market Oversight and Cybersecurity: https://www.auditor.on.ca/en/content/annualreports/arreports/en17/v1_306en17.pdf

[71] Although most resources participating in the GCG program are gas generators, the program is for non-quick start generators and includes a few resources that use fuels other than natural gas.

than during the operating period, leading to startup emission rates that can be more than 50% higher than operational emission rates.[72,73] By allowing full cost recovery of the emissions-intensive startup phase, the IESO's GCG program removes the incentive to invest in more fuel-efficient and emission-reducing technologies.[74] Therefore, the IESO's GCG program carbon cost reimbursement conflicts with the carbon pricing goal of discouraging less fuel-efficient generators.

3.2.2 Background – Federal and Provincial Carbon Pricing Policy in Ontario

In January 2017, the provincial government implemented carbon pricing in Ontario with a Cap and Trade system.[75] In 2018, following a provincial election and change in government, the Cap and Trade system was cancelled. In January 2019, without provincial carbon pricing in place, the federal government implemented its carbon pricing backstop system in Ontario which remains in place as of July 2021.

[72] The operating period refers to units operating at or above the Minimum Loading Point (MLP).

[73] The emission rate comparison between startup and operational periods is based on information provided by the IESO in the Real-time Generation Cost Guarantee Output Based Pricing System (OBPS) Carbon Cost Methodology Proposal dated October 28, 2020, slide 21. For more information, see: https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2020/rtgcg-20201028-presentation.ashx

[74] GCG-eligible resources are expected to compete based on their incremental energy cost as offered in the real-time market. Once they are determined to be economic based on their incremental energy costs, they can opt to have their pre-approved GCG costs recovered. This incents GCG-eligible resources to lower their incremental energy offers to be economic in the real-time market while recovering those costs via the pre-approved and guaranteed GCG costs.

[75] Generally, gas-fired generators in Ontario did not have a direct compliance obligation with Cap and Trade, the obligation was with gas utilities. For generators, Cap and Trade costs were experienced as an increase to the gas price on every unit of gas purchased from utilities. This approach differs from the current federal government's carbon pricing system and the upcoming provincial carbon pricing system.

For the federal government to “stand down” their carbon pricing backstop, the province must prove it will achieve at least the same GHG emissions reductions as the federal system.[76] Ontario has stated its intention to provide, in 2022, its own carbon pricing system for the electricity sector that is similar to the existing federal carbon pricing system.[77] The province initially proposed a weaker carbon pricing system for gas-fired generators in Ontario, however, this was recently updated to align with the federal government’s minimum standards for the electricity sector across Canada.[78] The federal government’s policies assume that the carbon pricing system in effect in Ontario, whether under a federal or provincial system, would contribute to achieving nation-wide GHG emission reduction targets.

While the carbon pricing system in effect is applied across the economy, large industrial facilities in certain sectors – like electricity – are charged on the basis of whether they exceed

[76] See the federal government’s “Notice of intent to amend the Output-Based Pricing System Regulations” which states “The Amending regulations and the Order would implement the measures set out below taken in response to the stated intention of the Government of Canada to stand down the Output-Based Pricing System (OBPS) in Ontario and New Brunswick […]” available at: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/notice-of-intent.html

[77] The federal and provincial governments will apply a similar approach to carbon pricing for industrial sectors, both applying the carbon price by facility based on their emission rate as compared to an industry leading “benchmark”. The federal program is called the OBPS and the provincial program will be called the Emission Performance Standards (EPS). The provincial Emission Performance Standards were announced in the “Made-in-Ontario Environment Plan” which intends to address climate change by making polluters accountable “by ensuring strong enforcement with real consequences and penalties, especially for repeat offenders”. For more information, see: https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf

[78] See the Environmental Registry of Ontario notice 019-3719, proposal from the Ministry of Environment, Conservation and Parks, “Amendments to support transition and implementation of Ontario’s Emissions Performance Standards program”, that states the EPS is to take effect in 2022, with the electricity sector benchmark aligned with the federal government’s OBPS at 370 t/GWh (Ontario had previously proposed a weaker benchmark of 420 t/GWh for the sector): https://ero.ontario.ca/notice/019-3719

a "benchmark" rate of GHG emissions per unit of output for each industry and fuel.[79] For example, a large facility that emitted GHG emissions at a rate 10% above the benchmark would pay the carbon price only on this excess 10% of its GHG emissions, not on all GHG emissions. This output-based benchmark method represents a reduction in the carbon cost that is intended to lessen the financial and competitive impact on firms while preserving the incentive to reduce emissions per unit of output. If a facility's emission rate is below the benchmark, that facility not only avoids the carbon price but receives emission credits that can be sold to other facilities.[80] Smaller facilities must pay the full carbon price on 100% of the fuel consumed.[81]

3.2.3 The IESO's GCG Carbon Cost Reimbursement Methodology

The IESO will reimburse a significant portion of the carbon price for gas-fired generators under its GCG program. The IESO reimbursement pays gas generators' carbon costs calculated during periods when the facility is producing GHG emissions by burning fuel during startup and little to no electricity is generated.[82] This reimbursement is substantial – the first two

[79] The electricity sector has three separate benchmarks based on solid, liquid and gaseous fuels. For more information, see the Environment and Climate Change Canada's web page on pollution pricing in Ontario: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/ontario.html

[80] The federal government refers to such credits as "surplus credits", to differentiate from offset credits. As only one type of credit is discussed in this report, surplus credits will be referred to as emission credits.

[81] Facilities that are able to take advantage of the carbon cost reduction through the OBPS have emitted more than 50,000 tonnes CO^2e historically. Those who have emitted more than 10,000 tonnes CO^2e can opt-in to the carbon cost reduction. For example, a "small" gas generator who has emitted 5,000 tonnes CO^2e would pay 100% of the carbon price for each tonne of GHG emissions. A "large", facility emitting 50,000 tonnes CO^2e would only pay a portion of the amount based on how much the benchmark emission rate was exceeded, resulting in an approximate 80% reduction in costs for the average large facility.

[82] Based on the methodology of the IESO's carbon cost reimbursement methodology that retroactively allocates carbon costs based on the heat rate of the generator, thereby providing the greatest costs (and reimbursement) during periods when the emission rate is highest, including when the unit is not yet generating. Alternative approaches to allocation of carbon costs do not lead to this outcome.

submissions from gas-fired generators seeking reimbursements from the IESO through out-of-market payments under the GCG program approached 50% of the total annual carbon cost charge from government based on 2019 operational data. The carbon price is expected to increase from $20/tonne in 2019 to $170/tonne by 2030.[83]

In October 2020, the IESO initially proposed a carbon cost reimbursement method for gas generators via the GCG program that would reimburse startup carbon costs, limited to the total carbon costs actually incurred for all operations during the year.[84] In response to stakeholder input, the IESO went further and lifted this payment limit so that it can now reimburse generators more than they were charged by the government.[85] As well, generators could receive two forms of compensation despite generating GHG emissions: emission credits from the government that can be sold to other emitters (if they emit at overall rates below the

[83] See the federal government climate plan titled, "A Healthy Environment and A Healthy Economy," available at: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/healthy-environment-healthy-economy.html

[84] The presentation is not easily accessible, as it is not included in the IESO's Real-Time Generation Cost Guarantee (RT-GCG) Cost Recovery Framework stakeholder engagement webpage, and is not searchable under the IESO's current or completed engagements. The presentation appeared during an October stakeholder presentation, along with other topics and is linked to below. Stakeholder feedback from APPrO and Atura was initially available on the webpage, but is currently not accessible as the submissions were de-linked by the IESO in trying to make their website more accessible (comments will be reposted). For more information, see: https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Overview/Public-Information-Sessions

[85] The IESO did not publicly provide a justification for the change in methodology. The IESO did provide an update to the Panel including the revised methodology and reasoning (Because the methodology was updated in a Market Manual, the Technical Panel was not updated on this change). The IESO initially stated that over-reimbursement was a concern: "Therefore, to avoid the risk of over-reimbursing a participant who is efficient enough to significantly reduce their carbon cost outside the startup period, consideration of their overall costs (which include costs resulting form their dispatchable operations) was deemed necessary." The IESO then changed the methodology based on feedback from APPrO and Atura.

benchmark) and the IESO's GCG carbon cost reimbursement. The IESO has not provided adequate justification for the change in its approach to remove the reimbursement limit.[86]

Information provided by the IESO in a stakeholder engagement showed two examples of generators – both with 12% of their total GHG emissions coming from the startup period – receiving "startup" carbon cost reimbursements from the IESO representing not 12% but 40% and 100% of their **total** carbon costs based on the initial proposal.[87] By applying the updated IESO reimbursement methodology to these two examples, the IESO would reimburse 40% of total carbon costs in the first example and 153% in the second example since the payment limit is removed (of 100% reimbursement) and reimbursements can now exceed the total carbon cost charge paid by the gas generator.

3.2.4 Impacts of the IESO's Carbon Cost Reimbursement

The IESO carbon cost reimbursement for startup generation under the GCG program undermines the carbon price for the electricity sector by insulating startup gas generation GHG emissions from exposure to the carbon price imposed by the government.

The IESO's approach of removing the startup carbon price signal from the electricity market with carbon cost reimbursements is also inconsistent with the IESO's long-term planning

[86] The IESO provided information to the Panel that states why the proposed methodology was updated with comments from stakeholders: "With respect to the treatment of compliance credits, APPrO has stated that to net the credits (full value or discounted value) from the reimbursement would remove all incentive to purchase the credits, which would offer no value to rate-payers and could interfere with the OBPS credit market." Although the IESO's Market Manual references an IESO "review of the verification report and proof of payment for the applicable compliance period", this statement does not imply that the IESO would not reimburse a generator if their "proof of payment" showed that no carbon costs were paid (and emissions credits were received instead) from operating below the benchmark during the compliance year.

[87] Two examples are provided by the IESO in the October 2020 presentation, receiving 40% and 100% of their total carbon costs. For more information, see the 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.ashx

document, the Annual Planning Outlook, that incorporates the carbon price to forecast gas generation and associated GHG emissions.[88,89] The IESO's forecast is considered the most accurate estimate of electricity sector GHG emissions in Ontario and is relied upon by stakeholders, including government. However, the IESO's Annual Planning Outlook forecasts do not yet reflect the significant carbon cost reimbursement for gas generators that removes a portion of the carbon cost from the market. This reimbursement blunts the impact of the carbon price and allows gas generators to lower their offers to be more competitive with other supply resources such as imports. The disconnect – between the IESO's flagship long-term planning document applying the carbon price to simulate the market and the IESO's real-time operations removing a portion of the carbon price from the market – will lead to inaccurate forecasts that underestimate gas generation and GHG emissions. The IESO should be transparent in its Annual Planning Outlook regarding what amount of the carbon price they plan to remove from the market with payments to gas generators and state the impact of the reimbursement on gas generation and GHG emissions.

If the IESO's reimbursements continue, potential improvements to carbon pricing by the federal or provincial governments could be frustrated. For example, if government sought to enact a gradually declining benchmark, similar to the federal regulation for new-build gas

[88] See the IESO's 2020 Annual Planning Outlook that describes how carbon pricing was integrated into the forecast, "As such, the carbon pricing applied with the OBPS acts as a pro-rated carbon price. As different gas-fired generation facilities have different emission rates, each facility will be charged an amount based on its GHG emissions and electricity production, leading to facility-specific carbon pricing. In order to more accurately forecast the impact of carbon prices on trade, the IESO has modelled the carbon pricing policies applied in neighbouring jurisdictions where there is a material impact on electricity sector emissions", available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Dec2020.ashx

[89] See the IESO's Resource Adequacy and Energy Assessment Methodology that outlines how carbon pricing is incorporated, "Fossil fuels are subject to a carbon price, consistent with the most recent applicable carbon price policies. For each facility, the heat rate is combined with a projection of fuel price and carbon price to determine the total fuel cost, in dollars per megawatt-hour, for each hour. The dispatch cost is the combination of total fuel cost, carbon price, and VO&M cost", available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Resource-Adequacy-Energy-Assessment-Methodology.ashx

generators, that change would be off-set by larger reimbursements from the IESO to gas generators.

The IESO's carbon cost reimbursement to gas generators is an obstacle for market-based approaches to reducing GHG emissions in the electricity sector. The IESO should embrace the market-based approach from both levels of government for addressing GHG emissions and allow the carbon price to be reflected in the electricity market, including startup.

The Panel believes that reimbursing generators for startup carbon cost charges is inefficient and significantly undermines the intent of carbon pricing. However, if the IESO feels compelled to provide carbon cost reimbursements to generators, there are alternative methods of calculation that would be less damaging to the GHG emission reduction goals of the carbon charge. One alternative would be to estimate startup GHG emissions, setting aside the benchmark rate, to determine what proportion of total annual GHG emissions they represent, and to reimburse the generator for that proportion of total annual carbon costs. This is still a "startup carbon cost reimbursement" because it is based on startup GHG emissions, but the reimbursement would be much less than under the IESO calculation. It would thus preserve some incentive to reduce startup GHG emissions, unlike the IESO calculation which eliminates that incentive.

The IESO states clearly in its Market Manual that "the RT-GCG Program is not a full cost-recovery program", and that its purpose is reliability.[90] Despite that declaration, the IESO has designed a carbon cost reimbursement that ensures not only full carbon cost-recovery but in some cases additional funds above any carbon costs incurred. The excess of the IESO's reimbursement is larger for a less efficient facility and larger for a facility with a high ratio of startup to runtime, creating a perverse incentive. The more you pollute in startup, the higher

[90] See the IESO's Market Manual 4: Market Operations Part 4.6: Real-Time Generation Cost Guarantee Program (RT-GCG), page 4: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-rtgcgprogram.ashx

the IESO's reimbursement to the point of reimbursing all carbon cost charges for the year, or even more.

One goal of the carbon pricing system for the electricity sector is to improve the overall efficiency of gas generators by encouraging reduced GHG emissions per unit of output, including during startup. The IESO's carbon cost reimbursement undermines this goal. As noted earlier, in July 2021 the federal government announced a new benchmark that will include requirements to ensure that government measures do not weaken the price signal. This increased stringency from the federal government resulted in the rejection of Saskatchewan's proposed carbon plan, that would have reduced the provincial gas tax to offset future increases in the federal carbon cost charge, as this negated the effect of the federal carbon price system.[91]

The Panel's previous concerns regarding the GCG program are now exacerbated by the implications of the IESO's reimbursement for the government's carbon pricing policy. The IESO's carbon cost reimbursement eliminates the incentive for generators to improve efficiency and reduce GHG emissions during startup which is counter to the goals of the carbon pricing system in Ontario.

Recommendation 3-3:

The IESO should immediately cease reimbursements to gas generators of carbon cost payments.

[91] See the Globe and Mail article "Saskatchewan's complaints about Ottawa playing favourites with province's carbon-pricing plans fall flat", July 17, 2021: https://www.theglobeandmail.com/business/article-saskatchewans-complaints-about-carbon-pricing-favoritism-fall-flat/

Recommendation 3-4:

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.

Recommendation 3-5:

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.

3.3 Non-Competitive Procurements

Non-competitive procurements in the IESO-Administered Markets are underway without sufficient consideration for competition or transparency and will likely lead to inefficient outcomes that increase costs for ratepayers.

3.3.1 Background

The Panel has provided its observations on the importance of competitive procurement on several occasions. In the Panel's Monitoring Report 33, published December 2020, the Panel made several recommendations to the IESO related to capacity needs and the associated procurements, many focused on addressing the lack of transparency.[92] The Panel also provided comments to the IESO's Resource Adequacy stakeholder engagement in February 2021 relating to competition and transparency.[93]

Most recently, the Panel provided its views on the Ministry of Energy's review of Long-Term Energy Planning, emphasizing that planning for competitive procurements is an essential input to the planning for electricity resources and assets.[94,95] The following excerpt from the Panel's comments is inserted here for emphasis and context:

> *A consistent purposeful, transparent and long-term approach to planning that leads to competitive procurement of necessary facilities will instill confidence in consumers and*

[92] See the Panel's Monitoring Report 33 published December 2020, on pages 54 to 60: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf

[93] See the Panel's comment to the IESO on the Resource Adequacy stakeholder engagement, dated February 17, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210217-market-surveillance-panel.ashx

[94] As a result of a Cabinet shuffle in June 2021, the Ministry of Energy has now assumed the energy portion of the portfolio previously housed in the Ministry of Energy, Northern Development and Mines. For simplicity, this section refers to the "Ministry" (or the "Minister").

[95] See the Environmental Registry of Ontario notice 019-3007, the Ministry's review of Ontario's long-term energy planning framework, posted January 27, 2021, with a comment period that ended on April 27, 2021 (as of the date of writing there have been no further updates), available at: https://ero.ontario.ca/notice/019-3007

Market Participants. Confidence is necessary to attract investment in the electric system components identified in the planning process.

The IESO is currently authorized to define reliability needs and procure the resources. The Panel's input to the government's Long-Term Energy Planning review advocates mandating that the Ontario Energy Board (OEB) oversee the IESO's needs assessment and procurement processes, in line with the recommendations and observations made in the Panel's Monitoring Report 33. The Panel also advocates that the IESO's governing statutes compel it to consider the cost impact of its decisions on ratepayers.

There were three ministerial directives issued in 2021 that directed the IESO to consider specific non-competitive procurements. It is therefore encouraging to see that the IESO subsequently received a letter from the Minister on May 31, 2021, that supports competition in procurements.[96]

3.3.2 Competition as an Outcome of the Planning Process

The IESO has recently provided its intended approach to electricity system reliability needs identification and procurement through its "Resource Adequacy Framework".[97] Separate from the framework, the Ministry has asked the IESO to develop an assessment process for unsolicited energy project proposals to address projects that:[98]

[96] See the letter from the Minister to the IESO, dated May 31, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/letter-from-MENDM-to-IESO-MC-994-2021-379.ashx

[97] See the IESO's presentation for Unsolicited Proposals to the Stakeholder Advisory Committee (SAC), dated February 17, 2021, slide 2, "Development of these [competitive] processes is the focus of the 'Resource Adequacy' Framework and when implemented, will be the primary method of committing resources": https://www.ieso.ca/-/media/Files/IESO/Document-Library/sac/2021/sac-20210217-unsolicited-proposals.ashx

[98] Ibid, slide 2.

1. *Provide electricity system benefits and reduce costs for ratepayers;*
2. *Are unique or innovative; and*
3. *Do not have a clear pathway to be acquired through a competitive process.*

The IESO has described how the assessment process requested by the Ministry will operate within the Resource Adequacy Framework.

The IESO's assessment criteria for the Ministry's unsolicited energy project proposals is as follows:[99]

1. *Assess the potential for the project to address forecasted system needs;*
2. *Assess the potential for the project to provide electricity system benefits and cost savings; and*
3. *Assess if the project already has a pathway to be acquired through an existing or future competitive acquisition mechanism (i.e., not just through the Unsolicited Proposal process).*

These assessments are only required if system needs have not been identified and competitive procurement processes for the system have not been developed. In the Panel's view, the IESO's proposed approach to implementing its Resource Adequacy Framework will effectively eliminate the need for such an assessment process.

