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

Market Surveillance Panel Report 34

MONITORING REPORT ON THE IESO-ADMINISTERED ELECTRICITY MARKETS

Released January 2021

2300 Yonge Street, 27th floor, P.O. Box 2319, Toronto, ON, M4P 1E4
2300 rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4

T 416-481-1967 1-888-632-6273
F 416-440-7656 **OEB.ca**

This page was intentionally left blank.

Table of Contents

List of Figures

List of Tables

Role of the Market Surveillance Panel

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

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

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

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

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

Executive Summary

This is the 34th Market Surveillance Panel Monitoring Report published since market opening in 2002. Monitoring Reports have historically each assessed one 6-month monitoring period; however, this report covers three 6-month monitoring periods, from November 1, 2018 to April 30, 2020 (Winter 2018/19, Summer 2019 and Winter 2019/20 Periods). Information relating to each of the three monitoring periods is presented separately to maintain consistency with previous Panel reports. The consolidation of three monitoring periods in this report will enable the Panel's future monitoring reports to cover 6-month periods that are closer to the date of issuance, increasing their relevance for interested stakeholders.

In addition to covering events for the three monitoring periods (Chapter 2 and Appendix A, B and C), this report also covers more recent events of interest in the electricity sector (Chapter 1).

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

- Chapter 1: Market Developments and Status of Recent Panel Recommendations
- Chapter 2: Analysis of Anomalous Market Outcomes
- Appendix A: Market Outcomes for the Winter 2018/19 Period
- Appendix B: Market Outcomes for the Summer 2019 Period
- Appendix C: Market Outcomes for the Winter 2019/20 Period

Chapter 1: Market Developments and Status of Recent Panel Recommendations

Seven recent market developments are considered noteworthy by the Panel: a change in the Industrial Conservation Initiative; summer 2020 Demand Response activations; developments relating to the IESO's proposed Capacity Auction and planning for resource adequacy; developments in the Operating Reserve market; the IESO's Storage Design project; activation payments for Demand Response resources; and the Ontario Energy Board's approval of Must-Offer Condition Agreements in connection with recent acquisitions of generation facilities by

Ontario Power Generation Inc. Responses from the IESO to previous Panel recommendations are also presented.

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter deals with events in the Winter 2018/19, Summer 2019 and Winter 2019/20 Periods that exceed predefined thresholds established to identify outcomes considered anomalous and are therefore potentially significant for the IESO-Administered Markets.

Chapter 1: Market Developments and Status of Recent Panel Recommendations

This chapter contains an update on recent developments related to the IESO-Administered Markets and provides commentary on the IESO's responses to recommendations contained in the Panel's previous semi-annual Monitoring Report.

1.1 Developments Related to the IESO-Administered Markets

1.1.1 COVID-19 Pandemic and Changes to the Industrial Conservation Initiative (ICI)

The COVID-19 pandemic and related policy actions have affected the real-time energy markets in many ways. Weekday demand was 7% to 14% lower than normal in April and May 2020.[1] As a result, there was oversupply that resulted in low prices, nearly nonexistent imports and very high exports. Market outcomes attributable to COVID-19 are discussed further in Appendix C: Market Outcomes for the Winter 2019/20 Period.

On June 26, 2020 the Government of Ontario announced a change in the Industrial Conservation Initiative (ICI) which effectively removed the need for existing Class A consumers to reduce their demand on peak days during the Summer 2020 season.[2] Class A demand reduction accounts for an estimated 1,600 MW, which is more than 7% of Ontario's 2019 peak

[1] See the IESO's presentation "Electricity System Impact of COVID-19", dated May 20, 2020, slide 23: http://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2020/Electricity-System-Impacts-of-COVID-20200520.pdf?la=en

[2] 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: http://www.ontario.ca/laws/regulation/040429 and https://news.ontario.ca/en/release/57417/ontario-provides-stable-electricity-pricing-for-industrial-and-commercial-companies

demand.[3] Amid the ICI peak demand factor hiatus and unusually hot temperatures, the 2020 summer peak was the highest since 2013 despite the overall demand reduction associated with COVID-19.[4]

1.1.2 Summer 2020 Demand Response Activations

Under program rules, Demand Response (DR) can be economically scheduled or, in an emergency, activated out-of-market by the IESO.[5] The Panel has previously questioned the value provided by DR resources, noting that these resources had not been activated in the energy market either economically or as an emergency resource. Both varieties of DR activation occurred for the first time in the summer of 2020.

On July 9, 2020, the IESO declared a North American Reliability Corporation (NERC) Energy Emergency Alert 1 due to summer peak demand conditions and unplanned generator outages. The control room activated all available DR resources later that day, and performed another emergency DR activation on July 10.[6] Preliminary performance results were presented at an October 2020 DR Working Group meeting; some DR resources failed to provide demand

[3] The peak reduction attributed to ICI has grown since its introduction in 2011. Consumer-initiated peak reduction in a given year can reduce capacity costs only if it also leads to reduced capacity acquisition in the future. Ontario had surplus capacity on long-term commitments in the 2010s, so the growing peak reduction from ICI has not lead to commensurate savings in capacity acquisition costs.

[4] 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.

[5] For more information on emergency procedures for a potential supply shortfall, including emergency DR activations, see Market Manual 7.1: IESO Controlled Grid Operating Procedures, Appendix B: http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/system-operations/so-SystemsOperations.pdf?la=en

[6] Two tranches of DR were activated at 12:04 (for hour ending (HE) 16 to HE 19) and at 13:44 (for HE 18 to HE 21). Control room logs show that the IESO had a need for a six-hour product (DR is required to provide up to four hours of demand reduction).

reductions as scheduled, while other DR resources provided greater reductions than the amount scheduled. As of December 15, 2020 – five months after the activations – final performance results remain unavailable.

Setting dispatch compliance aside, emergency DR activations also raise questions about energy pricing and out of merit dispatch. DR resources are compensated at their bid price – typically $1,999/MWh – for energy curtailed during an emergency activation. DR is the only resource type which can be dispatched in this way. In contrast, the Hourly Ontario Energy Price (HOEP) peaked at approximately $200/MWh on July 9 and $100/MWh on July 10.[7]

On August 27, 2020, a single DR resource was activated economically. Unconstrained prices were typical that day, with the HOEP peaking at about $25/MWh. DR resources are required to submit bids at or below the maximum market clearing price (MMCP) of $2,000/MWh during the availability window, and most bid at nearly the $ 2,000/MWh cap. DR resources are activated economically based on the results of the pre-dispatch constrained sequence, which can, in some cases, produce shadow prices that exceed the MMCP. In this case, the pre-dispatch shadow prices at this resource's node exceeded $38,000/MWh and as a result this resource was activated.

1.1.3 Capacity Auction and Resource Adequacy Engagement

Capacity procurement continues to be a complex and active area of development. Through the summer and fall 2020, the IESO provided more details on the planned 2020 Capacity Auction (CA) and launched the Resource Adequacy (RA) engagement, opening discussion of multi-

[7] When activated for an emergency, a DR resource is eligible for a payment based on the amount by which its bid – typically $1,999/MWh – exceeds the HOEP for that hour. For more information, see the IESO's Market Manual 5.5, page 49: http://www.ieso.ca/en/sector-participants/market-operations/-/media/b2ac386186ab499395164aa3146e9cca.ashx

year capacity commitments. The Panel has made several recommendations on capacity auctions with a focus on improving the transparency and oversight of auction targets.

The CA originally scheduled for June 2020 was rescheduled to December 2, 2020 due to COVID-19 impacts. The CA subsumed the DR auction that has run each December from 2015 to 2019. In addition to DR, the CA allowed participation from storage resources, dispatchable generators without a contract and a limited amount of system-backed, firm import capacity.[8]

Target capacities for the December 2020 auction were 700 MW for the Summer 2021 Period and 0 MW for the Winter 2021/22 Period. Using a summer-only target capacity is another significant change from the DR auction; the 2019 auction had a 675 MW target for both seasons.

The Panel has maintained that there is little value in procuring capacity when it is not needed. In the Panel's previous Monitoring Report 33 published in December 2020, the Panel questioned the utility of the "Reliability Assurance" rationale that appeared to be the basis for procuring capacity for the CA scheduled for the winter of 2020/21, recommending that the IESO publish the analysis and methodology.[9] The Panel understands this rationale is based on the concept of procuring resources that are not needed now to increase the likelihood that these resources will be available three to five years from now when there may be a need.

The IESO's recent decision to set the target capacity for the Winter 2021/22 Period to 0 MW suggests that "Reliability Assurance" is no longer being used as a means to justify

[8] The counterparty for a system-backed import is a Balancing Authority (BA). The IESO is adjacent to four BAs: two ISOs in the United States (NYISO and MISO) and two vertically-integrated utilities (Manitoba Hydro and Hydro-Québec). System-backed imports are contrasted with resource-backed imports, which may be provided by any other organization including private companies.

[9] See the Panel's Monitoring Report 33 published December 2020:

https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf procurements. If true, this would be a positive development. For further transparency, the IESO should publicly confirm this change.

The winter 2021/22 target capacity set for the December 2020 auction is a welcome change which promises to reduce the cost of capacity in the near-term without compromising reliability. The Panel notes that the IESO's changes to its stakeholdering process are consistent with the Panel's recommendations in its Monitoring Report 33 regarding the IESO's approach to dealing with capacity needs. The Panel continues to recommend greater transparency in relation to the data and processes used by the IESO to set auction capacity targets and looks forward to continuing improvements in the process.

On September 28, 2020, the IESO launched its Resource Adequacy engagement. The purpose of the engagement is to address feedback on the now defunct Incremental Capacity Auction and to develop a new long-term strategy for resource adequacy. A draft strategy was presented for stakeholder comment, with a final version to be released in Q1 of 2021. The length of capacity commitments, which greatly affects the amount of risk borne by suppliers, is among the most notable issues addressed by this engagement. The draft strategy combines 6-month seasonal commitments from an annual capacity auction with multi-year commitments from other mechanisms. The Panel will continue to monitor developments in the Resource Adequacy-related engagements that will continue in 2021.

1.1.4 Changes to the Operating Reserve (OR) Market

Since March 2019, the IESO has been conducting a stakeholder engagement to ensure that OR scheduled in the market is fully accessible for an activation. The proposed solution, an after-the-fact claw back mechanism, appears aimed at addressing Recommendation 3-1 from the Panel’s Monitoring Report 28 published May 2017.[10]

The Panel made two other recommendations related to OR activation performance in its Monitoring Report 29 published March 2018.[11] The Market Rules outline a different claw back mechanism for participants which fail OR activations, but it is currently not applied because the IESO Board of Directors set the materiality threshold for OR shortfalls to infinity.[12] The Panel’s first recommendation was to revise this threshold, and the second was an alternative formula for calculating the claw back.

In responding to a stakeholder question, the IESO acknowledged that the proposed OR changes would not address these recommendations.[13] They may indirectly improve OR activation performance by incentivizing more accurate OR offers. The IESO intends to evaluate OR activation performance for approximately one year after implementing the new claw back mechanism before addressing the Panel’s other OR recommendations.

1.1.5 Storage Design Project

On September 15, 2020, the IESO posted an Energy Storage Design Project Long-Term Design Vision Document which concludes the Storage Design Project engagement. The

[10] See the Panel’s Monitoring Report 28 published May 2017, pages 73-76: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf

[11] See the Panel’s Monitoring Report 29 published Mar 2018, pages 72-75: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20180322.pdf

[12] See Market Rules Chapter 9 Section 3.8.2.4 and the equations published for charge types 251, 253, and 255 in the IESO Charge Types and Equations manual: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-rules/mr-chapter9.ashx and http://ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/settlements/imo-charge-types-and-equations.pdf?la=en

[13] See the IESO's response to stakeholder feedback in the Improving Accessibility of Operating Reserve engagement, dated June 9, 2020: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/or/or-20200430-response-to-stakeholder-feedback.ashx

document outlines that the IESO has decided not to include the enduring storage design in the Market Renewal Program (MRP) while presenting several long-term design decisions on how storage resources will participate in the wholesale electricity market.

The Panel commented in this engagement. The Panel considers the exclusion of the enduring storage design from the scope of the IESO's MRP to be an impairment to the potential benefits that the MRP is intended to deliver. Although the Panel agrees that the reduction of uplift costs incurred by storage resources associated with energy that is re-injected into the market is a good step towards removing barriers in the market, the Panel commented on the lack of clarity on certain elements of the IESO's proposal for exempting storage resources from uplift on re-injected energy. The Panel suggested that the IESO consider alternative approaches to the uplift exemption, and provided an example of such an approach. The IESO, however, has opted to continue to deal with storage outside MRP and for a broader uplift exemption on all energy purchased as fuel. The Panel considers the IESO's treatment of uplift more complex to administer than the Panel's alternative, an alternative which would also limit costs being passed on to the market and encourage more efficient technology.

1.1.6 Activation Payments for DR Resources

The IESO concluded the engagement on Energy Payments for Economic Activation of Demand Response Resources.[14] It appears that the IESO will not introduce these payments at this time.

In addition to energy payments, the engagement also explored mechanisms to compensate DR providers for shut-down costs incurred for each activation. None of the four options considered were both acceptable to stakeholders and readily implementable by the IESO.

[14] The Panel also discussed this engagement in its Monitoring Report 32 published July 2020, pages 33-36: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

1.1.7 Must-Offer Condition Agreements

The Panel discussed Ontario Power Generation Inc.'s (OPG) recent acquisition of control of gas-fired generators from TC Energy and Canadian Utilities Limited in its Monitoring Report 32 published in July 2020.[15,16] OPG now controls just under half of the installed capacity registered in Ontario's energy market, which, as noted in that Monitoring Report, increases the risk of the exercise of market power.

To address concerns about market power and the competitiveness of the IESO-Administered Markets, the Ontario Energy Board (OEB) imposed additional licence conditions on OPG and its subsidiary Portlands Energy Centre L.P., known as Atura Power. One of the new licence conditions requires each of OPG and Atura to offer all of their available capacity into the IESO-Administered Markets for OR and energy, and into the Day Ahead Commitment Process. The licence condition also requires each of OPG and Atura to enter into an agreement with the IESO regarding this "must offer" requirement and to submit the agreement for OEB approval. On October 15, 2020, the OEB approved the Must-Offer Condition Agreements.[17] In addition to speaking to how OPG and Atura must participate in the markets, the Must-Offer Condition Agreements also outline the additional IESO monitoring that will be implemented to review OPG's and Atura's actions in the markets.

[15] Ibid. pages 24-31

[16] Atura Power operates Portlands Energy Centre Generating Station, Halton Hills Generating Station, Napanee Generating Station and Brighton Beach Generating Station. See the OPG media release "OPG subsidiary Atura Power finalizes acquisition of natural gas assets" dated April 29, 2020:

https://www.opg.com/media_release/opg-subsidiary-atura-power-finalizes-acquisition-of-natural-gas-assets/

[17] See the OEB correspondence dated October 15, 2020 (EB-2020-0110):
http://www.rds.oeb.ca/HPECMWebDrawer/Record/689938/File/document and
http://www.rds.oeb.ca/HPECMWebDrawer/Record/689936/File/document

1.2 Status of Recent Panel Recommendations

Below are the recommendations made in the Panel's Monitoring Report 33 published in July 2020 and the IESO's responses to them.[18]

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

Recommendation 2-1 **and** ***IESO Response***	**The IESO should eliminate the payment for start-up costs for second and subsequent RT-GCG runs in a day. Alternatively, when a generation unit has participated in the RT-GCG program once during a day, the IESO should consider ways to have the generation unit compensated on the basis of the lesser of the second and subsequent submitted start-up costs or the estimated cost of keeping the generation unit online between RT-GCG runs.**
	The IESO agrees that two-shifting generation facilities could be inefficient in certain circumstances. However, eliminating all second start guarantees could deter efficient starts from coming to market. Multi-hour optimization of three-part offers is necessary to verify the efficiency of second starts. As part of the Market Renewal Program (MRP), the IESO will be introducing multi-hour optimization of three-part offers (energy, start up, and speed-no-load) across the day-ahead, pre-dispatch, and real-time timeframes. Multi-hour optimization of three-part offers will only schedule generation facilities for two starts in the same day when it is economically efficient to do so. The IESO does not intend to take any additional actions to change the current RT-GCG program design in advance of MRP. The IESO will continue to conduct audits associated with the RT-GCG program (refer to Recommendation 2-2 below).

[18] See the letter from Terry Young, Interim President & CEO of the IESO, to Susanna Zagar, CEO of the OEB, dated January 11, 2021: https://www.oeb.ca/sites/default/files/IESO-MSP-Ltr-OEB-20210111.pdf

Recommendation 2-2 **and** ***IESO Response***	**The IESO should conduct an audit of RT-GCG cost submissions in situations when a generation unit has a second RT-GCG run within three hours of its first RT-GCG run and the submitted costs of the second run are equal to or higher than the submitted costs of the first run.**
	The IESO routinely audits the RT-GCG program and has been carrying out such audits since 2011. Consistent with the MSP's recommendation, the IESO's audits consider submitted costs and the circumstances of each RT-GCG start, including when a generation facility has a second start within three hours of its first start.
Recommendation 2-3 **and** ***IESO Response***	**The IESO should treat SAR activations in much the same way as it treats emergency imports; namely, by adding demand back in to the unconstrained schedule.**
	The IESO agrees that the MSP's recommendation would provide more intuitive and informative pricing signals for dispatchable resources. However, the IESO is evaluating the materiality of market efficiency benefits associated with this recommendation as well as consistency with the treatment of other control actions and potential implementation impacts to other initiatives. The IESO will provide an update to the MSP by the end of Q1 2021.
Recommendation 3-1 **and**	**The IESO should produce a report that probabilistically assesses the level of economic (i.e. non-firm) imports that would be appropriate to assume in their various resource adequacy studies for each year in the planning timeframe, with stakeholder input, using the Northeast Power Coordinating Council Review of Interconnection Assistance Reliability Benefits study as a reference.**

IESO Response	*The IESO agrees with the MSP on the need to assess the level of non-firm imports that would be appropriate to assume in resource adequacy studies. The IESO has initiated the Reliability Standards Review stakeholder engagement to examine planning assumptions related to resource adequacy. Through this engagement, the IESO has proposed a methodology to determine an appropriate assumption for non-firm imports which takes into account the Northeast Power Coordinating Council Review of Interconnection Assistance Reliability Benefits study. The stakeholder engagement is expected to conclude in Q1 2021.*
Recommendation 3-2 **and** ***IESO Response***	**The IESO should better align the assumptions used in planning documents on an ongoing basis or explain in detail the reason for remaining differences, with quantities. This should address, at a minimum, differences in economic import assumptions and different weather scenarios that lead to different capacity need outcomes.**
	The IESO agrees with the MSP on the need to align assumptions used in planning documents. The IESO is currently reviewing the differences in assumptions across planning documents, including non-firm imports and forecasted weather scenarios, and undertaking to align those assumptions through the IESO's Resource Adequacy stakeholder engagement. Further, the IESO also plans to align assumptions for embedded generation across planning documents.

Recommendation 3-3 **and** ***IESO Response***	**The IESO should examine and report on potential improvements to its communications with stakeholders regarding the process(es) used to assess the need for and procure resources to meet future capacity needs. The IESO should also provide greater clarity regarding the documents used to inform those procurements and how any auction or procurement targets are set. In particular:** **• the IESO should publish the analysis and methodology for the Reliability Assurance concept, which appears to be the basis for procuring capacity for the Capacity Auction scheduled for the winter of 2020/21; and** **• the IESO should explain the purpose of the Reliability Outlook, including a clear indication of which sections of that report may be used for outage planning, which sections (if any) may be used to inform procurements, and which sections have been included for informational purposes only.**
	The IESO agrees with the MSP on the need for transparent and clear communications for planning and procurement processes. Through the Resource Adequacy engagement, the IESO is working with stakeholders to develop a resource adequacy framework that will specify which processes and documents will be used to identify system needs, the methodologies used to translate those needs into procurement targets, and which processes will be used to procure resources.
Recommendation 3-4 **and**	**The IESO should periodically make available clear descriptions of the range of potential resources that may need to be procured, including the volume (MW), timelines, any required characteristics other than capacity (e.g. energy, ramp, etc.) and expected procurement mechanism (e.g. through capacity auctions, and/or alternative mechanisms) as part of its communication of future capacity needs in reports such as the Annual Planning Outlook.**

IESO Response	*The IESO agrees with the MSP on the need to make available clear descriptions of the range of resources that may need to be procured. Through the Resource Adequacy engagement, the IESO is working with stakeholders to develop a resource adequacy framework that will identify system needs (e.g. energy, capacity, flexibility etc.), and timelines for when those needs are expected to materialize. The framework will also identify the mechanisms to be used to procure resources to meet those needs.*
Recommendation 3-5 **and** ***IESO Response***	**The IESO should signal its confidence in different planning assumptions by publishing the uncertainty values associated with relevant assumptions and elements used to calculate the capacity need, including at a minimum a range of economic imports and a range of possible demand forecasts based on underlying economic drivers.**
	Through the Resource Adequacy engagement, the IESO will engage stakeholders on changes to power system planning information and documents, including communicating uncertainty associated with relevant assumptions used to calculate capacity need. Further, through the Reliability Standards Review engagement, the IESO has proposed a methodology to determine an appropriate assumption for non-firm imports. This methodology accounts for uncertainty in the availability of these resources by considering a range of non-firm imports. *In order to address uncertainties impacting electricity demand, the IESO has published two demand scenarios within the 2020 Annual Planning Outlook (APO). The assumptions behind each scenario are explained in the APO as well as supported via the methodology documents and data tables which are released in tandem with the APO.*

Recommendation 3-6 **and** ***IESO Response***	**The IESO should examine and report on potential improvements to its stakeholder engagements regarding the methods and assumptions used to develop capacity needs. Specific consideration should be given to a periodic streamlined process to review the case for procuring existing or new resources that involves stakeholders and is overseen by an objective third party.**
	The IESO is actively engaging stakeholders on capacity needs through the Reliability Standards Review and Resource Adequacy engagements. These engagements will support greater transparency regarding the methods and assumptions used to develop capacity needs and procurement mechanisms. The IESO is currently reviewing the MSP's recommendation regarding a periodic streamlined process for reviewing procurement targets overseen by a third party.

1.3 Panel Commentary on IESO Response

The Panel has raised concerns in Monitoring Report 33 concerning a lack of transparency regarding capacity procurements. One element of increased transparency would be improved clarity and specificity in addressing the recommendations, which is lacking in the responses provided by the IESO, namely:

- **Recommendation 2-1 Response:** The IESO declines action to address inefficiencies with the RT-GCG program identified by the Panel, even though other program changes are being developed (e.g. considering retroactive payments for carbon costs incurred by generators). The IESO indicates it does not know how frequently efficient second starts may occur, suggesting only that eliminating second start guarantees "could deter efficient starts". Although Market Renewal is expected to improve the efficiency of gas generator starts, the Panel believes that ratepayers could benefit in the meantime through relatively straightforward improvements in this area. For example, generators could have pre-approved values for second and subsequent starts.

- **Recommendation 2-2 Response:** Additional clarity on this topic is needed. It is unclear whether a particular emphasis is being placed on auditing two-shifting behaviour, as the Panel is recommending and, if not, why not.

- **Recommendation 3-1 Response:** The Panel welcomes the IESO's proposal for reintroducing non-firm imports as set out in its December 14, 2020 presentation "Reliability Standards Review Update".[19] That presentation's analysis for 2021 identifies 251 MW of imports as the amount "likely to flow under tight supply conditions/prices" (90th percentile dependable flow in top 5% HOEP hours, 2016-2019). The Panel supports a data-driven approach to determining the appropriate amount of non-firm imports to include in reliability studies. However, basing the non-firm import calculation on the Hourly Ontario Energy Price (HOEP) is problematic. First, imports are scheduled in pre-dispatch and cannot be expected to respond to a real-time price. Moreover, high prices in real-time are not necessarily caused by a shortage of available capacity. Many of the anomalous price spikes that the Panel examines occur due to short-term, intra-hour phenomena: forced outages or forecast errors with limited flexible resources online. The Panel suggests that the IESO use a metric grounded in supply and demand to estimate the amount of non-firm imports available during periods of capacity scarcity rather than using real-time prices as a gauge.

- **Recommendation 3-2 Response:** The Panel welcomes the IESO's agreement that there is an issue and their initiation of work to resolve it. However, no timeline is provided. The Panel believes that the IESO should announce a firm timeline for producing drafts of their updated planning documents with revised and consistent assumptions, and that it produce for stakeholder review an explanation of the changes made and the rationale for those changes.

[19] See the IESO's presentation "Reliability Standards Review Update", dated December 14, 2020: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rsr/rsr-20201214-presentation.ashx

- **Recommendation 3-3 Response:** Additional clarity on this topic is needed. The Panel made a specific recommendation, requesting the IESO publish the analysis supporting the “Reliability Assurance“ concept which has been introduced with very few details. The Panel also sought to clarify the purpose of the Reliability Outlook. Neither of these issues were acknowledged directly in the IESO response. . However, the Panel welcomes the IESO’s initiative to develop a more transparent and robust assessment and procurement process, and expects that the IESO will ensure that this recommendation is addressed through that initiative.
- **Recommendation 3-4, 3-5, 3-6 Responses:** The Panel will continue to track the Resource Adequacy and Reliability Standards Review engagements. The IESO should clarify when these recommendations are expected to be addressed, and when these engagements are expected to conclude. Further, the IESO should confirm whether these engagements are expected to address the lack of oversight relating to procurements.

The Panel acknowledges the IESO’s commitment to improvements in the transparency of capacity procurements and looks forward to the implementation of a more open approach.

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter provides observations for the three 6-month monitoring periods from November 1, 2018 to April 30, 2020. Section 2.1 consists of an overview for each of these periods of events that meet the Panel's thresholds to be considered anomalous, followed by more specific analysis of anomalous prices for energy and Operating Reserve (OR), Congestion Management Settlement Credit (CMSC) and Intertie Offer Guarantee (IOG) payments. Section 2.2 provides details on select anomalous events and behaviours.

2.1 Threshold Analysis for the Three 6-Month Monitoring Periods

This section discusses events that trigger the Panel's predefined thresholds for being considered anomalous. These thresholds are outlined in the tables below.

The focus of this section is on Hourly Ontario Energy Prices (HOEP)[20] that are either high or negative, as well as instances of significant CMSC, OR and IOG payments as these payments play an important role in the market and are recovered from Ontario consumers and exporters through uplift charges. The purpose of this section is to identify the anomalous events and outline some of their causes.

Three monitoring periods are reviewed in this report:

- Winter 2018/19 Period (November 1, 2018 to April 30, 2019),
- Summer 2019 Period (May 1, 2019 to October 31, 2019), and
- Winter 2019/20 Period (November 1, 2019 to April 30, 2020).

[20] The average of the twelve market clearing prices set in each hour is called the Hourly Ontario Energy Price, or HOEP. All electricity consumers in Ontario pay the wholesale price, except for those who have entered into a retail contract.

To account for seasonal factors, the Panel has compared the instances of anomalous events occurring in each of these periods to such events occurring in the same 6-month period the year prior.

Table 2-1 below compares the Winter 2018/19 Period to the Winter 2017/18 Period. From this comparison, the noteworthy categories are anomalous daily CMSC payments, which increased from 3 to 11 occurrences, and the number of hours when the HOEP was equal to or below $0/MWh, which decreased from 15% of all hours during the period (650 hours) to 9% of hours (373 hours). The subsequent table, Table 2-2, presents the dates on which the anomalous events occurred during the Winter 2018/19 Period. The ensuing discussion, starting at Section 2.1.1, explains how the events materialized.

Table 2-1: Summary of Anomalous Events – Winter 2018/19 Period and Winter 2017/18 Period

Anomalous Event Threshold	Number of Events	
	Winter 2018/19 (Nov 2018 to Apr 2019)	Winter 2017/18 (Nov 2017 to Apr 2018)
HOEP > $200/MWh	3	4
HOEP ≤ $0/MWh	373	650
Energy CMSC > $1 million/day	11	3
Energy CMSC > $500,000/hour	2	1
OR Payments > $100,000/hour	3	7
IOG > $1 million/day	2	3
IOG > $500,000/hour	4	7

The table above shows the number of anomalous events that occurred during the Winter 2018/19 and Winter 2017/18 Periods. CMSC thresholds consider the net payment after any applicable claw backs.

Table 2-2: Date and Time of Anomalous Events for the Winter 2018/19 Period

High HOEP	Daily CMSC	Hourly CMSC	High OR	Daily IOG	Hourly IOG
Nov 9 | HE 10			Nov 9 | HE 10		
	Nov 14				
	Nov 15				
	Nov 16				
	Nov 17				
	Nov 18				
	Dec 10				
Jan 21 | HE 10	Jan 21		Jan 21 | HE 10		
	Jan 31				
	Feb 11	Feb 11 | HE 1, 2			
				Mar 25	Mar 25 | HE 6, 8
	Mar 28				
	Mar 29				
				Apr 4	Apr 4 | HE 11, 12
Apr 29 | HE 24			Apr 29 | HE 24		

The table above shows the date and, where applicable, time (hour ending, HE) when anomalous events occurred during the period from November 2018 to April 2019.

Table 2-3 below compares the Summer 2019 Period to the Summer 2018 Period. The number of hours when the HOEP was equal to or below $0/MWh was significantly higher during the Summer 2019 Period (representing 29% of hours for the period (1,281 hours)) compared to the Summer 2018 Period (16% of hours (687 hours)). The number of days with anomalous CMSC payments was also higher, being 3 days in the Summer 2018 Period and 6 days in the Summer 2019 Period. However, aside from the few instances of anomalous OR payments (the occurrence of which decreased substantially as between the two periods), no other threshold for anomalous events was triggered. The subsequent table, Table 2-4, presents the dates on which the anomalous events occurred during the Summer 2019 Period. The ensuing discussion, starting at Section 2.1.1, explains how the events materialized.

Table 2-3: Summary of Anomalous Events – Summer 2019 Period and Summer 2018 Period

Anomalous Event Threshold	Number of Events	
	Summer 2019 (May 2019 to Oct 2019)	Summer 2018 (May 2018 to Oct 2018)
HOEP > $200/MWh	0	6
HOEP ≤ $0/MWh	1,281	687
Energy CMSC > $1 million/day	6	3
Energy CMSC > $500,000/hour	0	0
OR Payments > $100,000/hour	3	13
IOG > $1 million/day	0	4
IOG > $500,000/hour	0	12

The table above shows the number of anomalous events that occurred during the Summer 2019 and Summer 2018 Periods. CMSC thresholds consider the net payment after any applicable claw backs.

Table 2-4: Date and Time of Anomalous Events for the Summer 2019 Period

<table>
<tr><th>High HOEP</th><th>Daily CMSC</th><th>Hourly CMSC</th><th>High OR</th><th>Daily IOG</th><th>Hourly IOG</th></tr>
<tr><td rowspan="9">N/A</td><td></td><td rowspan="9">N/A</td><td>May 4 | HE 8</td><td rowspan="9">N/A</td><td rowspan="9">N/A</td></tr>
<tr><td></td><td>May 6 | HE 19</td></tr>
<tr><td>May 8</td><td></td></tr>
<tr><td>May 9</td><td></td></tr>
<tr><td>May 11</td><td></td></tr>
<tr><td>May 12</td><td></td></tr>
<tr><td>May 13</td><td></td></tr>
<tr><td>May 14</td><td></td></tr>
<tr><td></td><td>Sep 26 | HE 19</td></tr>
</table>

The table above shows the date and, where applicable, time (hour ending, HE) when anomalous events occurred during the period from May 2019 to October 2019.

Table 2-5 below compares the Winter 2019/20 Period to the Winter 2018/19 Period. As noted above, there was a relatively high number of anomalous daily CMSC payments in the Winter 2018/19 Period. This number decreased considerably from 11 to 3 in the Winter 2019/20 Period. The number of hours when the HOEP was equal to or below $0/MWh doubled as between the two periods, from 9% of hours during the Winter 2018/19 Period (373 hours) to 17% of hours (747 hours) in the Winter 2019/2020 Period. Instances of the HOEP being above $200/MWh also doubled and anomalous OR payments more than doubled. Other thresholds for anomalous events were not triggered in the Winter 2019/20

Period. The subsequent table, Table 2-6, presents the dates on which the anomalous events occurred during the Winter 2019/20 Period. The ensuing discussion, starting at Section 2.1.1, explains how the events materialized.

Table 2-5: Summary of Anomalous Events – Winter 2019/20 Period and Winter 2018/19 Period

Anomalous Event Threshold	Number of Events	
	Winter 2019/20 (Nov 2019 to Apr 2020)	Winter 2018/19 (Nov 2018 to Apr 2019)
HOEP > $200/MWh	6	3
HOEP ≤ $0/MWh	747	373
Energy CMSC > $1 million/day	3	11
Energy CMSC > $500,000/hour	0	2
OR Payments > $100,000/hour	8	3
IOG > $1 million/day	0	2
IOG > $500,000/hour	0	4

The table above shows the number of anomalous events that occurred during the Winter 2019/20 and Winter 2018/19 Periods. CMSC thresholds consider the net payment after any applicable claw backs.

Table 2-6: Date and Time of Anomalous Events for the Winter 2019/20 Period

High HOEP	Daily CMSC	Hourly CMSC	High OR	Daily IOG	Hourly IOG
Nov 14 | HE 9		N/A	Nov 14 | HE 9	N/A	N/A
	Nov 22				
	Nov 23				
	Nov 28				
Dec 1 | HE 9, 10			Dec 1 | HE 10		
Dec 10 | HE 19			Dec 10 | HE 18, 19		
Dec 12 | HE 8			Dec 12 | HE 8		
Jan 17 | HE 8			Jan 17 | HE 8		
			Jan 27 | HE 18		
			Apr 22 | HE 21		

The table above shows the date and, where applicable, time (hour ending, HE) when anomalous events occurred during the period from November 2019 to April 2020.

2.1.1 Anomalous Prices and OR Payments for the Three 6-Month Monitoring Periods

The IESO's Dispatch Scheduling and Optimization tool (DSO) co-optimizes the energy and OR markets. 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. As conditions change, prices in both markets typically move in the same direction.[21] Upon reviewing the HOEP and OR-related anomalous events for the three monitoring periods, the Panel determined that only two events warranted a detailed analysis – namely, events occurring on December 10, 2019 and April 22, 2020. The details of these events are provided below at Section 2.2. For the other events, a summary is provided to identify the main factors that likely contributed to each event triggering the anomalous threshold. Of the 15 events highlighted, the two most common influences on price spikes were variable generation shortfalls (13 events, or 87%) and under-forecast demand (11 events, or 73%). This summary of anomalous high HOEPs and OR payments is provided below at Table 2-7, Table 2-8 and Table 2-9.

[21] The IESO's 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. By assessing the relative impacts of energy and OR offers, production costs are minimized and economic gains from trade are maximized across both markets. However, when an additional megawatt is scheduled in one market it becomes unavailable in the other. This leads to cross-market price effects.

Table 2-7: Causes of Anomalous High HOEP and OR Payments Winter 2018/19 Period

Event Date	Event Hour Ending	Anomaly		Main Causes
		HOEP (/MWh)	OR (/hour)	
Nov 9	10	**$366**	**$256,381**	-Under-forecasted demand -Variable generation shortfall -Transmission outage leading to unavailable OR
Jan 21	10	**$222**	**$109,099**	-Under-forecasted demand -Variable generation shortfall -Multiple gas generators forced out of service due to severe cold weather -Nuclear derate
Apr 29	24	**$340**	**$272,609**	-Under-forecasted demand -Variable generation shortfall -Limited gas generators online -Nuclear derate -Limited hydroelectric generators available for OR as a result of must-run freshet conditions

The table above lists the factors contributing to anomalous high HOEPs or OR payments for each relevant event.

Table 2-8: Causes of Anomalous High HOEP and OR Payments Summer 2019 Period

Event Date	Event Hour Ending	Anomaly[22]		Main Causes
		HOEP (/MWh)	OR (/hour)	
May 4	8	$131	**$100,128**	-Under-forecasted demand -Variable generation shortfall -Limited hydroelectric generators available for OR as a result of must-run freshet conditions
May 6	19	$170	**$142,343**	-Variable generation shortfall -Limited hydroelectric generators available for OR as a result of must-run freshet conditions
Sep 26	19	$174	**$121,121**	-Variable generation shortfall

The table above lists the factors contributing to anomalous high HOEPs or OR payments for each relevant event.

[22] HOEP below $200/MWh and OR payments below $100,000/hour are not considered anomalous by the Panel. In instances when these figures are included in this table, it is done so to give context to the anomalous figures appearing in the same hour.

Table 2-9: Causes of Anomalous High HOEP and OR Payments Winter 2019/20 Period

Event Date	Event Hour Ending	Anomaly[23] HOEP (/MWh)	Anomaly[23] OR (/hour)	Main Causes
Nov 14	9	**$1,029**	**$756,993**	-Variable generation shortfall -Limited gas generators online due to a prior forced outage -Unavailable hydroelectric generators -OR shortfall throughout the hour
Dec 1	9	**$206**	$66,986	-Under-forecasted demand -Variable generation shortfall -Generator forced outage -Limited gas generators online
	10	**$498**	**$277,477**	-Under-forecasted demand -Variable generation shortfall -Generator forced outage -Limited gas generators online -OR activation
Dec 10	18	$170	**$112,823**	-Under-forecasted demand -OR activation -Disabled variable generation forecasting tool affecting variable generation modeling[24]
	19	**$350**	**$344,230**	-Under-forecasted demand -Disabled variable generation forecasting tool affecting variable generation modeling
Dec 12	8	**$960**	**$823,497**	-Under-forecasted demand -Variable generation shortfall -Failed imports -OR shortfall throughout the hour
Jan 17	8	**$1,258**	**$892,266**	-Under-forecasted demand -Variable generation shortfall -Generator forced outage -OR shortfall throughout the hour
Jan 27	18	$71	**$100,747**	-Variable generation shortfall -Failed imports
Apr 22	21	**$158**	**$120,128**	-Under-forecasted demand -Variable generation shortfall -Two gas generators unable to meet pre-dispatch schedule.

The table above lists the factors contributing to anomalous high HOEPs or OR payments for each relevant event.

[23] HOEP below $200/MWh and OR payments below $100,000/hour are not considered anomalous by the Panel. In instances when these figures are included in this table, it is done so to give context to the anomalous figures appearing in the same hour.

[24] See the Panel's Monitoring Report 30 published March 2019, pages 89-95: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20190429.pdf

Regarding low price hours, there were significant changes in instances of the HOEP being equal to or below $0/MWh in each of the three 6-month monitoring periods relative to their respective comparative periods from a year prior. Typically, fluctuations in the number of hours that the HOEP is equal to or below $0/MWh can be explained broadly by two main factors:

- **Low Ontario demand:** can result from non-seasonal weather conditions such as milder summer or winter temperatures requiring less electrical cooling or heating, leading to lower-priced resources in the supply stack setting the marginal price.
- **Abundant supply offered at negative prices:** can be influenced by seasonal conditions such as high winds (wind turbines), lack of cloud cover (solar), or heavy precipitation leading to high freshet levels (run-of-river hydro). Failed export transactions can also contribute to abundant supply at negative prices.

2.1.2 Anomalous CMSC for the Three 6-Month Monitoring Periods

CMSC payments are out-of-market uplift payments to compensate resources for divergences from their economically optimal level of generation or consumption. The following is a review of the CMSC payments associated with the anomalous events that were identified in Table 2-2, Table 2-4, and Table 2-6 above.

On November 13, 2018, ice forming on a circuit caused a transmission line outage that lasted until November 18, 2018. As a result of the outage, the dispatch of a number of resources was affected. Notably, a dispatchable load was constrained-off until the transmission line was back in-service. As it typically does, this dispatchable load submitted energy bids during the course of this outage at very high prices resulting in significant constrained-off CMSC payments. Its bid price was $1,999/MWh – essentially the maximum possible bid price for the resource to be considered dispatchable and thus eligible for CMSC. The total CMSC payments from November 14, 2018 to November 18, 2018 amounted to $10.8 million, with each affected day meeting the Panel's threshold for anomalous CMSC payments. The majority of the payments, approximately $9.5 million, went to the aforementioned Dispatchable Load.

On December 10, 2018, the IESO paid out $1.5 million in CMSC, with approximately $0.8 million of that amount being paid to a single gas generator. The gas generator requested the IESO Control Room Operators (CRO) to adjust its dispatch instructions due to an environmental concern. The CMSC was paid as a result of this request. The Panel expects this CMSC to be recovered by the IESO pursuant to Chapter 9, Section 3.5.6C of the Market Rules.

On January 21, 2019, the IESO paid out $1.2 million in CMSC. On this day, severe cold weather led to a number of operational issues on the grid leading to the HOEP exceeding $200/MWh. Due to the severe cold weather, multiple resources failed to synchronize or were declared unavailable. In addition, a 300 MW gas generator had a forced outage due to turbine issues; a nuclear unit was derated to 500 MW due to an operational issue; and wind generation was consistently under-forecasted (200 MW on average). As a result, the economic dispatch of a number of resources was affected throughout the day. Not surprisingly, Ontario Power Generation Inc. (OPG), owning the most generation capacity in Ontario, was the primary recipient of these payments, receiving approximately $0.7 million in aggregate. One OPG gas generator that was manually constrained on for reliability by the IESO received approximately $0.5 million in CMSC payments.

On January 31, 2019, the IESO paid out $2.0 million in CMSC. As was the case with January 21, severe cold weather led to a number of operational issues on the grid: 2,100 MW of capacity was declared unavailable, with multiple gas generators being derated or constrained off; 300 MW of nuclear capacity was made unavailable due to ice formation on the water intake screen; and wind generation was ramped down from 3,100 MW to 2,200 MW from Hour Ending (HE) 16 to HE 21. The result was similar to what happened on January 21, 2019 – the economic dispatch of a number of resources was affected throughout the day, with OPG receiving approximately $0.4 million in CMSC payments as a result. Approximately $0.2 million of that amount went to an OPG gas generator (the same generator mentioned above in relation to events on January 21), which the IESO again manually constrained on for reliability reasons. However, the most substantial payment, totalling approximately $1.0 million, arose as a result of CRO constraining off an intertie for multiple hours in real-time.

On February 11, 2019, the IESO paid out $1.5 million in CMSC, of which approximately $1.2 million was paid to a single gas generator. This event was also associated with the only instance in which the hourly CMSC threshold of more than $500,000/hour was exceeded in the Winter 2018/19 Period. The generator self-reported the event within 10 days, and following investigation by the Market Assessment and Compliance Division (MACD) repayment of the CMSC payments was processed in March 2020.

On March 28 and March 29, 2019, a planned outage to a circuit necessitated CRO to manually constrain on two hydroelectric generators to maintain grid reliability. Total CMSC payments over the course of these two days amounted to $2.2 million of which approximately $1.7 million was paid to the two generators.

On May 7, 2019, a forced outage occurred on a circuit. The outage lasted from May 7, 2019 to May 14, 2019. As a result of the outage, CMSC payments totalled $1.9 million on May 8, 2019 and $1.3 million on May 9, 2019. The vast majority of the payments – approximately $2.7 million – were made to the same dispatchable load that received substantial CMSC payments due to the November 13, 2018 outage (discussed above). From May 11 to May 14, 2019, CMSC payments totalled $6.4 million. Again, the vast majority – approximately $4.8 million of the payments – went to the same dispatchable load that was constrained off during the November 13, 2018 outage. The dispatchable load's bid price during the events was $1,999/MWh.

On November 21, 2019, a downed sky wire on a circuit led to a forced outage. The outage resulted in the CMSC threshold of more than $1 million/day being exceeded on two successive days. On November 22, 2019, the IESO paid $2 million in CMSC while on November 23, 2019 the payment was $1.6 million. The CMSC payments were primarily a result of CRO having to manually dispatch several hydroelectric generators out of economic merit order to maintain grid reliability. In addition, on November 23, 2019, approximately $0.4 million in CMSC payments were paid to the same dispatchable load that was constrained off during the November 13, 2018 and the May 7, 2019 to May 14, 2019 outage. The bid price for this dispatchable load was again $1,999/MWh. Overall, this dispatchable load was paid approximately $17 million in CMSC payments over the course of the three 6-month monitoring periods while submitting bids of $1,999/MWh during these events.

On November 28, 2019, the IESO paid out $1.1 million in CMSC. A loose sky wire on a circuit again led to a forced outage. The CMSC payments were a result of CRO having to manually dispatch a number of generators out of their economic merit order to maintain grid reliability.

2.1.3 Anomalous Intertie Offer Guarantee Payments for the Three 6-Month Monitoring Periods

Importers scheduled day-ahead are guaranteed to be paid their day-ahead offer price if their scheduled volumes flow in real-time. This guarantee is provided through an IOG payment. Conditions leading to anomalously high IOG payments were discussed extensively in the Panel's Monitoring Report 31, published December 2019.[25] Essentially, importers have a strong incentive to reduce their day-ahead offer price to an extreme negative price after they have been scheduled based on their initial day-ahead offer price. By reducing their offer price, the importers increase the likelihood of their scheduled volumes flowing in real-time. The following is a review of the anomalous IOG payments identified in Table 2-1 above.

On March 25, 2019, damage to Hydro-Québec-owned equipment led to the IESO significantly limiting the capacity of the Outaouais intertie. The intertie's import capacity was reduced from 1,230 MW to 50 MW leading to severe import congestion in three hours: HE 6, HE 8, and HE 9. As a result, the Outaouais Intertie Zonal Prices in these hours dropped to extreme

[25] See the Panel's Monitoring Report 31 published December 2019, pages 16-20: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

negative values: -$2,000/MWh in HE 6; -$1,435/MWh in HE 8; and -$948/MWh in HE 9. These were the prices that importers, in this case predominantly Hydro-Québec,[26] paid for every megawatt-hour of energy imported. The IOG payments ensured that these significant costs of imports were offset. On this day, the IESO paid out $2.5 million in IOG payments, of which $2.4 million was paid in HE 6, HE 8, and HE 9. Two of these hours, HE 6 and HE 8, met the Panel's anomalous threshold for hourly IOG payments (more than $500,000/hour) at $0.8 million and $1.1 million, respectively. Payments in HE 9, although below the Panel's threshold, were nevertheless substantial, totalling almost $0.5 million. As indicated, by far the largest beneficiary of the IOG payments was Hydro-Québec, receiving a total of $2.3 million.

Conditions similar to those described above also led to high IOG payments on April 4, 2019. A forced extension to a transmission line outage in Québec led to the IESO reducing the import capacity of the Outaouais intertie. The intertie's import capacity was reduced from 1,230 MW to 600 MW leading to severe import congestion in two hours: HE 11 and HE 12. The Outaouais Intertie Zonal Prices in these hours dropped to -$1,449/MWh and -$1,445/MWh, respectively. The IOG payments on this day were $2.3 million, of which $2.1 million was paid during HE 11 and HE 12. Hydro-Québec was the sole recipient of the IOG payments for these two hours. As noted above, the payments ensured that Hydro-Québec's costs of importing energy into Ontario were offset.

2.2 Detailed Review of Anomalous Outcomes

This section provides more details about certain anomalous events that the Panel believes warrant further discussion. The section also identifies other events that did not meet the Panel's thresholds for constituting anomalous events, but that the Panel nevertheless considers significant enough to merit comment.

[26] For further clarity, the prices were paid by HQ Energy Marketing Inc. which is a registered market participant (intertie trader) in the IESO-administered markets and a wholly owned subsidiary of Hydro-Québec. For convenience, this report does not differentiate between the wholly owned subsidiary (HQ Energy Marketing Inc.) or the parent company (Hydro-Québec).

2.2.1 Details of the December 10, 2019 Price Spike

On December 10, 2019, the HOEP spiked at $170/MWh and $350/MWh in HE 18 and HE 19, respectively, with OR payments of $0.1 million and $0.3 million for these hours. These price spikes were due mainly to the side-effects of disabling of the Variable Generation (VG) Forecasting Tool by the IESO. This issue was identified in the Panel's Monitoring Report 30 published in April 2019. Such price spikes do not reflect the actual system conditions, but are artefacts of the faulty assumptions the dispatch tool uses when the VG Forecasting Tool is disabled.[27]

In January 2020, the IESO advised the Panel that it would take action to address the issue of disabling the VG Forecasting Tool. The price spike on December 10, 2019 occurred prior to this and as such reflects a continuation of the pre-existing situation which the IESO has since undertaken to remedy.

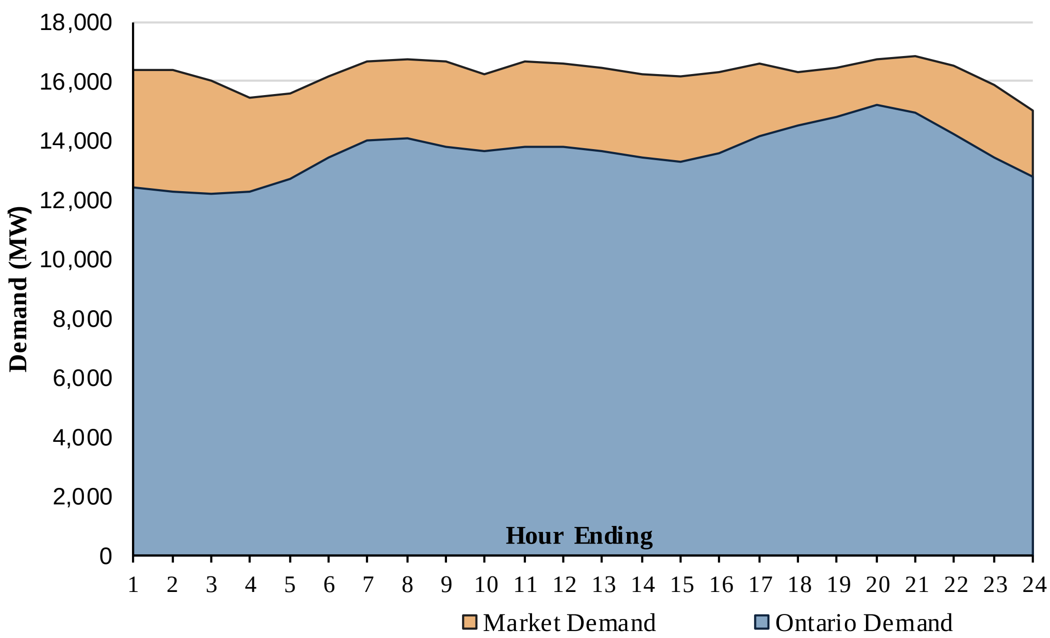
2.2.2 Details of the April 22, 2020 Price Spike

In HE 21 on April 22, 2020, the HOEP rose to $158/MWh and OR payments were $0.1 million. The major contributing factors were under-forecasted demand, a shortfall in variable generation, and tight supply conditions in the energy and OR markets.

The following graph shows Ontario and market demand for April 22, 2020. Although the demand profile throughout the day was generally steady, market demand peaked at 16,863 MW during the hour in question.

[27] See the Panel's Monitoring Report 30 published April 2019, pages 89-95: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20190429.pdf

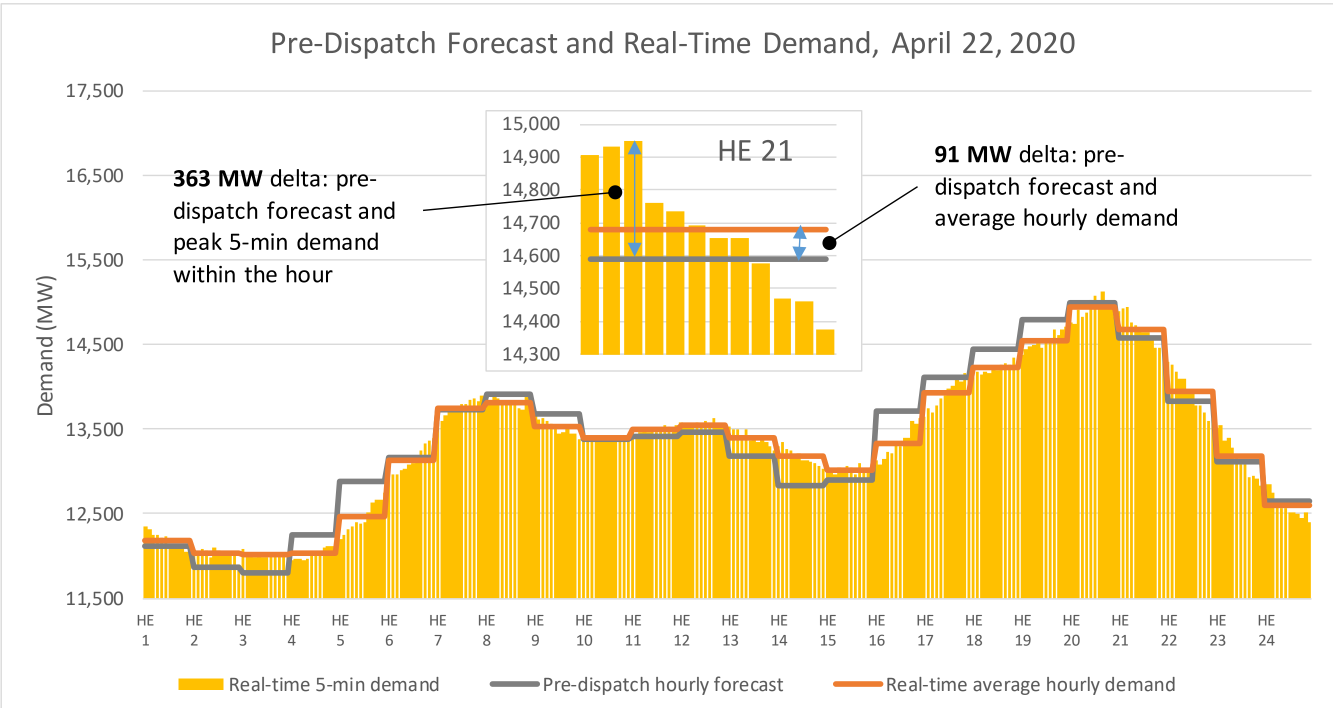
Figure 2-1: Ontario and Market Demand for April 22, 2020



The figure above shows the Ontario and market demand for April 22, 2020.

More impactful than the overall demand, however, was the IESO's forecast of demand. Figure 2-2 below shows the comparison of the pre-dispatch (PD-1) demand forecast to the real-time demand. For the hour in question, the average hourly real-time demand was 91 MW higher than the PD-1 forecast and the 5-minute peak was 363 MW above the PD-1 forecast.

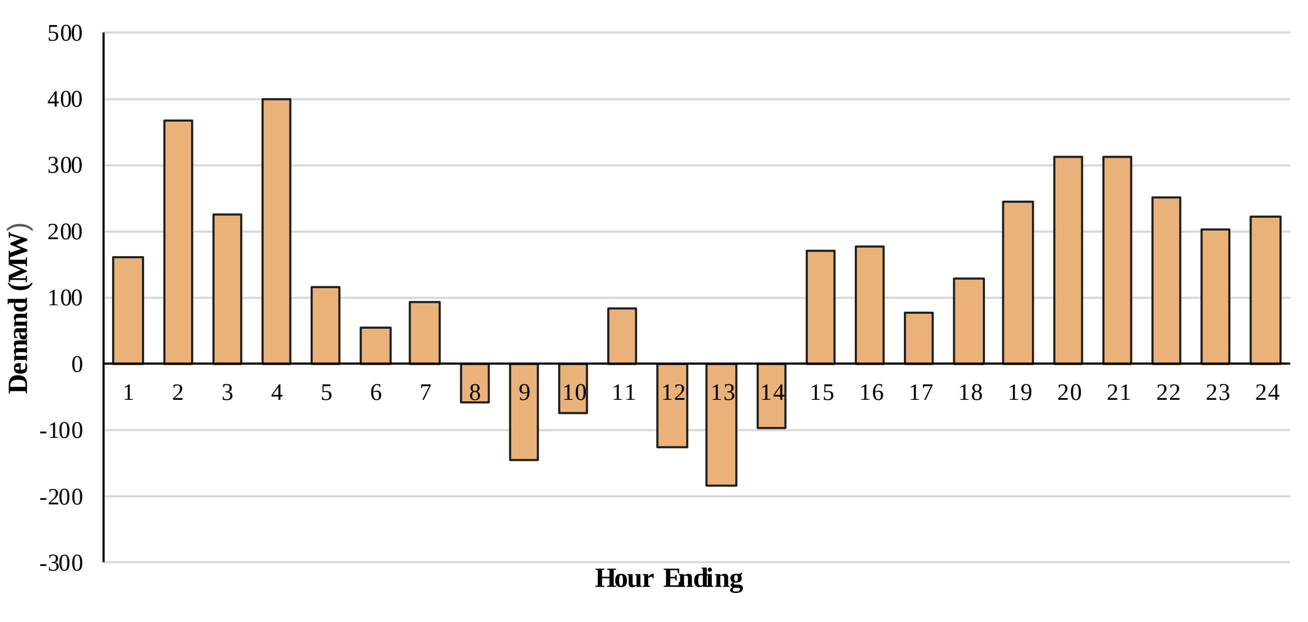
Figure 2-2: Pre-Dispatch vs Real-Time Demand for April 22, 2020



The figure above compares the pre-dispatch demand forecast to the demand that materialized in real-time on April 22, 2020.

From a supply perspective, an important factor to consider when determining price effects is the performance of variable generation. The graph below shows hourly shortfalls (positive values) in wind generation throughout the day. The wind shortfall in HE 21 was the fourth highest of the day at 311 MW. Both the under-forecasted demand and the wind shortfall put upward pressure on energy and OR prices.

Figure 2-3: Hourly Wind Shortfalls for April 22, 2020

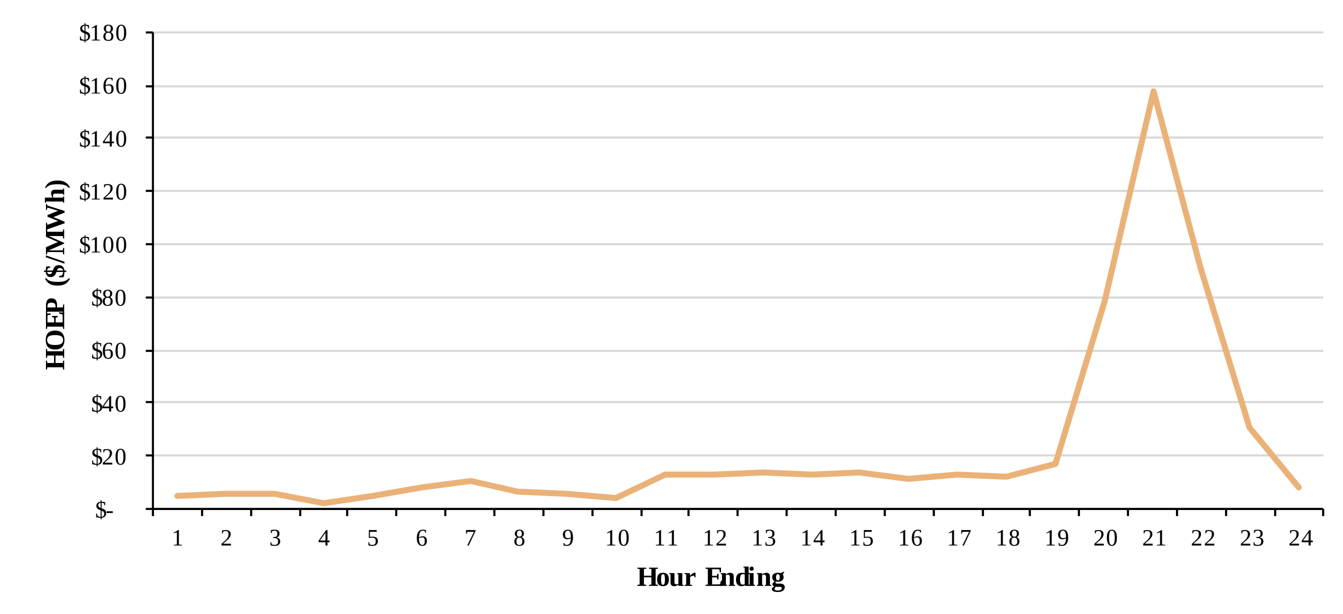


The figure above shows the hourly shortfalls in wind generation throughout April 22, 2020.

In addition, the offer behaviour of two non-quick start generators may have exacerbated the situation. The generators' energy and OR offers were inconsistent with their prevailing operational capabilities and, as such, neither could provide the energy and OR capacity scheduled to be delivered in pre-dispatch. In aggregate, the two generators were scheduled for approximately 220 MW of energy and 80 MW of OR. In real-time, however, the energy and OR that was scheduled in pre-dispatch did not materialize since both generators were hours away from being operationally ready.

The graph below shows the HOEP throughout the day. There was a significant increase in the HOEP in HE 21.

Figure 2-4: HOEP for April 22, 2020



The figure above shows the HOEP for April 22, 2020.

All Market Participants have an obligation under the Market Rules to submit offers and bids that are consistent with their units' actual capabilities. Instead, it appears that offers submitted by both generators ought to have been revised hours before PD-1 to account for their ramping capability to achieve their Minimum Loading Point.

2.2.3 IESO's Use of Simultaneous Activation of Reserve

Simultaneous Activation of Reserve (SAR) is a program between a number of neighbouring electricity market system operators (New York Independent System Operator (ISO), ISO-New England, New Brunswick Power, Pennsylvania New Jersey Maryland (PJM) Interconnection and the IESO) to jointly activate operating reserves when one of the jurisdictions suffers a supply loss greater than or equal to 500 MW (300 MW in the case of New Brunswick). When SAR is activated, other participating jurisdictions will supply up to half of the lost generation as a “free” import for up to half an hour. The energy is treated as inadvertent interchange for power balancing purposes and is later “paid back” in kind by the Ontario market.[28]

The IESO’s treatment of SAR has a non-intuitive effect on prices, as discussed in the Panel’s Monitoring Report 33 published December 2020.[29] By design, the incoming energy from SAR is considered “out-of-market” and is subtracted from demand, resulting in lower-priced offers setting the Market Clearing Price (MCP). As such, the upward pressure on the MCP that would be expected during a contingency event involving a lack of supply is significantly suppressed. The Panel has recommended that the IESO treat SAR activations in much the same way as it treats emergency imports, whereby demand is added back to the unconstrained schedule.[30]

During the three 6-month monitoring periods, the IESO activated SAR on 14 occasions for a total of 6 GW of incoming energy from neighbouring electricity market system operators. The average amount of activation was 837 MW. For comparison, in the three 6-month monitoring periods between November 1, 2016 and April 30, 2018, the IESO activated SAR on 12 occasions for a total of 9 GW (more than 80% of which were provided by Ontario resources). The average amount of activation during the three 6-month monitoring periods between November 1, 2016 and April 30, 2018 was 750 MW. Although the Panel has not conducted a detailed review of each activation, it is likely (based on the design of the program) that each led to a significant suppression of the HOEP.

[28] Inadvertent flow is the difference between the scheduled amount of energy interchange at one, or multiple interties, and actual metered flow. SAR energy is added (or subtracted depending on direction) from this inadvertent quantity. The inadvertent flow fluctuates on its own through normal operations but when it exceeds a threshold the balancing authorities agree to “over” or “under” generate to zero it out. Ontario generators produce extra energy to “pay back” and less energy to “be paid back” from other jurisdictions. That energy comes out of or into the market and increases or reduces costs paid by Ontario customers.

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

[30] Ibid.

2.2.4 Operating Reserve Offers from Hydroelectric Generators

During the Summer 2018 Period – just prior to the three monitoring periods covered by this report – there was a significant change in the way hydroelectric resources were offered into the OR market. This shift continued to be observed during the three monitoring periods covered in this report.

OR is a supply cushion of stand-by power or demand reduction that the IESO can call upon with short notice to manage an unexpected mismatch between generation and demand. OR requirements are set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

There are three classes of OR, defined by the time required to bring the energy into use: 10-minute spinning OR (10S, already synchronized to the grid), 10-minute non-spinning OR (10N, not synchronized) and 30-minute OR (30R, not synchronized). 10-minute OR must be at least equal to the largest contingency and at least 25% of that amount must be synchronized to the grid. 30R must equal one-half of the second largest contingency.

In May 2018, the IESO made a Market Rule change to enable increases to the 30R requirement by 200 MW which has been used to enable system flexibility.

Beginning in July 2018, and continuing throughout all three 6-month monitoring periods, offer quantities from hydroelectric generators in the 30R market were reduced to virtually zero. At the same time, offer quantities in the 10S and the 10N markets have also noticeably decreased. The effect of the changes in offer behaviour on OR and energy prices has not yet been evaluated but may be revisited in future reports.

Appendix A: Market Outcomes for the Winter 2018/19 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Winter 2018/19 Period (November 1, 2018 to April 30, 2019), 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.

HOEP and GA

Table A-1: Average Effective Price by Consumer Class and Period ($/MWh), 3 Periods

Customer Class	Average Weighted HOEP ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Average Effective Price ($/MWh)
Class A – Winter 2018/19	22.31	53.30	3.07	78.68
Class A – Summer 2018	19.14	53.68	3.16	75.98
Class A – Winter 2017/18	19.23	47.52	2.89	69.65
Class B – Winter 2018/19	26.46	89.77	3.27	119.51
Class B – Summer 2018	24.59	95.98	3.71	124.27
Class B – Winter 2017/18	23.11	87.51	3.15	113.77
All Consumers – Winter 2018/19	*N/A*	*N/A*	*N/A*	107.79
All Consumers – Summer 2018	*N/A*	*N/A*	*N/A*	110.34
All Consumers – Winter 2017/18	*N/A*	*N/A*	*N/A*	101.79

Table A-1 summarizes the average effective price in dollars per MWh by consumer class for the Winter 2018/19 Period (November 1, 2018 to April 30, 2019), Summer 2018 Period (May 1, 2018 to October 31, 2018), and Winter 2017/18 Period (November 1, 2017 to April 30, 2018).

The 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.[31] 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 distribution. Results are reported for three consumer groups: "Class A consumers", "Class B consumers" and "All Consumers".[32, 33]

Starting with the Panel's Monitoring Report 29 published in March 2018, the Panel moved embedded Class A consumers from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table A-1.[34]

[31] 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.

[32] 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

[33] 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 total consumption by all consumers in each of those hours. To the extent that Class A consumers reduce their demand during those hours, their share of GA is reduced. The remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel's Industrial Conservation Initiative (ICI) Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[34] Following past practice, the Panel assumes that embedded Class A consumers have the same average load profile as directly-connected Class A consumers. Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and from "Class B & Embedded Class A" to just "Class B"), there is no direct comparison to be made between effective prices reported in this report and those from reports issued before the Panel's Monitoring Report 29 published March 2018. All references to effective price in the Panel's reports going forward – including all tables and figures – reflect the Panel's updated methodology.