The IESO has clearly articulated the goal of the acquisition process element of its Resource Adequacy Framework and how it intends to achieve it. The acquisition process is to meet identified system needs in a transparent and cost-effective manner by maximizing competition, to the greatest extent possible.

[99] See the IESO's presentation for Unsolicited Proposals to SAC, dated February 17, 2021, slide 4: https://www.ieso.ca/-/media/Files/IESO/Document-Library/sac/2021/sac-20210217-unsolicited-proposals.ashx

The IESO states that it will achieve this by:[100]

- *Providing information on needs on a regular and transparent basis*
- *Outlining how these needs translate into acquisition quantities and mechanisms*
- *Communicating the results and price outcomes transparently.*

In order to achieve its stated goals, the IESO has a continuous requirement to ensure that any project proposal that addresses identified needs can be part of a competitive procurement process. Simply stated, if the IESO has identified all system needs and has ensured that competitive procurement plans are in place for all of those needs, there will be no place for unsolicited energy proposals.

3.3.3 The IESO's Annual Acquisition Report

In July 2021, the IESO released its inaugural Annual Acquisition Report.[101] Although the report discusses the benefits of competition and provides greater transparency relating to system needs and procurement targets, there continues to be opportunities for increased competition and transparency relating to non-competitive procurements.

In response to a request for information, the IESO informed the Panel that five non-competitive procurements are now in advanced stages and another six projects may lead to non-competitive procurements, with project details considered confidential. The IESO has referred to the five advanced non-competitive procurements in the Annual Acquisition Report, identifying two as IESO-led "bilateral negotiations" and the remaining three procurements as "government policy".

[100] See the IESO's Resource Adequacy stakeholder engagement presentation, dated January 26, 2021, slide 31: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210126-presentation.ashx

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

The two non-competitive procurements referred to as “bilateral negotiations” are significant in size, with a combined unforced capacity (UCAP) of 2,119 MW, exceeding the amount to be procured from the competitive Medium- and Long-Term RFPs, combined (1,750 MW).

The IESO has not clearly articulated the specific quantities, locations and timelines relating to the local needs that non-competitive procurements are meant to address.[102] The IESO has also not communicated why the six-year length of the transitional contract for the Lennox Generating Station (GS) is warranted.

Without sufficient information relating to the precise needs and benefits for proposed non-competitive procurements, it is difficult to assess how well the proposed solutions address the identified needs.

3.3.4 Improving Competition and Transparency in Procurements

The Panel recognizes that certain needs cannot be competitively procured in the short-term. However, greater effort should be made to be transparent about the precise needs that are being addressed, the efforts made to encourage competition and the reasons why a competitive outcome was not possible. These details should be included in the next iteration of the Annual Acquisition Report. The Panel expects that inclusion of this information would enhance confidence in the market.

The Panel notes that any analysis designed to determine if a sole-source procurement is the only apparent option would require well-defined needs. Rather than entering into sole-source negotiations at a given point, the well-defined needs should be constituted as a Request for Proposals (RFP). RFPs are inherently valuable in allowing the market to respond, even if they don’t attract multiple market responses. The IESO would be able to negotiate terms of

[102] The Annual Acquisition Report does specify the quantity and timelines relating to the needs and proposed solutions relating to global adequacy (on page 35 and 36), however, this level of detail is not provided for the needs addressed by non-competitive procurements.

agreements in the event of a single proposal response. In the Panel's view, the RFP approach is aligned with the IESO's recently announced Resource Adequacy Framework and expects that the IESO contemplates its use.

Recommendation 3-6:

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).

Recommendation 3-7:

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 Panel recognizes that energy project proposals have been, and will continue to be, brought forward that have public value beyond the electricity system. The Panel provided its views on the need for appropriate attribution of costs of any benefits that are not rooted in electricity system needs in its commentary on the Long-Term Energy Planning review:[103]

> *Clear separation of energy policy from other public interests should be maintained to allow allocation of related costs and appropriate means of cost recovery.*

[103] Comments submitted to the Environmental Registry of Ontario for the review of Ontario's long-term energy planning framework have not yet been publicly posted. The original notice, dated January 27, 2021 is available at: https://ero.ontario.ca/notice/019-3007

The recommendation to maintain this separation and to establish revenue collection for non-system costs separate from ratepayer funding of system costs aligns with the government's recent decision to identify and remove certain renewable energy costs from the Global Adjustment (GA).[104] The Panel considers it appropriate that the IESO develop an open and public approach to determining cost attribution of projects that have benefits beyond the electricity system, which would allow for the comparison of competing proposals based on electricity system costs and benefits.

Recommendation 3-8:

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.

[104] See the IESO's news release "2020 Ontario Budget: Proposal to Reduce GA Costs for Consumers", dated November 5, 2020: https://www.ieso.ca/Sector-Participants/IESO-News/2020/11/2020-Ontario-Budget-Proposal-to-Reduce-Global-Adjustment-Costs-for-Consumers

Appendix A: Market Outcomes for the Summer 2020 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Summer 2020 Period (May 1, 2020 to October 31, 2020), 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) and uplift charges), Operating Reserve (OR) prices and Transmission Rights (TR) auction prices.

Total System Cost (HOEP, GA and Uplift Charges)

Table A-1: Total System Cost by Period, 2 Periods

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

Table A-1 summarizes the total system cost and the total HOEP, GA and Uplift costs for the Summer 2020 Period, (May 1, 2020 to October 31, 2020) and the Winter 2019/20 Period (November 1, 2019 to April 30, 2020).[105]

[105] The Panel defines the total system cost as the addition of charges related to HOEP, 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.

Average Effective Price (HOEP, GA and Uplift Charges)

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

	Consumer Class	Summer 2019	Winter 2019/20	Summer 2020
Average Weighted HOEP ($/MWh)	Class A	10.04	13.76	**12.22**
	Class B	13.38	16.21	**15.70**
Average Global Adjustment ($/MWh)	Class A	63.78	60.21	**62.28**
	Class B	123.20	111.78	**119.45**
Average Uplift ($/MWh)	Class A	2.62	2.01	**2.33**
	Class B	2.82	2.17	**2.69**
Average Effective Price ($/MWh)	Class A	76.43	75.97	**76.83**
	Class B	139.40	130.16	**137.84**
	All Consumers	**120.39**	**114.65**	**120.55**

Table A-2 summarizes the average effective energy price in dollars per MWh by consumer class as well as the total system cost in dollars by consumer class for the Summer 2020 Period, (May 1, 2020 to October 31, 2020), Winter 2019/20 Period (November 1, 2019 to April 30, 2020), and the Summer 2019 Period (May 1, 2019 to October 31, 2019).

The average effective price is the sum of the HOEP, the GA and the uplift charges paid by a given class of consumers (whose nominal sum equals total system cost), divided by the total quantity of energy consumed.[106] Accordingly, it captures the hourly market price, payments under IESO reliability and other programs, prices payable for contracted and regulated generation and the costs of conservation and Demand Response (DR) programs. It does not include all charges that appear on electricity bills, such as charges for transmission and

[106] The average HOEP reported for each class is an average of the HOEP values in the reporting 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.

distribution. Results are reported for three consumer groups: "Class A consumers", "Class B consumers" and "All Consumers".[107,108]

During the Summer 2020 Period, the Ontario Government deferred a portion of GA charges from April 2020 to June 2020. As a result of this change, Class A consumers received a reduction in GA charges and the Class B GA rate was limited to a maximum rate of $115/MWh.[109] The prices listed within this Appendix consider the actual costs for Class A and B consumers and do not reflect the rate changes made by the Ontario Government.

As discussed in Chapter 1 of the Panel's Monitoring Report 34 published in February 2021, the Government of Ontario announced a change in the Industrial Conservation Initiative (ICI) on June 26, 2020 which effectively removed the need for existing Class A consumers to reduce

[107] 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

[108] 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 ICI Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[109] For more information on the rate changes made by the Ontario Government, see: https://www.ieso.ca/en/Sector-Participants/Settlements/Global-Adjustment-for-Class-B

their demand on peak days during the Summer 2020 Period.[110] During this time, the Summer 2020 demand peaks were highest since 2013, which contributed to an overall increase in Ontario demand during the Summer 2020 Period, relative to the Summer 2019 Period.[111]

The average effective price for all consumers remained relatively constant in the Summer 2020 Period compared to the Summer 2019 Period. As a result, the average effective price for both Class A and B consumers remained constant. Each consumer class experienced an increase in the HOEP, with reductions in the GA and the uplift. As a whole, the amount of unavailable capacity (see Figure A-23) and the output from gas resources increased in the Summer 2020 Period relative to the Summer 2019 Period. These factors would have likely contributed to more significant changes in the 6-month HOEP, the GA and the uplift between the Summer 2019 Period and the Summer 2020 Period, but were likely offset by a stable average Ontario demand (see Figure A-20) that peaked during months where minimum available capacity was highest (see Figure A-23) and by reductions in hourly uplift charges such as OR Payments (see Table A-6).

Although the Summer 2020 Period coincided with the COVID-19 pandemic which impacted the electricity sector, the average effective prices of the Summer 2020 Period were similar to those of the previous summer.

The HOEP and the GA costs tend to be inversely related. When the HOEP increases, contracted and rate-regulated generators receive more market revenue for every MWh of

[110] Class A consumers who established peak demand factors in the 2019-2020 Base Period will maintain them for the 2021-2022 Adjustment Period instead of establishing new peak demand factors in the 2020-2021 Base Period. For more information on the amendment, see Ontario Regulation 335/20 made under the Electricity Act, 1998, or the related news release available at: https://www.ontario.ca/laws/regulation/040429 and https://news.ontario.ca/en/release/57417/ontario-provides-stable-electricity-pricing-for-industrial-and-commercial-companies

[111] There was downward pressure on peak demand for much of the last decade due to the IESO's energy efficiency programs, the growth of contracted embedded generation from 2010 to 2016 and the expansion of Class A eligibility in 2017.

energy that they produce, lowering the compensation through the GA required to meet their contracted or regulated rates that these generators receive for every MWh of energy that they produce, thus reducing the GA. This effect was observed during the Summer 2020 Period, as the 6-month average HOEP increased and the 6-month average GA decreased (see Table A-2).

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

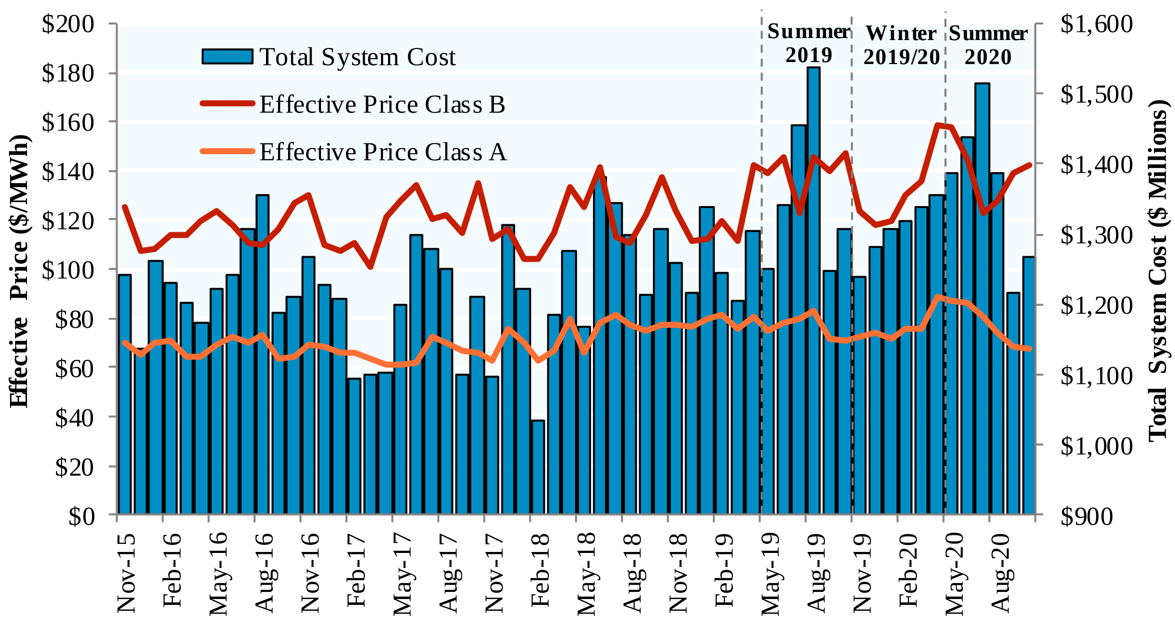


Figure A-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five-year period from November 2015 through October 2020.

The total system cost borne by Ontario consumers in the Summer 2020 Period increased less than 1% compared to the Summer 2019 Period, but increased by 4.8% from the Winter 2019/20 Period (see Table A-1). This increase across summer reporting periods is less than the average over the last five years of 2.8% per year. The total system cost rose by about $70 million between the Summer 2019 Period and the Summer 2020 Period, consisting of about a $156 million increase in the HOEP, about a $76 million decrease in the GA and about a $9 million decrease in the uplift. The HOEP was highest during July 2020 and August 2020, during which the average Ontario demand was highest (see Figure A-20) and gas resources set the real-time Market Clearing Price (MCP) most frequently (see Figure A-7).

The monthly average effective prices for Class A and B consumers were highest during May 2020, when the average Ontario demand was lowest in the Summer 2020 Period, an unusual combination. The low demand was likely due to the stricter COVID-19 public health measures in effect for Ontario at the beginning of the summer season. The change in the average effective price for Class A and B consumers is much smaller than the average change in effective prices over the last five years, which is approximately $3/MWh for Class A consumers and approximately $5/MWh for Class B consumers.

The GA is approximately equal to the guaranteed revenue less HOEP and uplift payments. The GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases, but this is not necessarily a one-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 Class B consumers pay. The average effective price for Class A consumers steadily declined during the Summer 2020 Period, while the average effective price for Class B consumers increased towards the end of the Summer 2020 Period.

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

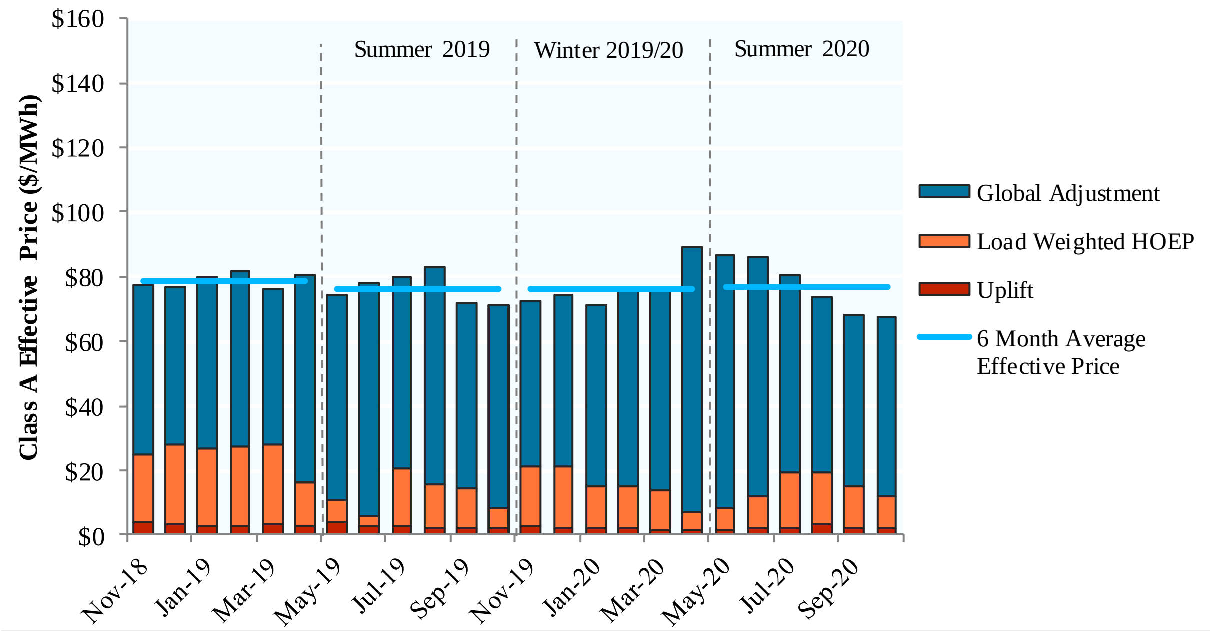


Figure A-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for each month over the two-year period from November 2018 through October 2020. It also shows the total effective price averaged over each 6-month period.[112, 113]

[112] 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 (which are dependent on the HOEP, and thus are dependent on the demand), and their contracted rates or regulated rates set by the Ontario Energy Board. For some contracted facilities, their share of the GA is calculated on the basis of the guaranteed payments toward fixed costs less the demand operating profits from participation in the energy (HOEP) market ([HOEP – Contracted Variable Costs] * MWh for hours deemed to be at or below the HOEP). The GA also includes costs 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

[113] For illustration, the 6-month average Class A effective price (unit cost) shown here is the sum of the HOEP, the GA and the uplift charges paid by Class A consumers, divided by the total quantity of energy consumed.

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

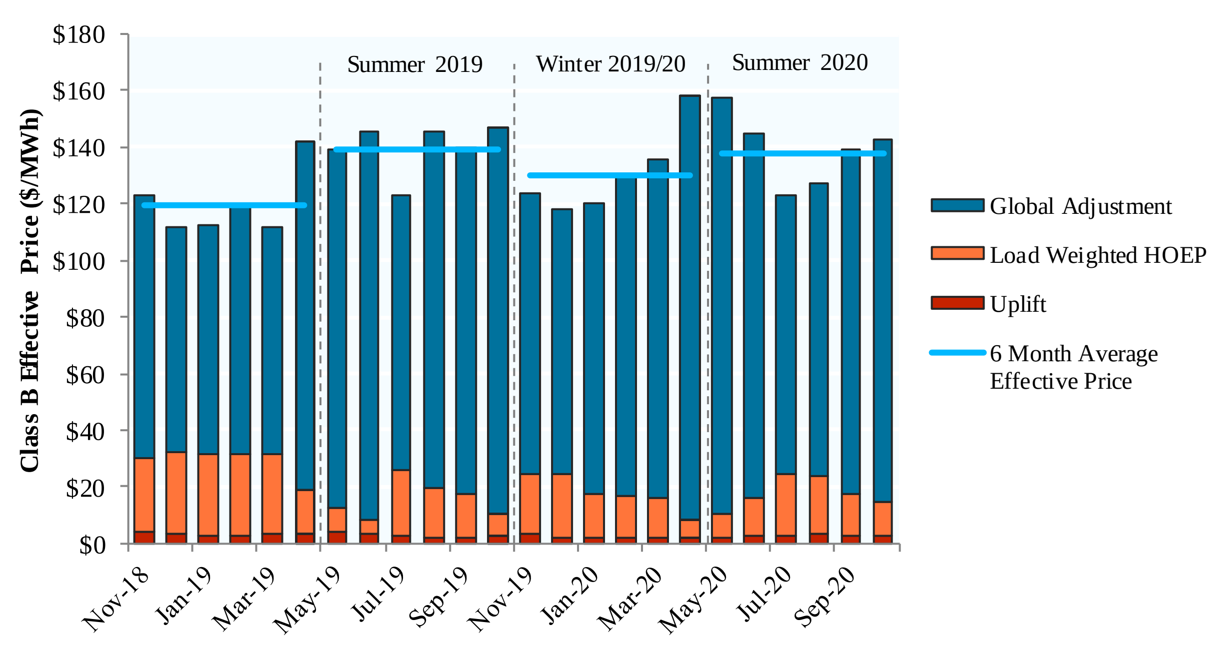


Figure A-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for each month over the two-year period from November 2018 through October 2020. It also shows the total effective price averaged over each 6-month period.[114]

Most Class B consumers are subject to the Regulated Price Plan (RPP) and pay prices that are typically reviewed by the Ontario Energy Board (OEB) twice a year and reset if required, with more frequent resets since the beginning of the COVID-19 Pandemic as a result of government action.[115] 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 RPP. The decrease in the average Class B effective price was primarily driven by a decrease in the

[114] The 6-month average Class B effective price is the sum of the HOEP, the GA and the uplift charges paid by Class A consumers, divided by the total quantity of energy consumed.