The average effective price for all consumers increased by 6% in the Winter 2018/19 Period compared to the Winter 2017/18 Period as a result of increases in the HOEP, GA and uplift. This overall increase was reflected in a 13% increase in the average effective price for Class A consumers and a 5% increase in the average effective price for Class B consumers. Both the HOEP and GA increased for both classes. Although there was a slight increase in the total Ontario demand in the Winter 2018/19 Period, the increase in the Class A and B HOEP was likely due to the drop in nuclear production that occurred during the Winter 2018/19 Period, resulting in higher output from gas-fired resources to fill this gap (see Figure A-21). The increased frequency of gas-fired resources setting the real-time Market Clearing Price (MCP) contributed to a higher HOEP for both Class A and B consumers during the Winter 2018/19 Period (see Figure A-7).

The HOEP and GA have an inverse relationship. However, in the Winter 2018/19 Period both the HOEP and GA increased (GA increased by about 4%). Since little new capacity was added to the Ontario generation fleet (see Table A-8), the increase in GA was driven by an increase in payments to existing facilities. Payments to nuclear facilities increased by 17% (about $330 million) during the Winter 2018/19 Period in comparison to the Winter 2017/18 Period (see Figure A-11), while production from nuclear facilities decreased. In March 2018, the Ontario Energy Board (OEB) issued a Payment Amounts Order for Ontario Power Generation's (OPG's) rate regulated hydroelectric and nuclear facilities for 2017-2021.[35] As a result of this Order, there was a substantial increase in the price of OPG's nuclear energy production. Because the change in nuclear rates was implemented at the end of the Winter 2017/18 Period, its full effect is not apparent in the 6-month average prices until the Summer 2018 Period. There was also a more modest increase in the rate paid to OPG's hydroelectric facilities.

[35] See the OEB Payment Amounts Order dated March 29, 2018 (EB-2016-0152): http://www.rds.oeb.ca/HPECMWebDrawer/Record/603940/File/document

During the Winter 2018/19 Period, the increase in the average effective price for Class A consumers was much greater than the increase in the average effective price for Class B consumers. This occurred because Class A GA is reassessed annually based on each consumers' contribution to peak demand hours in the previous year. In the Winter 2018/19 Period, Class A consumers paid a higher share of GA, relative to their share of load, than in a typical winter. This effect may have contributed to the faster growth of the average Class A effective price, compared to Class B, during the Winter 2018/19 Period.

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

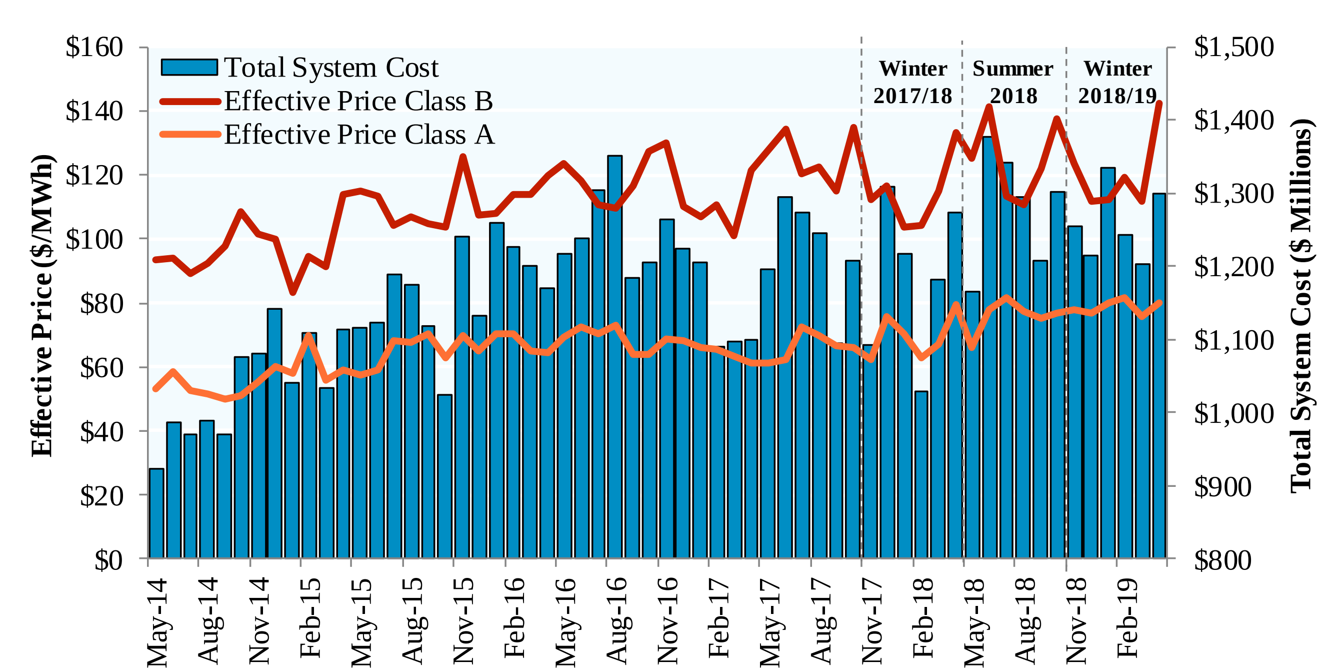


Figure A-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five years.

The total system cost borne by Ontario consumers in the Winter 2018/19 Period rose 6.2% compared to the Winter 2017/18 Period, but decreased by 1.8% from the Summer 2018 Period. This increase in the total system cost across winter reporting periods is above average: over the last five years, the total system cost has grown by about 4.1% per year. The total system cost rose by about $444 million, with about a $228 million increase in the HOEP, about a $206 million increase in GA, and about $10 million increase in uplift. The increase in the total system cost observed in the Winter 2018/19 Period compared to the Winter 2017/18 Period could be a result of reduced supply conditions, as there was about 9% more unavailable capacity in the Winter 2018/19 Period compared to the Winter 2017/18 Period (see Figure A-22). Gas-fired resources set the real-time MCP about 12% more frequently during the Winter 2018/19 Period in comparison to the Winter 2017/18 Period (see Figure A-7), while the output from gas-fired resources increased by about 31% between the Winter periods (see Figure A-21). The increase in the frequency of gas-fired resources setting the real-time MCP along with the increase in the output from gas-fired resources likely contributed to the increased total system cost between the Winter 2017/18 Period and the Winter 2018/19 Period. Total uplift also rose between the Winter 2017/18 Period and the Winter 2018/19 Period, further increasing the total system cost. Ontario demand was little changed between the periods (see Figure A-20) and is not a driver of the total system cost increase.

Both the Class A and Class B effective prices increased significantly between the Winter 2017/18 Period and the Winter 2018/19 Period, with both prices peaking in February 2019 and increasing toward April 2019. On average, the increase in the Class B effective price in the Winter 2018/19 Period aligns with the average increase of the Class B effective price over the past five years, which was less than $6/MWh. However, the average increase in the effective price for Class A consumers during the Winter 2018/19 Period was significantly higher than the average increase of the Class A effective price over the past five years, which was less than $5/MWh. See Table A-1 for more information on the increase in the Class A effective price during the Winter 2018/19 Period.

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

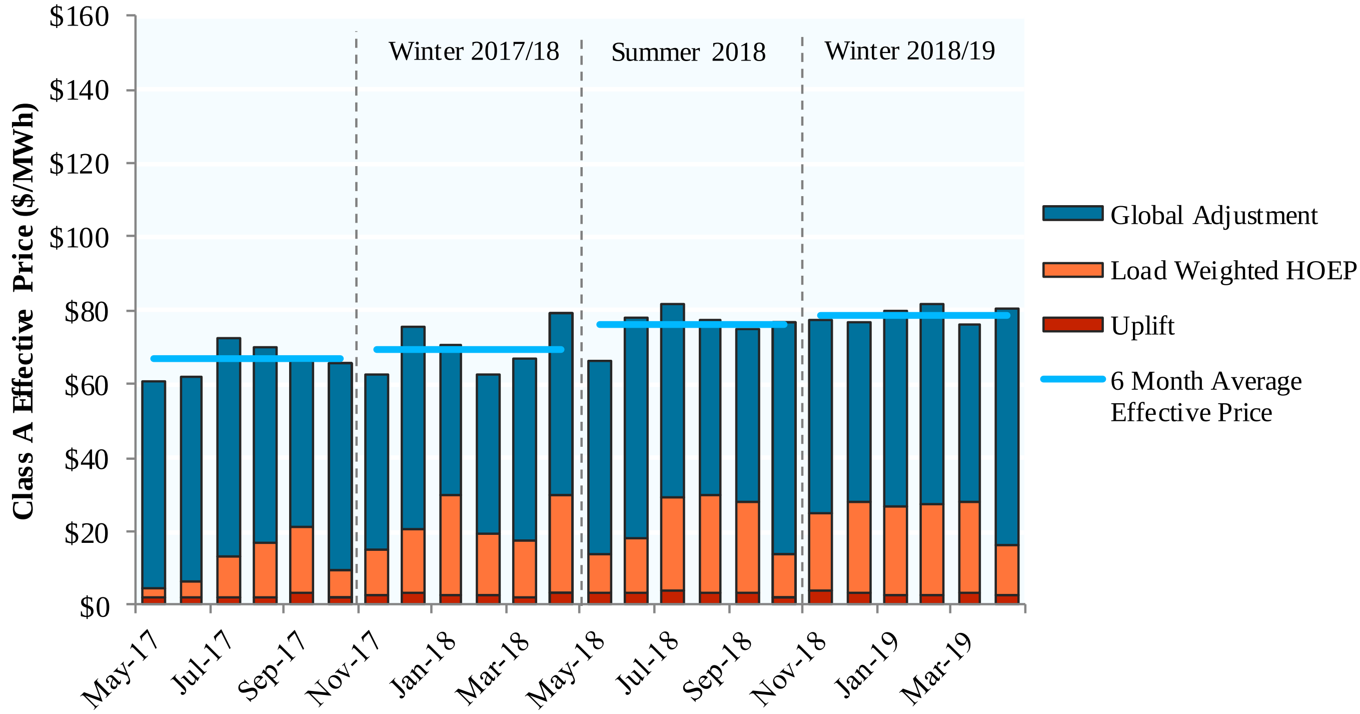


Figure A-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period.[36], [37]

[36] 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 demand), and their contracted rates of revenue or regulated rates set by the OEB. 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

[37] The six-month average Class A 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.

The GA is the guaranteed revenue less the HOEP and uplift payments for Class A and B consumers. 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. A higher GA tends to increase the effective price more for Class B than Class A consumers because the current GA allocation methodology has the effect of allocating to Class A consumers a lower share of GA per MWh consumed than Class B consumers pay.

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

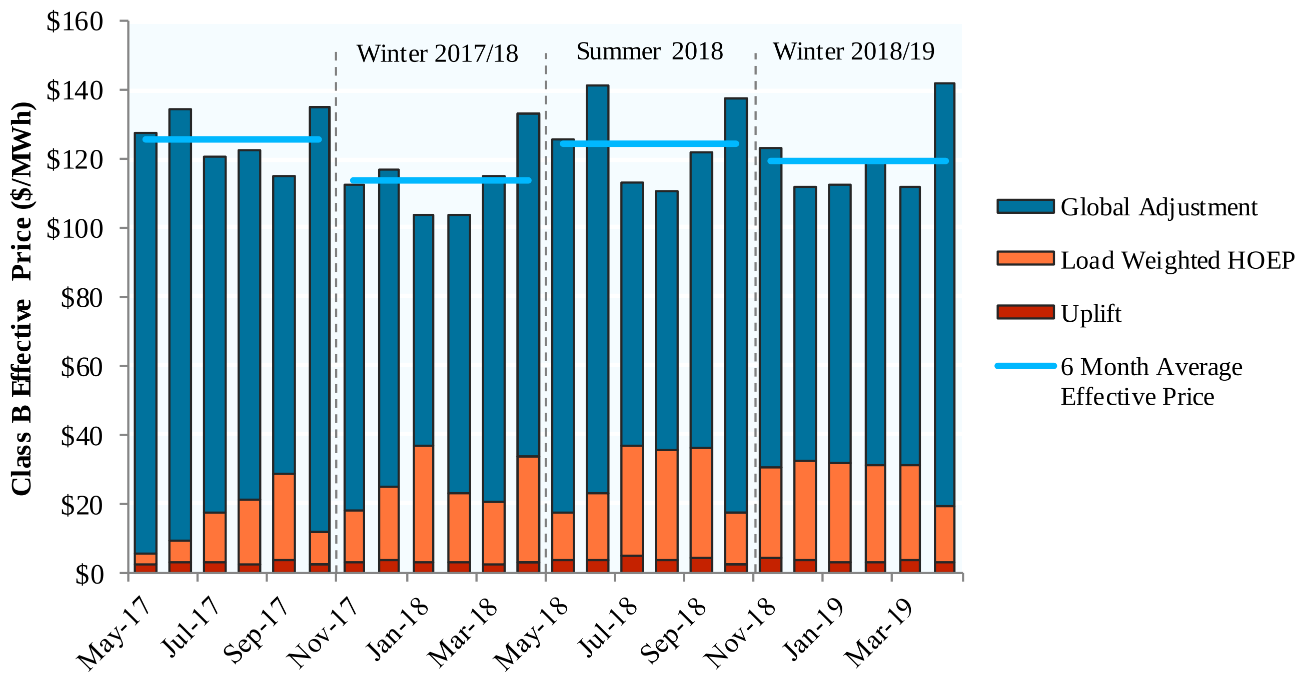


Figure A-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period.[38]

The 6-month average effective price for Class A consumers increased significantly from $69.65/MWh in the Winter 2017/18 Period to $78.68/MWh in the Winter 2018/19 Period. On a

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

monthly basis, higher Class A prices did not necessarily occur during the months when the HOEP was the highest during the Winter 2018/19 Period.

Generally, most Class B consumers are subject to the Regulated Price Plan (RPP) and pay prices that are reviewed by the Ontario Energy Board (OEB) twice a year and reset if required.[39] As a result, Class B consumers are usually less affected by monthly effective price variations in comparison to Class A consumers who do not pay RPP prices. The 6-month average effective price for Class B consumers increased from $113.77/MWh in the Winter 2017/18 Period to $119.51/MWh in the Winter 2018/19 Period. As detailed previously, the increase in the average Class B effective price was driven by the increase in HOEP discussed below and an increase in GA due to higher regulated rates for OPG's nuclear resources.

There was an increase in the 6-month average HOEP from $20.95/MWh in the Winter 2017/18 Period to $24.19/MWh in the Winter 2018/19 Period. See Table A-1 for more information on the increase in the HOEP during the Winter 2018/19 Period. As discussed below, higher gas prices also likely contributed to the increase in the HOEP. Monthly HOEPs were consistently high from December through March.

[39] More information on the RPP is available at: https://www.oeb.ca/industry/policy-initiatives-and-consultations/regulated-price-plan-rpp

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

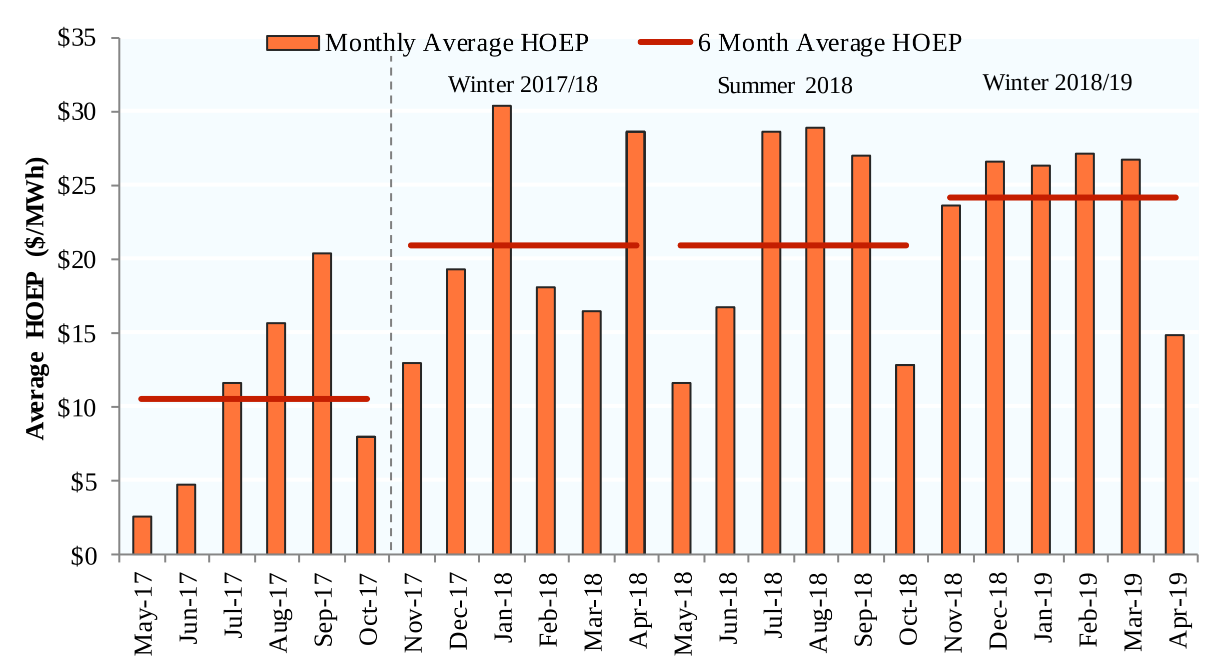


Figure A-4 displays the monthly average HOEP unweighted by the volume of energy consumed in any given interval (the "simple HOEP"), for each month between May 2017 and April 2019. Figure A-4 also displays the simple monthly average HOEP for each 6-month period since May 2017. The HOEP is the unweighted average of the twelve Market Clearing Prices (MCPs) set every five minutes within an hour.

The average gas price during on-peak hours was $4.33/MMBtu in the Winter 2018/19 Period, 12% above the $3.87/MMBtu in the Winter 2017/18 Period. It was $3.78/MMBtu in the Summer 2018 Period and $3.83/MMBtu in the Summer 2017 Period.

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

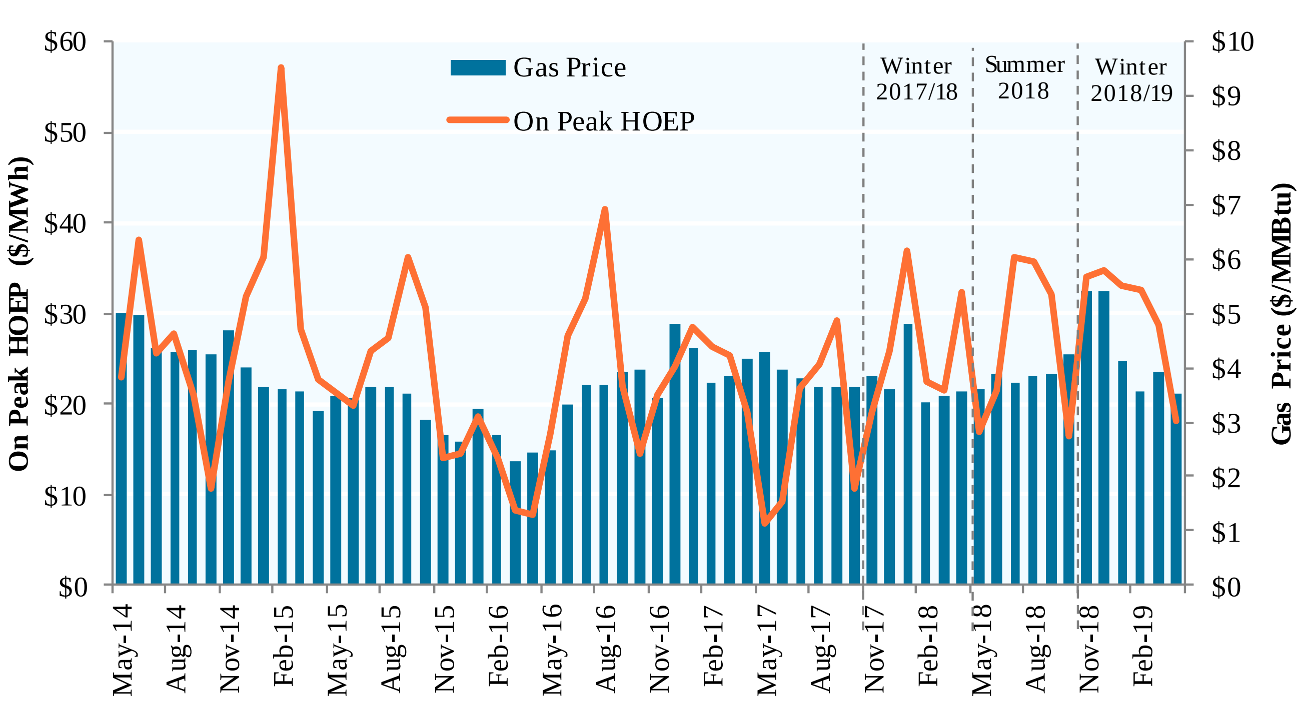


Figure A-5 plots the average monthly HOEP during on-peak hours and the monthly average of Henry Hub natural gas spot prices for days with on-peak hours for the previous year.[40] Natural gas prices are compared to the HOEP for on-peak hours as gas-fired facilities frequently set the price during these hours. Gas-fired facilities typically purchase gas day-ahead.

A correlation coefficient of 0.46 was observed between average daily natural gas prices and daily averages of on-peak HOEP values during the Winter 2018/19 Period. This correlation was much higher than in the Summer 2018 Period, but lower than that observed in the Winter 2017/18 Period. When the supply of generation is tight, or when the demand for energy is high, high-priced (that is, high marginal cost) resources tend to set the MCP more frequently.

[40] 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

As nuclear, wind and hydro resources all typically offer energy at lower prices than natural gas resources, natural gas resources often set the MCP under these conditions. Although both the on-peak HOEP and natural gas prices increased in the Winter 2018/19 Period and peaked from November 2018 to January 2019, natural gas resources set the real-time MCP most often during February 2019 to April 2019 when average monthly nuclear outages were highest.[41] Generally, the on-peak HOEP was highest during months when gas prices were also high during the Winter 2018/19 Period. Therefore, it is likely that the price of natural gas contributed to the overall increase in the HOEP observed during the Winter 2018/19 Period.

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

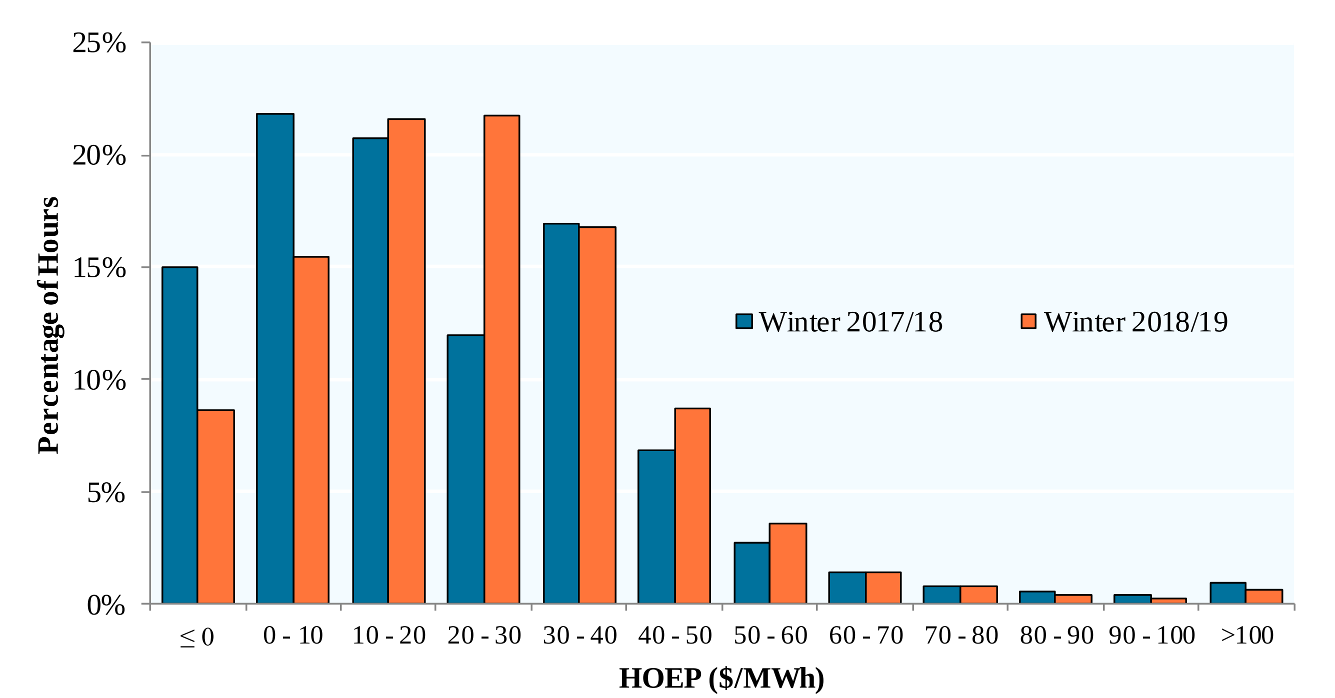


Figure A-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Winter 2018/19 and Winter 2017/18 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh hours.

[41] This outcome assumes that changes in Ontario natural gas prices affect the fuel costs of natural gas generators. Increasing the marginal cost of fuel should give these generators the incentive to increase their offer prices, which would increase electricity prices if natural gas generators are setting the real-time MCP. This should result in a positive correlation between natural gas prices and the HOEP.

In the Winter 2018/19 Period, there was a large decrease in the frequency of hours when the HOEP was negative or zero, and an increase in the frequency of hours with a high HOEP. Only 8.6% of hours in the Winter 2018/19 Period had a negative HOEP, compared to 15% in the Winter 2017/18 Period, while 54% of hours had HOEPs of at least $20/MWh in the Winter 2018/19 Period, up from 42% in the Winter 2017/18 Period. As noted earlier, this is likely because of an increase in the number of nuclear outages and a decrease in available supply from nuclear resources in the Winter 2018/19 Period compared to the Winter 2017/18 Period, giving higher-priced gas resources more opportunity to set the MCP (as shown in Figure A-7).

The percentage of hours that natural gas resources set the real-time MCP increased from 33% in the Winter 2017/18 Period to 45% in the Winter 2018/19 Period, while the percentage of hours that wind and nuclear resources set the real-time MCP decreased from 21% to 12% and from 2% to 0.13%, respectively. Nuclear resources did not set the real-time MCP in the Winter 2018/19 Period except in April 2019. This, too, likely arose from the reduced availability of wind and nuclear capacity in the Winter 2018/19 Period, which resulted in higher-cost gas resources being used more frequently to satisfy supply. Hydroelectric resources set the real-time MCP during 42% of intervals in the Winter 2018/19 Period compared to 45% for gas resources, breaking the trend observed in previous monitoring periods where hydroelectric resources set the real-time MCP more frequently than any other resource.

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

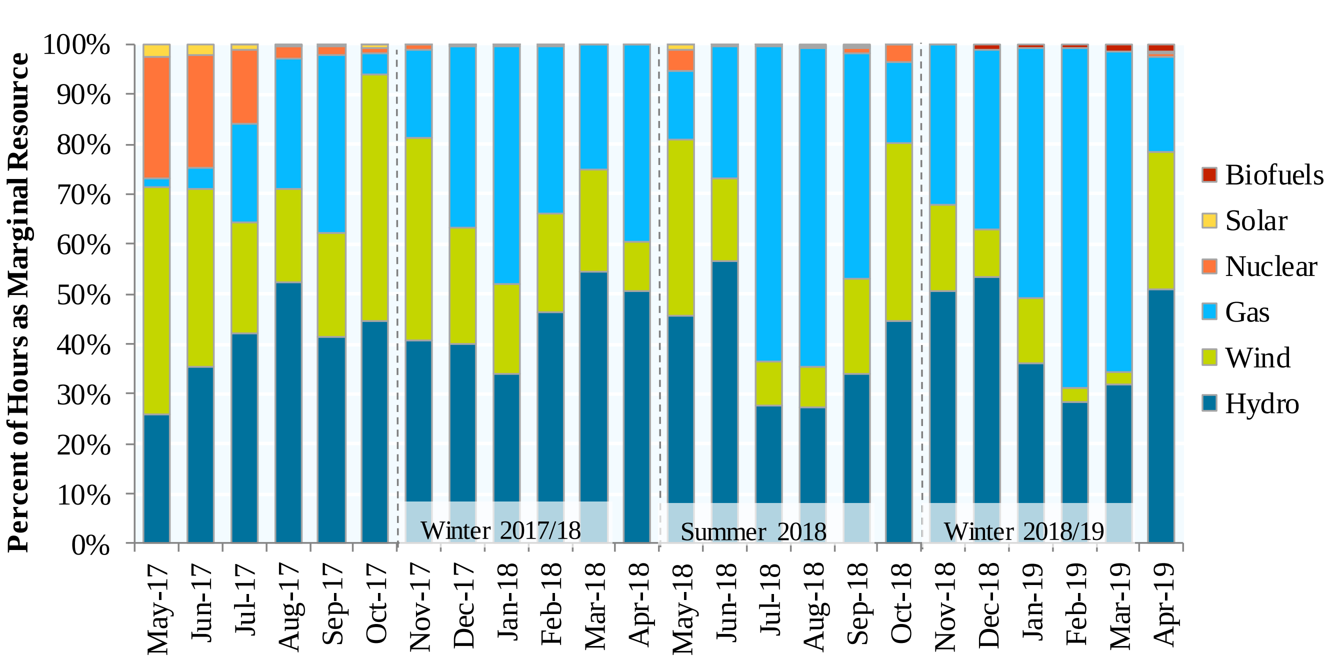


Figure A-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the previous two years. The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

The frequency with which imports and exports set the pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[42] 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.

[42] 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.

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

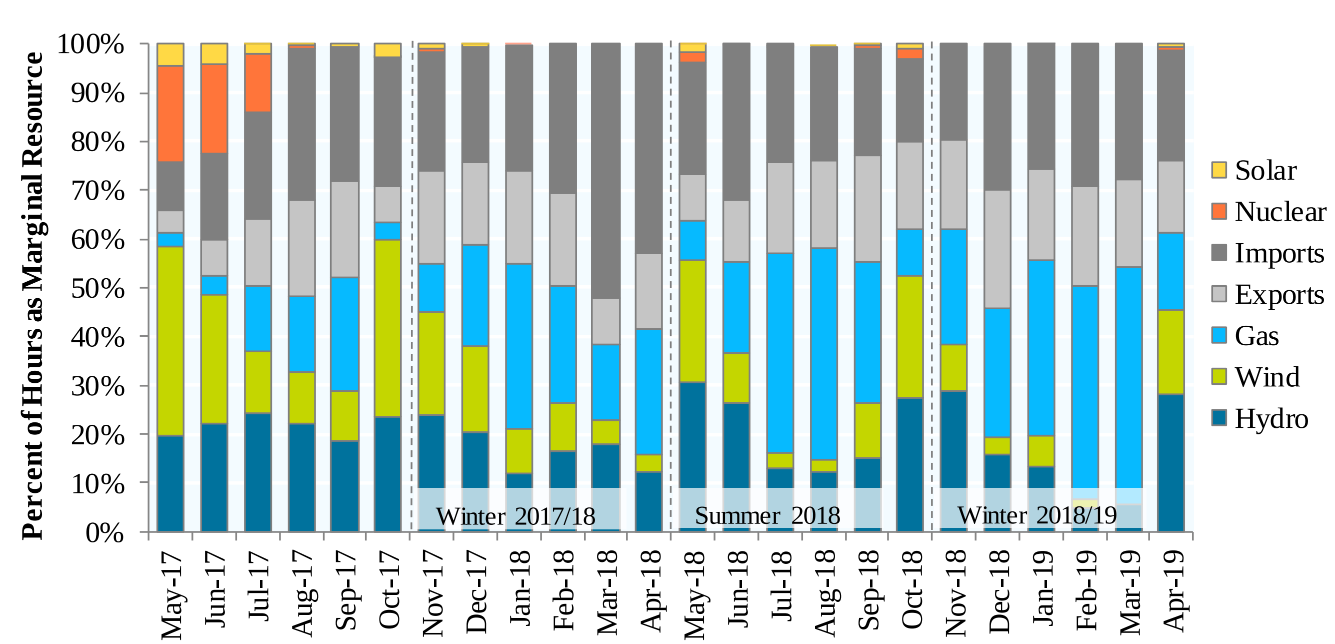


Figure A-8 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP in each month of the previous two years. When compared with Figure A-7, Figure A-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

Nuclear resources did not set the PD-1 MCP during the Winter 2018/19 Period except in April 2019. Natural gas resources set the PD-1 MCP in 32% of hours in the Winter 2018/19 Period, compared to 22% in the Winter 2017/18 Period. This increase in the frequency of natural gas resources setting the PD-1 MCP in the Winter 2018/19 Period was likely caused by a significant increase in the amount of nuclear unavailable capacity, resulting in the scheduling of more expensive marginal resources (see Figure A-21). PD-1 MCP setting by wind and nuclear resources fell from 11% and 0.1% of hours in the Winter 2017/18 Period to 6.3% and 0.1% of hours in the Winter 2018/19 Period. The frequency of hydro resources setting the PD-1 MCP fell from 17% of hours in the Winter 2017/18 Period to 16% of hours in the Winter 2018/19 Period.

Imports set the PD-1 MCP in 26% of hours in the Winter 2018/19 Period, compared to 33% of hours in the Winter 2017/18 Period. Exports set the PD-1 MCP in 19% of hours in the

Winter 2018/19 Period, compared to 16% of hours in the Winter 2017/18 Period. The decrease in the proportion of intervals where imports set the PD-1 MCP correlates to the decrease in the average amount of energy imported in the Winter 2018/19 Period (see Figure A-24).

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, these transactions are settled based on the Intertie Zonal Price (IZP), which is the sum of the real-time MCP and the Intertie Congestion Price (ICP). 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 Winter 2018/19 Period, there was a variation of less than $10/MWh between PD-1 and real-time prices for 71% of hours, up from 69% in the Winter 2017/18 Period. The average absolute deviation between PD-1 and real-time prices in the Winter 2018/19 Period of $9.9/MWh decreased slightly from the Winter 2017/18 Period average deviation of $11/MWh. A decreased in wind generation and increase in natural gas generation to offset the increase in the average unavailable capacity in the Winter 2018/19 Period may have contributed to less variability between pre-dispatch and real-time prices.

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time.[43] Identifying the factors that lead to deviations between the PD-1 MCP and the real-time MCP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as offers and bids are entered into the market.

[43] The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the 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.

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

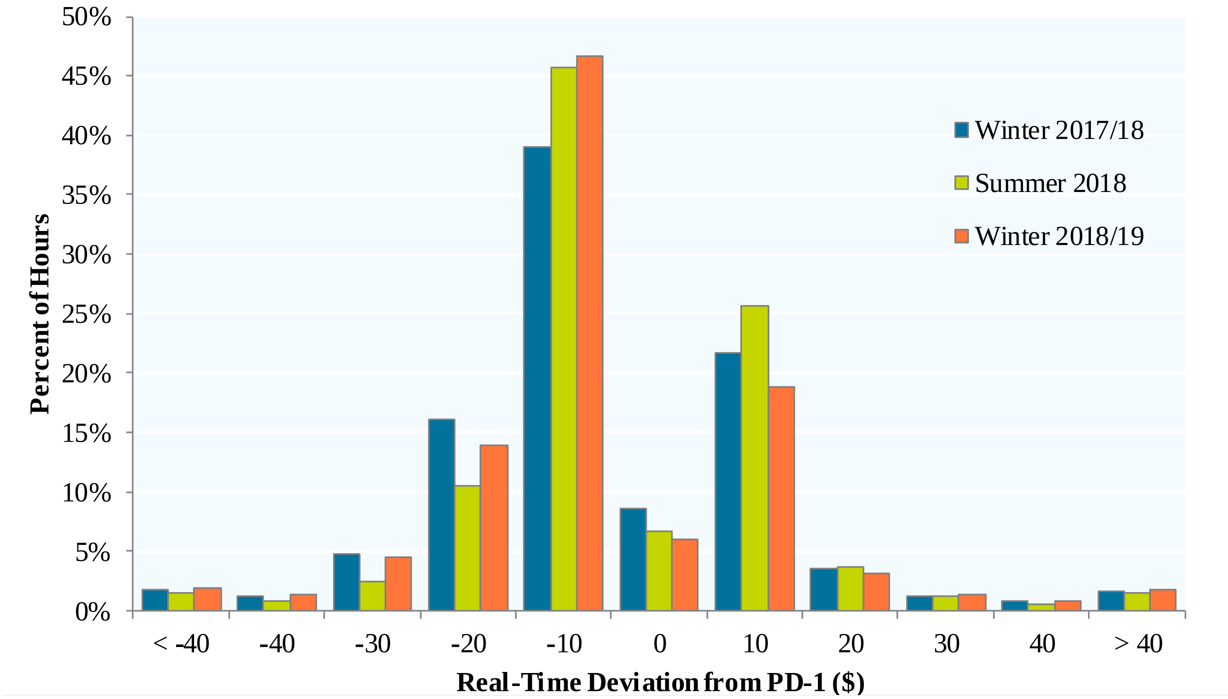


Figure A-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Winter 2018/19, Summer 2018 and Winter 2017/18 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the 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 demand forecast deviation, the most significant source of deviation between the PD-1 MCP and the HOEP, remained constant in the Winter 2018/19 Period relative to the Winter 2017/18 Period. The next most significant source of deviation, wind forecasts, increased between the Winter 2017/18 and Winter 2018/19 Periods. Although the total wind output in the Winter 2018/19 increased only slightly compared to the Winter 2017/18 Period, the absolute average deviation of the wind forecast increased significantly. An increase in wind resource outages in the Winter 2018/19 Period contributed to an increase in the average amount of unavailable wind capacity, which helps explain the increased wind forecast deviation. Self-scheduling and intermittent forecast deviation, as well as net export curtailments, also increased between the Winter2017/18 and Winter 2018/19 Periods.

Table A-2: Factors Contributing to Differences between PD-1 MCP and HOEP, 3 Periods

Factor	Winter 2018/19: Average Absolute Difference		Summer 2018: Average Absolute Difference		Winter 2017/18: Average Absolute Difference	
	MW	% of Ontario Demand	MW	% of Ontario Demand	MW	% of Ontario Demand
Ontario Average Demand	15,979 MW		15,547 MW		15,869 MW	
Forecast Deviation	226 MW	1.41%	251 MW	1.61%	226 MW	1.42%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	20 MW	0.12%	14 MW	0.09%	14 MW	0.09%
Wind Forecast Deviation	175 MW	1.09%	143 MW	0.92%	131 MW	0.83%
Net Export Failures/Curtailments	74 MW	0.46%	63 MW	0.40%	61 MW	0.39%

Table A-2 displays the average absolute difference between PD-1 and real-time for all of the factors identified by the Panel as contributing to the difference between PD-1 and real-time, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

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 the PD-3 MCP 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.[44] Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

[44] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that the facility 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.

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

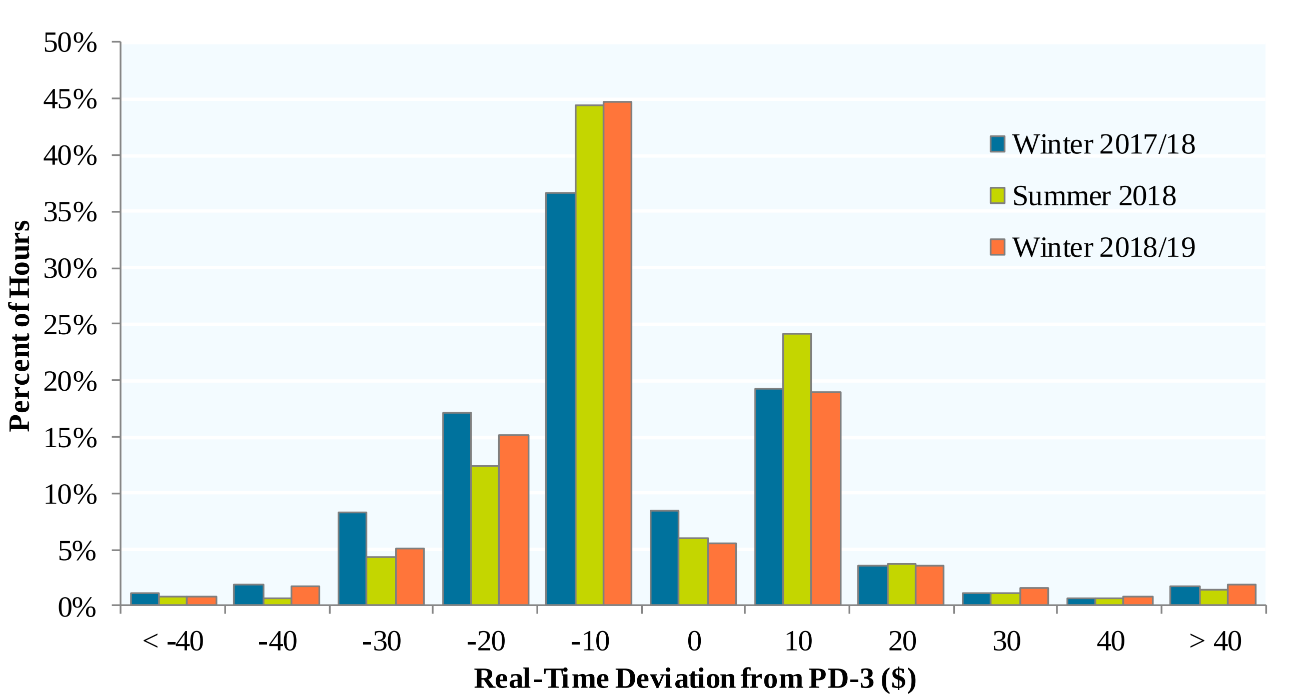


Figure A-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Winter 2018/19, Summer 2018 and Winter 2017/18 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and 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.

PD-3 prices were within $10/MWh of the real-time MCP in 75% of hours in the Winter 2018/19 Period, up from 65% of hours in the Winter 2017/18 Period. The average absolute deviation between PD-3 and real-time MCPs was lower in the Winter 2018/19 Period ($9.15/MWh) compared to the Winter 2017/18 Period ($10.41/MWh). These trends are closely aligned with the deviations observed in PD-1 prices, as the percentage of prices within $10/MWh of the real-time MCP for PD-1 prices and the average absolute deviation for PD-1 prices also decreased.

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

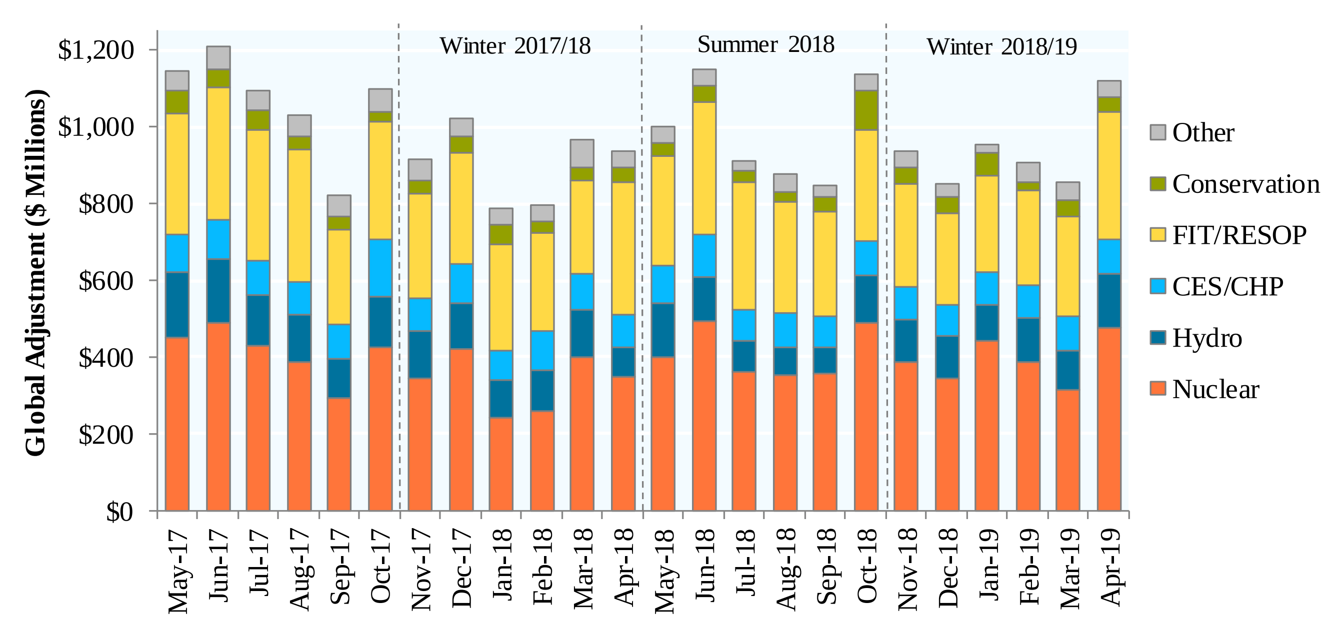


Figure A-11 plots the payments to various resources and recovered through the GA each month by component for the previous two years.

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 OPG's Lennox Generating Station).

The total GA throughout the Winter 2018/19 Period was about 3.7% more than the total GA during the Winter 2017/18 Period, increasing from $5.4 billion to $5.6 billion. Most of the change is due to a 17% increase in GA payments made to nuclear generators between the Winter 2017/18 Period and the Winter 2018/19 Period. The HOEP was also higher in the Winter 2018/19 Period, which partially offset the increase in GA due to nuclear payments. The nuclear share of GA rose from 37% to 42%, while the FIT/RESOP share fell from 31% to 28%. As discussed above, the payment amounts set by the OEB for OPG's regulated nuclear generators were increased substantially in March 2018.

Regulatory Charges

The cost of services provided by the Independent Electricity System Operator (IESO) to operate the wholesale electricity market and maintain the reliability of the high voltage power grid 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".[45] Regulatory charges include both amounts set or approved by the OEB (e.g. IESO Administration Charge and the Rural or Remote Electricity Rate Protection (RRRP) charge) and amounts that are not set or approved by the OEB such as charges associated with reliability or transmission losses.[46]

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

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

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

demand.[47]below summarizes a number of the amounts captured by regulatory charges, the majority of which are "uplift" costs for wholesale market participants.[48] 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 (PCG)[49] 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 these regulatory charges by month.[50]

The total of these charges in the Winter 2018/19 Period was $371 million, a 4% increase from the Winter 2017/18 Period of $357 million. Notable increases since the previous winter period include: Rural or Remote Electricity Rate Protection (45% increase or $9.2 million), PCG (50% increase or $6.4 million), and 30-minute OR (179% increase or $5.1 million). These increases were offset by notable decreases since the previous winter period including: IOG (33% decrease or $8.6 million), 10-minute spinning OR (35% decrease or $5.5 million) and RT-GCG (25% decrease or $5.5 million).

[47] This applies to all monthly and daily uplifts with the exception of costs associated with demand response. 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.

[48] The Panel has not previously provided this information in tabular form. The table separates previously aggregated charges and considers two other charges previously omitted from Panel reports: the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge.

[49] 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.

[50] For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge have been omitted from Figure A-12.

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

Settlement Resolution	Regulatory Charges	Winter 2018/19 ($ million)	Summer 2018 ($ million)	Winter 2017/18 ($ million)
Hourly	Congestion Management Settlement Credits (CMSC)	67.3	59.3	61.8
	Transmission Losses	37.1	34.8	30.6
	Intertie Offer Guarantee (IOG)	17.3	35.9	25.9
	Operating Reserve: 10-minute spinning reserve	10.4	14.2	15.8
	Operating Reserve: 10-minute non-spinning reserve	9.0	12.6	12.2
	Operating Reserve: 30-minute reserve	8.0	8.3	2.9
	Hourly Reactive Support and Voltage Control	7.5	11.0	6.6
	Hourly Charges Subtotal	**156.5**	**176.2**	**155.9**
Monthly	Cost Guarantee: RT-GCG program	17.0	17.4	22.5
	Cost Guarantee: PCG program	19.5	20.3	13.0
	Ancillary Services: Black Start	0.9	0.7	0.6
	Ancillary Services: Regulation	29.6	25.5	26.1
	Ancillary Services: Monthly Reactive Support and Voltage Control	0.9	1.5	1.2
	Demand Response Capacity Payments	21.6	23.6	21.4
	IESO Administration Charge	93.9	91.2	92.4
	Rural or Remote Electricity Rate Protection	29.5	20.2	20.3
	Other: Additional Compensation for Admin Pricing	0.0	0.0	0.0
	Other: Station Service Reimbursement	1.7	1.8	1.8
	Other: Local Market Power	0.0	0.4	1.2
	Monthly Charges Subtotal	**214.5**	**202.7**	**200.7**
Total Regulatory Charges		**371.1**	**378.9**	**356.5**

Table A-3 compares the regulatory charges for the Winter 2018/19, Summer 2018 and Winter 2017/18 Periods, separated by hourly and monthly charges.

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

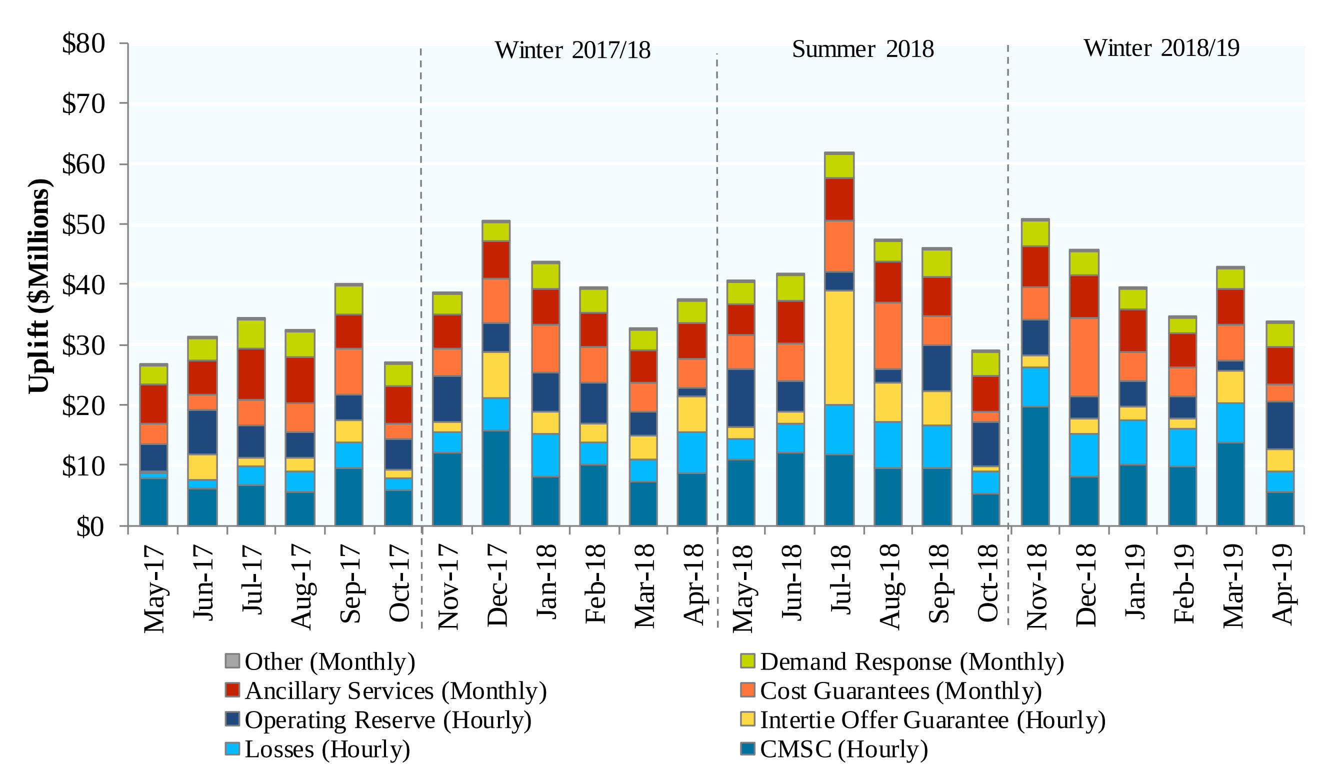


Figure A-12 presents the total uplift charges by component on a monthly basis for the previous two years. This includes both hourly and monthly uplift, which were displayed in separate figures in previous Panel reports. In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee Program (RT-GCG) payments are combined as Cost Guarantees. For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Rate 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.[51,52]

The increased procurement of 30-minute OR may have increased the uplift and average 30-minute OR price for this period.

Uplift from OR was $27 million for Winter 2018/19 Period, down from $31 million in the Winter 2017/18 Period. Average OR prices for both 10-minute non-spinning ($5.30/MW) and 10-minute spinning ($4.44/MW) decreased by more than 30% compared to the Winter 2017/18 Period. This decrease in average prices was offset by a more than doubling of the 30-minute reserve price to $3.55/MW), a trend that began in the Summer 2018 Period. These two trends have led to similar pricing for all OR classes in the Winter 2018/19 Period. The average prices of all three classes of OR followed a similar trend throughout the Winter 2018/19 Period, as seen in Table A-4.

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

[52] This Market Rule Amendment and its justification was discussed in the Panel's Monitoring Report 32 published July 2020, pages 76-88: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

Table A-4: Average Operating Reserve Prices by Period, 2 Years

Operating Reserve Markets	Winter 2018/19 ($/MW)	Summer 2018 ($/MW)	Winter 2017/18 ($/MW)	Summer 2017 ($/MW)
10-minute spinning (10S)	5.30	8.10	7.89	7.84
10-minute non-spinning (10N)	4.44	5.65	6.88	6.10
30-minute reserve (30R)	3.55	3.68	1.45	2.26

Table A-4 presents the average OR prices by period for the past 2 years 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 lead to an increased monthly average price. High average monthly prices arise primarily from two of the three high OR priced hours summarized in Chapter 2 where prices were approximately $300/MW: November 9, 2018 Hour Ending (HE) 10 and April 29, 2019 HE 24. The third hour highlighted in Chapter 2, January 21, 2019 HE 10, barely exceeded $100/MW and as such had a smaller impact on the average monthly price.

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

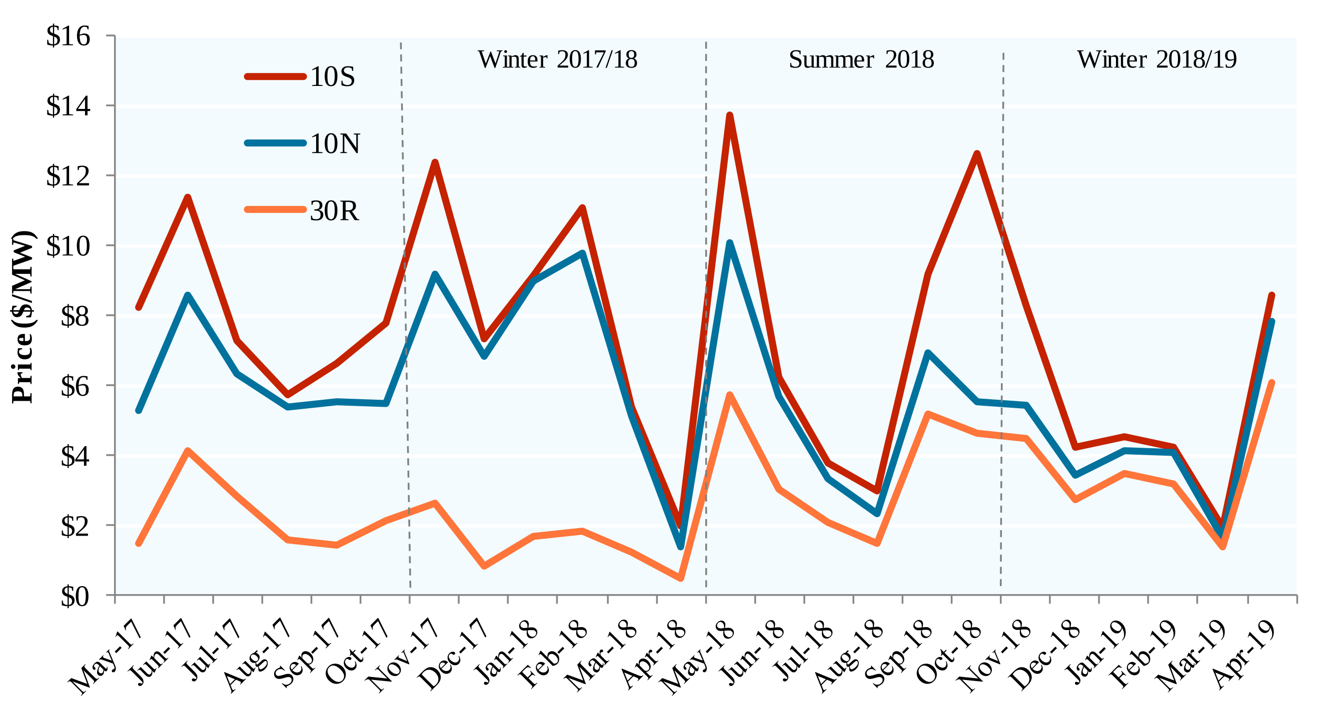


Figure A-13 plots the monthly average OR price for the previous two years for the three OR markets: 10--minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).

The Panel notes a shift in offer behaviour first observed in Summer 2018 that has continued throughout the Winter 2018/19 Period: the significant reduction in hydro resources being offered into the OR markets. Beginning in July 2018, hydro offers in the 30-minute OR market were reduced to virtually zero, while offers in the 10-minute spinning and non-spinning reserve markets also declined. The influence of this offer behaviour on OR prices has not yet been measured but may be revisited by the Panel in future.

Nodal Prices

Nodal prices approximate the marginal cost of electricity in each region and reflect Ontario's internal transmission constraints and losses. 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, most zones had higher average prices in the Winter 2018/19 Period compared to the previous winter, except for the East and Northwest.

In general, monthly average nodal prices outside the two northern zones are similar and move together. Most of the time, the nodal prices in the Northwest and Northeast zones are significantly lower than in the rest of the province because there is more low-cost generation 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.

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.

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

Zone	Winter 2018/19	Summer 2018	Winter 2017/18
Bruce	$20.63	$16.26	$15.28
East	$9.67	$15.13	$12.15
Essa	$21.36	$16.99	$16.56
Niagara	$21.06	$15.50	$15.71
Northeast	$15.88	$14.39	$15.14
Northwest	$3.98	$14.85	$17.98
Ottawa	$20.47	$17.36	$16.14
Southwest	$21.33	$17.29	$15.96
Toronto	$21.07	$16.87	$16.06
West	$27.58	$18.62	$13.49

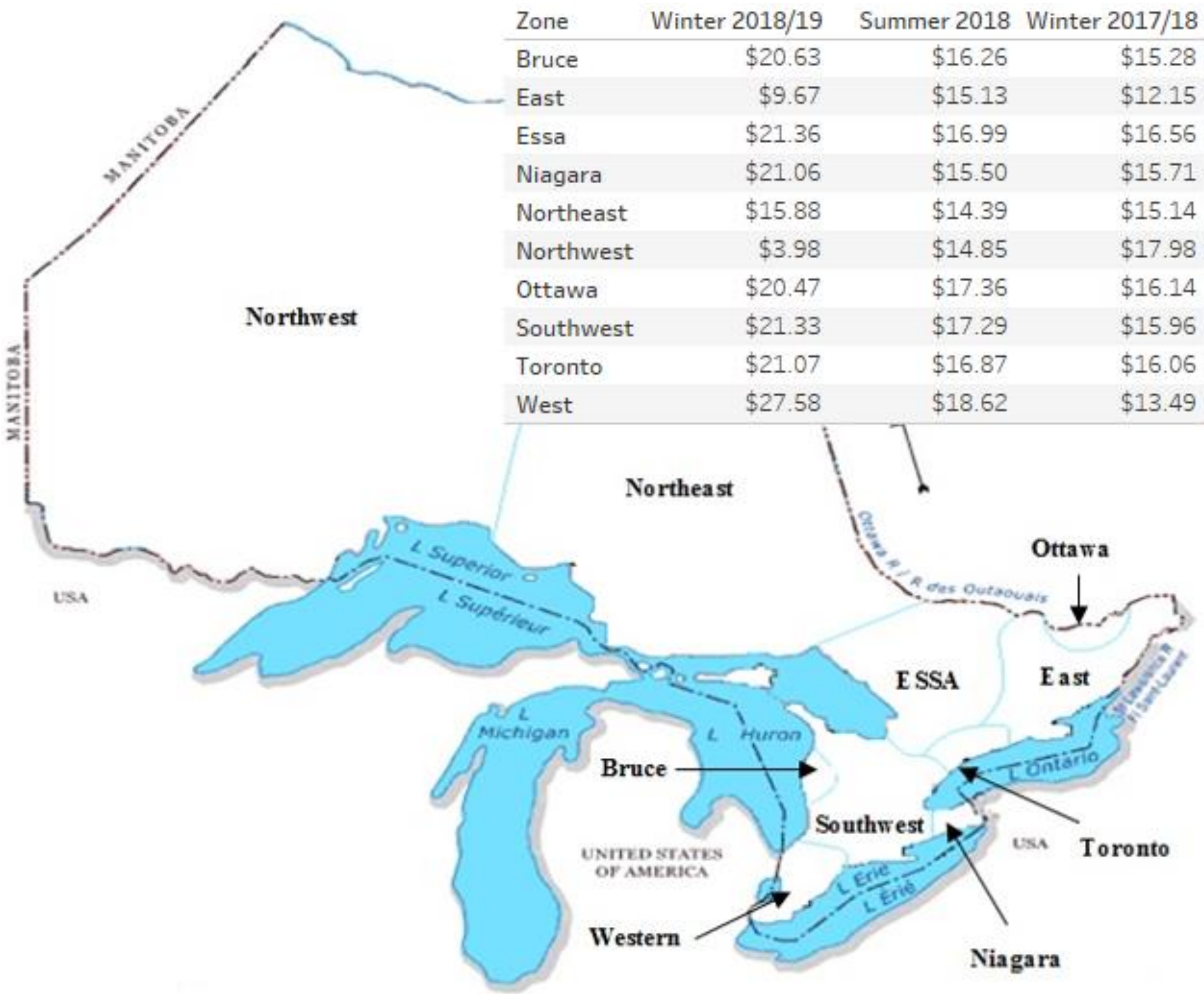


Figure A-14 illustrates the average nodal prices of Ontario's ten internal zones for the Winter 2018/19, Summer 2018 and Winter 2017/18 Periods.[53]

[53] 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 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 MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 and signals when there are more economic transactions than the intertie transmission lines can accommodate (if there is no congestion, the ICP is zero). The ICP is positive when there is export congestion and negative when there is import congestion.

Figure A-15: Hours per Month of Import Congestion by Intertie, 2 Years

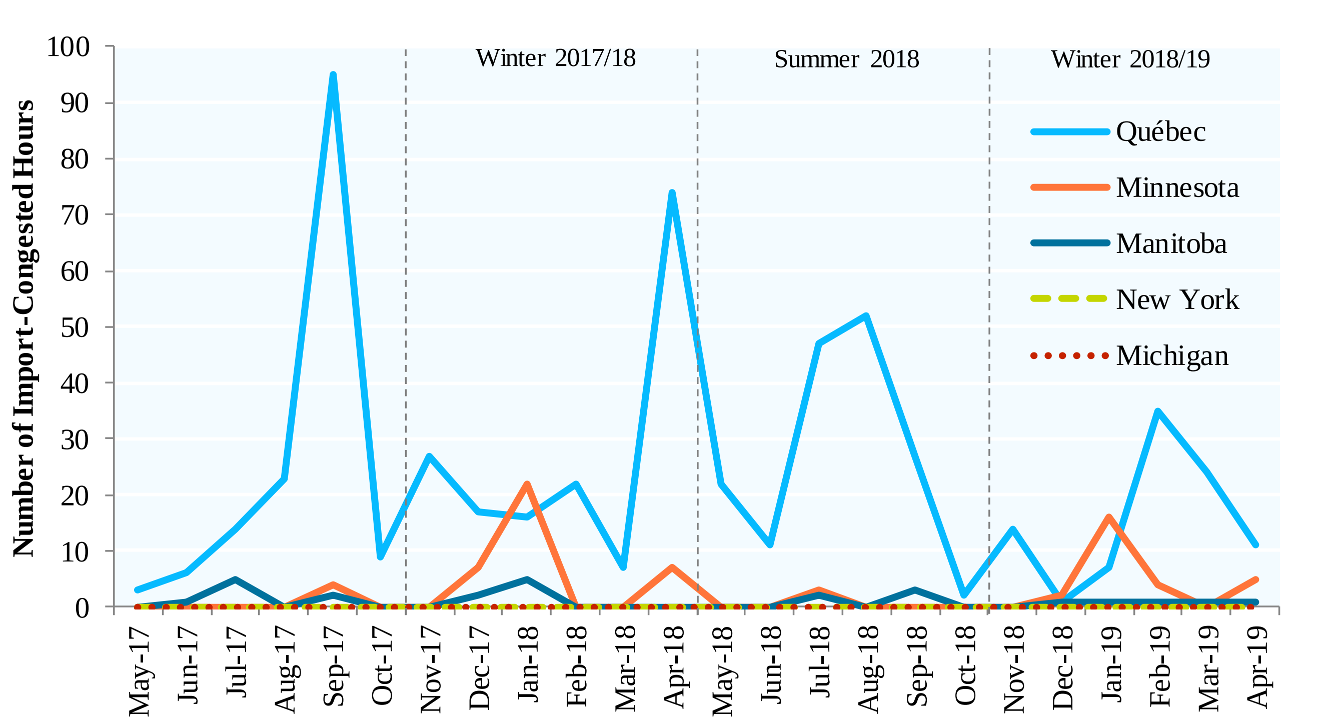


Figure A-15 reports the number of hours per month of import congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

For the Winter 2018/19 Period, Québec experienced the highest number of import congestion hours. The Québec intertie experienced a decrease in the number of import-congested hours from 163 hours in the Winter 2017/18 Period to 92 hours in the Winter 2018/19 Period. Congestion on the Québec intertie was highest in February with 35 hours.