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

Class B GA resulting from increases in the average 6-month Class B HOEP from the Summer 2019 Period to the Summer 2020 Period.

During the Summer 2020 Period, there was an increase in the unweighted 6-month average HOEP compared to the Summer 2019 Period, rising from $10.99/MWh to $13.29/MWh. Although the average Ontario demand increased minimally during the summer periods, the increase in the unweighted 6-month average HOEP was likely in part driven by supply conditions, as the overall amount of unavailable capacity, particularly from nuclear resources (see Figure A-23) increased between the Summer 2019 Period and the Summer 2020 Period, and was highest from September 2020 to October 2020. This reduced supply combined with a higher demand in July 2020 and August 2020 to increase the output from more expensive gas resources, likely contributing to an increase in the HOEP.

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

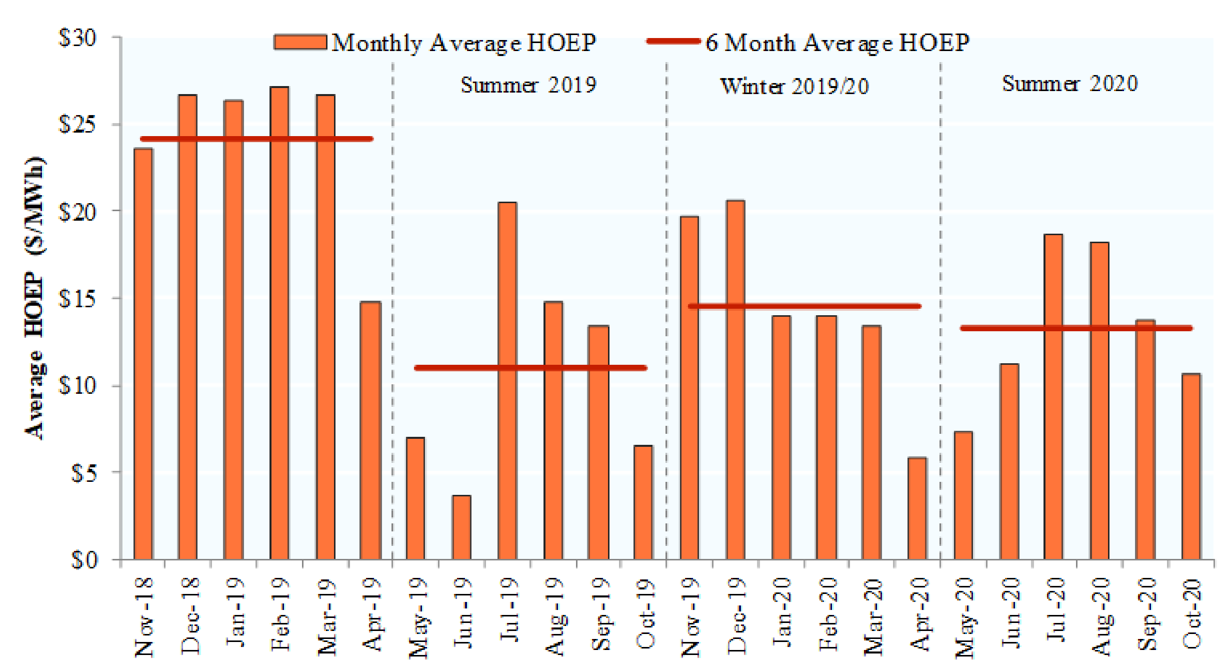


Figure A-4 displays the monthly average HOEP unweighted by the volume of energy consumed in any given interval (the "simple HOEP"), for each month between the two-year period from November 2018 through October 2020. Figure A-4 also displays the simple average HOEP for each 6-month period since November 2018. The HOEP is the unweighted average of the twelve Market Clearing Prices (MCPs) set every five minutes within an hour.

The average gas price during on-peak hours was $2.63/MMBtu in the Summer 2020 Period, much less than the $3.21/MMBtu in the Summer 2019 Period. The gas price decreased from $4.33/MMBtu in the Winter 2018/19 Period to $2.76/MMBtu in the Winter 2019/20 Period.

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

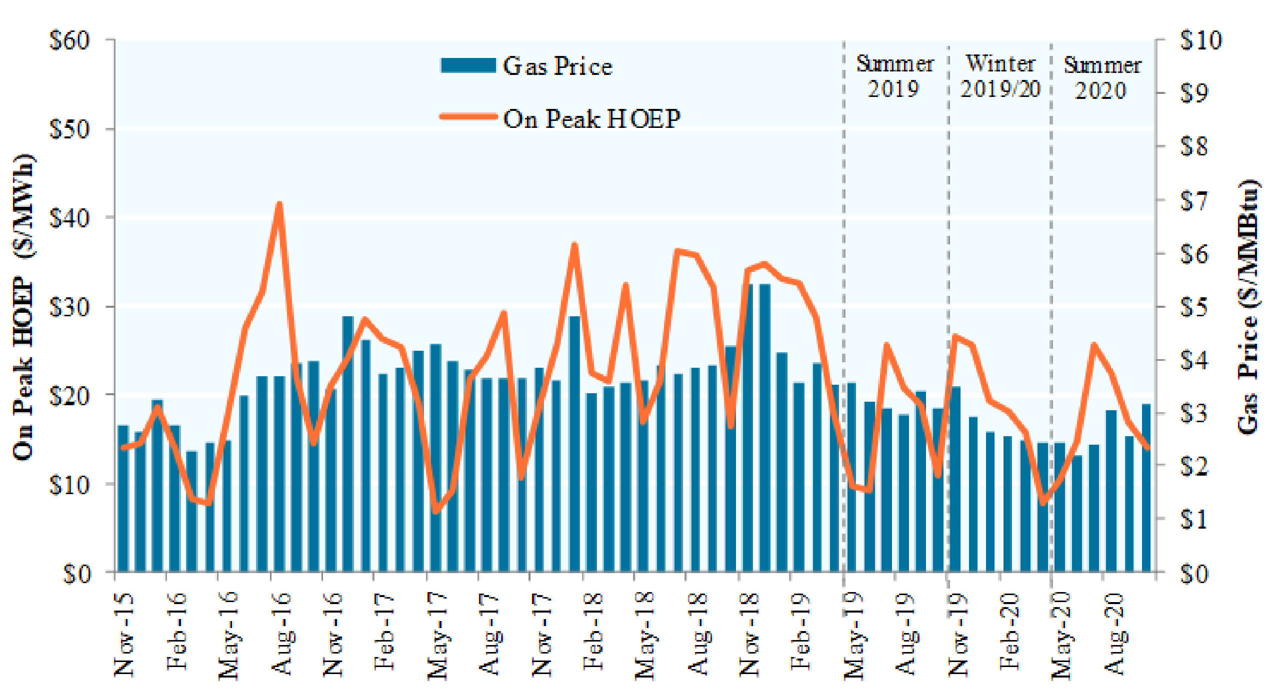


Figure A-5 plots the average monthly HOEP during on-peak hours and the monthly average of Henry Hub natural gas prices for days with on-peak hours for the five-year period from November 2015 through October 2020.[116] Natural gas prices are compared to the HOEP for on-peak hours as gas-fired facilities frequently set the price during these hours. Gas-fired facilities typically purchase gas day-ahead.

When the supply of baseload is low, or when the demand for energy is high, high-priced (that is, high marginal cost) resources tend to set the MCP more frequently. Since natural gas resources are often marginal at higher prices compared to other resources such as nuclear, wind and hydro, natural gas resources often set the MCP under these conditions. When these conditions occur, there is usually a positive correlation between the on-peak HOEP and the

[116] 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

price of natural gas. The gas-HOEP correlation remained relatively low in the Summer 2020 Period despite an increase in the correlation relative to the Summer 2019 Period.

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

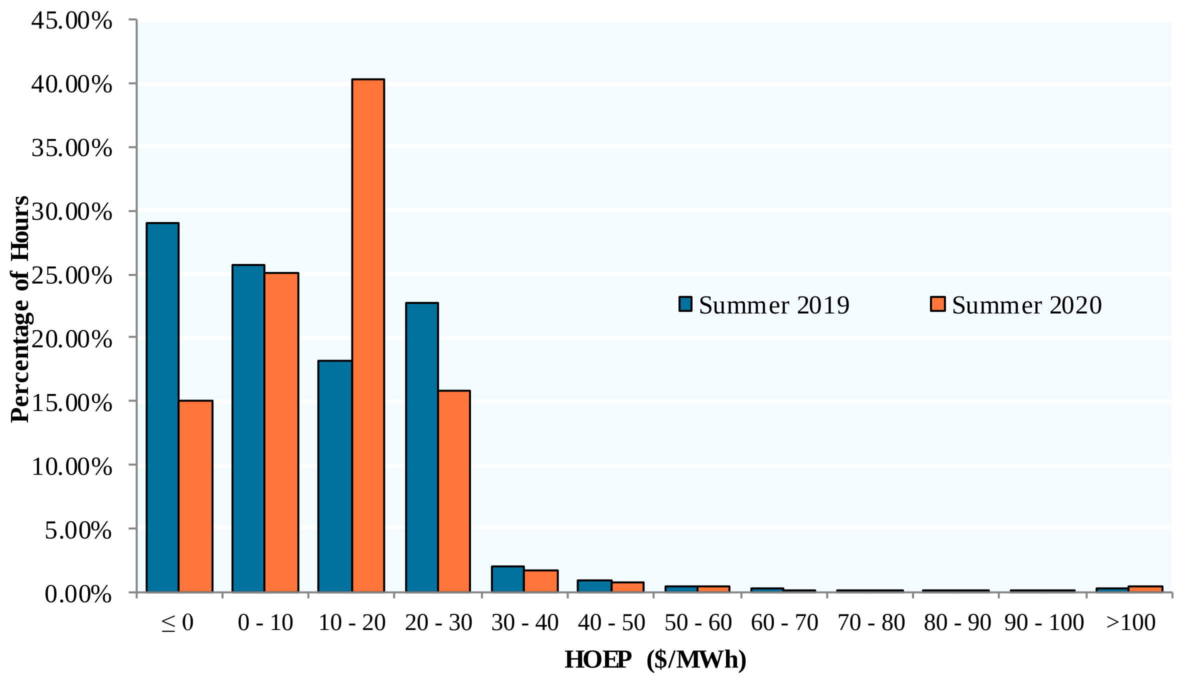


Figure A-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Winter 2018/19 and Winter 2017/18 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh hours.

During the Summer 2020 Period, about 15% of hours had a negative HOEP, compared to 29% in the Summer 2019 Period, while 20% of hours in the Summer 2020 Period had HOEPs of at least $20/MWh, down from 27% in the Summer 2019 Period. Although there were fewer negatively-priced hours during the Summer 2020 Period, about 40% of hours had a HOEP between $10/MWh and $20/MWh, which decreased the number of high-priced hours (hours priced at least $20/MWh) that occurred in the period. The amount of unavailable capacity increased in the Summer 2020 Period, along with an increase in nuclear outages (see Figure A-23). A reduction in available baseload supply during the Summer 2020 Period likely contributed to the reduction of negatively-priced hours and hours with a HOEP of at least

$20/MWh. Additionally, there was a 45% increase in supply from gas generators and a 27% increase in supply from wind generators during the Summer 2020 Period in comparison to the Summer 2019 Period. However, output from less expensive resources such as hydro and solar also increased modestly (see Figure A-21). The reduction in available capacity from nuclear generators was slightly offset by modest increases in supply from hydro, solar and wind resources, which likely resulted in fewer negatively-priced hours during the Summer 2020 Period.

The decrease in output from baseload resources increased the need for production from gas resources (see Figure A-21) and likely increased the hours that gas resources set the real-time MCP during the Summer 2020 Period in comparison to the Summer 2019 Period. Although there was an increase in the output from wind generators during the Summer 2020 Period relative to the Summer 2019 Period, there was a modest increase in wind outages during the Summer 2020 Period, relative to the Summer 2019 Period, which likely reduced the percentage of hours that wind resources set the real-time MCP (See Table A-3).

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

Resource Share (%)	Summer 2019	Winter 2019/20	Summer 2020
Hydro	34%	42%	39%
Wind	29%	24%	21%
Gas	28%	32%	38%
Nuclear	**7.3%**	0.02%	**0.8%**
Solar	0.8%	0.01%	0.09%
Biofuel	0.7%	1.6%	1.2%

Table A-3 presents the share of intervals in which each resource type set the real-time MCP in the Summer 2019 Period, the Winter 2019/20 Period and the Summer 2020 Period.[117]

[117] The frequencies of each resource type from the Summer 2019 Period noted within this report are the most up to date versions of these figures.

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

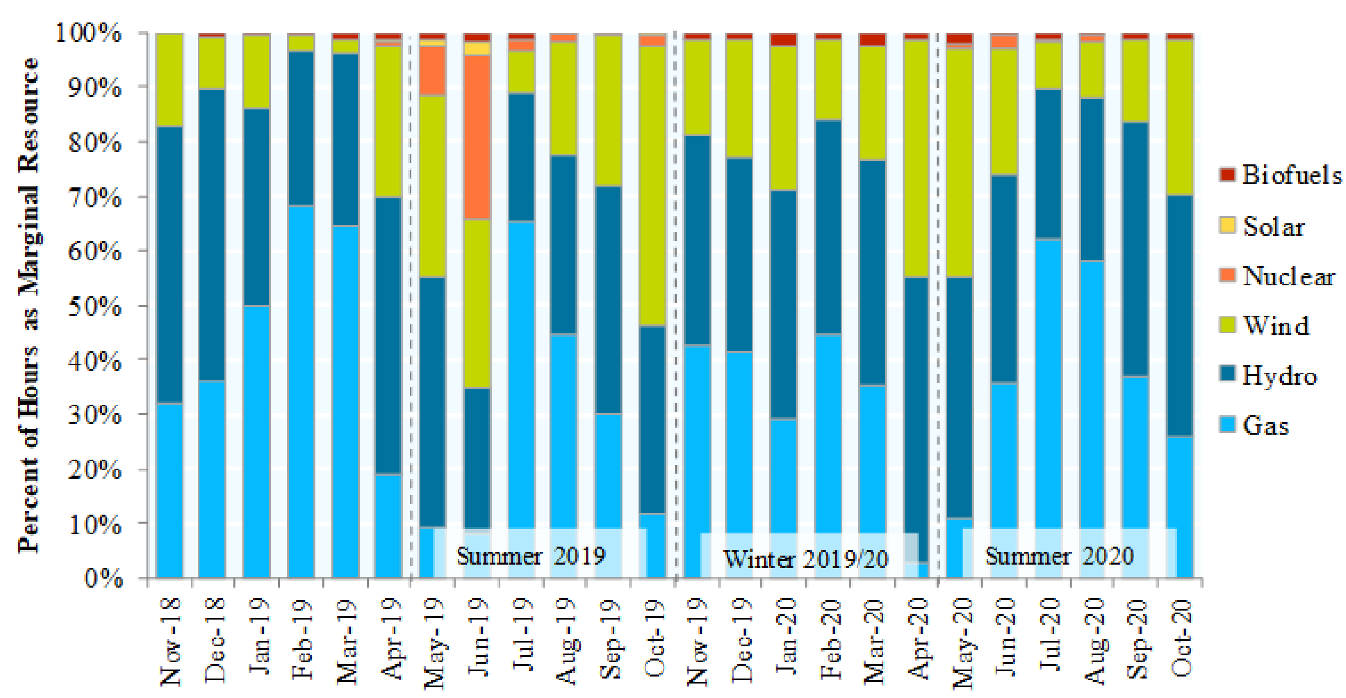


Figure A-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the two-year period from November 2018 through October 2020. The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

The frequency with which imports and exports set the pre-dispatch (PD-1) Market Clearing Price (MCP) is important, as these transactions are unable to set the real-time MCP.[118] 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.

[118] Due to scheduling protocols, imports and exports are scheduled hour-ahead. In real-time imports and exports are fixed for any given hour and their offer and bid prices adjusted to -$2,000 and $2,000/MWh, respectively. 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

Resource Share (%)	Summer 2019	Winter 2019/20	Summer 2020
Hydro	18%	20%	22%
Wind	18%	12%	10%
Gas	23%	21%	29%
Nuclear	**5%**	0%	**0.3%**
Solar	1%	0.02%	0.2%
Biofuel	0.5%	1%	1%
Imports	15%	21%	12%
Exports	19%	25%	25%

Table A-4 presents the share of intervals in which each resource type, imports and exports set the Pre-Dispatch MCP in the Summer 2019 Period, the Winter 2019/20 Period and the Summer 2020 Period.

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

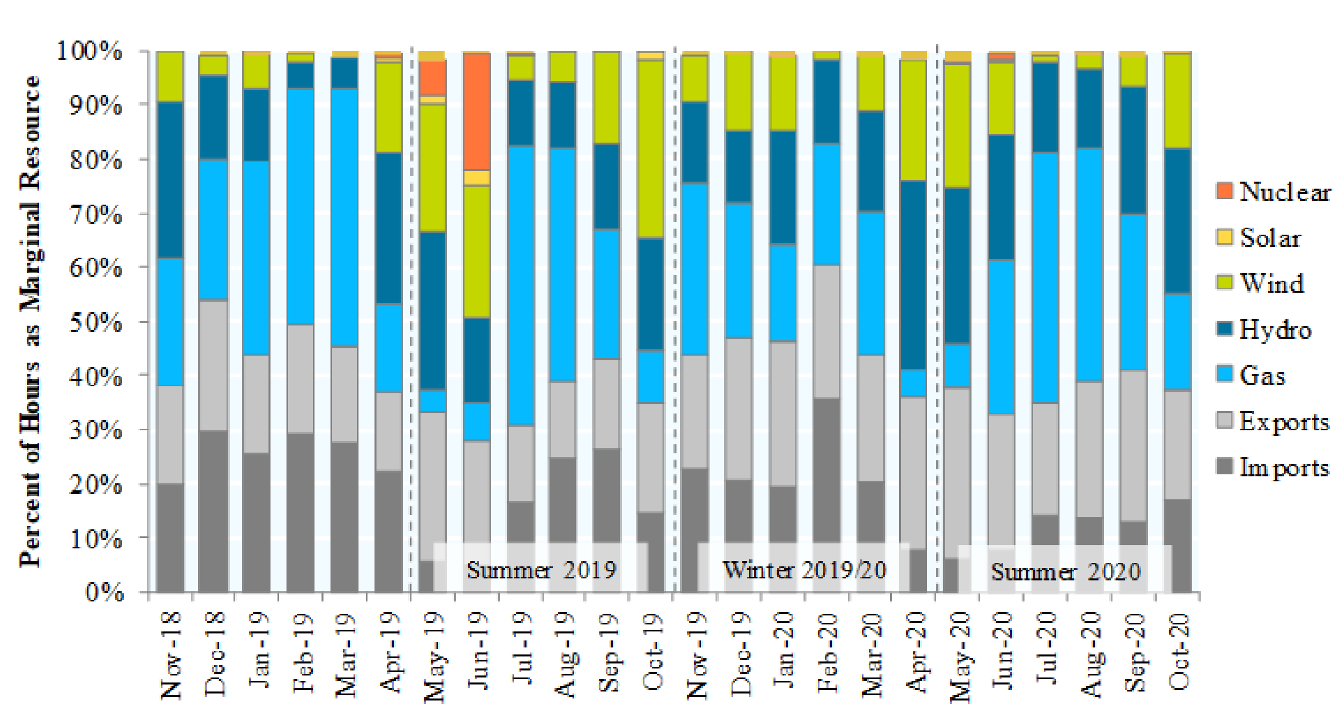


Figure A-8 presents the share of hours in which each resource type, imports or exports set the one-hour ahead pre-dispatch (PD-1) MCP in each month of the two-year period from November 2018 through October 2020. When compared with Figure A-7, Figure A-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

Similar to the share of hours that gas resources set the real-time MCP, the increase in the share of hours that gas resources set the PD-1 MCP likely resulted from a higher need for output from gas generators during the Summer 2020 Period compared to the Summer 2019 Period (see Figure A-21). The drop in the percentage of hours that nuclear resources set the PD-1 MCP aligned with the increase in the number of nuclear outages that occurred during the Summer 2020 Period compared to the previous summer. The proportion of intervals that imports and exports set the PD-1 MCP changed similarly from the Summer 2019 to the Summer 2020 Period. These observations closely aligned with the trends noted in real-time.

The PD-1 MCP and the PD-1 schedules are used for import and export transactions for real-time delivery. While intertie transactions are scheduled based on the PD-1 MCP, they are settled based on the Intertie Zonal Price (IZP). 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 the real-time MCP.

In the Summer 2020 Period, there was a positive or negative variation of less than $10/MWh between PD-1 and real-time prices for 91% of hours, up slightly from 87% in the Summer 2019 Period. The average absolute deviation between PD-1 and real-time prices in the Summer 2020 Period was similar to the Summer 2019 Period average deviation ($4.77/MWh compared to $4.71/MWh). As a whole, the Summer 2020 Period had slightly more variation between PD-1 and real-time prices.

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time.[119] Identifying the factors that lead to deviations between the PD-1 MCP and the

[119] 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.

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.

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

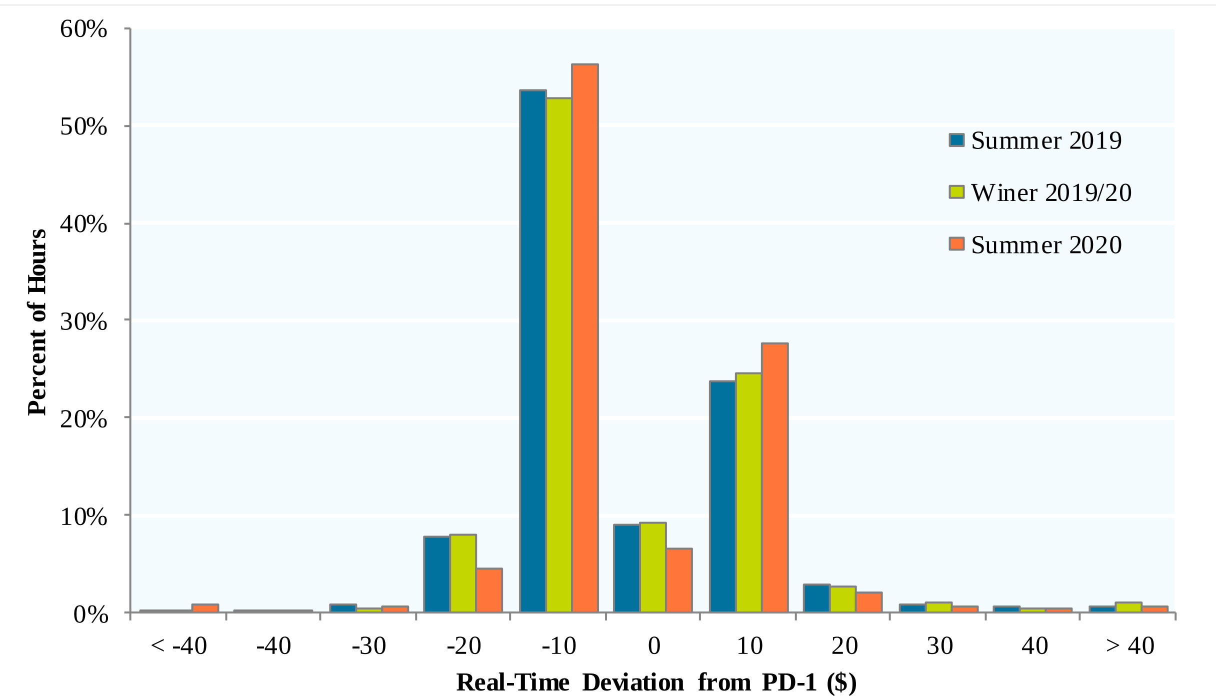


Figure A-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2019, Winter 2019/20 and Summer 2020 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP, 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.

Average hourly demand forecast deviation, the most significant source of deviation between the PD-1 MCP and the HOEP, increased in the Summer 2020 Period relative to the Summer 2019 Period. The next most significant source of deviation, wind generation forecast deviations, also increased in the Summer 2020 Period relative to the Summer 2019 Period. These increases are expected as both the average Ontario demand and the output from wind resources increased during the Summer 2020 Period compared to the Summer 2019 Period.

The amount of unavailable capacity from wind resources also increased modestly during the Summer 2020 Period (see Figure A-23).

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

Factor	Summer 2019: Absolute Difference		Winter 2019/20: Absolute Difference		Summer 2020: Absolute Difference	
	Average (MW)	Maximum (MW)	Average (MW)	Maximum (MW)	Average (MW)	Maximum (MW)
Ontario Demand	14,947	21,722	15,386	20,801	15,043	24,990
Forecast Demand Deviation	213	1,337	216	1,089	242	2,213
Self-Scheduling Generation and Intermittent Forecast Deviation (Excluding Wind)	27	304	29	666	15	81
Wind Generation Forecast Deviation	148	922	166	1,012	156	1,430
Net Export Failures/Curtailments	79	1,219	78	1,261	68	951

Table A-5 displays the hourly average absolute difference and hourly maximum absolute difference between PD-1 and real-time for all of the above-noted factors, save for the effect of generator outages.[120] Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Maximum and average hourly Ontario demand is also included to provide a relative sense of the size of the deviations. Wind generation forecast deviation does not consider dispatches that were fixed or on economic release mode.

[120] Minimum absolute deviations are generally negligible, as a result they are not shown in Table A-5.

The three-hour ahead pre-dispatch (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.[121] 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

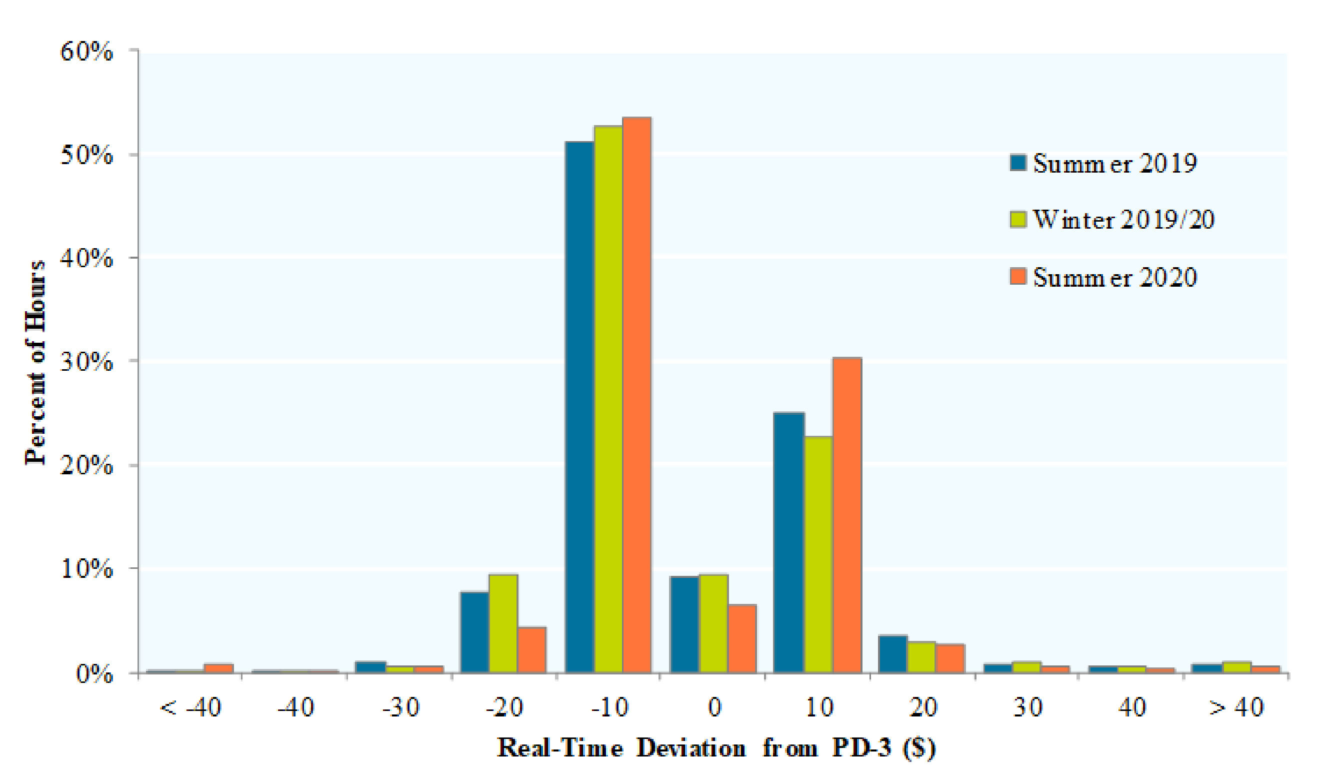


Figure A-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Summer 2019, Winter 2019/20 and Summer 2020 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the 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.

[121] 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 90% of the hours in the Summer 2020 Period, up from 85% of the hours in the Summer 2019 Period. The percentage of prices within $10/MWh of the real-time MCP for PD-1 prices also increased from the Summer 2019 Period to the Summer 2020 Period. The average absolute deviation between PD-3 and real-time MCPs was essentially unchanged in the Summer 2020 Period ($4.96/MWh) compared to the Summer 2019 Period ($4.94/MWh). The average absolute deviation between PD-1 prices and the real-time MCPs increased from the Summer 2019 Period to the Summer 2020 Period.

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

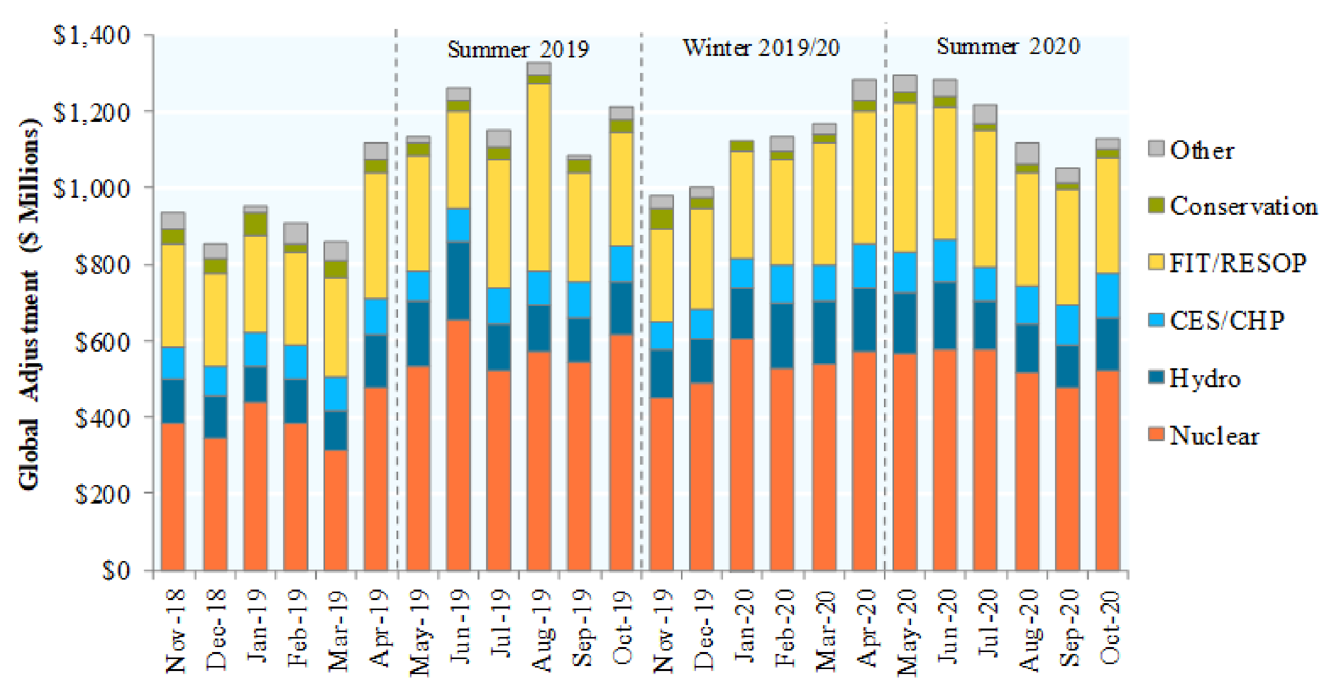


Figure A-11 plots the payments to various resources and recovered through the GA each month by component for the two-year period from November 2018 through October 2020.

Total GA is divided into six components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation Inc.'s (OPG) nuclear assets);
- 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 (NUG) contracts and Ontario Power Generation Inc.'s (OPG's) Lennox Generating Station).

The total GA throughout the Summer 2020 Period was similar to the Summer 2019 Period, decreasing from $7.2 billion to $7.1 billion. GA payments made to nuclear and hydro generators decreased by 6% and 4% respectively from the Summer 2019 Period to the Summer 2020 Period. Payments made to conservation programs decreased by 28%, while payments to holders of CES and CHP contracts and payments to others increased by 19% and 59% respectively. Napanee Generating Station, a combined cycle gas turbine plant in Eastern Ontario operated by Atura Power, came into service in March 2020. Napanee Generating Station was a significant addition to the CES/CHP component of GA and likely contributed to the rise in payments made to holders of CES/CHP contracts between the Summer 2019 Period and the Summer 2020 Period.[122] The increase in payments to resources categorized as "others" from the Summer 2019 Period to the Summer 2020 Period were

[122] Atura Power is the brand name for Ontario Power Generation's wholly-owned subsidiary that operates Portlands Energy Centre Generating Station, Halton Hills Generating Station, Napanee Generating Station and Brighton Beach Generating Station.

largely due to significant increases in the balancing amounts paid to Market Participants, rather than an increase in NUG contract payments, or payments to OPG's Lennox Generating Station.[123] The relative contribution of each component to the total GA in the Summer 2020 Period remained largely unchanged from the Summer 2019 Period. Since the HOEP and GA tend to be inversely related, higher market payments result in lower payments required to be recovered through GA to meet a generator's contracted or regulated rate revenues. The Summer 2020 GA trends closely aligned with this inverse relationship as the average HOEP increased and the GA decreased during the Summer 2020 Period compared to the Summer 2019 Period.

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".[124] Regulatory charges include both amounts set or approved by the Ontario Energy Board (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.[125]

[123] Payments to others includes NUG Contract Payments, Payments to Ontario Power Generation (OPG)'s Lennox Generating Station and other balancing amounts paid to participants.

[124] For convenience, this section refers to "regulatory charges".

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

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.[126]

Table A-6 below summarizes a number of components of regulatory charges, the majority of which are "uplift" costs for wholesale Market Participants.[127] 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)[128] 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.[129]

Total Wholesale Market Service Charges in the Summer 2020 Period were $317 million, a 4% decrease from the Summer 2019 Period of $329 million. Notable decreases compared to the previous Summer Period include: CMSC (8% decrease or $3.9 million), 10-minute spinning OR (46% decrease or $8.1 million), 10-minute non-spinning OR (53% decrease or $7.5 million), 30-minute OR (63% decrease or $7.1 million) and ancillary regulation charges (34%

[126] 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.

[127] 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 or Remote Electricity Rate Protection Charge.

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

[129] 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.

decrease or $10.5 million). These decreases were partially offset by notable increases including: IOG (134% increase or $7.9 million), PCG (56% increase or $5.1 million) and DR Capacity Payments (49% increase or $8.9 million).

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

Settlement Resolution	Regulatory Charges	Summer 2019 ($ million)	Winter 2019/20 ($ million)	Summer 2020 ($ million)
Hourly	Congestion Management Settlement Credits (CMSC, Charge Type 155)	49.07	31.40	45.18
	Transmission Losses (Charge Type 150, Charge Type 1131)	17.46	21.44	19.93
	Intertie Offer Guarantee (IOG, Charge Type 1131)	**5.86**	4.48	**13.80**
	Intertie Failure Charge Rebate (Charge Type 186)	-0.39	-0.37	-0.51
	Operating Reserve (OR): 10-minute spinning reserve (Charge Type 250)	**17.75**	7.43	**9.68**
	Operating Reserve: 10-minute non-spinning reserve (Charge Type 252)	**14.21**	8.65	**6.65**
	Operating Reserve: 30-minute reserve (Charge Type 254)	**11.30**	5.65	**4.25**
	Hourly Reactive Support and Voltage Control (Charge Type 451)	12.40	9.01	11.46
	Hourly Charges Subtotal	**127.66**	**87.70**	**110.43**
Monthly	Cost Guarantee: RT-GCG program (Charge Type 183)	15.94	15.54	17.73
	Cost Guarantee: PCG program (Charge Type 1550)	9.05	5.75	14.24
	Ancillary Services: Black Start (Charge Type 450)	0.86	0.86	0.83
	Ancillary Services: Regulation (Charge Type 454)	31.22	30.85	20.69
	Ancillary Services: Monthly Reactive Support and Voltage Control (Charge Type 452)	1.01	0.71	0.92
	Demand Response Capacity Payments (Charge Type 1350, 1351)	18.13	17.75	27.03
	IESO Administration Charge (Charge Type 9990)	90.72	92.95	89.67
	Rural or Remote Electricity Rate Protection (Charge Type 753)	32.40	32.91	32.56
	Other: Additional Compensation for Admin Pricing, Station Service Reimbursement, Local Market Power [130]	1.50	1.10	2.46
	Monthly Charges Subtotal	**200.83**	**197.43**	**206.11**
Total Regulatory Charges		**328.50**	**285.12**	**316.54**

Table A-6 compares the Wholesale Market Service Charges for the Summer 2019, Winter 2019/20 and Summer 2020 Periods, separated into hourly and monthly charges.