Figure A-16: Hours per Month of Export Congestion by Intertie, 2 Years

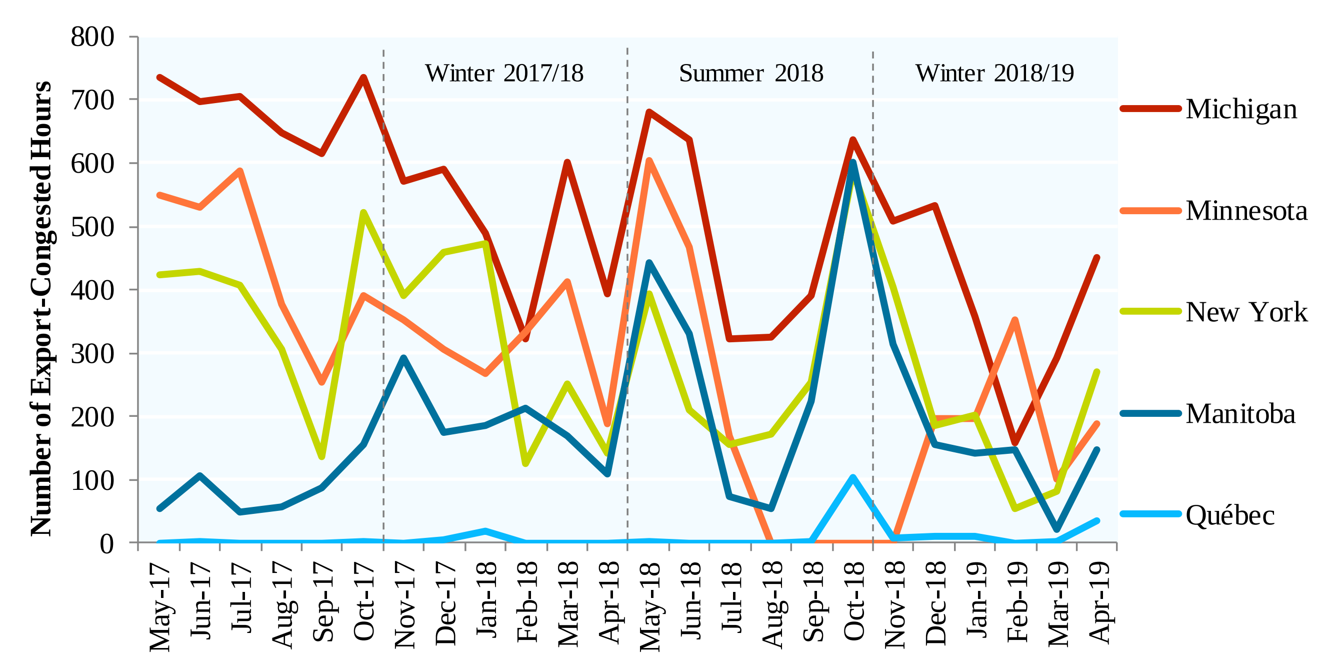


Figure A-16 reports the number of hours per month of export congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

There were 5,517 hours of export congestion in the Winter 2018/19 Period, a 30% decrease compared to the previous winter period. Minnesota had the greatest decrease in export-congested hours, from 1,860 hours in the Winter 2017/18 Period to 1,032 hours in the Winter 2018/19 Period.

Table A-5: Monthly Electricity Spot Prices – Ontario & Surrounding Jurisdictions, 1 Period

Date	Ontario (HOEP) ($/MWh)	Manitoba ($/MWh)	Michigan (MISO[54]) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO[55]) ($/MWh)	PJM[56] ($/MWh)
Nov 2018	23.62	41.79	49.56	43.10	38.55	28.88
Dec 2018	26.60	35.97	46.06	38.02	38.54	27.40
Jan 2019	26.36	39.41	42.45	39.98	30.93	34.33
Feb 2019	27.08	36.84	35.26	39.57	37.25	28.61
Mar 2019	26.70	30.32	37.14	34.63	28.79	30.76
Apr 2019	14.79	30.76	23.51	32.08	32.62	29.46

Table A-5 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA or uplift. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table A-5. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs.

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.

The average HOEP continued to be the lowest market price as compared to Manitoba, Michigan, Minnesota, New York and PJM. The price difference is mainly due to export congestion. In other words, there is not enough transmission available to move low cost energy from Ontario to other markets.

[54] Midcontinent Independent System Operator

[55] New York Independent System Operator

[56] Pennsylvania New Jersey Maryland

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

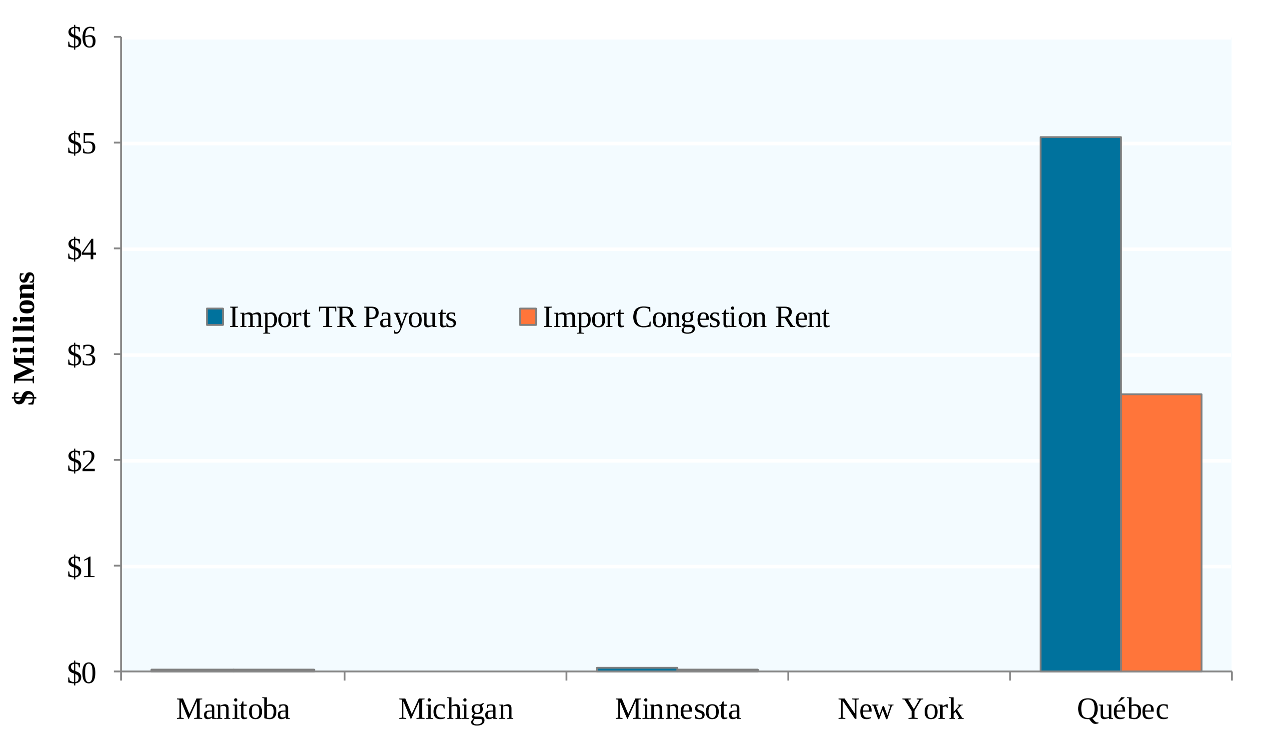


Figure A-17 compares the total import congestion rent collected to total TR payouts by intertie for the Winter 2018/19 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

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

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. 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 shortfalls are covered primarily by TR auction revenues, which are the proceeds from selling TRs (a payment into the TRCA).

Total import TR payouts in the Winter 2018/19 Period were $5.1 million, while total import congestion rent was $2.6 million, creating a congestion rent shortfall of $2.5 million. This shortfall was essentially all on the Québec intertie ($2 million). Québec's congestion rent shortfall was largely due to there being more megawatts of TRs for the Québec intertie than there were megawatts being transacted over the intertie during hours of extreme import congestion in the Winter 2018/19 Period, causing TR payments to outweigh the congestion rent collected during these hours.

Export TR payouts in the Winter 2018/19 Period totalled $44.7 million, while export congestion rent totalled $52.5 million. This $7.9 million surplus of congestion rent is primarily due to the $7.1 million imbalance between congestion rent and TR Payouts on the Michigan intertie, as well as the $3.5 million imbalance between congestion rent and TR payouts on the New York intertie. These surpluses in congestion rent in the Winter 2018/19 Period were partly offset by congestion rent shortfalls, primarily the $2 million shortfall on the Québec intertie.

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

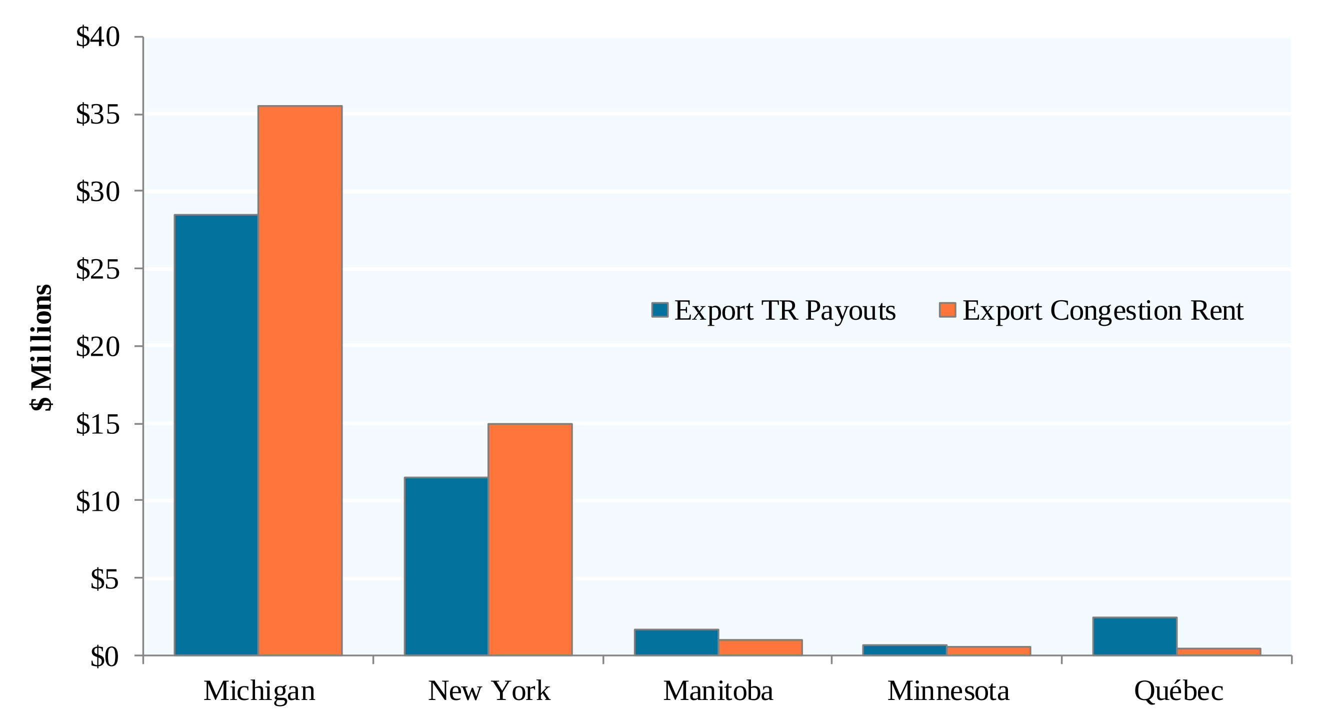


Figure A-18 compares the total export congestion rent collected to total TR payouts by intertie for the Winter 2018/19 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

Long-term (12-month) import TR prices for the February 2019 auction decreased from the previous auction across all jurisdictions except for Minnesota, indicating that traders likely expected import congestion to decrease for the first quarter of 2020 for all jurisdictions except Minnesota. No long-term TRs were auctioned for either direction along the Minnesota intertie for the August 2018 auction.

Table A-6: Average 12-Month TR Auction Prices by Intertie & Direction

Direction	Auction Date	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-18	Jul-18 to Jun-19	1,179	193	2,996	150	6,462
	Aug-18	Oct-18 to Sep-19	1,449	218	-	208	8,700
	Nov-18	Jan-19 to Dec-19	1,436	145	1,648	175	12,751
	Feb-19	Apr-19 to Mar-20	1,010	83	2,509	71	7,775
Export	May-18	Jul-18 to Jun-19	36,721	140,168	60,773	57,154	2,707
	Aug-18	Oct-18 to Sep-19	38,632	123,458	-	52,185	3,068
	Nov-18	Jan-19 to Dec-19	28,339	129,949	44,392	63,584	4,929
	Feb-19	Apr-19 to Mar-20	37,656	100,937	54,593	40,057	2,273

Table A-6 lists the average auction prices for 1 MW of long-term (12-month) TRs for each intertie in either direction for each auction since May 2018. 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 Winter 2018/19 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.

For the February 2019 auction, long-term export TR prices fell for Michigan, New York and Québec – indicating traders expected import congestion to decrease – while long-term export TR prices rose for Manitoba and Michigan as compared to the November 2018 auction. No long-term TRs were auctioned for either direction along the Minnesota intertie in the August 2018 auction.

Table A-7: Average One-Month TR Auction Prices by Intertie & Direction, 1 Year

Direction	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-18	15	0	89	1	260
	Jun-18	18	1	158	11	400
	Jul-18	20	7	202	37	455
	Aug-18	28	13	222	37	744
	Sep-18	-	7	-	7	255
	Oct-18	65	3	-	10	760
	Nov-18	23	2	-	11	72
	Dec-18	50	8	-	2	305
	Jan-19	185	9	231	8	521
	Feb-19	111	2	235	24	470
	Mar-19	90	2	-	28	521
	Apr-19	36	2	-	2	368
Export	May-18	1,250	11,822	4,523	4,836	5
	Jun-18	3,622	12,161	6,120	5,076	9
	Jul-18	2,686	11,664	-	3,758	10
	Aug-18	2,322	8,555	-	3,921	12
	Sep-18	-	8,752	-	3,276	14
	Oct-18	3,413	12,671	-	5,246	10
	Nov-18	6,133	11,111	-	6,300	194
	Dec-18	4,892	12,055	-	6,735	1,153
	Jan-19	3,601	12,685	4,247	8,184	1,585
	Feb-19	4,251	4,065	-	3,333	1,431
	Mar-19	2,842	3,775	-	2,155	42
	Apr-19	3,031	6,746	-	1,800	66

Table A-7 lists the auction prices for 1 MW of short-term (one-month) TRs for each intertie in either direction for each auction during the Winter 2018/19 and Summer 2018 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 continue to be volatile from month-to-month. Short-term TRs for the Minnesota interties were only sold in 3 of the past 12 months.

The balance of the TRCA decreased to $111.2 million at the end of the Winter 2018/19 Period (April 2019), a decrease from $125.9 million at the end of the Summer 2018 Period (October 2018).[57,58] The April 2019 balance was $91.2 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance for the 6-month monitoring period was composed of:[59]

1. $122.5 million in revenue, specifically:
    - $55.2 million in congestion rent
    - $65.9 million in total auction revenues
    - $1.4 million in interest
2. $137.2 million in debits, specifically:
    - $49.9 million in TR payouts
    - $87.3 million in disbursements to Ontario consumers and exporters.

[57] 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.

[58] For reference, the balance at the end of the Winter 2017/18 Period (April 2018) was $145.3 million.

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

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

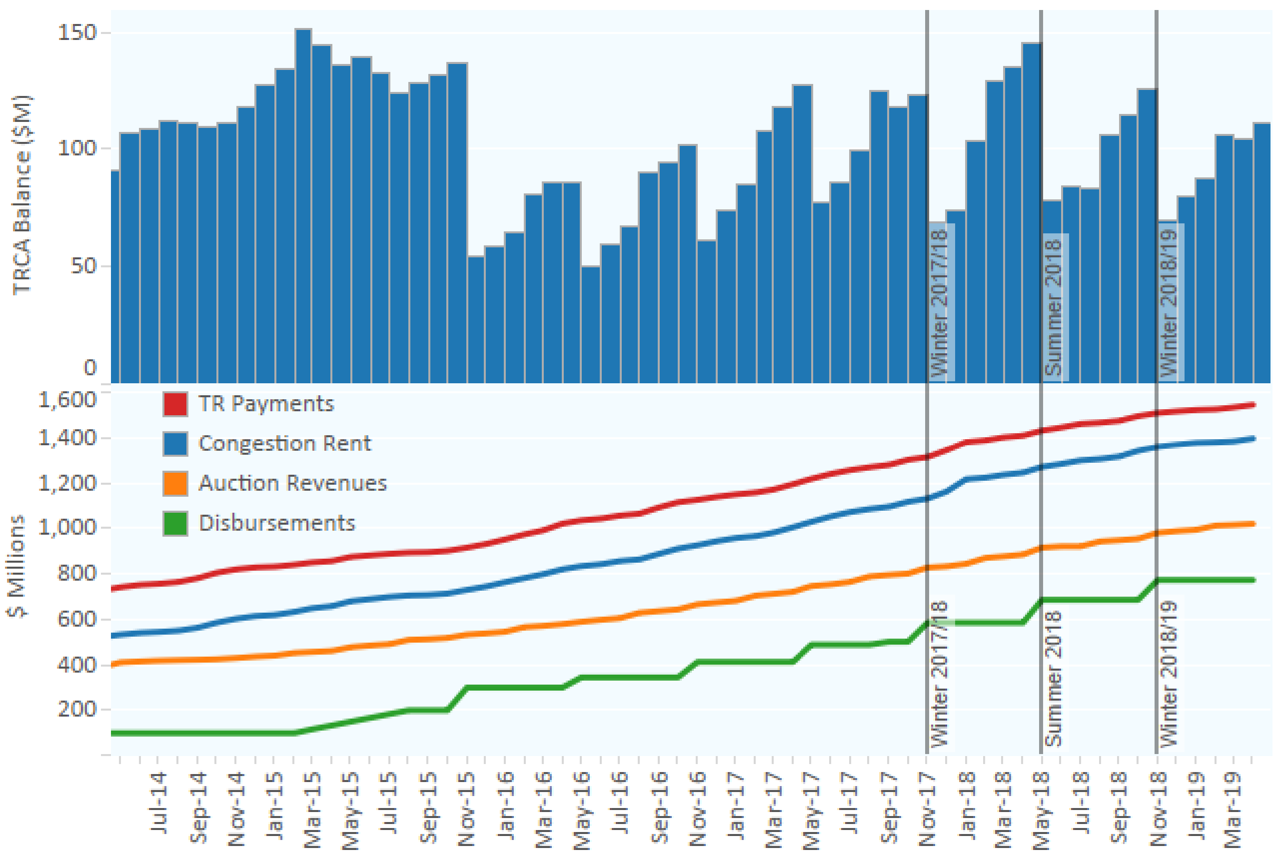


Figure A-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account.

A.2 Demand

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

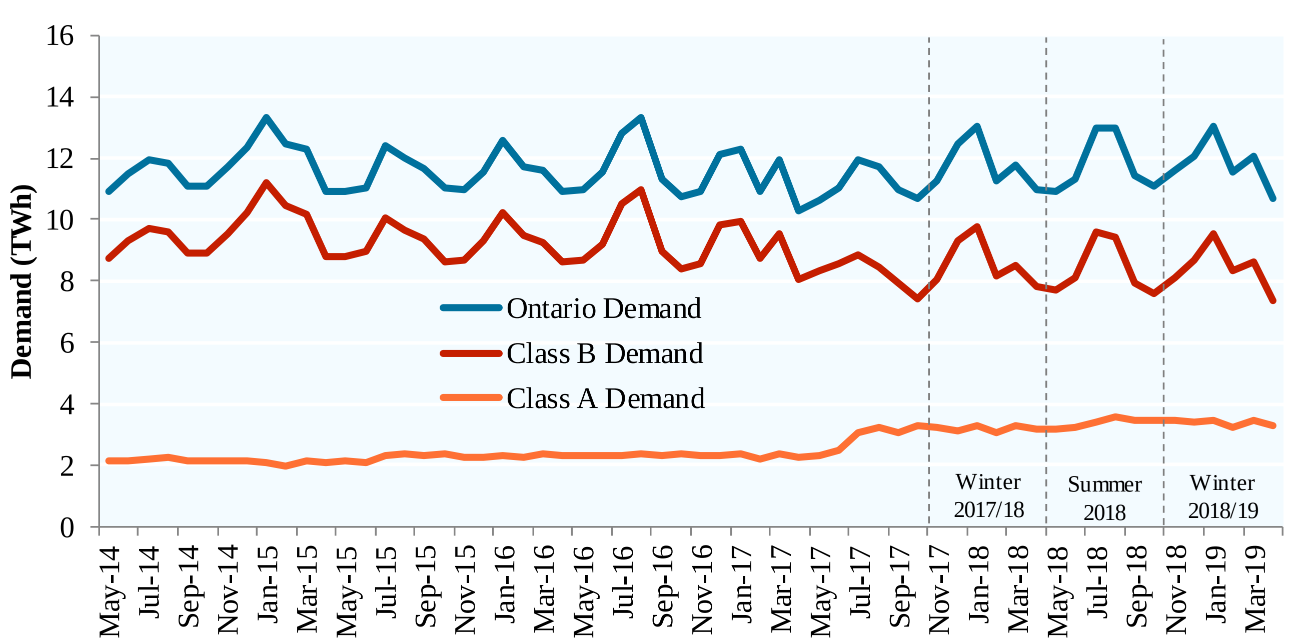


Figure A-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand–not grid-connected demand–in that it includes demand satisfied by embedded generators.[60]

Total demand in the Winter 2018/19 Period was 71.0 TWh – 0.3% higher than the total demand of 70.8 TWh in the Winter 2017/18 Period. Weather and economic conditions were similar between the two periods.

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

A.3 Supply

This section presents data on generating capacity, actual generation, and Operating Reserve (OR) supply for the Winter 2018/19 Period relative to previous years.

Table A-8: Changes in Generating Capacity, Q4 2018 to Q1 2019

Generation Type	Grid-connected		Distribution-level ("Embedded")	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	-	13,009	-	-
Natural Gas	-	10,277	-	-
Hydro	9	8,482	-	278
Wind	74	4,486	-	591
Solar	-	380	40	2,153
Biofuel	-200	295	-1	109
Gas-Fired and Combined Heat and Power	-	-	-	271
Energy from Waste	-	-	-	24
Total	-117	36,929	39	3,426

Table A-8 lists the quantity of nameplate generating capacity that completed commissioning and was added to the IESO-controlled grid's total capacity during the fourth quarter of 2018 and first quarter of 2019, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[61] Total capacity of each type at the end of the first quarter of 2019 is also shown.

Little new capacity was added to the Ontario generation fleet at either the IESO-controlled grid or the distribution level. The capacity added was mostly variable generation that generally offers into the wholesale spot market at low prices, potentially contributing to the continuation

[61] 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 http://www.ieso.ca/power-data/supply-overview/transmission-connected-generation#Historical%20Quarterly%20Progress%20Reports%20on%20Contracted%20Electricity%20Supply

of low wholesale spot prices in Ontario. There was a net decrease in generating capacity caused by a 200 MW reduction in biofuel capacity.

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

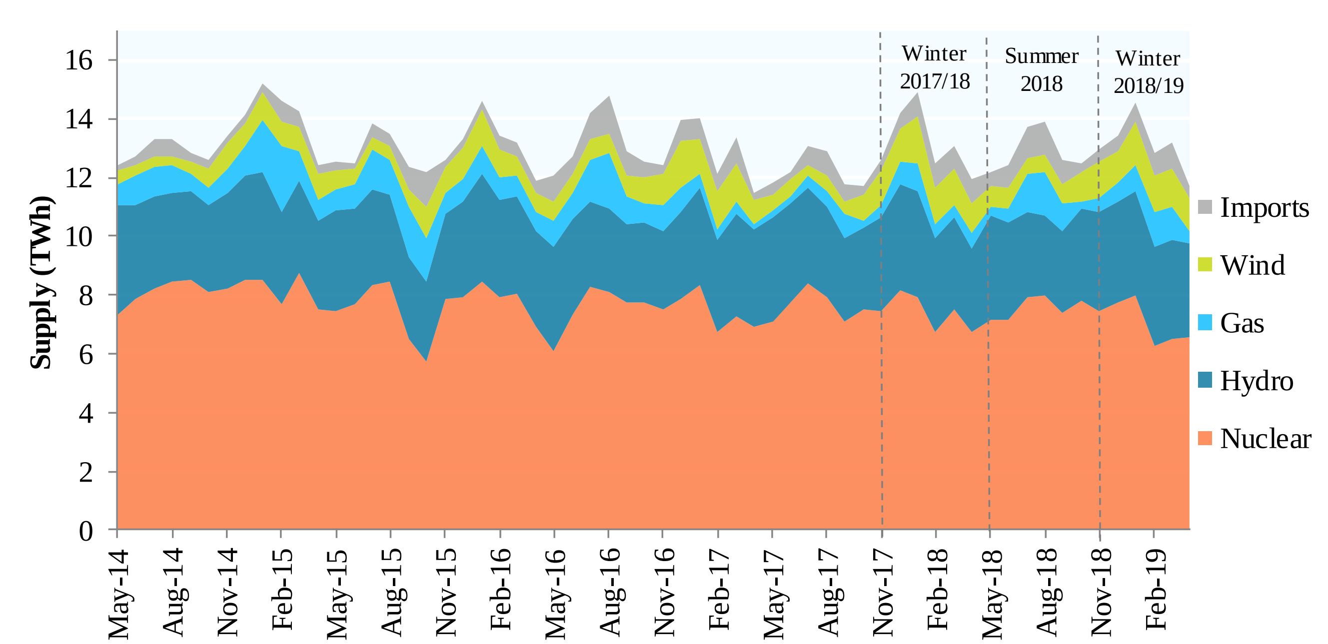


Figure A-21 displays the real-time unconstrained production schedules from May 2014 to April 2019 by resource or transaction type: imports, wind, gas-fired, hydroelectric and nuclear.[62] Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand or seasonal fuel variations (for example, during the spring snowmelt or freshet when hydroelectric plants have an abundant supply of water).

Compared to the Winter 2017/18 Period, the Winter 2018/19 Period showed a 4.7% decrease in the output of nuclear generators from 44.6 TWh to 42.5 TWh. The decrease is offset by a 31.4% increase in the output of gas-fired generators from 3.5 TWh to 4.6 TWh and a smaller increase in hydroelectric output.

[62] Solar and biofuel are excluded from the figure as these fuel types 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.

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

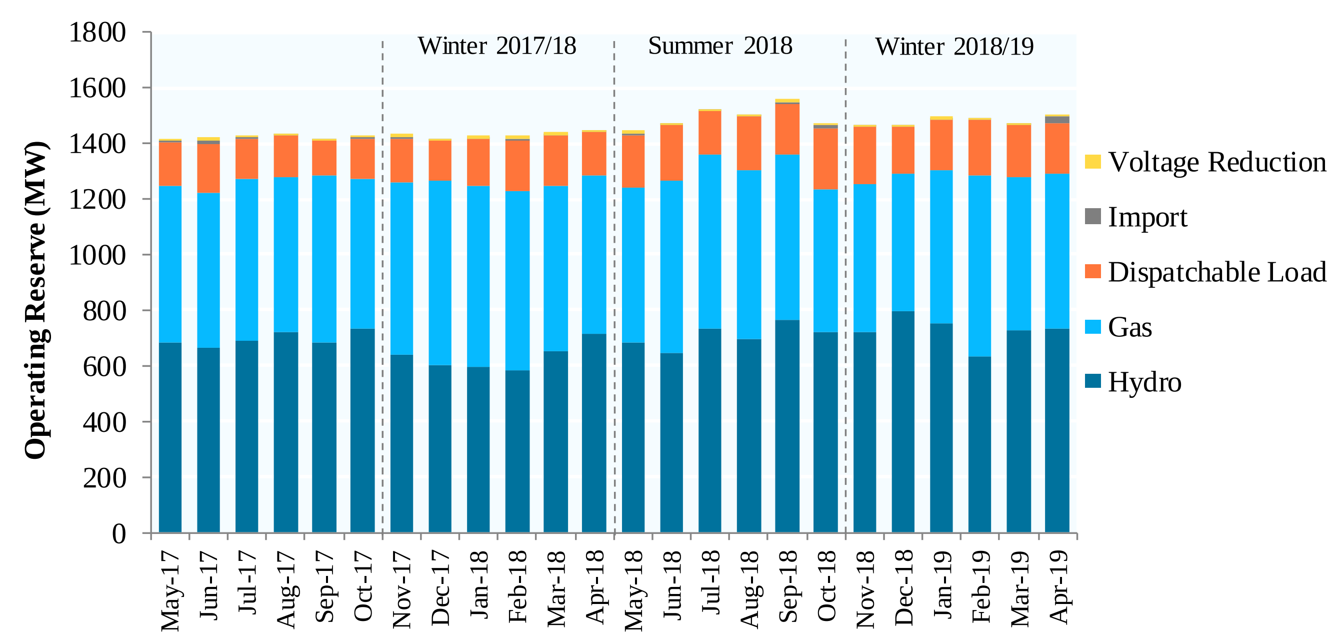


Figure A-22 displays the real-time unconstrained OR schedules from May 2017 to April 2019 by resource or transaction type: hydroelectric, gas-fired, dispatchable loads, imports and voltage reduction (taken as a control action by the IESO).[63] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

[63] 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-9: Average Hourly OR Scheduled by Resource Type and Season, 3 Periods

Quantity	Winter 2017/18	Summer 2018	Winter 2018/19
Average OR Scheduled (MW)	1,435 MW	1,497 MW	1,484 MW
Dispatchable Load Share (%)	12%	13%	13%
Natural Gas Share (%)	43%	39%	38%
Hydro Share (%)	44%	47%	49%
Other Share (%)	1%	1%	1%

Table A-9 reports the seasonal average quantity of hourly OR scheduled and the fraction of total OR that is provided by resource or transaction type. It is based on the same data as Figure A-22. "Other" is the sum of OR from imports and voltage reduction.

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

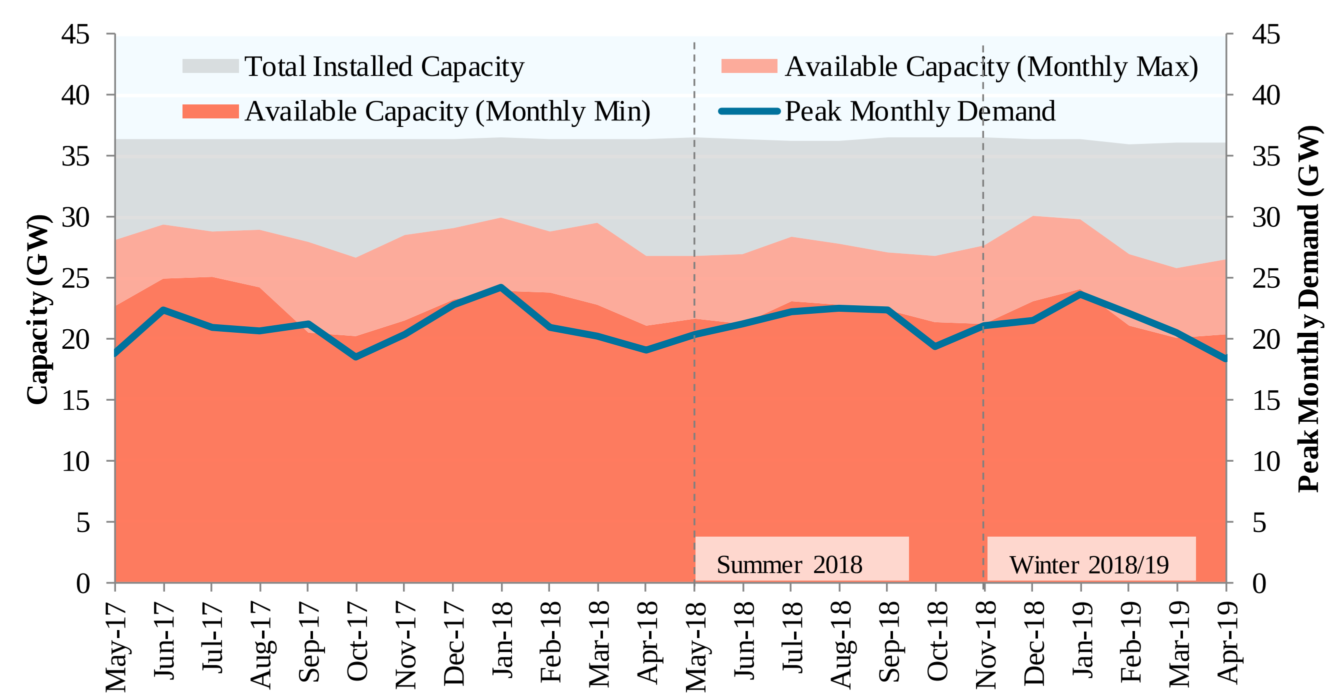


Figure A-23 plots the monthly minimum and maximum available generation capacity, accounting for unavailable capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from May 2017 to April 2019. 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.[64]

The Winter 2018/19 Period had, on average, 11.6 GW of unavailable capacity, which is 9% more than the average of 10.7 GW of capacity that was unavailable in the Winter 2017/18 Period. This difference was primarily driven by more nuclear outages starting in February 2019, although there were smaller increases in outages of wind and gas.