[130] Additional Compensation for Admin Pricing includes Charge Type 163, Station Service Reimbursement includes Charge Type 169 and Local Market Power includes Charge Type 170.

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

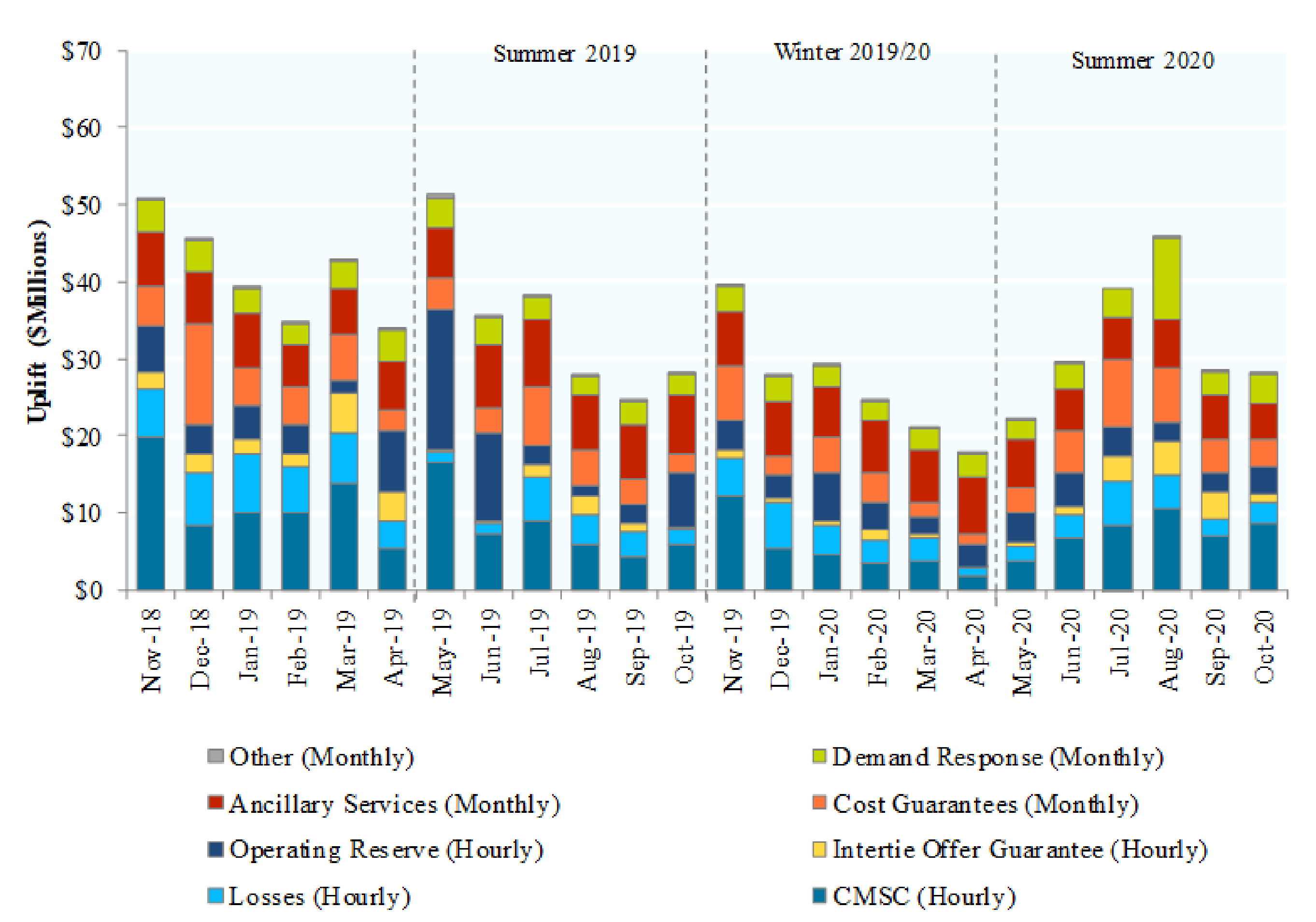


Figure A-12 presents the total uplift charges by component on a monthly basis for the two-year period from November 2018 through October 2020. This includes both hourly and monthly uplift, which were displayed in separate figures in previous Panel reports. In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while PCG and RT-GCG Program payments are combined as Cost Guarantees. For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Protection Charge have been omitted from Figure A-12.

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.[131,132]

Uplift from OR was $21 million for Summer 2020 Period, less than half of the $43 million in the Summer 2019 Period. Average OR prices for all classes decreased in comparison to the Summer 2019 Period and were much less than the average OR class prices of the last two years. The 10-minute non-spinning price ($3.57/MW) and 30-minute reserve price ($2.13/MW) decreased by more than 50% compared to the Summer 2019 Period. The price for 10-minute spinning reserve ($4.88/MWh) decreased by about 39% compared to the Summer 2019 Period. A higher number of OR offers at lower offer prices are generally associated with a lower Market Clearing Price (MCP) in OR markets, as reflected in the decrease of all OR prices from the Summer 2019 Period to the Summer 2020 Period. Low OR prices generally occurred during August 2020 and October 2020, likely due to a rise in OR supply from hydro resources during this time (see Figure A-22).

[131] See the Market Rule Amendment "MR-00436: Enabling System Flexibility – Thirty-Minute OR", 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

[132] This Market Rule Amendment and its justification was discussed in the Panel's Monitoring Report 32 (Nov 2017-Apr 2018) published July 30, 2020, Chapter 3, available at: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

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

Operating Reserve Markets	Winter 2018/19 ($/MW)	Summer 2019 ($/MW)	Winter 2019/20 ($/MW)	Summer 2020 ($/MW)
10-minute spinning (10S)	5.30	**8.02**	4.67	**4.88**
10-minute non-spinning (10N)	4.44	**7.32**	3.79	**3.57**
30-minute reserve (30R)	3.55	**5.01**	3.04	**2.13**

Table A-7 presents the average OR prices by period from Winter 2018/19 through Summer 2020 for the three OR markets.

Figure A-13 illustrates the monthly fluctuations of OR prices. Because OR prices are usually low, a single high-priced hour can significantly increase the monthly average price. During the Summer 2020 Period, the average prices for each class of OR were lower and steadier relative to the Summer 2019 Period. The drop in average OR prices between the Summer 2019 Period and the Summer 2020 Period was largely due to an unusual spike in average OR prices that occurred at the beginning of the Summer 2019 Period as a result of two high-priced energy and OR hours. Therefore, the Summer 2020 OR price trends represent a return to normal seasonal price fluctuations. Excluding 30-minute reserve OR, higher average monthly OR prices for 10-minute spinning and 10-minute non-spinning during June 2020 and July 2020 likely resulted from the June 2020 and July 2020 high-priced hours noted in Chapter 2, Table 2-3.

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

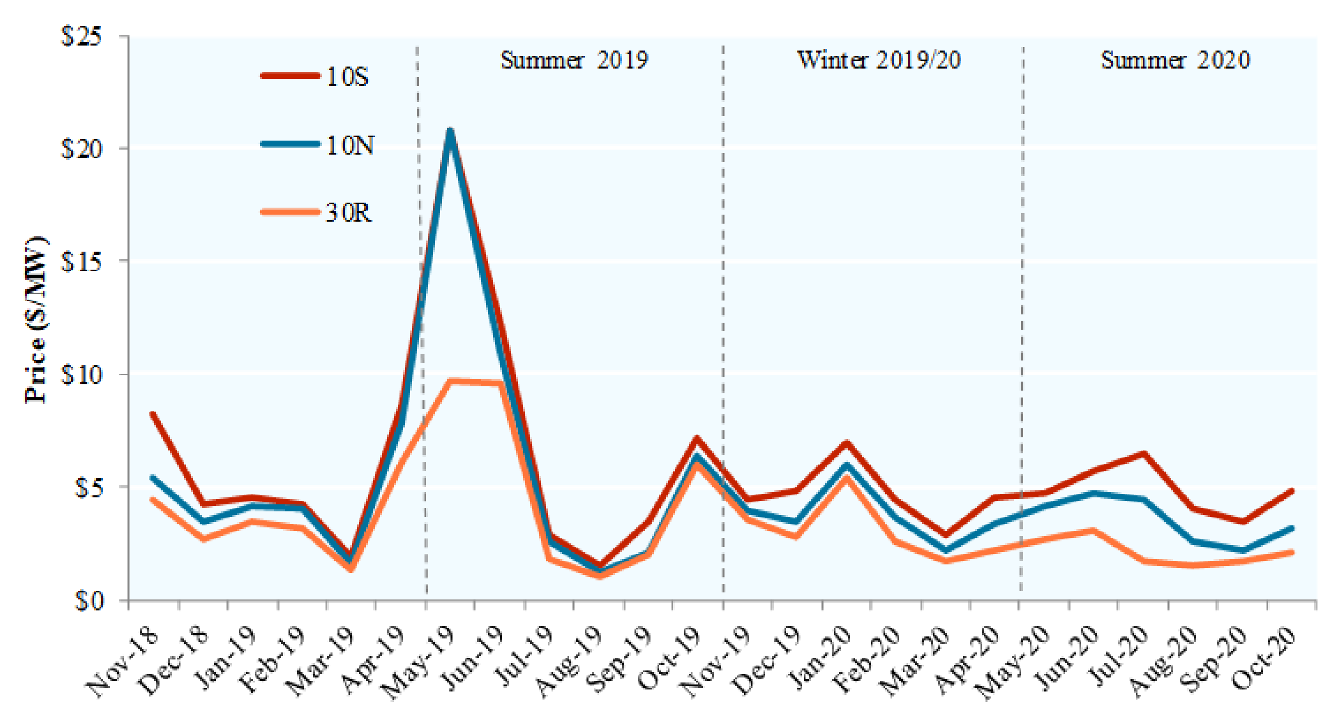


Figure A-13 plots the monthly average OR price for the two-year period from November 2018 through October 2020 for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N) and 30-minute reserve (30R).

Nodal Prices

Nodal prices approximate the marginal cost of electricity in each region 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.

As shown in Figure A-14, aside from West and Northeast, most zones had higher average prices in the Summer 2020 Period compared to the Summer 2019 Period.

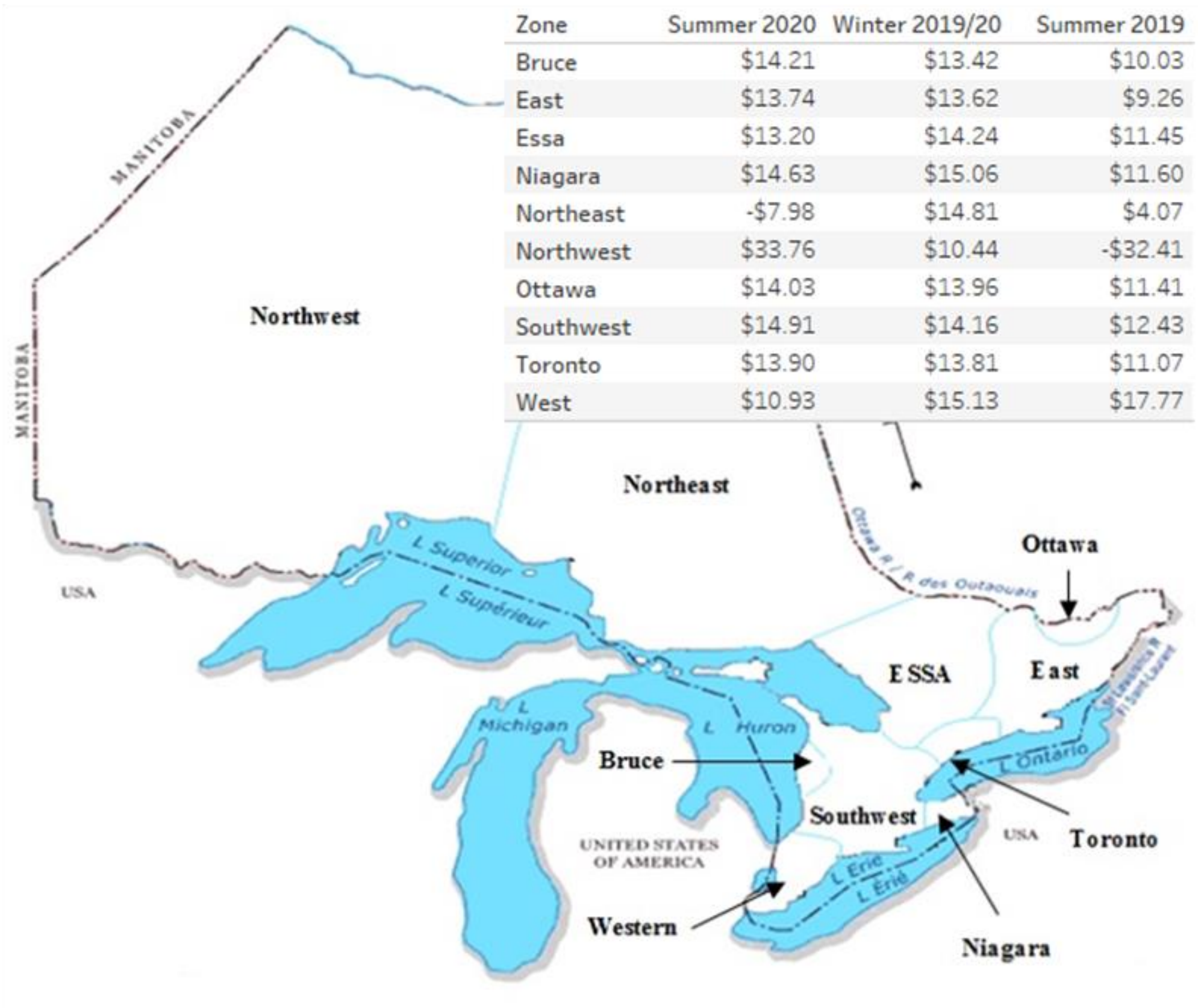
In general, monthly average nodal prices outside the two northern zones are similar and move together. Most of the time, the nodal prices in the Northwest and Northeast zones are significantly lower than in the rest of the province because there is more low-cost generation (typically hydroelectric supply) 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. For these reasons, prices in the Northwest and the Northeast zones are generally highly sensitive to changes in demand and hydroelectric supply.

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 in the Northeast likely caused the observed drop in nodal prices in the Summer 2020 Period, relative to the Summer 2019 Period.

The opposite of this effect occurred in the Northwest since the region’s hydroelectric supply dropped significantly and the nodal price increased substantially in the Summer 2020 Period, relative to historical averages. The nodal price in the Northwest was the highest nodal price across Ontario during the Summer 2020 Period. Prices in the Northwest were higher on average across all months in the Summer 2020 Period relative to the Summer 2019 Period, peaking between July 2020 and October 2020. As a whole, the average monthly demand in Northwest increased minimally in the Summer 2020 Period relative to the Summer 2019 Period, contributing little to the rise in the region’s zonal price. However, supply from hydroelectric generators in the Northwest fell by more than 20% in the Summer 2020 Period, relative to the Summer 2019 Period, the most significant decline in the region’s hydroelectric supply observed over the last five years (November 2015 through October 2020).[133] Since a majority of the Northwest's supply comes from hydroelectric resources, this decline was likely the most significant contributor to the rise in the region's zonal price in the Summer 2020 Period, relative to the Summer 2019 Period. Although there were significant increases in the nodal prices of resources near the Ontario-Manitoba intertie in the Northwest between July 2020 and October 2020, these changes likely had a much lower effect on the zonal price than the changes in hydroelectric supply.

[133] Hydroelectric supply conditions in the Northwest were evaluated by comparing the total hydroelectric supply available during a 6-month period across like seasons. For example, summer seasonal totals were not compared to winter seasonal totals.

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



Zone	Summer 2020	Winter 2019/20	Summer 2019
Bruce	$14.21	$13.42	$10.03
East	$13.74	$13.62	$9.26
Essa	$13.20	$14.24	$11.45
Niagara	$14.63	$15.06	$11.60
Northeast	-$7.98	$14.81	$4.07
Northwest	$33.76	$10.44	-$32.41
Ottawa	$14.03	$13.96	$11.41
Southwest	$14.91	$14.16	$12.43
Toronto	$13.90	$13.81	$11.07
West	$10.93	$15.13	$17.77

Figure A-14 illustrates the average nodal prices of Ontario's ten internal zones for the Summer 2020, Winter 2019/20 and Summer 2019 Periods.[134]

[134] Each zone has a series of nodes, with each node having its own shadow price. The average price for each zone is calculated by taking the simple average of the shadow prices for the nodes within that zone over every hour in the monitoring Period, and then taking a simple average of the price calculated for each hour in the monitoring Period associated with that particular zone.

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 pre-dispatch (PD-1) 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.

There were 175 hours of import congestion during the Summer 2020 Period, a 58% increase compared to the Summer 2019 Period. For the Summer 2020 Period, Québec experienced the highest number of import-congested hours. The Québec intertie experienced a 58% increase in the number of import-congested hours relative to the Summer 2019 Period. The highest number of import-congested hours occurred during July 2020 and August 2020, during which monthly imports from Québec were highest compared to other months during the Summer 2020 Period. During July 2020, the largest number of import congested hours within the month along the Québec intertie occurred on July 6, July 9 and July 10, 2020. Across all interties during July 2020, import congestion was highest from July 6, 2020 to July 10, 2020 compared to other days of the month, likely due to a high volume of scheduled imports during this time due to a rise in Ontario demand and the Hourly Ontario Energy Prices (HOEP). The highest number of import-congested hours also occurred in July 2019 and August 2019 of the Summer 2019 Period. The increase in the number of import congested hours along the Québec intertie indicates that there were likely more economic import offers along the Québec intertie for a given hour during the Summer 2020 Period than what could physically flow along the intertie. This trend was not observed during the Winter 2019/20 Period or the

Summer 2019 Period, since there was a decrease in the number of import congested hours along the Québec intertie during each of these periods.

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

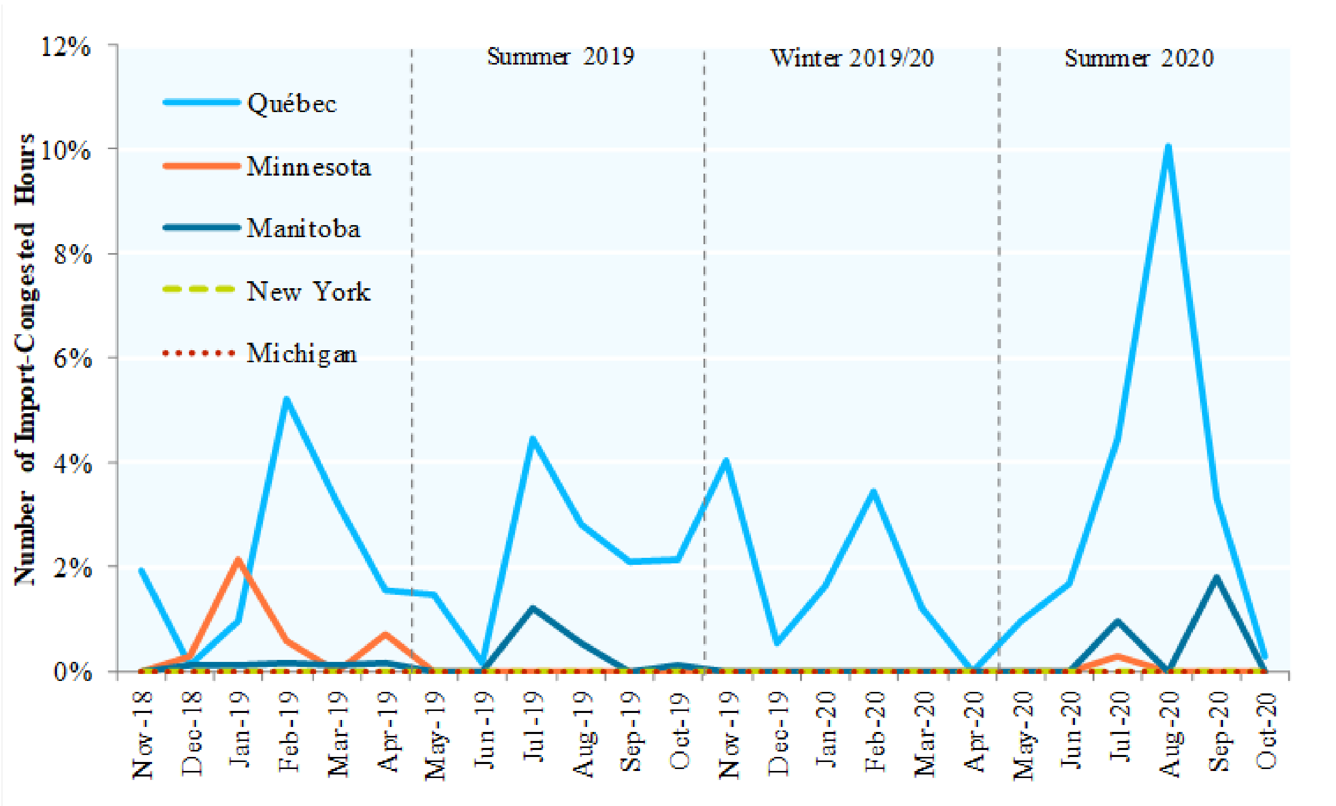


Figure A-15 reports the share of hours per month of import congestion by intertie relative to the total number of import congested hours of each season for the two-year period from November 2018 through October 2020. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

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

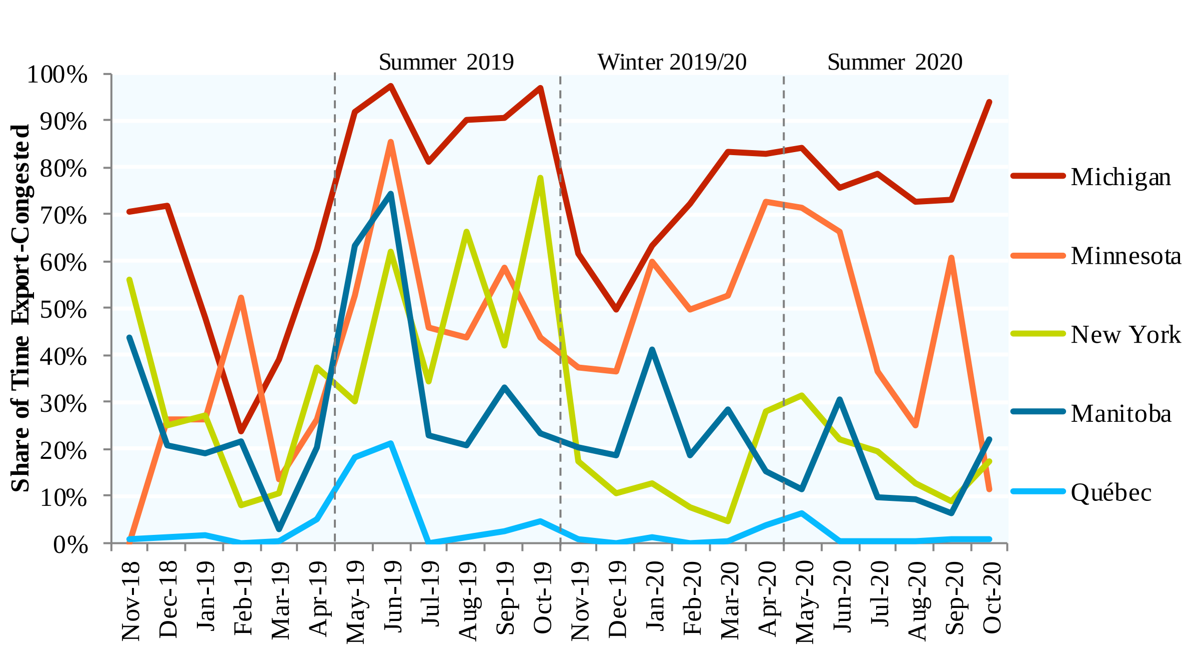


Figure A-16 reports the share of hours per month of export congestion by intertie relative to the total number of export congested hours of each season for the two-year period from November 2018 through October 2020. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

There were 7,051 hours of export congestion in the Summer 2020 Period, a 35% decrease compared to the previous summer. This decrease likely occurred because the Summer 2020 Period had higher Ontario prices than the previous Summer 2019 Period, giving Ontario less opportunity to export energy to other jurisdictions, reducing the probability of export congestion. The Québec intertie experienced the greatest decrease in export-congested hours, from 350 hours in the Summer 2019 Period to just 66 hours in the Summer 2020 Period. The number of export-congested hours decreased on all other interties during the Summer 2020 Period in comparison to the Summer 2019 Period. Across all interties during July 2020, export congestion was very low from July 9, 2020 to July 10, 2020, likely due to the rise in the average Ontario demand and the HOEP during this time. Generally, the amount of export congestion is significantly higher than the amount of import congestion experienced during a given season. Export congestion along the New York intertie was generally concentrated throughout the overnight hours of the Summer 2020 Period relative to the

Summer 2019 Period. There were no other distinct hourly trends across other interties during the Summer 2020 Period.

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.

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 – Ontario & Surrounding Jurisdictions, 1 Period

Date	Ontario (HOEP) ($/MWh)	Manitoba ($/MWh)	Michigan (MISO[135]) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO[136]) ($/MWh)	PJM[137] ($/MWh)
May 2020	7.31	18.34	27.05	26.62	13.31	13.31
Jun 2020	11.22	18.65	28.41	20.89	17.22	17.22
Jul 2020	18.60	24.78	43.07	27.57	24.56	24.56
Aug 2020	18.17	23.66	32.61	27.86	24.29	24.29
Sep 2020	13.78	17.75	25.21	19.47	19.47	18.69
Oct 2020	10.65	24.31	31.45	27.93	27.93	18.11

Table A-8 lists the average hourly real-time spot prices for electricity, by month in the Summer 2020 Period, in Ontario and the surrounding 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 average HOEP 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, when

[135] Midcontinent Independent System Operator

[136] New York Independent System Operator

[137] Pennsylvania New Jersey Maryland

there is not enough transmission available to move low cost energy from Ontario to other markets. Michigan and Minnesota had the highest number of congested hours during the Summer 2020 Period compared to other interties, which is reflected in the large difference in market price relative to Ontario's HOEP.

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

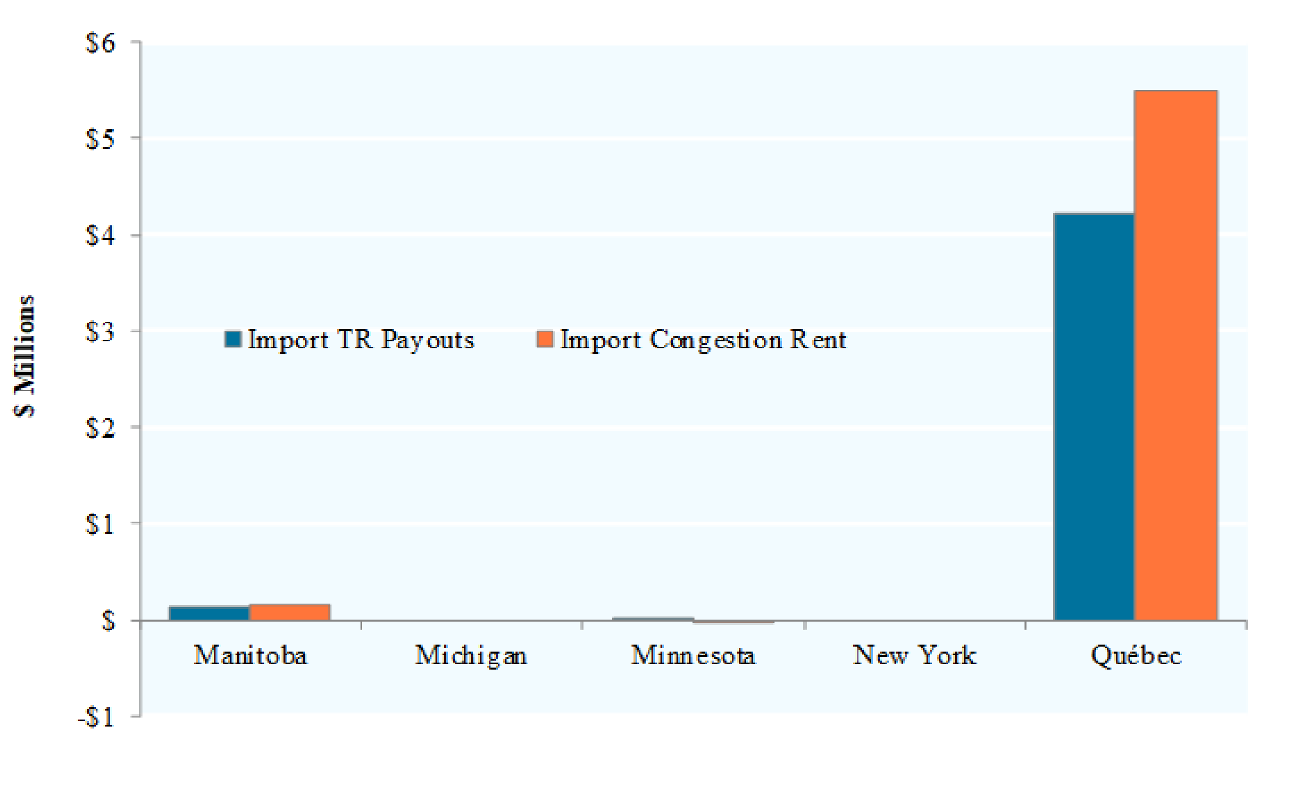


Figure A-17 compares the total import congestion rent collected to total TR payouts by intertie for the Summer 2020 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

An IZP is less than the Ontario price when an intertie is import congested; the difference in prices is the pre-dispatch ICP and is equal to the difference (if any) between the pre-dispatch PD-1 Market Clearing Price (MCP) and the PD-1 IZP. In real-time, the ICP is equal to the difference between the real-time IZP and the real-time MCP. 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. 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.[138] 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 covered primarily by funds from the TRCA, which include TR auction revenues, (proceeds from selling TRs, a payment into the TRCA), and surplus revenues from other ties.

Total import TR payouts in the Summer 2020 Period were $4.3 million, while total import congestion rent was $5.6 million, creating a congestion rent surplus of $1.3 million. This congestion rent surplus was essentially all on the Québec intertie. Québec’s congestion rent surplus was largely due to there being less megawatts of TRs for the Québec intertie than there were megawatts being transacted over the intertie during hours of extreme import congestion in the Summer 2020 Period, causing congestion rent to exceed TR payments collected during these hours.

[138] For more information on the short-term and long-term TR auctions held by the IESO, see page 11 of: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-TransmissionRights.ashx

Export TR payouts in the Summer 2020 Period totalled $48.3 million, while export congestion rent totalled $52.8 million. This $4.5 million surplus of congestion rent is primarily due to the $3.2 million excess of congestion rent over TR Payouts on the New York intertie, as well as the $1.6 million excess of congestion rent over TR payouts on the Michigan intertie. These surpluses in congestion rent in the Summer 2020 Period were partly offset by smaller congestion rent shortfalls on the Manitoba intertie.

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

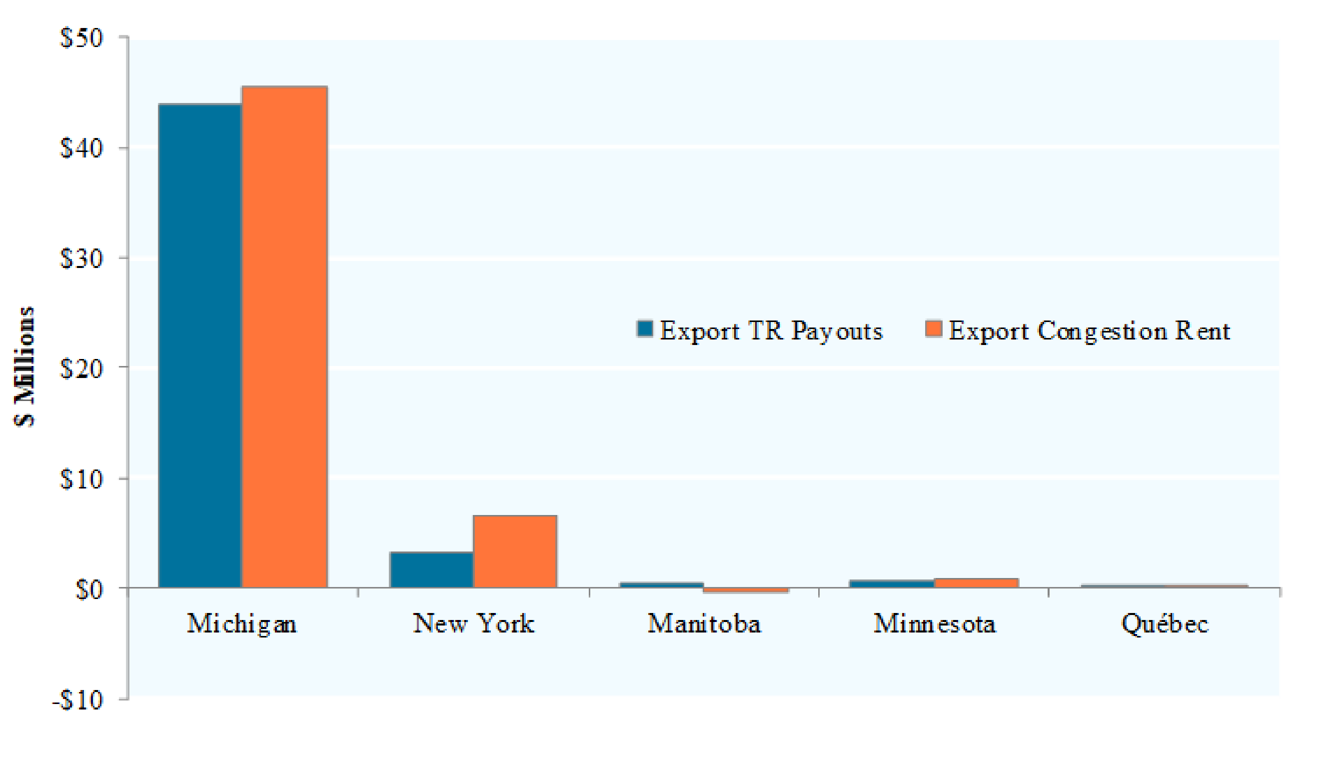


Figure A-18 compares the total export congestion rent collected to total TR payouts by intertie for the Winter 2018/19 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

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 import congestion to increase, and vice versa. Long-term import TR prices for the May 2020 auction decreased for Manitoba and Michigan, increased for Minnesota and were little changed for

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

Table A-9: Average 12-Month TR Auction Prices by Intertie & Direction, 1 Year

Direction	Auction Date	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	Nov-19	Jan-20 to Dec-20	225	23	773	95	1,587
	Feb-20	Apr-20 to Mar-21	363	112	1,082	228	4,634
	May-20	Jul-20 to Jun-20	169	49	1,239	239	4,600
	Aug-20	Oct-20 to Sep-21	210	140	981	218	7,540
Export	Nov-19	Jan-20 to Dec-20	22,376	21,582	20,639	11,159	1,023
	Feb-20	Apr-20 to Mar-21	14,053	80,706	40,339	19,909	3,610
	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

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 from November 2019 through August 2020. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie. These are the TRs that would have been valid during the Summer 2020 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.

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	Nov-19	35	2	97	-	185
	Dec-19	1,015	131	966	210	8,784
	Jan-20	31	-	375	19	543
	Feb-20	27	-	271	10	565
	Mar-20	28	-	-	12	655
	Apr-20	22	-	-	12	670
	May-20	23	-	-	5	306
	Jun-20	15	-	-	5	224
	Jul-20	14	-	-	1	655
	Aug-20	-	1	-	7	1,116
	Sep-20	-	-	-	6	900
	Oct-20	-	1	-	5	766
Export	Nov-19	4,248	9,254	4,777	-	158
	Dec-19	36,103	83,555	48,400	36,102	4,480
	Jan-20	-	2,805	3,378	2,777	400
	Feb-20	-	2,680	4,444	955	494
	Mar-20	-	3,817	4,717	744	67
	Apr-20	-	6,502	-	510	55
	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

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 Summer 2020 and Winter 2019/20 Periods. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie. Auction prices signal Market Participant expectations of intertie congestion conditions for the forward period.

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.

The balance of the Transmission Rights Clearing Account (TRCA) decreased to $75.0 million at the end of the Summer 2020 Period (October 2020), down from $85.1 million at the end of the Winter 2019/20 Period (April 2020).[139, 140] The October 2020 balance was $55 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:[141]

1. $101.8 million in revenue, specifically:
    - $58.5 million in congestion rent
    - $43.1 million in auction revenues
    - $0.2 million in interest
2. $111.9 million in debits, specifically:
    - $52.7 million in TR payouts
    - $59.2 million in disbursements to Ontario consumers and exporters.