[64] 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

A.4 Imports, Exports and Net Exports

This section examines import and exports transactions in the unconstrained sequence, as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[65]

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

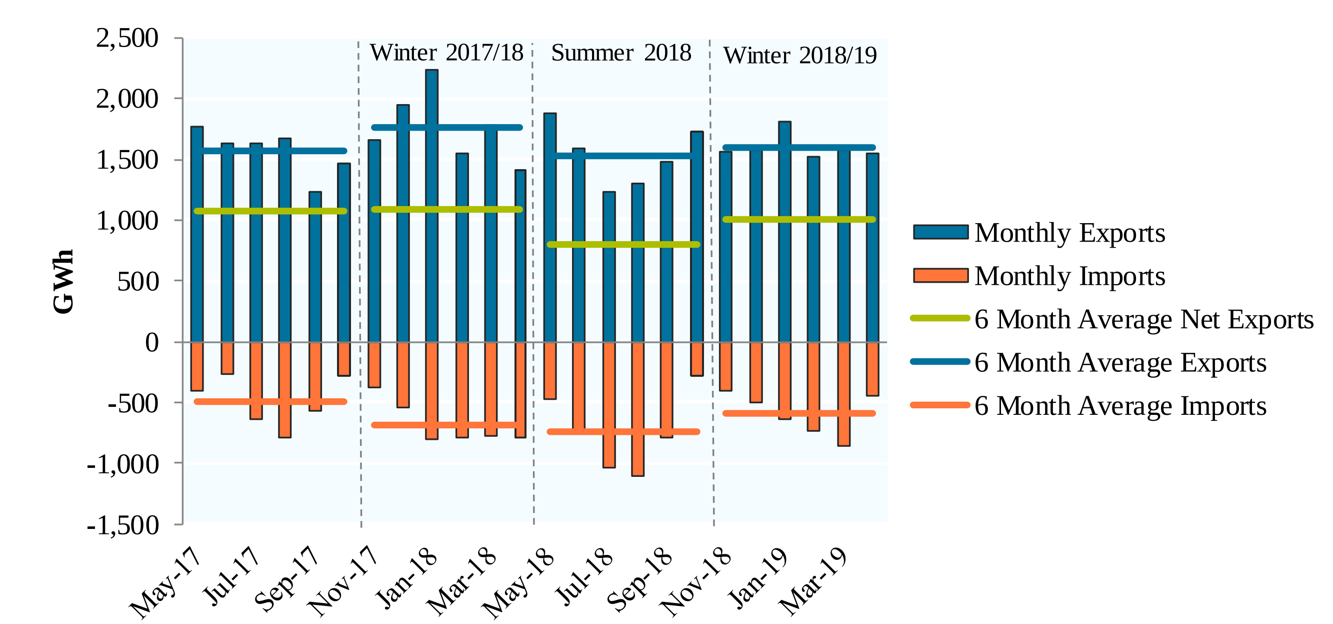


Figure A-24 plots total monthly imports and exports from May 2017 to April 2019, as well as the average monthly imports, exports and net exports calculated over each 6-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Ontario remained a net exporter in the Winter 2018/19 Period, with net exports of 6.02 TWh, down from 6.49 TWh in the Winter 2017/18 Period. Compared to the Winter 2017/18 Period, exports fell by 1.00 TWh, and imports fell by 0.52 TWh. The decrease in net exports was primarily driven by a large decrease in exports to New York.

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

Figure A-25: Exports by Intertie, 2 Years

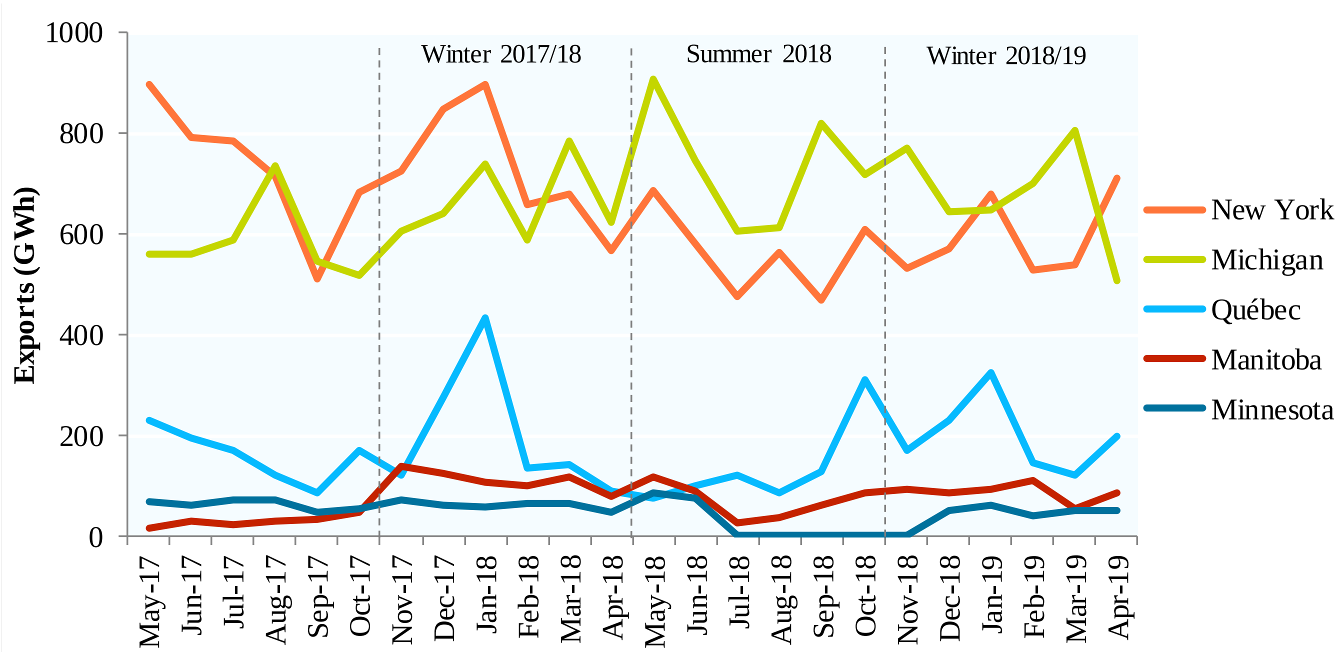


Figure A-25 presents a breakdown of exports from May 2017 to April 2019 to each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly export quantities over the Winter 2018/19 and Summer 2018 Periods are given for each intertie in Table A-10.

Figure A-26: Imports by Intertie, 2 Years

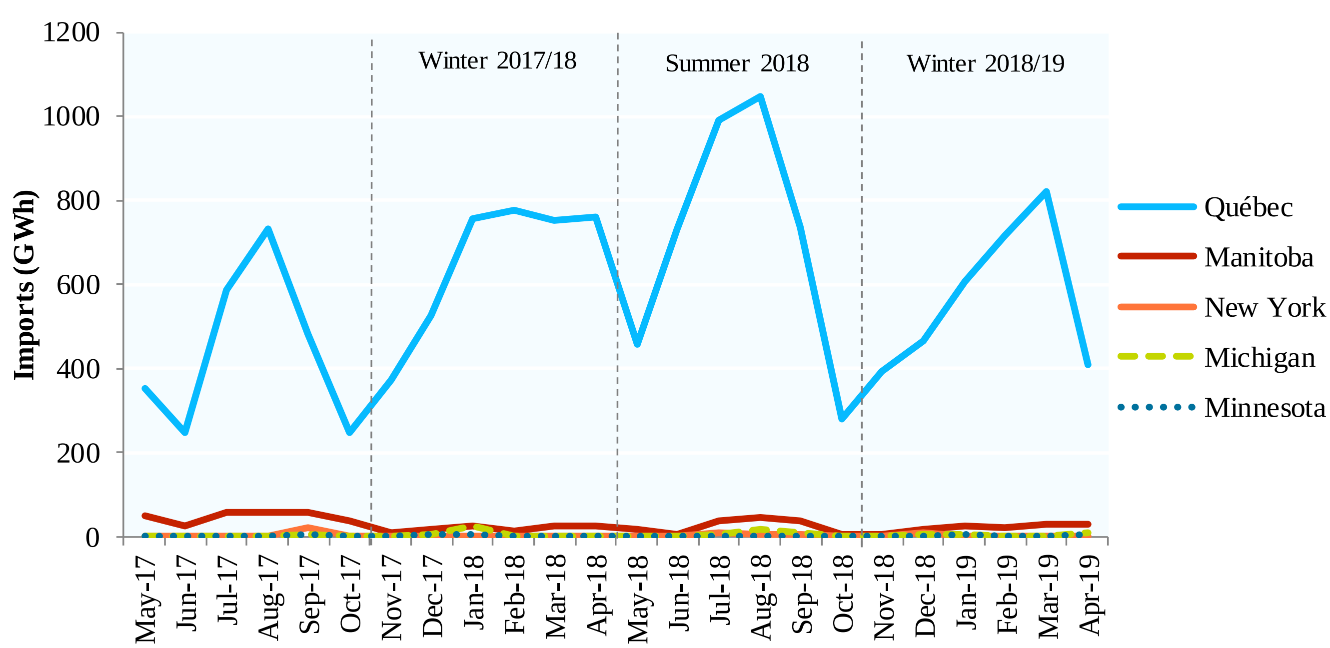


Figure A-26 presents a breakdown of imports from May 2017 to April 2019 from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly import quantities over the Winter 2018/19 and Summer 2018 Periods are given for each intertie in Table A-11.

Exports to New York fell considerably in the Winter 2018/19 Period compared to the Winter 2017/18 Period, decreasing by 136 GWh per month on average. New York experienced high energy prices in December 2017 and January 2018 compared to Michigan and Ontario, leading to unusually high exports to New York in those months. During the Winter 2018/19 Period, energy prices in New York were closer to prices in Ontario and Michigan. The HOEP was also higher in the Winter 2018/19 Period compared to the Winter 2017/18 Period, which would tend to reduce all export opportunities from Ontario.

Imports from Québec decreased in the Winter 2018/19 Period compared to the Winter 2017/18 Period, falling from an average of 657 GWh per month to an average of 568 GWh per month. Much of this reduction occurred in April 2019, when a lower Ontario HOEP may have made imports from Québec less economic.

Failed or curtailed exports reduce demand between pre-dispatch (PD-1) and real-time. The Market Participant (MP) percentage failure rate of exports on the Manitoba intertie remained much higher than on the other interties in Winter 2018/19. The volume of MP failed exports on the Manitoba intertie was nearly twice as high in the Winter 2018/19 Period compared to the previous winter.

The rates of Independent System Operator (ISO)-curtailed exports to Québec, Manitoba and Minnesota appear to follow a seasonal trend. The Québec intertie experienced a slight increase in total ISO-curtailed exports in the Winter 2018/19 Period compared to the Summer 2018 Period. However, the rate of ISO-curtailed exports to Québec was about the same as the Winter 2017/18 period. Similarly, the rate of ISO-curtailed exports to Manitoba and Minnesota in the Winter 2018/19 Period was lower than in the Summer 2018 Period but about the same as the Winter 2017/18 Period.

Table A-10: Average Monthly Exports and Export Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		Market Participant Failure		ISO Curtailment		Market Participant Failure	
	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018
New York	588	570	2.4	3.0	5.9	8.1	0.4%	0.5%	1.0%	1.4%
Michigan	618	629	3.5	1.8	7.4	7.1	0.6%	0.3%	1.2%	1.1%
Manitoba	103	70	1.2	2.4	23.5	19.2	1.2%	3.4%	22.8%	27.3%
Minnesota	33	8	0.4	0.7	1.1	0.2	1.2%	8.8%	3.4%	2.1%
Québec	202	134	8.0	2.9	2.1	1.2	4.0%	2.1%	1.0%	0.9%

Table A-10 reports average monthly export curtailments and failures over the Winter 2018/19 and Summer 2018 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.[66] Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Market Participant 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 rate of MP failures for imports remains very high for Michigan and Minnesota, although the total amount of imports over those interties is relatively low. The rate of ISO Curtailments for Québec imports was lower in the Winter 2018/19 Period compared to both the Summer 2018 and Winter 2017/18 Periods. ISO Curtailments of imports were also less frequent for New

[66] 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.

York, Manitoba, and Minnesota in the Winter 2018/19 Period compared to the Summer 2018 Period.

Table A-11: Average Monthly Imports and Import Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate			
			ISO Curtailment		Market Participant Failure		ISO Curtailment		Market Participant Failure	
	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018	Winter 2018/19	Summer 2018
New York	3	4	0.0	0.1	0.1	0.2	0.4%	2.7%	1.6%	4.6%
Michigan	6	9	0.1	0.2	1.2	1.6	2.0%	1.9%	21.7%	17.7%
Manitoba	42	48	1.1	4.4	0.5	1.2	2.6%	9.2%	1.3%	2.4%
Minnesota	8	7	0.3	0.5	1.5	1.1	3.3%	6.9%	18.5%	15.3%
Québec	477	556	2.4	4.4	0.6	0.5	0.5%	0.8%	0.1%	0.1%

Table A-11 reports average monthly import failures and curtailments the Winter 2018/19 and Summer 2018 Periods by intertie and cause. The Market Participant failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Appendix B: Market Outcomes for the Summer 2019 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Summer 2019 Period (May 1, 2019 to October 31, 2019), with comparisons to previous reporting periods as appropriate.

B.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.

HOEP and GA

Table B-1: Average Effective Price by Consumer Class and Period ($/MWh), 3 Periods

Customer Class	Average Weighted HOEP ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Average Effective Price ($/MWh)
Class A – Summer 2019	10.04	63.78	2.62	76.43
Class A – Winter 2018/19	22.31	53.30	3.07	78.68
Class A – Summer 2018	19.14	53.68	3.16	75.98
Class B – Summer 2019	13.38	123.20	2.82	139.40
Class B – Winter 2018/19	26.46	89.77	3.27	119.51
Class B – Summer 2018	24.59	95.98	3.71	124.27
All Consumers – Summer 2019	*N/A*	*N/A*	*N/A*	120.39
All Consumers – Winter 2018/19	*N/A*	*N/A*	*N/A*	107.79
All Consumers – Summer 2018	*N/A*	*N/A*	*N/A*	110.34

Table B-1 summarizes the average effective price in dollars per MWh by consumer class for the Summer 2019 Period (May 1, 2019 to October 31, 2019), Winter 2018/19 Period (November 1, 2018 to April 30, 2019) and Summer 2018 Period (May 1, 2018 to October 31, 2018).

The 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.[67] 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 distribution. Results are reported for three consumer groups: "Class A consumers", "Class B consumers" and "All Consumers".[68, 69]

Starting with the Panel's Monitoring Report 29 (May 2016-Oct 2016) published in March 2018, the Panel moved embedded Class A consumers from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table B-1.[70]

[67] 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.

[68] 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

[69] 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 total consumption by all consumers in each of those hours. To the extent that Class A consumers reduce their demand during those hours, their share of GA is reduced. The remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel's Industrial Conservation Initiative (ICI) Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[70] Following past practice, the Panel assumes that embedded Class A consumers have the same average load profile as directly-connected Class A consumers. Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and from "Class B & Embedded Class A" to just "Class B"), there is no direct comparison to be made between effective prices reported in this report and those from reports issued before the Panel's Monitoring Report 29 published March 2018. All references to effective price in the Panel's reports going forward – including all tables and figures – reflect the Panel's updated methodology.

The average effective price for all consumers increased significantly by 10% in the Summer 2019 Period compared to the the Summer 2018 Period. This overall increase was reflected in a minimal 0.6% increase in the average effective price for Class A consumers and a notable 12% increase for Class B consumers. Total energy demand was approximately 4% lower in the Summer 2019 Period compared to the Summer 2018 Period (see Figure B-20), causing the effective HOEP for both Class A and B consumers to drop almost by half. Significant decreases in the frequency of Congestion Management Settlement Credit (CMSC) payments, transmission loss payments, Intertie Offer Guarantee (IOG) payments and cost guarantee payments (see Figure B-12) caused the effective uplift for both Class A and B consumers to decrease. However, in March 2018, the Ontario Energy Board (OEB) issued a Payment Amounts Order for Ontario Power Generation's (OPG's) rate regulated nuclear and hydroelectric facilities for 2017-2021.[71] As a result of the Order, the price of OPG's nuclear energy production increased in January 2019. A similar annual increase was observed in January 2020. There was also a more modest increase in the rate paid to OPG's hydroelectric facilities. The increase in payments to nuclear and hydro facilities arising from this Order contributed to the increase in GA and the average effective price for Class B consumers observed during the Summer 2019 Period.

As explained in further detail below, the HOEP and GA costs tend to move inversely to one another. During the Summer 2019 Period, the total system cost increased, while the Class A price dropped substantially with the HOEP, leaving more GA to be paid by Class B consumers. As a result of the Class B GA allocation and an increase in the average effective price for all consumers, Class B GA increased by 28%.

The GA makes up a smaller portion of the average effective price of Class A consumers compared to Class B consumers. Therefore, the absolute decrease in the average weighted

[71] See the OEB Payment Amounts Order dated March 29, 2018 (EB-2016-0152):http://www.rds.oeb.ca/HPECMWebDrawer/Record/603940/File/document

HOEP for Class A consumers was slightly smaller than the increase in the average GA for Class A consumers, causing the average effective price for Class A consumers to increase only slightly in the Summer 2019 Period, when compared to the Summer 2018 Period. Conversely, the absolute decrease in the average weighted HOEP for Class B consumers was significantly smaller than the increase in average GA for Class B consumers, causing the average Class B effective price to increase notably in the Summer 2019 Period, when compared to the Summer 2018 Period.

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

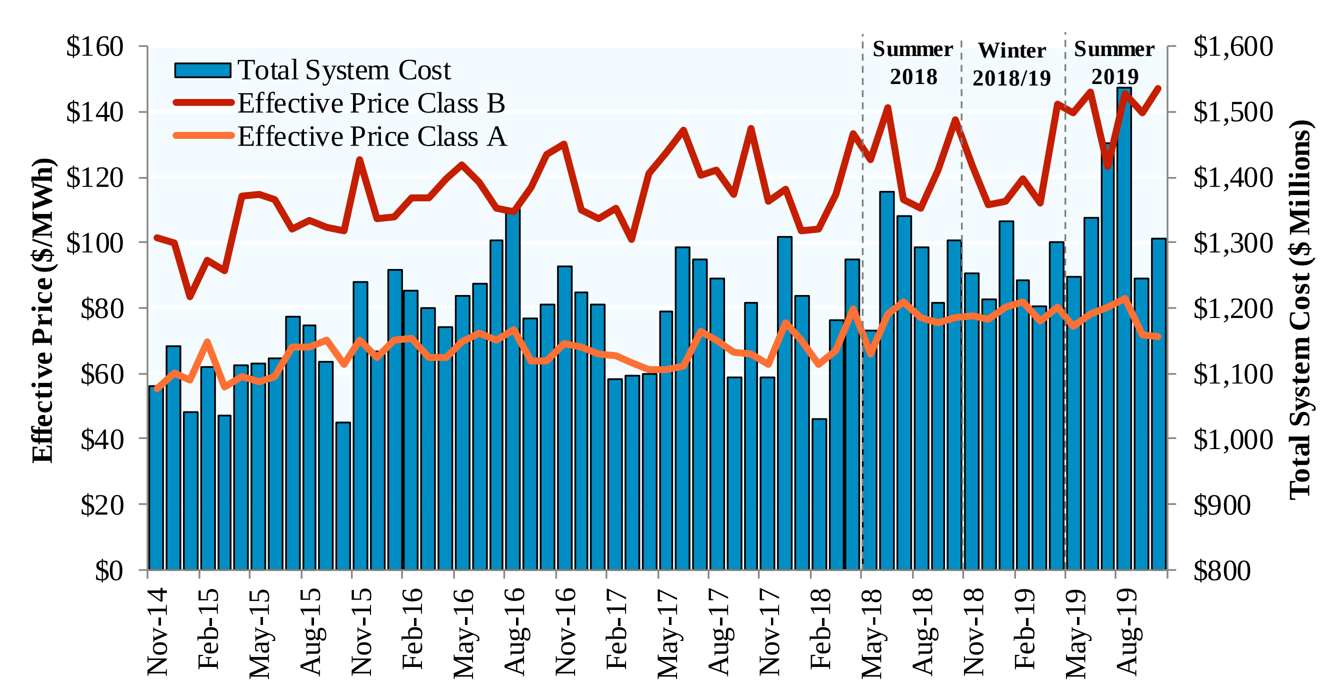


Figure B-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five years.

The total system cost borne by Ontario consumers in the Summer 2019 Period rose 5.7% compared to the Summer 2018 Period, and rose 7.7% from the Winter 2018/19 Period. This increase in the total system cost across summer reporting periods is above average: over the last five years, the total system cost has grown by about 3.5% per year. The total system cost rose by about $437 million, with about a $749 million decrease in the HOEP, a $1,243 million increase in GA, and about $56 million decrease in uplift. The total system cost peaked during July and August, when both the HOEP and Ontario demand were highest during the Summer 2019 Period.

The average Class B effective price increased substantially by $15.13/MWh to $139.40/MWh, while the average Class A effective price increased slightly by $0.45/MWh to $76.43/MWh and peaked during August 2019. The increase in the average effective price for Class A was far below the average increase in the Class A effective price over the last five years, which was less than $4/MWh per year. The increase in the average effective price for Class B greatly exceeded the average increase in Class B effective prices over the last five years, which was just above $6/MWh per year.

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

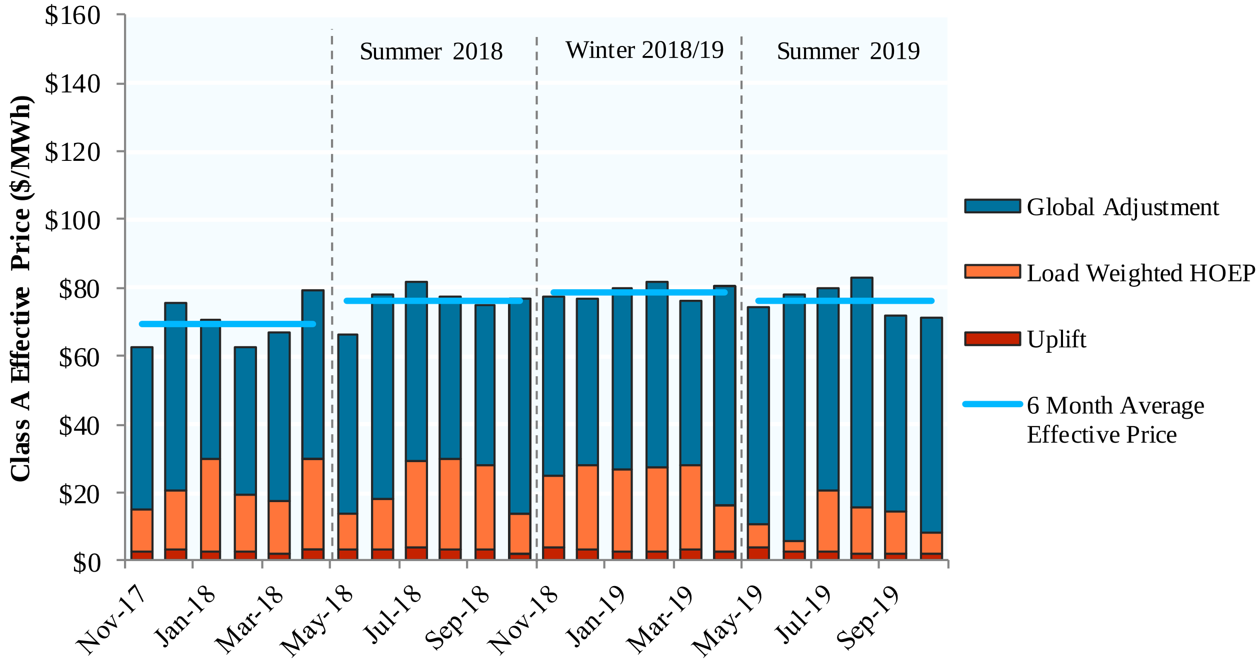


Figure B-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period.[72, 73]

The GA is the guaranteed revenue less the HOEP and uplift payments for Class A and B consumers. 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. A higher GA tends to increase the effective price more for Class B than Class A consumers because the current GA

[72] 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 demand), and their contracted rates of revenue or regulated rates set by the OEB. 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

[73] The six-month average Class A 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.

allocation methodology has the effect of allocating to Class A consumers a lower share of GA per MWh consumed than Class B consumers pay.

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

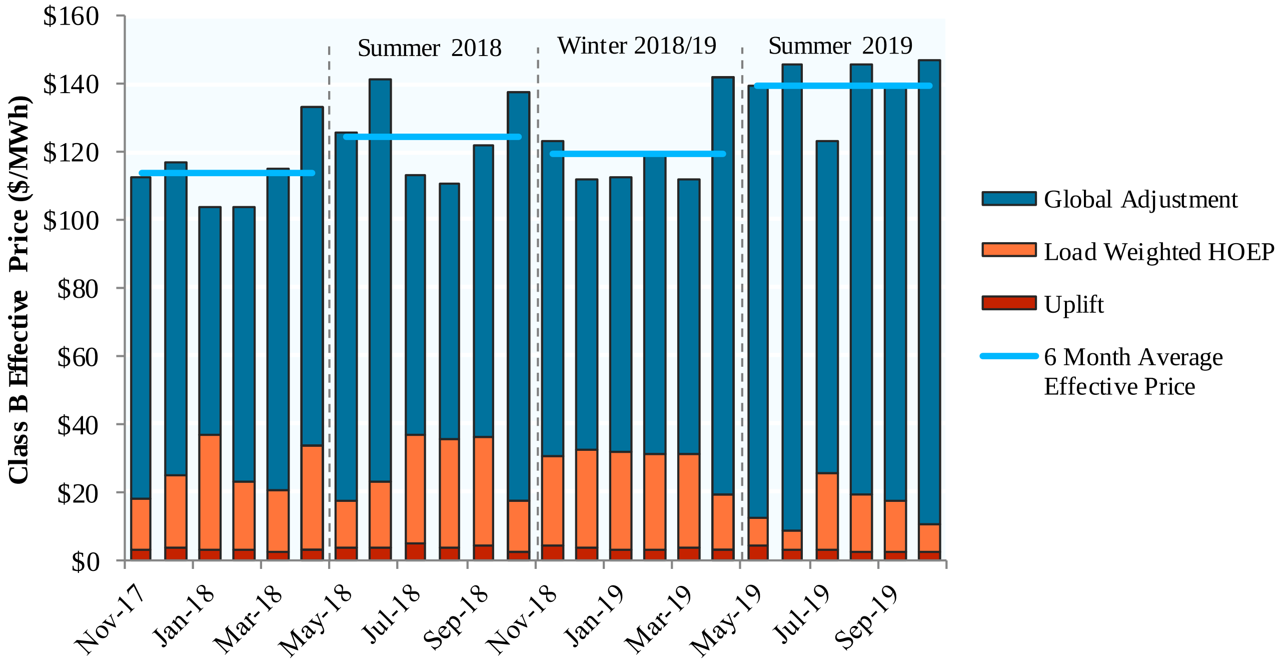


Figure B-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period.[74]

The 6-month average effective price for Class A consumers increased slightly from $75.98/MWh in the Summer 2018 Period to $76.43/MWh in the Summer 2019 Period. Generally, Class A prices continued to be higher during months when the HOEP was high, and Class B prices continued to be higher during months when the GA was high. Conversely, the

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

Class A effective price was highest between July and August, when the HOEP was highest during the Summer 2019 Period.

Generally, most Class B consumers are subject to the Regulated Price Plan (RPP) and pay prices that are reviewed by the Ontario Energy Board (OEB) twice a year and reset if required.[75] As a result, Class B consumers are usually less affected by monthly effective price variations in comparison to Class A consumers who do not pay RPP. The 6-month average effective price for Class B consumers increased from $124.27/MWh in the Summer 2018 Period to $139.30/MWh in the Summer 2019 Period. There was a substantial decrease in the 6-month average HOEP from $20.92/MWh in the Summer 2018 Period to $10.99/MWh in the Summer 2019 Period. In addition to a decrease in energy demand, the Summer 2019 Period had less unavailable capacity in comparison to the Summer 2018 Period, reducing the need to dispatch more expensive resources to meet demand. The lowest HOEPs in the Summer 2019 Period occurred in May, June and October – these months all had lower than average demand. The highest HOEP in the period occurred in July and August, followed by a steady decline into September when temperatures usually begin to fall.

[75] More information on the RPP is available at: https://www.oeb.ca/industry/policy-initiatives-and-consultations/regulated-price-plan-rpp

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

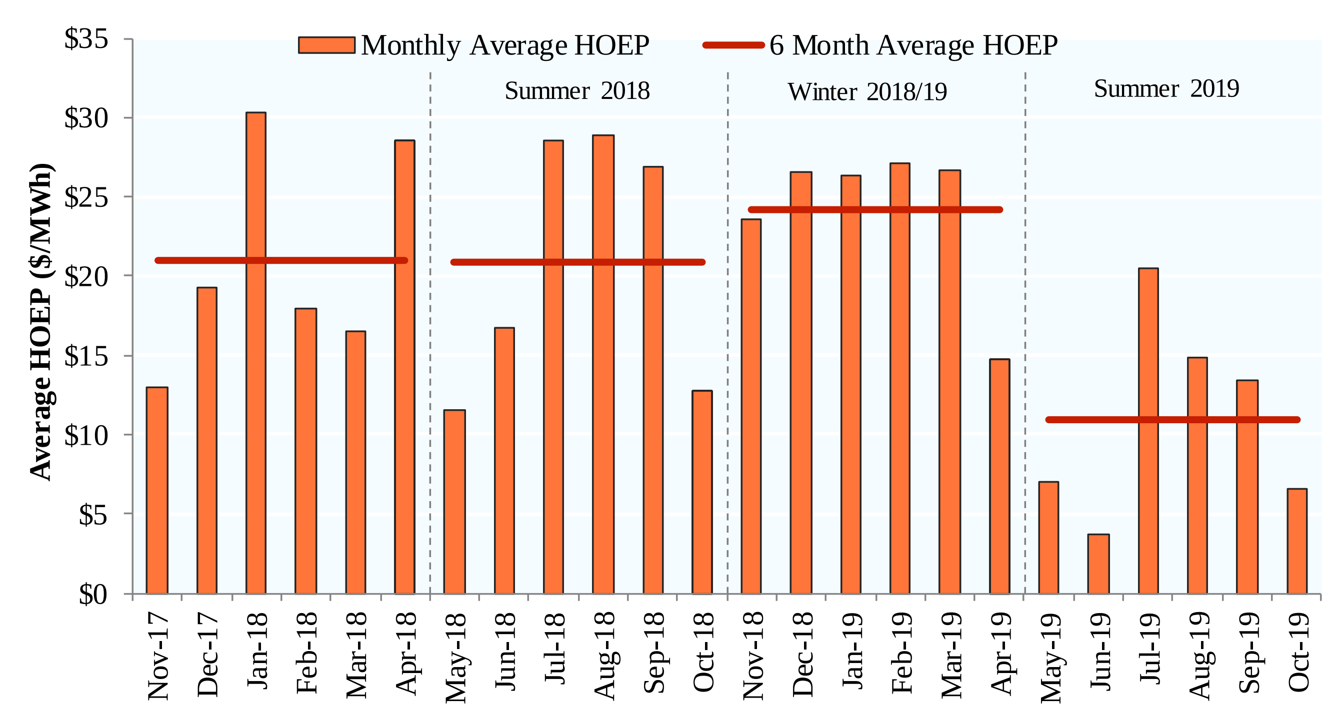


Figure B-4 displays the monthly average HOEP unweighted by the volume of energy consumed in any given interval (the "simple HOEP"), for each month between November 2017 and October 2019. Figure B-4 also displays the simple monthly average HOEP for each 6-month period since November 2017. The HOEP is 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 $3.21/MMBtu in the Summer 2019 Period compared to $3.87/MMBtu in the Summer 2018 Period. The price increased from $3.78/MMBtu in the Winter 2017/18 Period to $4.33/MMBtu in the Winter 2018/19 Period.

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

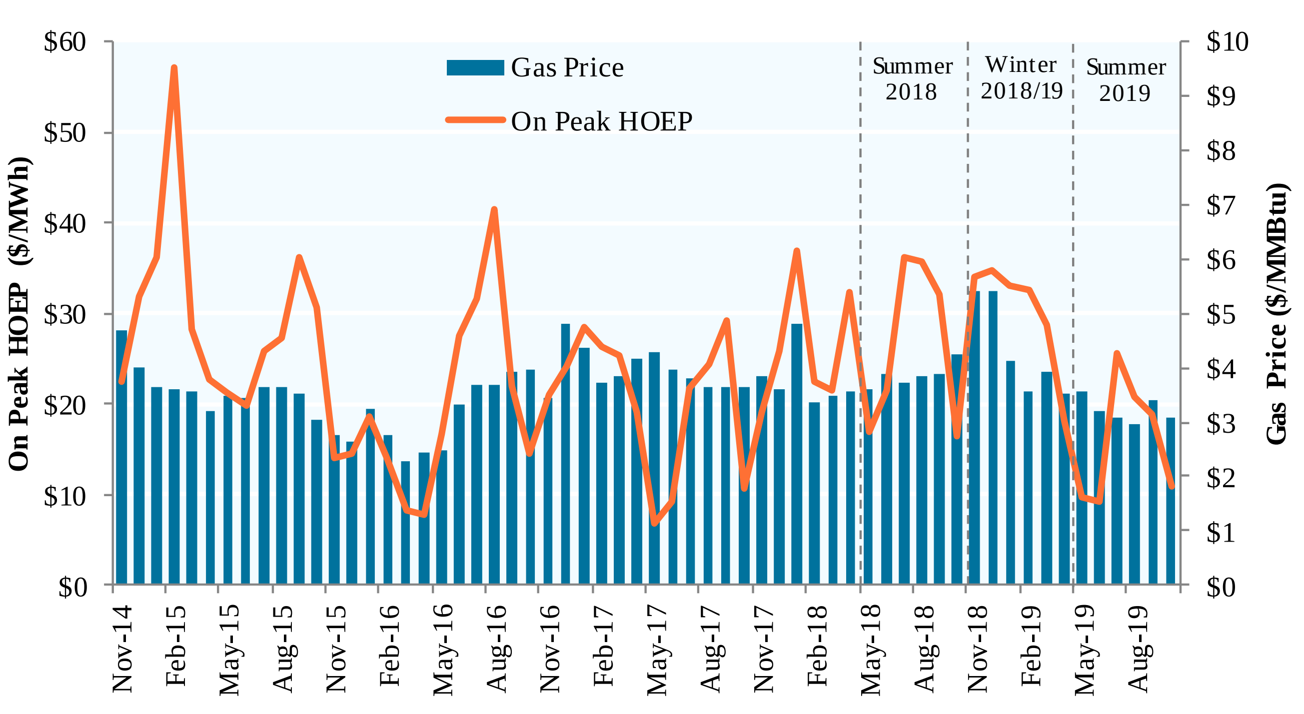


Figure B-5 plots the average monthly HOEP during on-peak hours and the monthly average of Henry Hub natural gas spot prices for days with on-peak hours for the previous year.[76] Natural gas prices are compared to the HOEP for on-peak hours as gas-fired facilities frequently set the price during these hours. Gas-fired facilities typically purchase gas day-ahead.