[139] 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.

[140] For reference, the balance at the end of the Summer 2019 Period (October 2019) was $94.4 million.

[141] 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; monthly, 5 Years

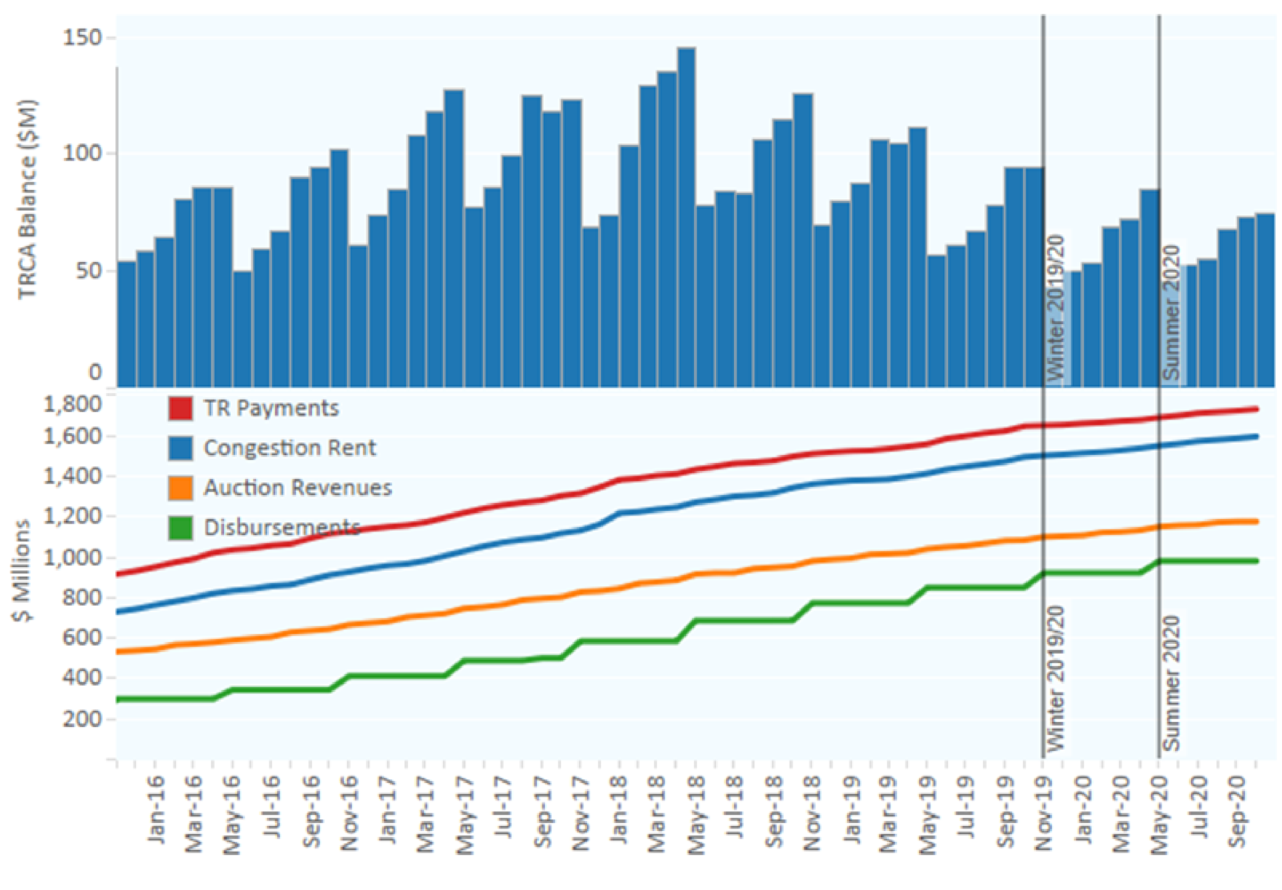


Figure A-19 shows the estimated balance in this account at the end of each month for the five-year period from November 2015 through October 2020, as well as the cumulative effect of each type of transaction impacting the account.

A.2 Demand

Total demand in the Summer 2020 Period was 68.7 TWh – 0.9% higher than the total demand of 68.1 TWh in the Summer 2019 Period. The increase in total demand was generally concentrated throughout the months of June 2020 to August 2020, when average temperatures were higher than historical seasonal averages. Total demand was highest during July 2020 and August 2020 when Ontario's COVID-19 public health measures became more relaxed and enabled many nonessential businesses to re-open. Ontario experienced high Summer 2020 demand peaks, likely due to the increase in temperatures and the Industrial Conservation Initiative (ICI) peak demand factor hiatus.[142]

In reference to the total seasonal demand, demand from Class A consumers in the Summer 2020 Period was 19.4 TWh – a 5.4% reduction compared to the Summer 2019 Period. As a result of the stay-in-place order, more people were working from home during the Summer 2020 Period which increased residential consumption, particularly in the residential sector air conditioning load, as temperatures increased.[143] The Class B demand for the Summer 2020 Period was 49.2 TWh – a 3.5% increase compared to the Summer 2019 Period. Generally, Class B consumers tend to be more weather sensitive than Class A consumers. As a result, the Class B demand peaked in July 2020 and August 2020, when temperatures were highest during the Summer 2020 Period and when Ontario's economy began to re-open allowing industrial and commercial loads increase their consumption to pre-COVID levels.[144]

[142] For more information on the Summer 2020 demand peaks, see the IESO's Reliability Outlook for October 2020 to March 2022, page 6: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook

[143] Ibid.

[144] Ibid.

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

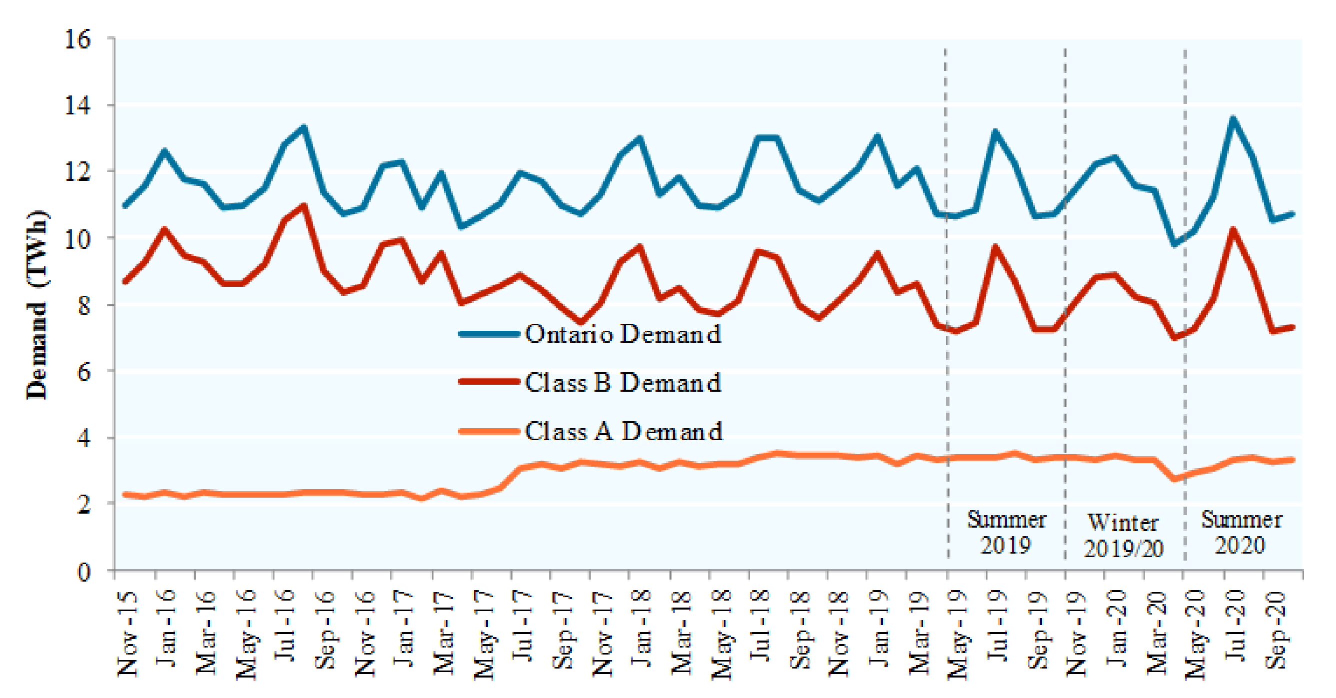


Figure A-20 displays energy consumption by all Ontario consumers in each month of the five-year period from November 2015 through October 2020, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand – not grid-connected demand – in that it includes demand satisfied by embedded generators.[145]

[145] 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: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_Nov2013- and the Panel's ICI Report published December 2018: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

A.3 Supply

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

Table A-11: Changes in Generating Capacity, During Q2 and Q3 of 2020

Generation Type	Grid-connected		Distribution-level ("Embedded")	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	0	13,009	0	0
Natural Gas	**47**	**11,317**	0	0
Hydro	-5	9,060	11	297
Wind	0	4,486	0	590
Solar	0	478	0	2,166
Biofuel	0	295	0	110
Gas-Fired and Combined Heat and Power (CHP)	0	0	0	299
Energy from Waste	0	0	0	24
Total	42	38,645	11	3,486

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 second and third quarters of 2020, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[146] Total capacity of each type at the end of the third quarter of 2020 is also shown.

Little new capacity was added to the Ontario generation fleet at either the IESO-controlled grid or the distribution level. The 47 MW increase in grid-connected natural gas likely resulted from an earlier increase in grid-connected gas in the Winter 2019/20 Period from a Napanee facility.

[146] Grid-connected capacity totals were obtained from the quarterly Reliability Outlook and embedded capacity totals were obtained from the quarterly Progress Report on Contracted Energy Supply: http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook and https://www.ieso.ca/power-data/supply-overview/transmission-connected-generation

Small amounts of embedded generation hydro were also added by the end of the third quarter of 2020.

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

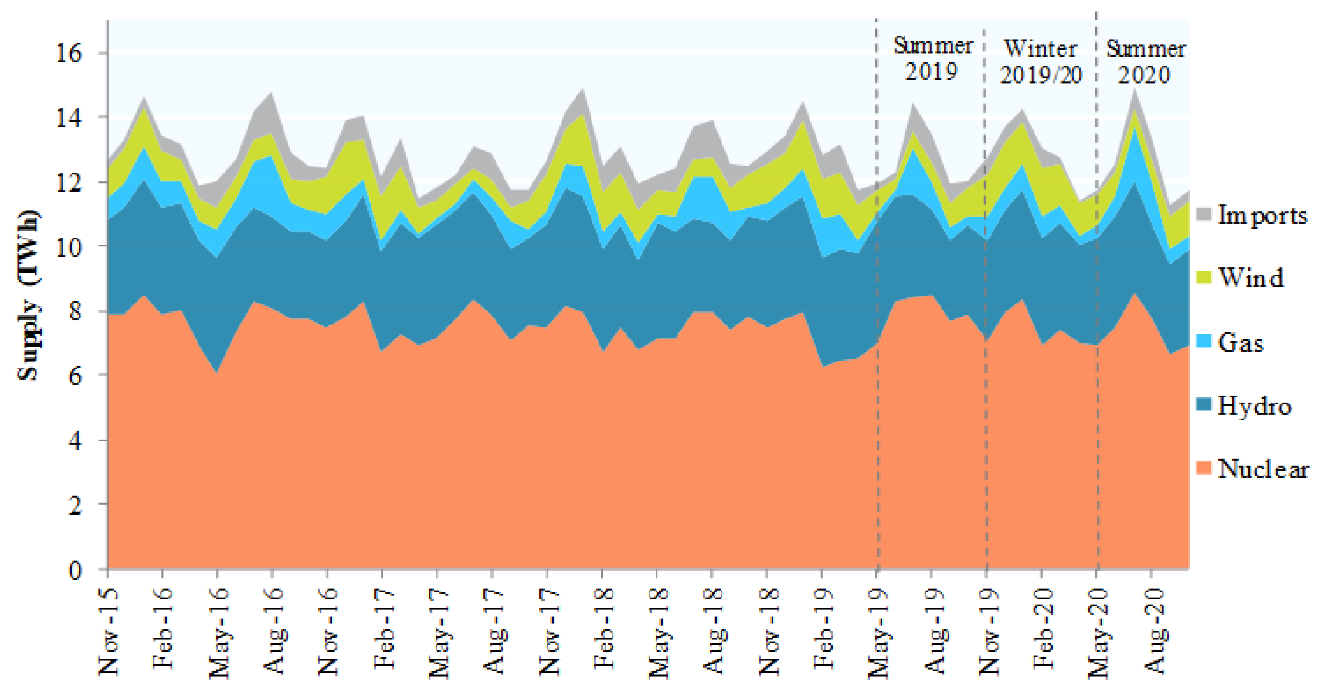


Figure A-21 displays the real-time unconstrained production schedules for each month of the five-year period from November 2015 through October 2020 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear and imports.[147] Changes in the resources scheduled may be the result of 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).

Compared to the Summer 2019 Period, the Summer 2020 Period showed a 7% decrease in the output of nuclear generators from 47.8 TWh to 44.2 TWh. Output from gas-fired generators increased by 45% from 3.4 TWh to 4.9 TWh. Output from wind resources increased by 27%

[147] Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time. Ontario has significant solar and wind generation connected at the distribution level that is not included in this figure. These embedded resources are not scheduled in the IESO-Administered Market. Average output from these embedded generators was approximately 0.5 TWh per month; due to data constraints, this quantity cannot be broken down by type of generation.

from 3.8 TWh to 4.9 TWh. Output from imports decreased by 14% from 2.9 TWh to 2.5 TWh. Output from imports were highest during July 2020 and August 2020, when import congestion was highest during the Summer 2020 Period. This is similar to the Summer 2019 Period, where imports also peaked during these months at higher magnitudes. Within the month of July 2020, daily imports were highest from July 8, 2020 to July 10, 2020. The significant increase in the output from gas-fired generators was concentrated during July 2020 and August 2020, when the average monthly Hourly Ontario Energy Prices (HOEP) and the average monthly Ontario demand were highest in the Summer 2020 Period. Although output from imports also peaked during these months, it contributed much less than production from gas resources.

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

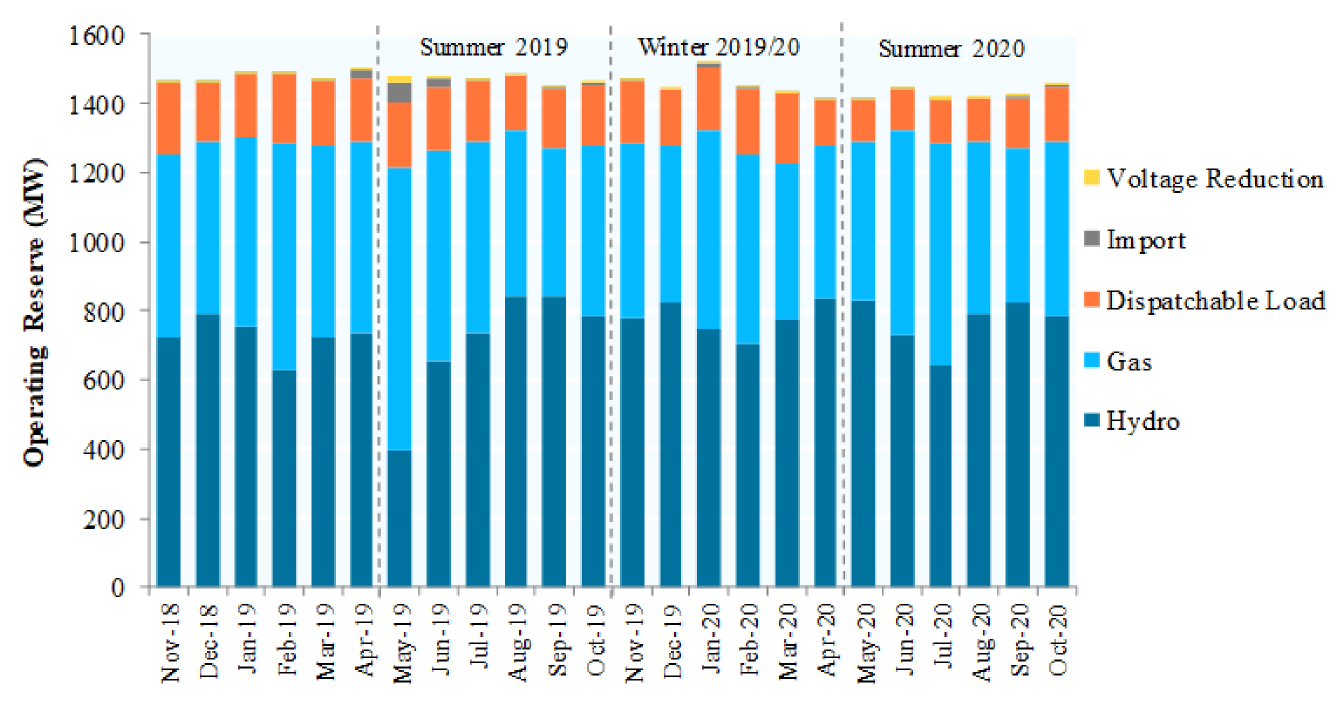


Figure A-22 displays the real-time unconstrained OR schedules for each month of the two-year period from November 2018 through October 2020 by resource or transaction type: hydroelectric, gas-fired, dispatchable loads, imports and voltage reduction (taken as a control action by the IESO).[148] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

[148] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only scheduled in real-time, never in pre-dispatch. Voltage reductions are an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.

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

Quantity	Summer 2019	Winter 2019/20	Summer 2020
Average OR Scheduled (MW)	1,472 MW	1,460 MW	1,435 MW
Dispatchable Load Share (%)	12%	12%	9%
Natural Gas Share (%)	38%	34%	37%
Hydro Share (%)	48%	53%	54%
Other Share (%)	2%	1%	1%

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 in the Summer 2019, Winter 2019/20 and Summer 2020 Periods. It is based on the same data as Figure A-22. "Other" is the sum of OR from imports and voltage reduction.