A correlation coefficient of 0.42 was observed between average daily natural gas prices and daily averages of on-peak HOEP values during the Summer 2019 Period, which was slightly higher than that observed in the Winter 2017/18 Period, but significantly higher than that observed in the Summer 2018 Period. Although the HOEP and the average price of natural gas both decreased in the Summer 2019 Period, a strong correlation between the daily

[76] 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

variables is likely not to be expected, as the monthly average price of natural gas and the monthly average HOEP did not follow similar peak trends in Figure B-5. Natural gas resources frequently set the Market Clearing Price (MCP) during July and August 2019, when the on-peak HOEP was highest in the Summer 2019 Period (see Figure B-7) and the price of natural gas was lower than average.[77]

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

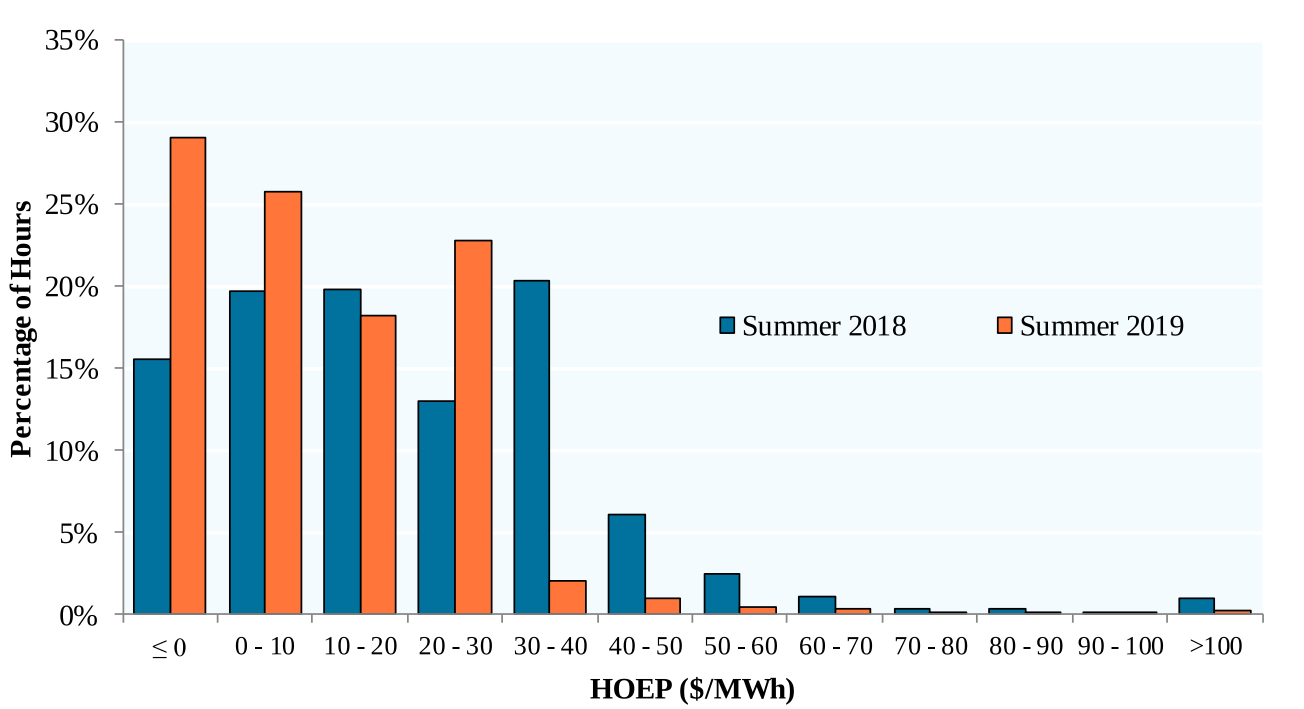


Figure B-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Summer 2019 and Summer 2018 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh hours.

In the Summer 2019 Period, there was a large increase in the frequency of hours when the HOEP was negative or zero, and a decrease in the frequency of hours with a more expensive

[77] This outcome assumes that changes in Ontario natural gas prices affect the fuel costs of natural gas generators. Increasing the marginal cost of fuel should give these generators the incentive to increase their offer prices, which would increase electricity prices if natural gas generators are setting the real-time MCP. This should result in a positive correlation between natural gas prices and the HOEP.

HOEP. During the Summer 2019 Period, 29% of hours had a negative HOEP, compared to 16% in the Summer 2018 Period, while 27% of hours had HOEPs of at least $20/MWh in the Summer 2019, down considerably from 45% in the Summer 2018 Period. This is likely because the average Ontario demand was lower in the Summer 2019 Period than it was in the Summer 2018 Period and nuclear output increased.

The amount of unavailable supply decreased by about 5% during the Summer 2019 Period compared to the Summer 2018 Period (see Figure B-23), and was primarily driven by less outages of nuclear capacity. The increase in nuclear capacity resulted in nuclear resources setting the real-time MCP 4.8% of the time during the Summer 2019, an increase from 1.6% in the Summer 2018 Period. The increase in nuclear capacity likely reduced the frequency of hours with high HOEPs during the Summer 2019 Period.

The percentage of hours that natural gas resources set the real-time MCP increased from 38% in the Summer 2018 Period to 53% in the Summer 2019 Period, while the percentage of hours that wind resources set the real-time MCP decreased from 21% to 19%. Although the frequency of gas resources setting the real-time MCP increased substantially during the Summer 2019 Period despite a decrease in overall demand, there was a reduction in supply from natural gas resources (see Figure B-21) as a result of increased supply from nuclear generators and lower demand during the Summer 2019 Period. The increase in the percentage of hours that natural gas resources set the real-time MCP could have resulted from an increase in the amount of wind forecast deviation (see Table B-2) and import failures observed during the Summer 2019 Period (see Table B-11) in comparison to the Summer 2018 Period (see Table A-11).[78]

[78] For more information on the amount of import failures observed during the Summer 2018 Period, see page 120 of the Panel's Monitoring Report 33 published December 2020: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf

Hydroelectric resources set the real-time MCP during 22% of intervals in the Summer 2019 Period, a drop from 39% in the Summer 2018 Period. This drop is likely correlated with the decrease in supply from hydroelectric resources during the Summer 2019 Period (see Figure B-21).

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

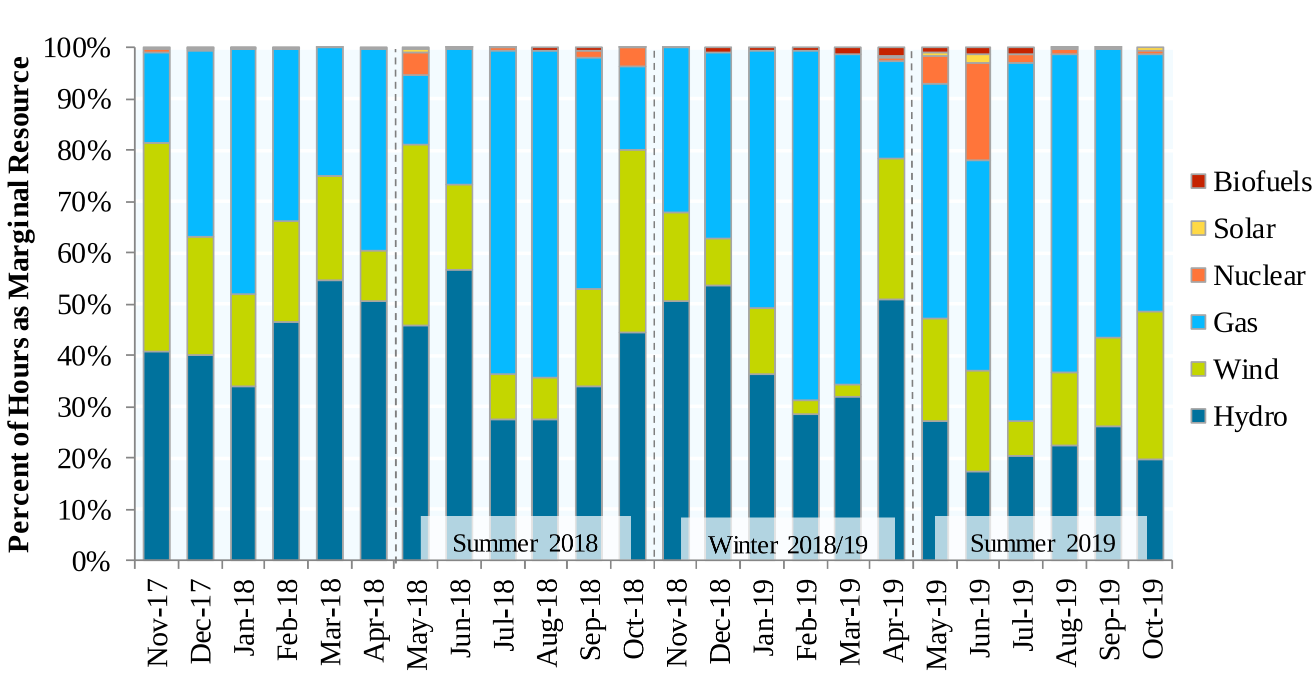


Figure B-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the previous two years. The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

The frequency with which imports and exports set the pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[79] When the price is set by an import

[79] 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.

or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

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

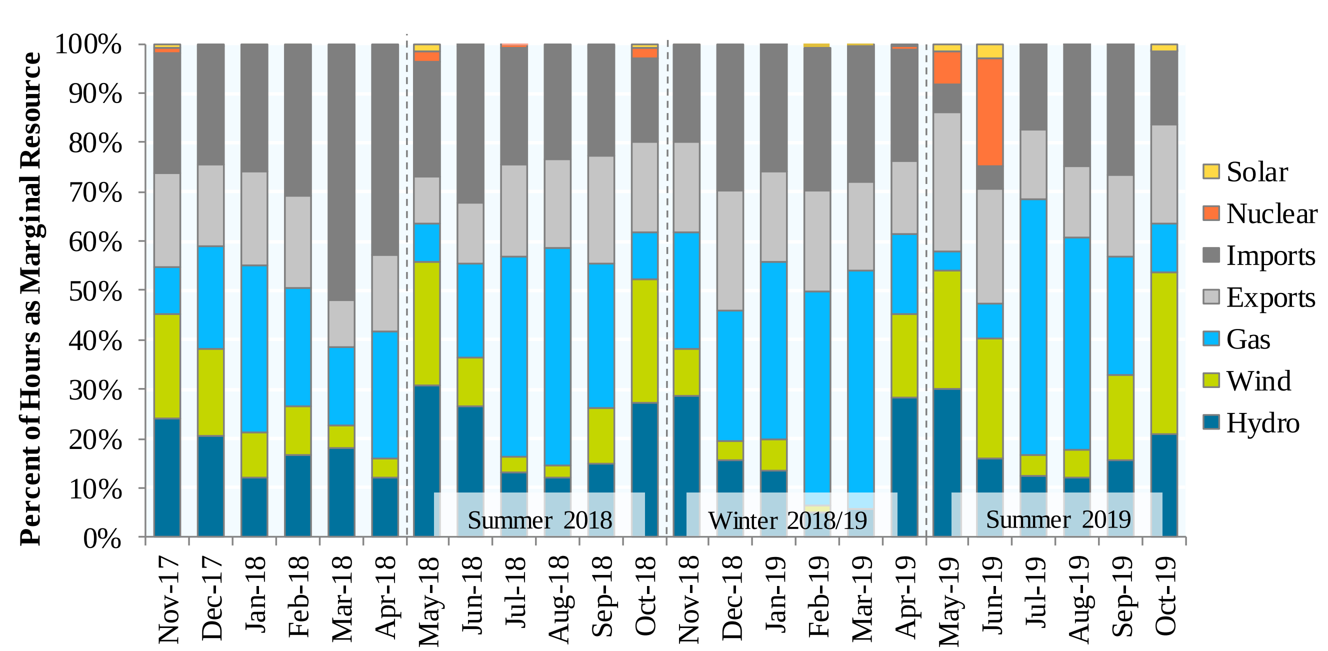


Figure B-8 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP in each month of the previous two years. When compared with Figure B-7, Figure B-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

Natural gas resources set the PD-1 MCP in 23% of hours in the Summer 2019 Period, compared to 25% in the Summer 2018 Period. The frequency with which nuclear resources set the PD-1 MCP decreased from 8% in the Summer 2018 Period to 5% in the Summer 2019 Period. Hydro resources set the PD-1 MCP 18% of the time in the Summer 2019 Period compared to 21% in the Summer 2018 Period. Conversely, the frequency with which wind resources set the PD-1 MCP increased from 13% in the Summer 2018 Period to 18% in the Summer 2019 Period. The increase in the frequency of wind resources setting the PD-1 MCP was likely driven by decrease in demand observed during the Summer 2019 Period as less expensive resources were required to satisfy demand.

Imports set the PD-1 MCP in 15% of hours during the Summer 2019 Period, compared to 23% of hours in the Summer 2018 Period. This drop is consistent with the decrease in supply from imports observed during the Summer Figure B-21). Exports set the PD-1 MCP in 19% of hours during the Summer 2019 Period, compared to 16% of hours during the Summer 2018 Period.

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, these transactions are settled based on the Intertie Zonal Price (IZP), which is the sum of the real-time MCP and the Intertie Congestion Price (ICP). 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 2019 Period, there was a variation of less than $10/MWh between PD-1 and real-time prices for 87% of hours, a strong increase from 78% in the Summer 2018 Period. The average absolute deviation between PD-1 and real-time prices in the Summer 2019 Period of $4.71/MWh was about 40% below the Summer 2018 Period average deviation of $8.11/MWh. Lower demand for energy and a reduction in supply from wind resources in the Summer 2019 Period (see Figure B-21) may have contributed to the drop in variability between pre-dispatch and real-time prices.

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time.[80] Identifying the factors that lead to deviations between the PD-1 MCP and the real-time MCP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as offers and bids are entered into the market.

[80] The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the 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.

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

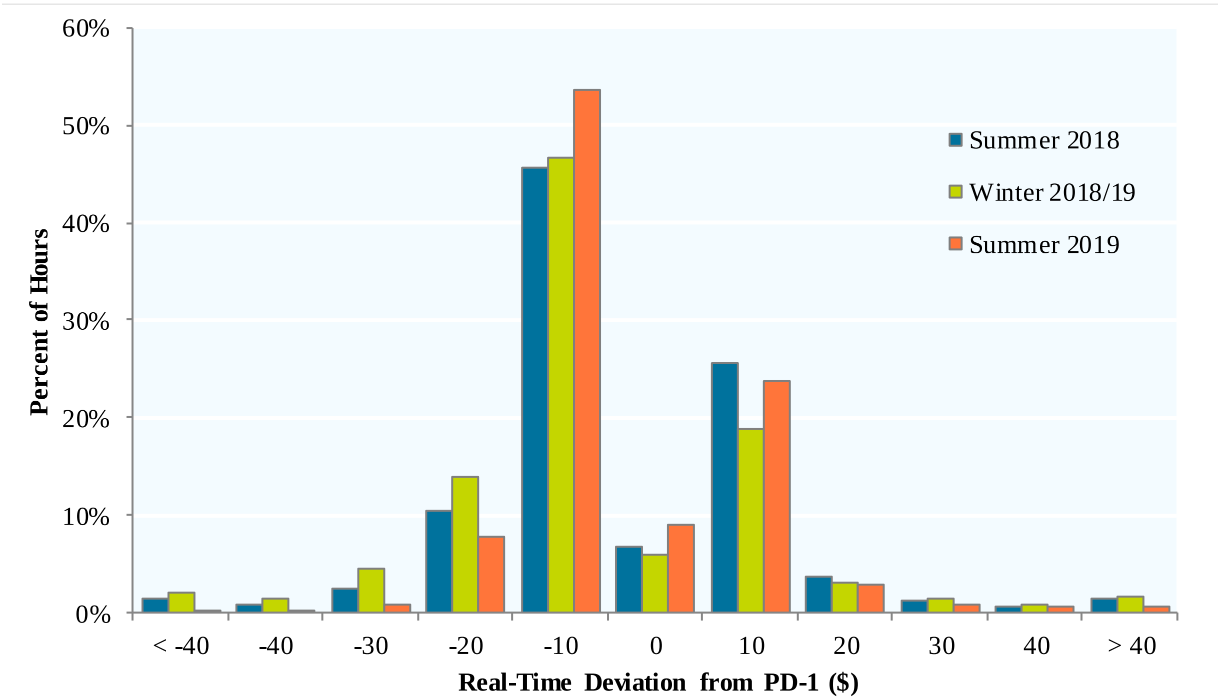


Figure B-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2019, Winter 2018/19 and Summer 2018 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP, 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 demand forecast deviation, the most significant source of deviation between the PD-1 MCP and the HOEP, dropped in the Summer 2019 Period relative to the Summer 2018 Period. The next most significant source of deviation, wind forecasts, increased between the Summer 2018 and Summer 2019 Periods. The frequency with which wind resources set the PD-1 MCP increased between the Summer 2018 Period and the Summer 2019 Period, but the frequency with which wind resources set the real-time MCP decreased between these periods (see Figure B-7 and Figure B-8). Therefore, it is expected that wind forecast deviation increased during the Summer 2019 Period. This deviation was likely compensated for by an increased use of gas resources in real-time.

Self-scheduling and intermittent forecast deviation, as well as net export curtailments, had similar increases between the Summer 2018 and Summer 2019 Periods. The frequency of exports setting the PD-1 MCP increased in the Summer 2019 Period relative to the Summer 2018 Period, although the frequency with which natural gas resources set the real-time MCP increased drastically between these periods (see Figure B-7 and Figure B-8). Since there was a reduction in demand in the Summer 2019 Period, natural gas resources were likely utilized more frequently to offset the increase in failed/curtailed net exports that occurred.

Table B-2: Factors Contributing to Differences between PD-1 MCP and HOEP, 3 Periods

Factor	Summer 2019: Average Absolute Difference		Winter 2018/19: Average Absolute Difference		Summer 2018: Average Absolute Difference	
	MW	% of Ontario Demand	MW	% of Ontario Demand	MW	% of Ontario Demand
Ontario Average Demand	14,947 MW		15,979 MW		15,547 MW	
Forecast Deviation	213 MW	1.43%	226 MW	1.41%	251 MW	1.61%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	27 MW	0.18%	20 MW	0.12%	14 MW	0.09%
Wind Forecast Deviation	148 MW	0.99%	175 MW	1.09%	143 MW	0.92%
Net Export Failures/Curtailments	79 MW	0.53%	74 MW	0.46%	63 MW	0.40%

Table B-2 displays the average absolute difference between PD-1 and real-time for all of the factors identified by the Panel as contributing to the difference between PD-1 and real-time, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

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 the PD-3 MCP 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.[81] Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

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

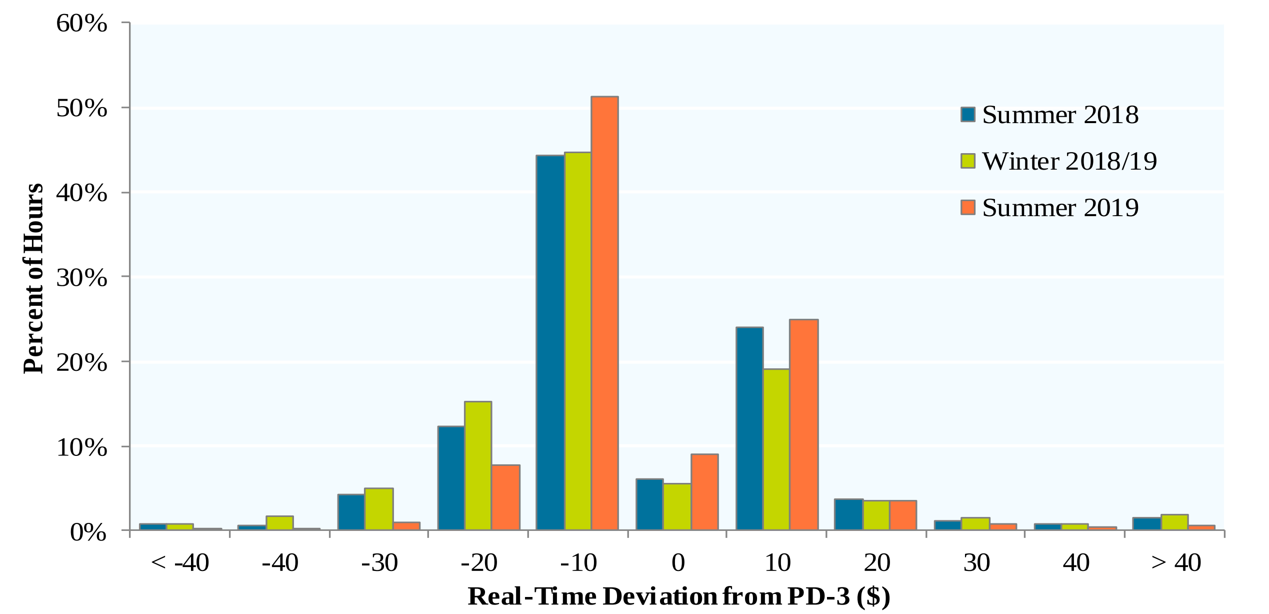


Figure B-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Summer 2019, Winter 2018/19 and Summer 2018 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the 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.

PD-3 prices were within $10/MWh of the real-time MCP in 85% of hours in the Summer 2019 Period, up from 75% of hours in the Summer 2018 Period. The average absolute deviation between PD-3 and real-time MCPs was also significantly lower in the Summer 2019 Period

[81] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that these facilities 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.

($4.94/MWh) compared to the Summer 2018 Period ($8.32/MWh). These trends are closely aligned with the deviations observed in relation to PD-1 prices.

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

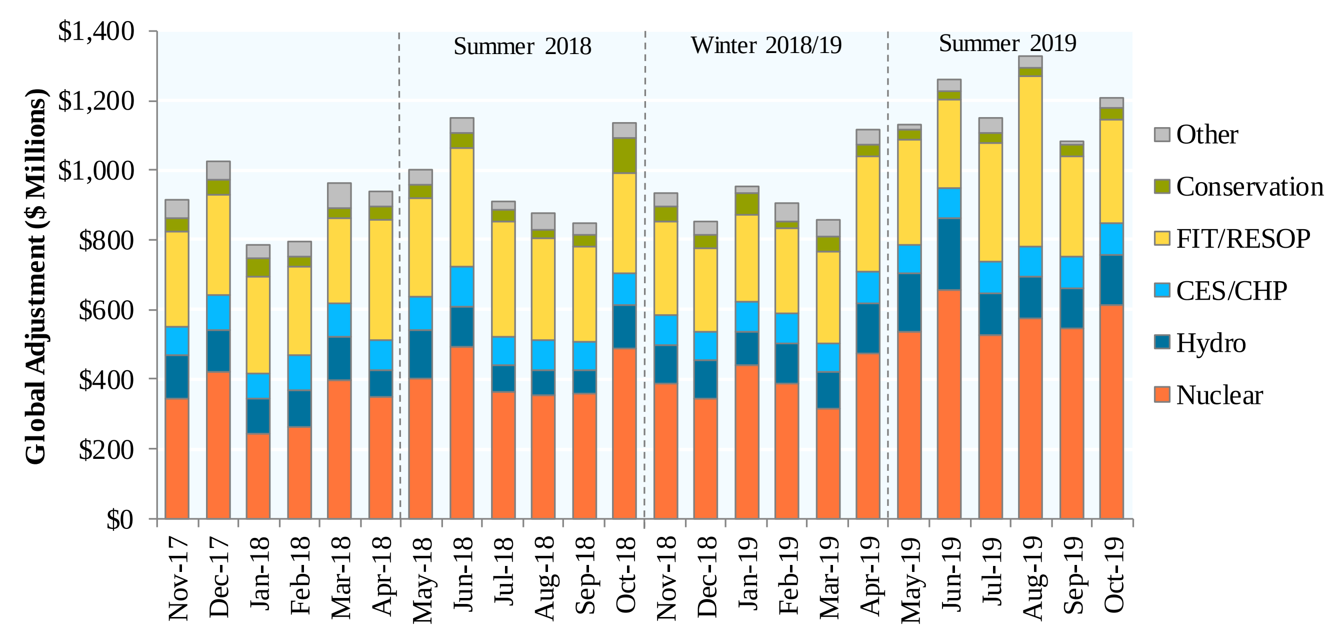


Figure B-11 plots the payments to various resources and recovered through the GA each month by component for the previous two years.

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 OPG's Lennox Generating Station).

The total GA throughout the Summer 2019 Period was about 21% more than the total GA during the Summer 2018 Period, rising from $5.9 billion to $7.2 billion. The overall increase in GA is mainly in the nuclear and hydroelectric components. From the Summer 2018 Period to the Summer 2019 Period, GA payments to these generators increased notably by 44% and 41% respectively. This was due to the combined effects of higher nuclear production, substantially higher regulated hydroelectric and nuclear rates for 2019, and the lower HOEP. Since the HOEP and GA tend to be inversely related, lower market payments result in higher payments required to be recovered through GA to meet a generator's contracted or regulated rate revenues. The nuclear share of GA rose from 41% to 48%, while the hydroelectric share rose from 10% to 12% and the FIT/RESOP share fell from 31% to 28%.

Regulatory Charges

Regulatory charges includes the cost of services provided by the Independent Electricity System Operator (IESO) to operate the wholesale electricity market and maintain the reliability of the high voltage power grid 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".[82] Regulatory charges include both amounts set or approved by the OEB (e.g. IESO Administration Charge and the Rural or Remote Electricity Rate Protection (RRRP) charge)

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

and amounts that are not set or approved by the OEB such as charges associated with reliability or transmission losses.[83]

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.[84]

Table B-3 below summarizes a number of the amounts captured by regulatory charges, the majority of which are “uplift” costs for wholesale market participants.[85] 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 (PCG)[86] 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 B-12 shows these regulatory charges by month.[87]

The total of these charges in the Winter 2018/19 Period were $329 million, a decrease from the Summer 2018 Period ($379 million). Notable decreases since the previous summer period

[83] See the OEB’s webpage “Understanding Your Electricity Bill”: https://www.oeb.ca/rates-and-your-bill/electricity-rates/understanding-your-electricity-bill

[84] This applies to all monthly and daily uplifts with the exception of costs associated with Demand Response (DR). The costs of DR 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.

[85] The Panel has not previously provided this information in tabular form. 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.

[86] 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.

[87] For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge have been omitted from Figure B-12.

include: IOG (84% decrease or $30.1 million), Losses (50% decrease or $17.3 million), PCG (55% decrease or $11.3 million). These decreases were offset by notable increases since the previous summer period including: Rural or Remote Rate Settlement Charge (60% increase or $12.2 million) and Regulation (22% increase or $5.7 million).

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

Settlement Resolution	Regulatory Charges	Summer 2019 ($ million)	Winter 2018/19 ($ million)	Summer 2018 ($ million)
Hourly	Congestion Management Settlement Credits (CMSC)	49.1	67.3	59.3
	Transmission Losses	17.5	37.1	34.8
	Intertie Offer Guarantee (IOG)	5.9	17.3	35.9
	Operating Reserve: 10-minute spinning reserve	17.8	10.4	14.2
	Operating Reserve: 10-minute non-spinning reserve	14.2	9.0	12.6
	Operating Reserve: 30-minute reserve	11.3	8.0	8.3
	Hourly Reactive Support and Voltage Control	12.4	7.5	11.0
	Hourly Charges Subtotal	**128.1**	**156.5**	**176.2**
Monthly	Cost Guarantee: RT-GCG program	15.9	17.0	17.4
	Cost Guarantee: PCG program	9.1	19.5	20.3
	Ancillary Services: Black Start	0.9	0.9	0.7
	Ancillary Services: Regulation	31.2	29.6	25.5
	Ancillary Services: Monthly Reactive Support and Voltage Control	1.0	0.9	1.5
	Demand Response Capacity Payments	18.1	21.6	23.6
	IESO Administration Charge	90.7	93.9	91.2
	Rural or Remote Electricity Rate Protection	32.4	29.5	20.2
	Other: Additional Compensation for Admin Pricing	0.0	0.0	0.0
	Other: Station Service Reimbursement	1.5	1.7	1.8
	Other: Local Market Power	0.0	0.0	0.4
	Monthly Charges Subtotal	**200.8**	**214.5**	**202.7**
Total Regulatory Charges		**328.9**	**371.1**	**378.9**

Table B-3 compares the regulatory charges for the Summer 2019, Winter 2018/19 and Summer 2018 Periods, separated by hourly and monthly charges.

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

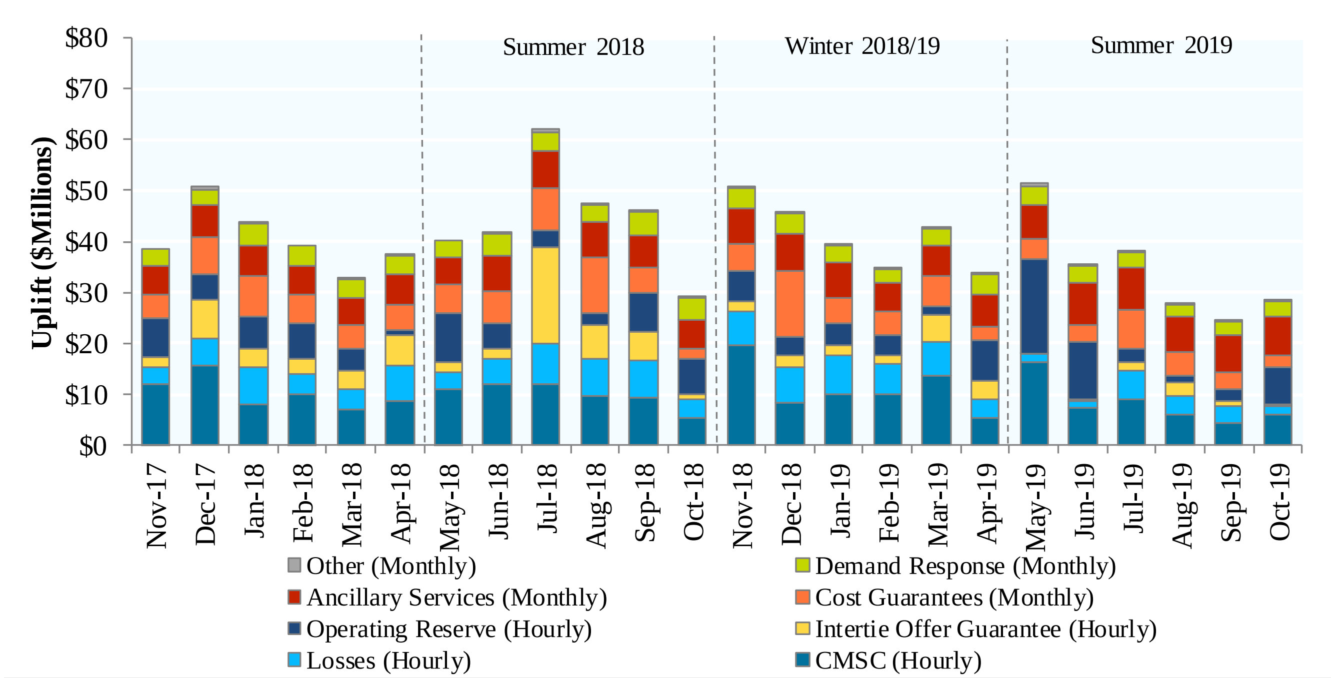


Figure B-12 presents the total uplift charges by component on a monthly basis for the previous two years. This includes both hourly and monthly uplift, which were displayed in separate figures in previous Panel reports. In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee Program (RT-GCG) payments are combined as Cost Guarantees. For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge have been omitted from Figure B-12.

Operating Reserve Prices

The three OR markets are co-optimized with the energy market, so prices in these markets tend to be subject to similar dynamics. 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.[88,89]

The increased procurement of 30-minute OR may have increased the uplift and average 30-minute OR price for this period.

Uplift from OR was $43 million for Summer 2019 Period, up from $35 million in the Summer 2018 Period. Average OR prices for both 10-minute non-spinning ($7.32/MW) and 30-minute ($5.01/MW) increased by approximately 30% compared to the Summer 2018 Period, as prices pushed closer to the 10-minute spinning average ($8.02/MW) as seen in Table B-10.