Figure A-23: Unavailable Generation Relative to Installed Capacity, 2 Years

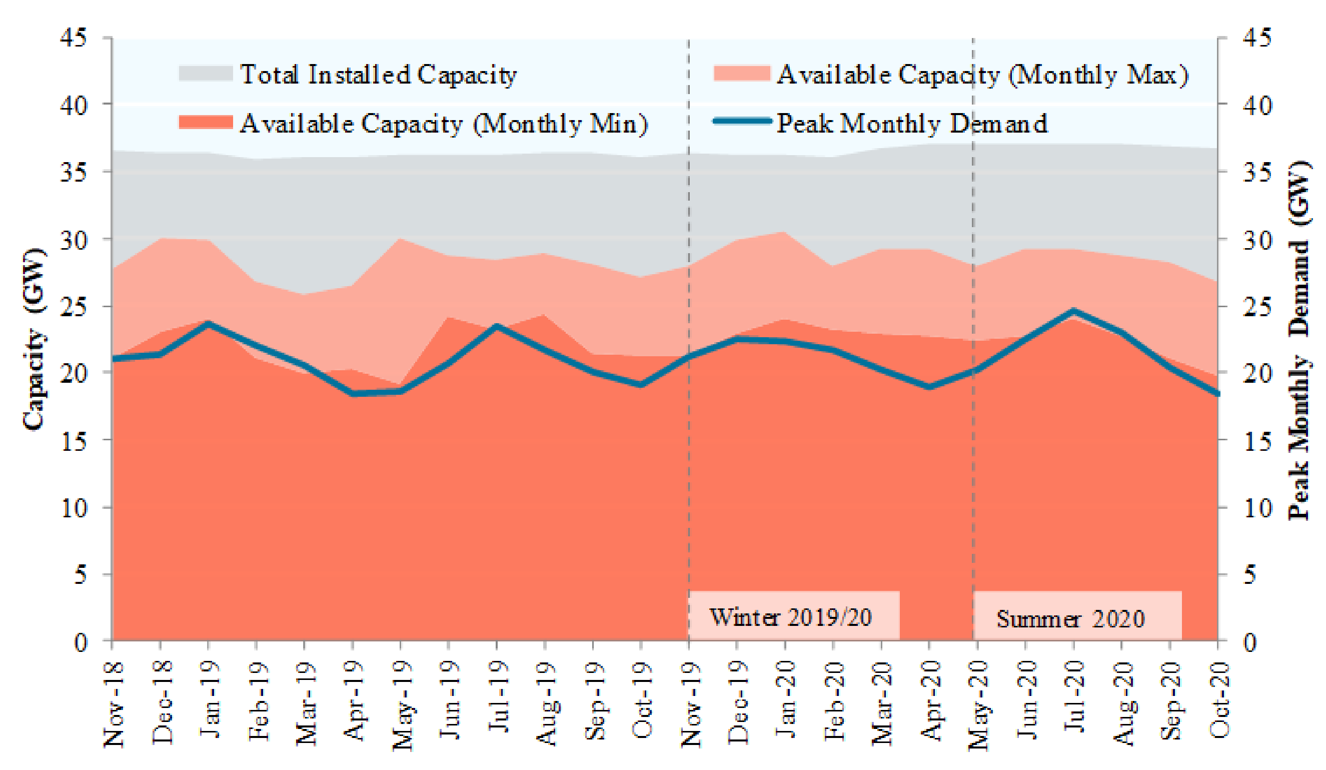


Figure A-23 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits for the two-year period from November 2018 through October 2020. The maximum and minimum megawatts on outage during a given month can be observed by comparing the total installed capacity to the monthly minimum and maximum available capacity, respectively. For reference, the figure also includes the monthly peak market demand, excluding demand served by imports.[149]

As a whole, the Summer 2020 Period had, on average, 11.9 GW of unavailable capacity, which is 7% more than the average of 11.1 GW of capacity that was unavailable in the Summer 2019 Period. This difference was primarily driven by a 42% increase in nuclear outages between the Summer 2019 Period and the Summer 2020 Period. A majority of

[149] Unavailable generation capacity data was obtained from adequacy reports published daily by the IESO. Daily, weekly and monthly market summaries published by the IESO can be found on the IESO website, available at: http://www.ieso.ca/power-data/market-summaries-archive

nuclear outages took place between September 2020 to October 2020. There were smaller increases in wind and solar outages. Minimum and maximum available capacity were lower in the Summer 2020 Period by about 0.13 GW and 0.22 GW on average compared to the Summer 2019 Period, respectively. Although there was an increase in the overall amount of unavailable capacity during the Summer 2020 Period, the monthly minimum available capacity was highest during July 2020, when the peak monthly demand was highest during the season. During July 2020, daily amounts of unavailable capacity were highest on July 8, 2020 to July 10, 2020 in comparison to other days within the month. During July 2020, the daily unavailable capacity from gas resources peaked on July 7, 2020, July 8, 2020 and July 10, 2020. Similarly, the daily unavailable capacity from nuclear resources was highest from July 9, 2020 to July 11, 2020 compared to other days of the month. During the Summer 2020 Period, average monthly unavailable capacity was highest during September 2020 and October 2020 when peak monthly demand was lower on average.

A.4 Imports, Exports and Net Exports

This section examines import and export transactions in the constrained sequence, as schedules in this sequence mostly closely reflect actual power flows.[150]

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

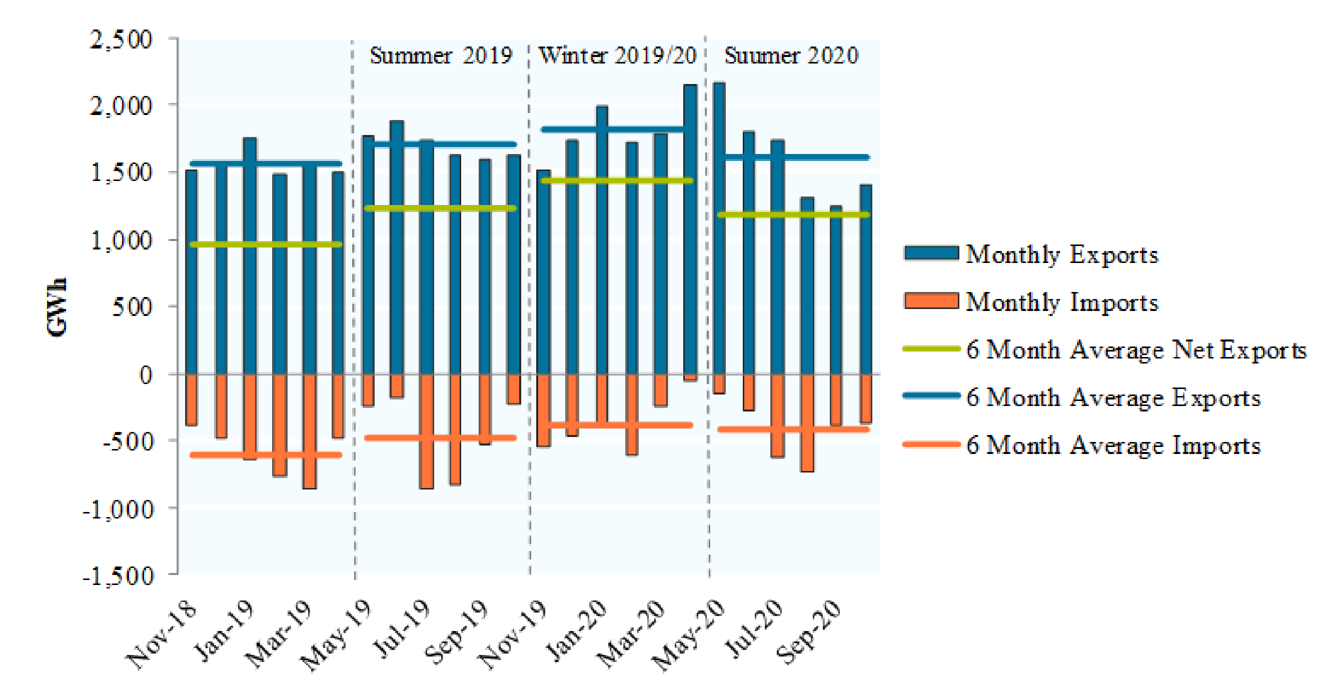


Figure A-24 plots total monthly imports and exports for the two-year period from November 2018 through October 2020, as well as the average monthly imports, exports and net exports calculated over each 6-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Ontario remained a net exporter in the Summer 2020 Period, with net exports of 7.11 TWh over the six months, down from 7.36 TWh in the Summer 2019 Period. Compared to the Summer 2019 Period, exports fell by 0.57 TWh, and imports decreased by 0.32 TWh. The decrease in net exports over the Summer 2020 Period was primarily driven by a large

[150] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not impact Intertie Congestion Prices (ICPs) or the Ontario uniform price.

decrease in exports to Manitoba, Québec and Minnesota, likely due to the rise in the Hourly Ontario Energy Price (HOEP) during the Summer 2020 Period. Imports likely decreased due to a drop in the average volume of energy imported from Québec in the Summer 2020 Period compared to the Summer 2019 Period.

Figure A-25: Exports by Intertie, 2 Years

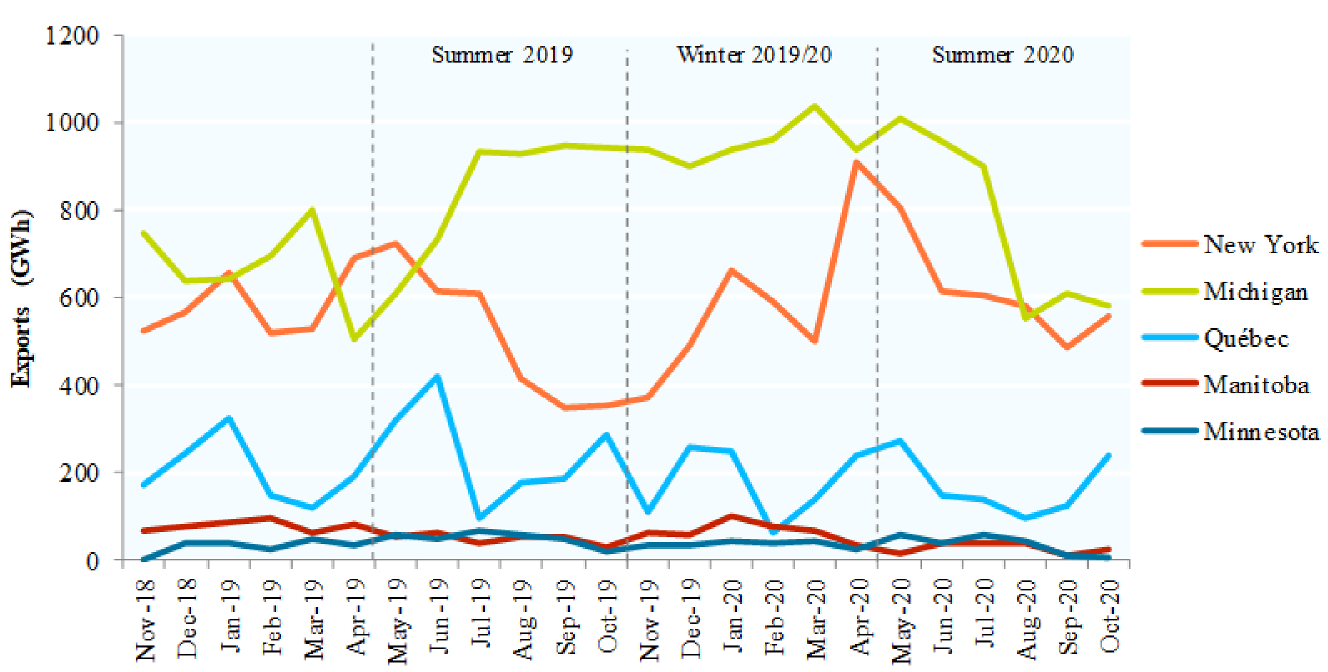


Figure A-25 presents a breakdown of exports for each month of the two-year period from November 2018 through October 2020 from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly export quantities over the Winter 2019/20 and Summer 2020 Periods are given for each intertie in Table A-13.

Figure A-26: Imports by Intertie, 2 Years

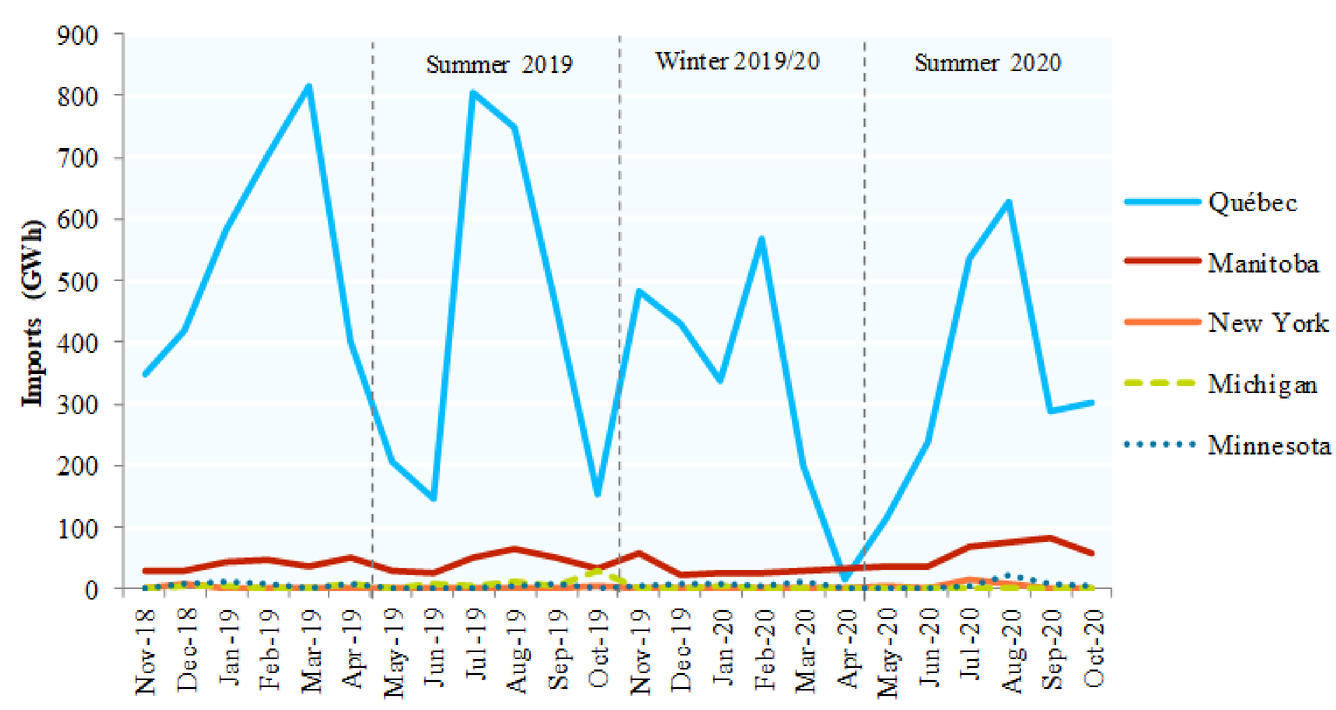


Figure A-26 presents a breakdown of imports for each month of the two-year period from November 2018 through October 2020 to and from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly import quantities over the Winter 2019/20 and Summer 2020 Periods are given for each intertie in Table A-14.

Exports fell across all jurisdictions except New York. Exports to New York rose from an average of 511 GWh per month in the Summer 2019 Period to an average of 607 GWh per month in the Summer 2020 Period. Exports to New York were highest during May 2020 when the average monthly HOEP was lowest in the Summer 2020 season. Generally, exports to New York and the average monthly HOEP have a moderate inverse relationship. This trend indicates that New York generally purchased more energy from Ontario when prices were lower than average.

The drop in exports to Manitoba, Minnesota, Michigan and Québec were likely driven by the increase in the HOEP in the Summer 2020 Period compared to the Summer 2019 Period, which generally reduces all export opportunities from Ontario.

Imports from Québec decreased from an average of 420 GWh per month in the Summer 2019 Period to an average of 351 GWh per month in the Summer 2020 Period. Imports from Québec were lower on average between July 2020 and September 2020 compared to the monthly averages between July 2019 and September 2019. During July 2020, daily imports from Québec were highest on July 8, 2020 and July 9, 2020 compared to other days of the month.

Aside from a decline in imports from Québec and Michigan, imports from all other jurisdictions increased significantly between the Summer 2019 Period and Summer 2020 Period. New York and Minnesota supplied the largest increase in imports between the Summer 2019 Period and the Summer 2020 Period, from 1.84 GWh to 4.46 GWh and 3.12 GWh to 6.46 GWh, respectively. Looking at individual days, during July 2020, daily imports from New York and Michigan were highest from July 8, 2020 to July 10, 2020 compared to other days of the month. Aside from Manitoba and Minnesota where monthly imports were highest during July 2020 and August 2020, monthly imports across all other interties were substantially greater during the months of July 2020 and August 2020 compared to other months of the Summer 2020 Period.

Failed or curtailed exports reduce demand between pre-dispatch (PD-1) and real-time. The Market Participant (MP) percentage failure rate of exports increased from Winter 2019/20 to Summer 2020 on the Manitoba and New York interties. As in previous periods, in the Summer 2020 Period the Market Participant percentage failure rate for Manitoba remained much higher than for other interties.

The rate of Independent System Operator (ISO)-curtailed exports in the Summer 2020 Period was relatively low for all of Ontario’s interties. This rate tends to follow a seasonal pattern for Manitoba and Minnesota, with higher failure rates in the summer and lower rates in the winter.

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

Intertie	Average Monthly Export (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate (Percent)			
			ISO Curtailment		Market Participant Failure		ISO Curtailment		Market Participant Failure	
	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020
New York	597	621	1.7	0.6	9.1	13.2	0.3%	0.1%	1.5%	2.1%
Michigan	942	769	3.1	1.6	10.9	8.8	0.3%	0.2%	1.2%	1.1%
Manitoba	93	49	1.2	1.5	24.0	19.5	1.2%	3.1%	**25.9%**	**39.9%**
Minnesota	39	37	0.5	0.7	1.0	0.9	1.2%	1.8%	2.5%	2.5%
Québec	172	167	2.6	2.4	2.0	1.0	1.5%	1.4%	1.2%	0.6%

Table A-13 average monthly export curtailments and failures over the Summer 2020 and Winter 2019/20 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.[151] Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (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.

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 MP Failures and ISO Curtailments.

The percentage rate of ISO Curtailments for imports increased in the Summer 2020 Period compared to the Winter 2019/20 Period for all interties except Michigan and Québec. The Market Participant Failure rate for imports increased on the Michigan and Minnesota interties in the Summer 2020 Period compared to the Winter 2019/20 Period.

[151] A linked wheel transaction is one in which an import and an export are explicitly linked together from a scheduling perspective, with the intention of moving power through Ontario.

Table A-14: Average Monthly 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 (Percent)			
			ISO Curtailment		Market Participant Failure		ISO Curtailment		Market Participant Failure	
	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020	Winter 2019/20	Summer 2020
New York	1	5	0.0	0.1	0.2	0.2	0.0%	1.2%	**29.8%**	**3.5%**
Michigan	1	1	0.1	0.1	0.0	0.2	6.7%	4.1%	**5.2%**	**15.7%**
Manitoba	34	66	0.9	4.7	0.5	1.1	2.6%	7.1%	1.3%	1.7%
Minnesota	7	8	0.2	0.7	0.6	1.2	2.1%	8.5%	**8.2%**	**13.9%**
Québec	316	340	4.7	4.0	0.7	0.3	1.5%	1.2%	0.2%	0.1%

Table A-14 reports average monthly import failures and curtailments the Summer 2020 and Winter 2019/20 Periods by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.