Table B-4: Average Operating Reserve Prices by Period, 2 Years

Operating Reserve Markets	Summer 2019 ($/MW)	Winter 2018/19 ($/MW)	Summer 2018 ($/MW)	Winter 2017/18 ($/MW)
10-minute spinning (10S)	8.02	5.30	8.10	7.89
10-minute non-spinning (10N)	7.32	4.44	5.65	6.88
30-minute reserve (30R)	5.01	3.55	3.68	1.45

Table B-4 presents the average OR prices by period for the past 2 years for the three OR markets.

Figure B-13 illustrates the monthly fluctuations of OR prices. Because OR prices are usually low, a single high-priced hour can lead to an increased monthly average price. High average monthly prices in May arise primarily from two of the high energy and OR priced hours summarized in Chapter 2: May 4 Hour Ending (HE) 8 and May 6 HE 19.

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

[89] This Market Rule Amendment and its justification was discussed in the Panel's Monitoring Report 32 published July 2020, pages 76-88: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

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

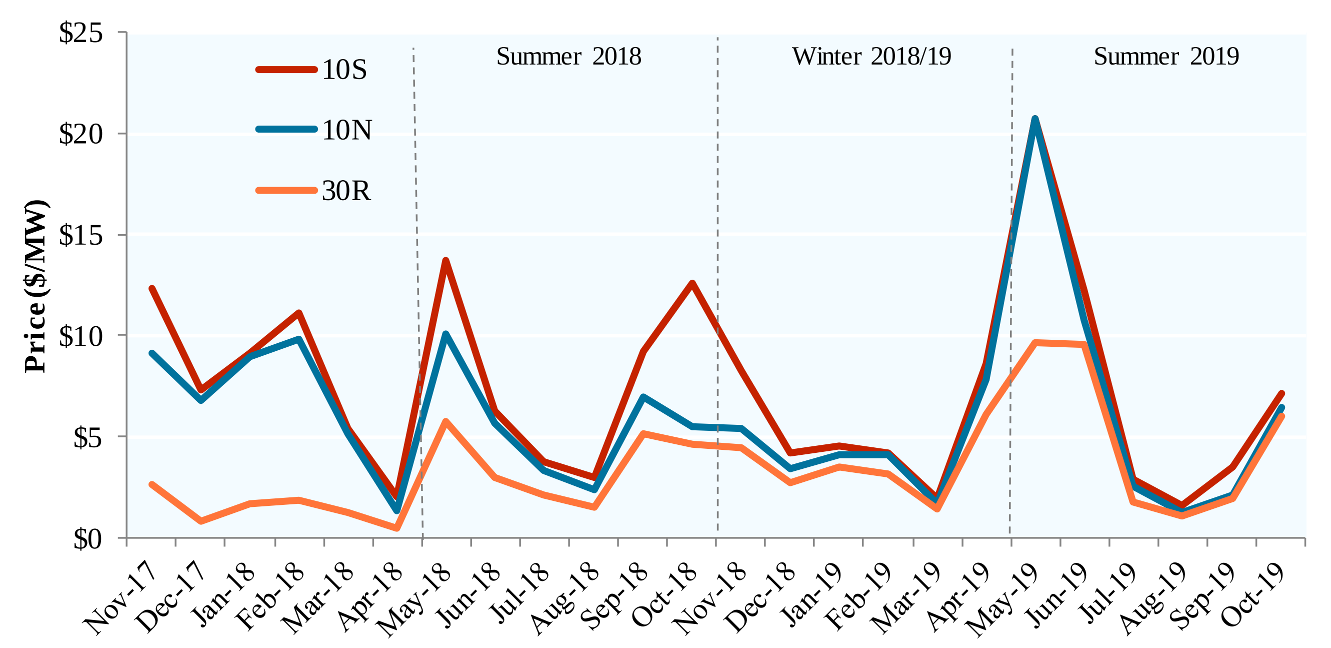


Figure B-13 plots the monthly average OR price for the previous two years for the three OR markets: 10--minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).

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 B-14, most zones had similar average prices in the Summer 2019 Period compared to the previous summer, except for the Northeast and Northwest, which returned to more typical low average prices.

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 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 where there is more demand. There may also be greater congestion costs for resources in the north as compared to the south.

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.

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

Zone	Summer 2019	Winter 2018/19	Summer 2018
Bruce	$10.03	$20.63	$16.26
East	$9.26	$9.67	$15.13
Essa	$11.45	$21.36	$16.99
Niagara	$11.60	$21.06	$15.50
Northeast	$4.07	$15.88	$14.39
Northwest	-$32.41	$3.98	$14.85
Ottawa	$11.41	$20.47	$17.36
Southwest	$12.43	$21.33	$17.29
Toronto	$11.07	$21.07	$16.87
West	$17.77	$27.58	$18.62

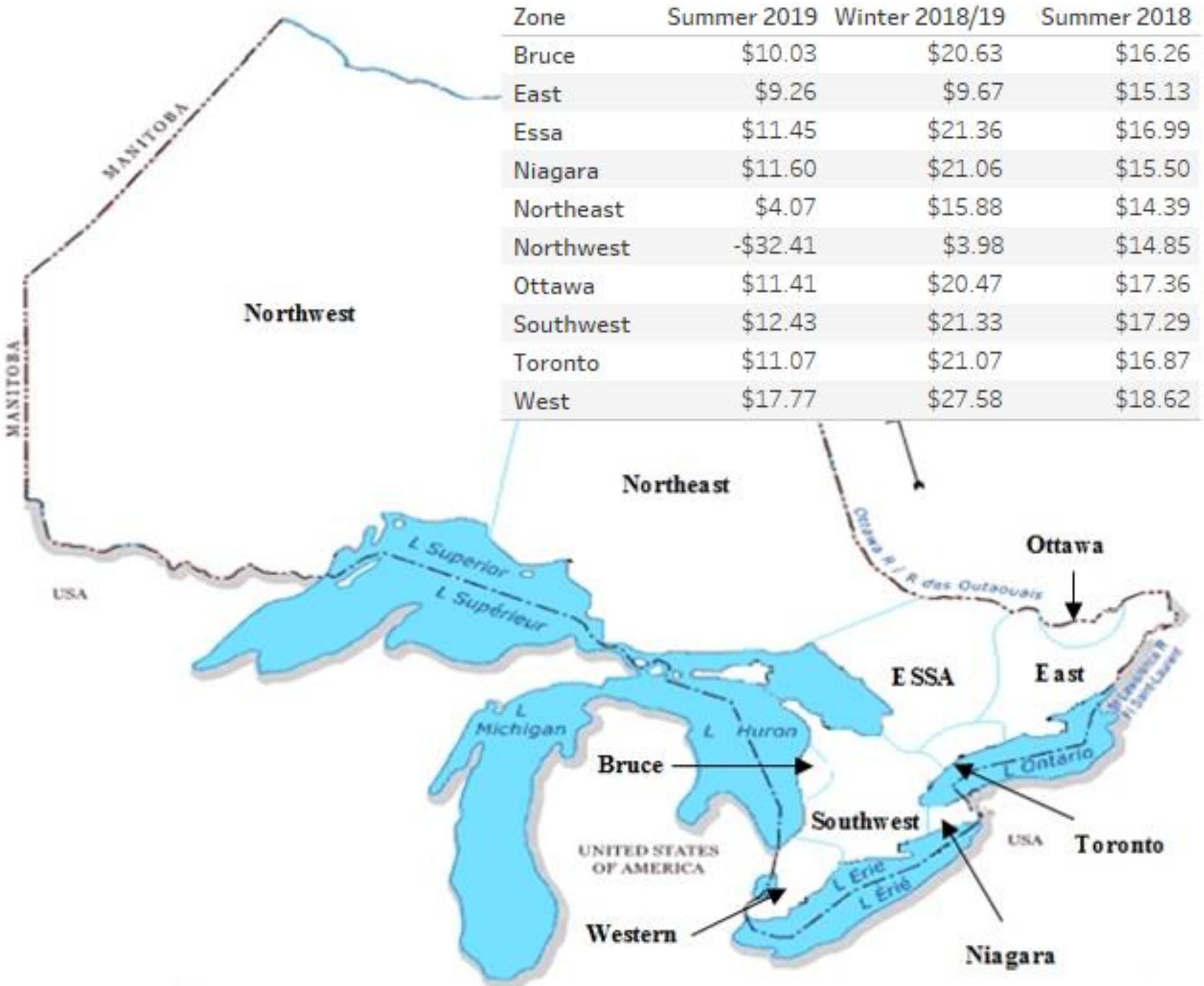


Figure B-14 illustrates the average nodal prices of Ontario's ten internal zones for the Summer 2019, Winter 2018/19 and Summer 2018 Periods.[90]

[90] 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 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.

Figure B-15: Hours per Month of Import Congestion by Intertie, 2 Years

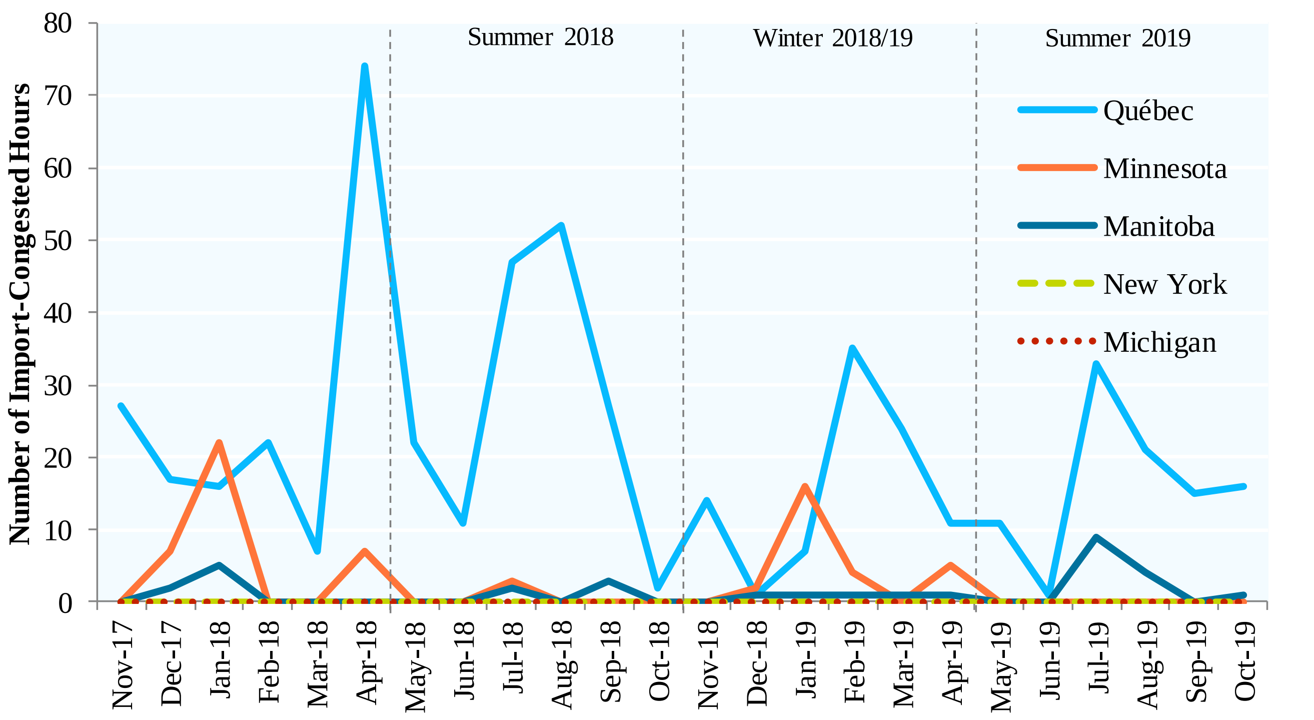


Figure B-15 reports the number of hours per month of import congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

Québec continued to experience the highest number of import congestion hours as compared to other jurisdictions. Compared to the Summer 2018 Period, the Québec intertie did experience a substantial decrease in the number of import-congested hours from 161 hours to 97 hours in the Summer 2019 Period. Congestion on the Québec intertie was highest in July with 33 hours.

Figure B-16: Hours per Month of Export Congestion by Intertie, 2 years

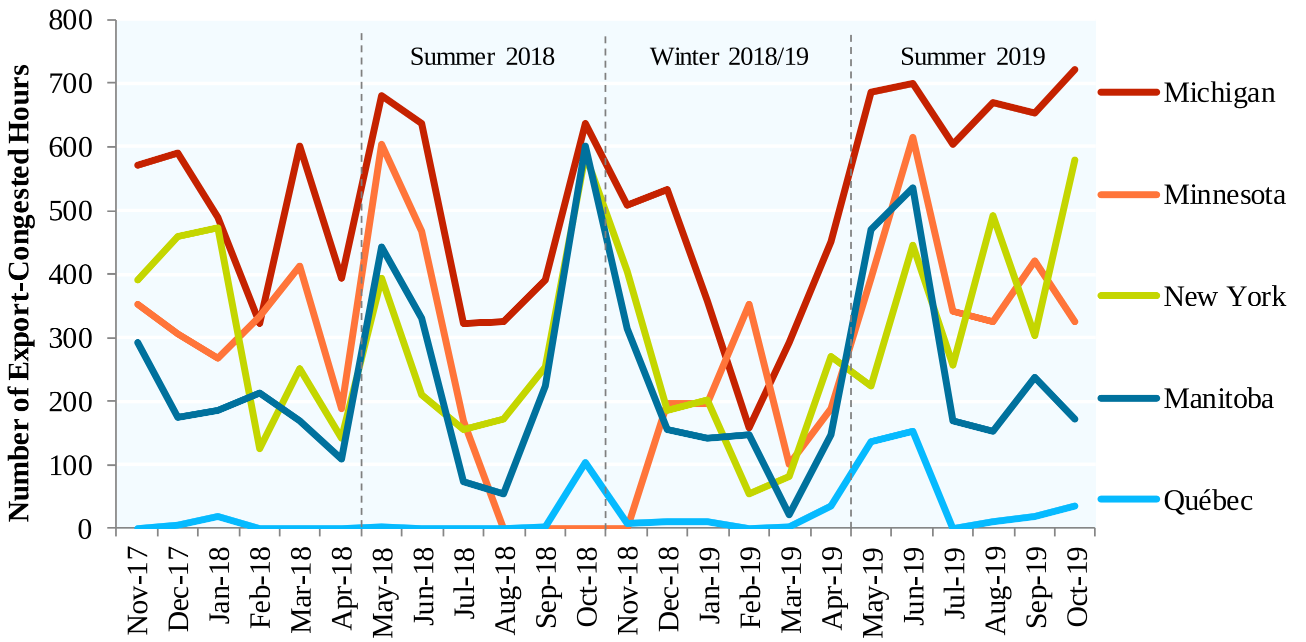


Figure B-16 reports the number of hours per month of export congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

There were 10,843 hours of export congestion in the Summer 2019 Period, a 38% increase compared to the previous summer period. Minnesota had the greatest increase in export-congested hours, from 1,240 hours in the Summer 2018 Period to 2,422 hours in the Summer 2019 Period.

Table B-5: Monthly Electricity Spot Prices – Ontario & Surrounding Jurisdictions, 1 Period

Date	Ontario (HOEP) ($/MWh)	Manitoba ($/MWh)	Michigan (MISO[91]) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO[92]) ($/MWh)	PJM[93] ($/MWh)
May 2019	7.01	24.32	33.36	26.80	14.73	28.89
Jun 2019	3.68	22.72	30.66	27.06	7.20	27.40
Jul 2019	20.53	23.19	37.77	32.08	27.56	34.33
Aug 2019	14.81	20.13	30.97	24.73	25.42	28.61
Sep 2019	13.37	23.44	33.10	25.86	18.40	30.76
Oct 2019	6.55	19.83	31.57	27.46	15.38	29.47

Table B-5 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA or uplift. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table B-5. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs.

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.

The average HOEP continued to be the lowest market price as compared to Manitoba, Michigan, Minnesota, New York and PJM. The price difference is mainly due to export congestion. In other words, there is not enough transmission available to move low cost energy from Ontario to other markets.

[91] Midcontinent Independent System Operator

[92] New York Independent System Operator

[93] Pennsylvania New Jersey Maryland

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

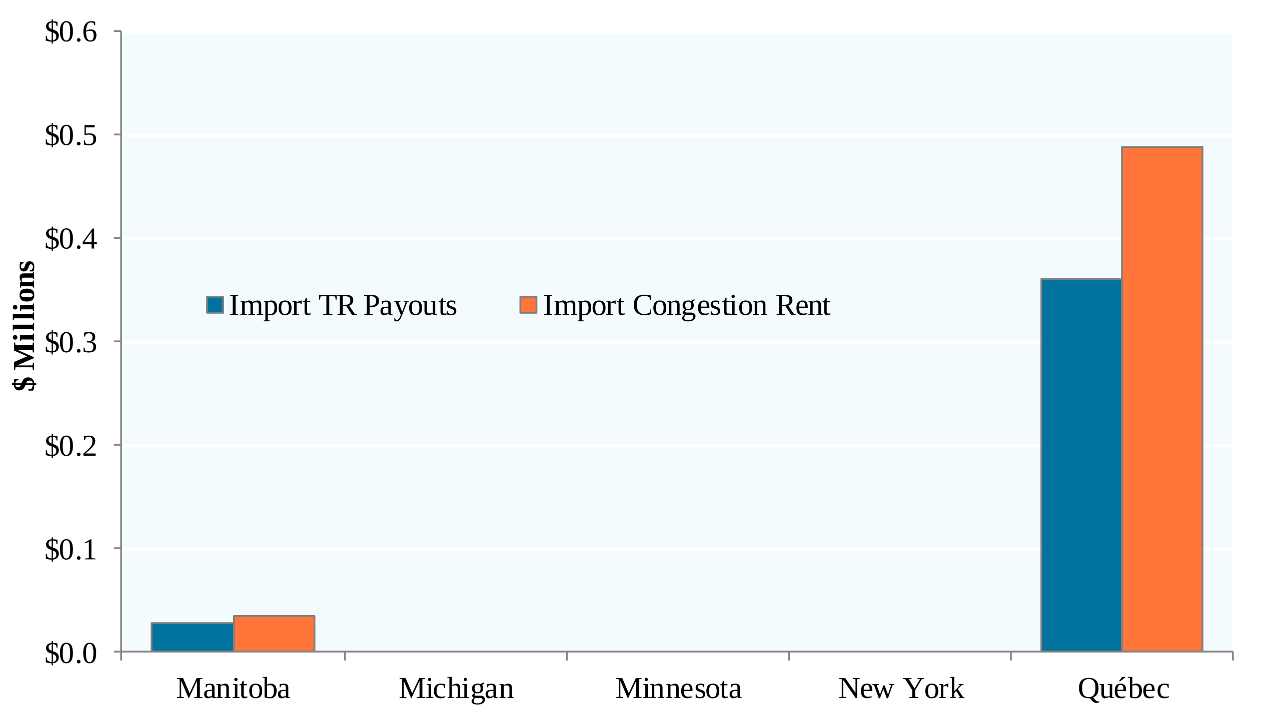


Figure B-17 compares the total import congestion rent collected to total TR payouts by intertie for the Summer 2019 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

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

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. 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 shortfalls are covered primarily by TR auction revenues, which are the proceeds from selling TRs (a payment into the TRCA).

Total import TR payouts in the Summer 2019 Period were much lower than the previous summer at $0.4 million, while total import congestion rent was $0.5 million, creating a congestion rent surplus of $0.1 million. This 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 2019 Period, causing congestion rent to outweigh TR payments during these hours.

Export TR payouts in the Summer 2019 Period totalled $100.0 million, while export congestion rent totalled $95.6 million. This $4.2 million shortfall of congestion rent is primarily due to the $6.1 million imbalance between congestion rent and TR Payouts on the Michigan intertie.

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

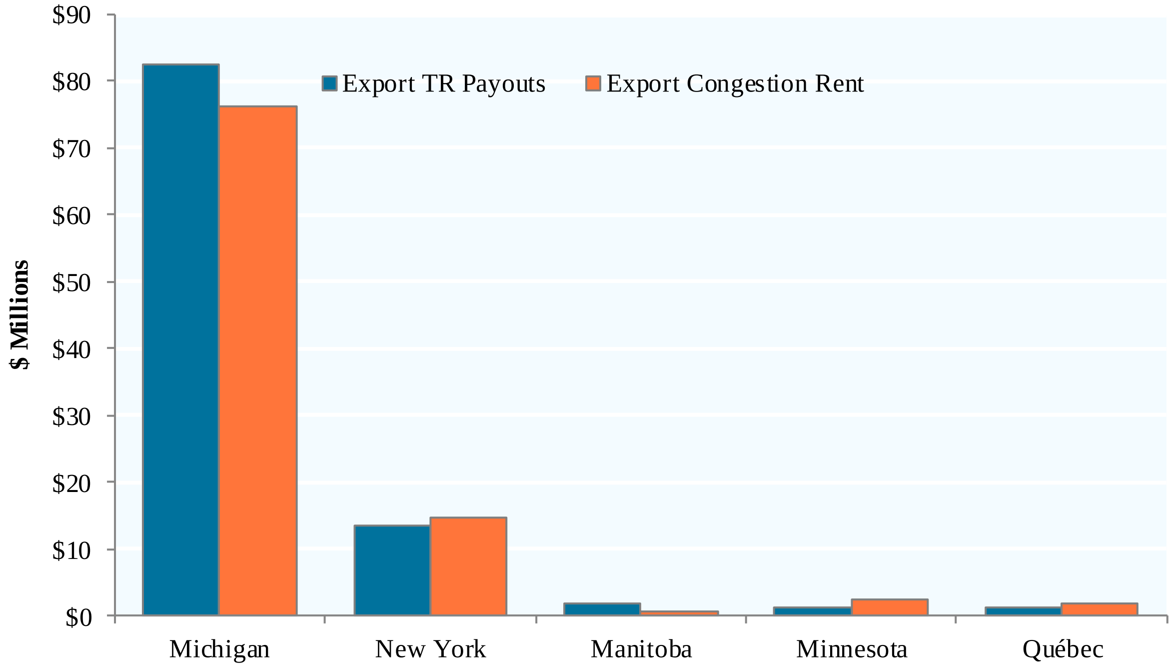


Figure B-18 compares the total export congestion rent collected to total TR payouts by intertie for the Summer 2019 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

Long-term import TR prices for the May 2019 auction increased in Québec compared to the February 2019 auction, indicating that traders expected import congestion to increase in Québec in the second quarter of 2020. Conversely, long-term import TR prices for the May 2019 auction decreased in Manitoba compared to the February 2019 auction, indicating that traders expected import congestion to decrease in Manitoba in the second quarter of 2020.

Table B-6: Average 12-Month TR Auction Prices by Intertie & Direction

Direction	Auction Date	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	Nov-18	Jan-19 to Dec-19	1,436	145	1,648	175	12,751
	Feb-19	Apr-19 to Mar-20	1,010	83	2,509	71	7,775
	May-19	Jul-19 to Jun-20	656	65	2,460	146	11,423
	Aug-19	Oct-19 to Sep-20	1,104	261	2,579	220	8,243
Export	Nov-18	Jan-19 to Dec-19	28,339	129,949	44,392	63,584	4,929
	Feb-19	Apr-19 to Mar-20	37,656	100,937	54,593	40,057	2,273
	May-19	Jul-19 to Jun-20	40,089	84,032	39,792	54,878	2,966
	Aug-19	Oct-19 to Sep-20	40,779	80,146	47,656	36,933	3,493

Table B-6 lists the average auction prices for 1 MW of long-term (12-month) TRs for each intertie in either direction for each auction since November 2018. 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 2019 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 B-7: 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-18	23	2	-	11	72
	Dec-18	50	8	-	2	305
	Jan-19	185	9	231	8	521
	Feb-19	111	2	235	24	470
	Mar-19	90	2	-	28	521
	Apr-19	36	2	-	2	368
	May-19	13	2	-	7	558
	Jun-19	22	2	87	8	720
	Jul-19	26	4	100	4	558
	Aug-19	61	1	130	5	767
	Sep-19	26	6	223	2	612
	Oct-19	30	1	75	5	298
Export	Nov-18	6,133	11,111	-	6,300	194
	Dec-18	4,892	12,055	-	6,735	1,153
	Jan-19	3,601	12,685	4,247	8,184	1,585
	Feb-19	4,251	4,065	-	3,333	1,431
	Mar-19	2,842	3,775	-	2,155	42
	Apr-19	3,031	6,746	-	1,800	66
	May-19	3,841	10,788	-	3,906	186
	Jun-19	4,250	2,794	-	4,363	72
	Jul-19	4,873	7,901	4,873	4,070	103
	Aug-19	4,427	4,956	-	2,284	119
	Sep-19	3,082	7,063	3,679	2,735	70
	Oct-19	3,800	11,450	-	3,746	25

Table B-7 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 2019 and Winter 2018/19 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 continue to be volatile from month-to-month, with infrequent short-term TRs sold in Minnesota.

The balance of the Transmission Rights Clearing Account (TRCA) decreased to $94.4 million at the end of the Summer 2019 Period (October 2019), a decrease from $111.2 million at the end of the Winter 2018/19 Period (April 2019).[94,95] The October 2019 balance was $74.4 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance for the 6-month monitoring period was composed of:[96]

1. $160.1 million in revenue, specifically:
    - $96.3 million in congestion rent
    - $62.6 million in total auction revenues
    - $1.2 million in interest
2. $176.9 million in debits, specifically:
    - $100.5 million in TR payouts
    - $76.4 million in disbursements to Ontario consumers and exporters.

[94] 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.

[95] For reference, the balance at the end of the previous Summer 2018 Period (October 2018) was $125.9 million.

[96] 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 Report because the settlement database records revenue on a cash flow basis and not an accrual basis.

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

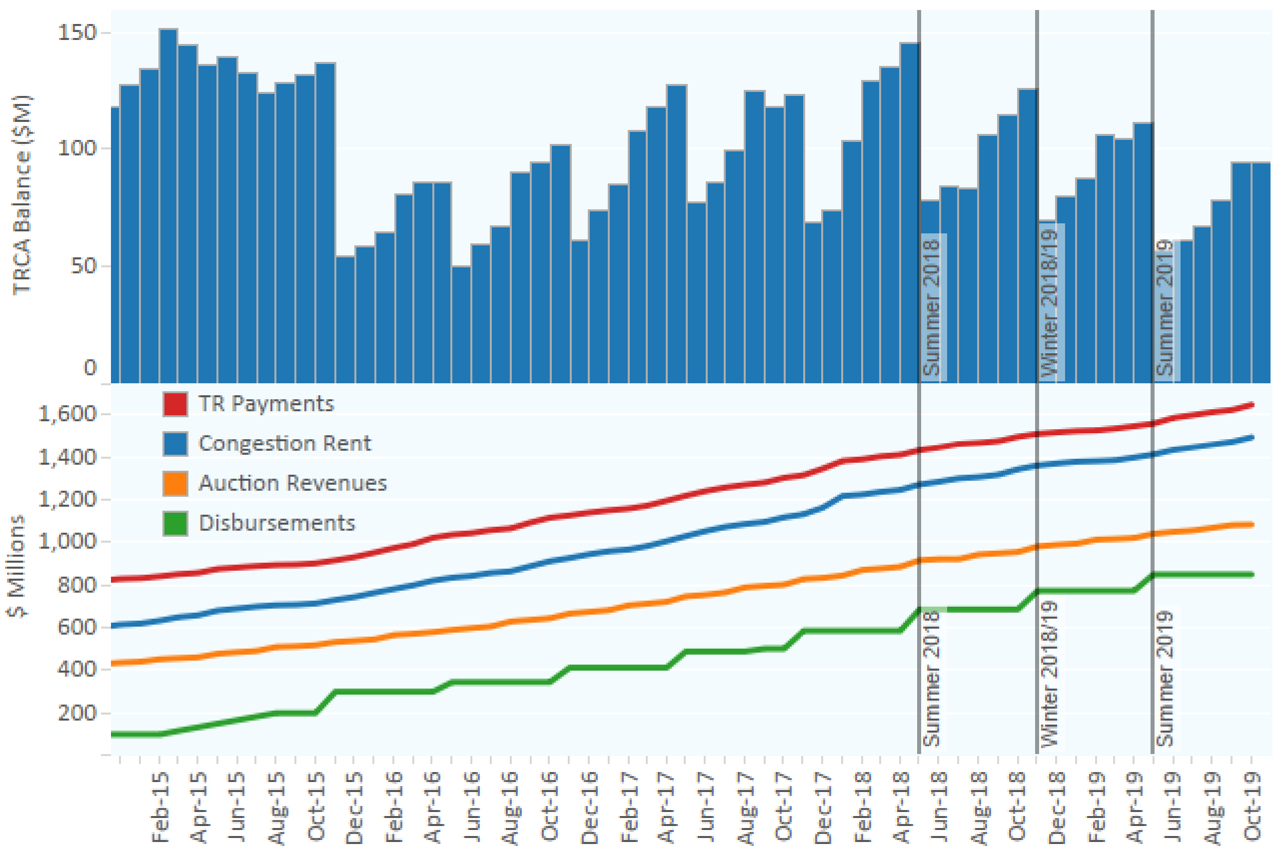


Figure B-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account.

B.2 Demand

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

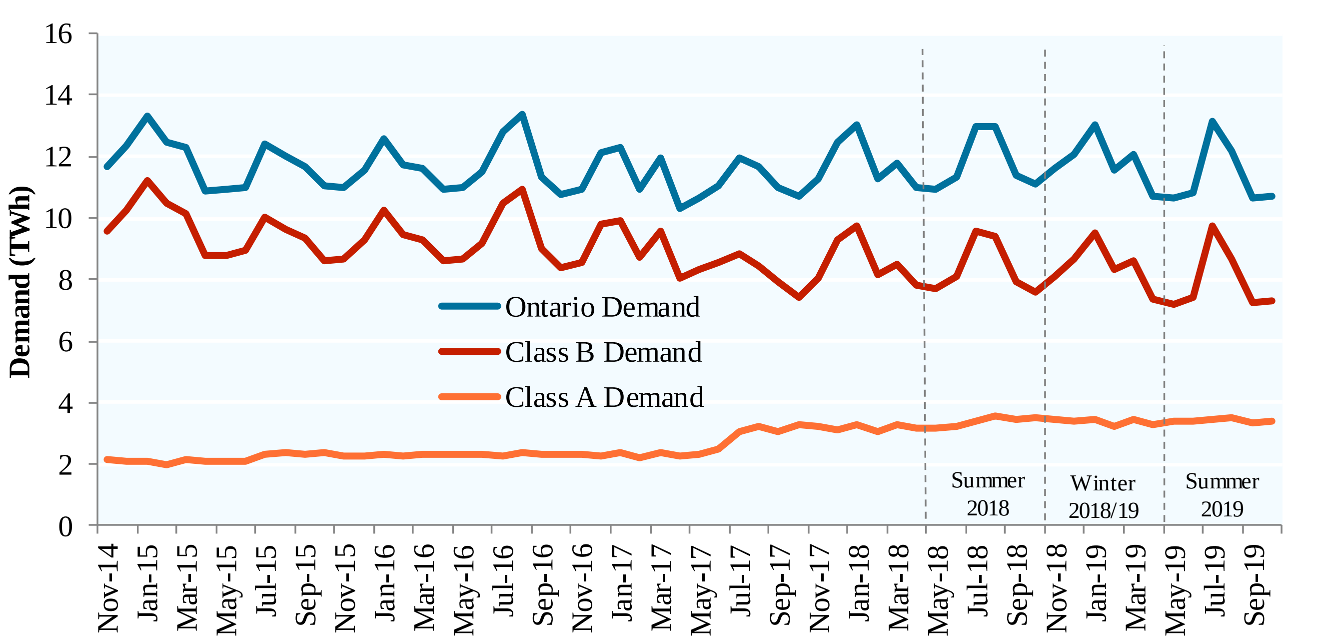


Figure B-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand–not grid-connected demand–in that it includes demand satisfied by embedded generators.[97]

Total demand in the Summer 2019 Period was 68.1 TWh – 3.7% lower than the total demand of 70.7 TWh in the Summer 2018 Period. This decrease in demand in the Summer 2019 Period was caused primarily by the weather, which was near historical averages, in contrast, the Summer 2018 Period which was warmer than average.

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

Compared to the Summer 2018 Period, Class A demand increased by 0.2 TWh or 1%. The change in total demand was mostly due to a 2.8 TWh reduction in Class B demand. Class B consumers tend to be more weather-sensitive than Class A consumers.

B.3 Supply

This section presents data on generating capacity, actual generation, and Operating Reserve (OR) supply for the Summer 2019 Period relative to previous years.

Table B-8: Changes in Generating Capacity, Q2 2019 to Q3 2019

Generation Type	Grid-connected		Distribution-level ("Embedded")	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	-	13,009	-	-
Natural Gas	-	10,277	-	-
Hydro	583	9,065	2	280
Wind	-	4,486	-	591
Solar	44	424	12	2,165
Biofuel	-	295	1	110
Gas-Fired and Combined Heat and Power	-	-	3	274
Energy from Waste	-	-	-	24
Total	627	37,556	18	3,444

Table B-8 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 quarter of 2019, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[98] Total capacity of each type at the end of the third quarter of 2019 is also shown.

Little new capacity was added to the Ontario generation fleet at either the IESO-controlled grid or the distribution level. The 583 MW increase in grid-connected hydroelectric capacity is due

[98] 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 http://www.ieso.ca/power-data/supply-overview/transmission-connected-generation#Historical%20Quarterly%20Progress%20Reports%20on%20Contracted%20Electricity%20Supply

to a change in calculation methodology and does not indicate an increase in resource capability.

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

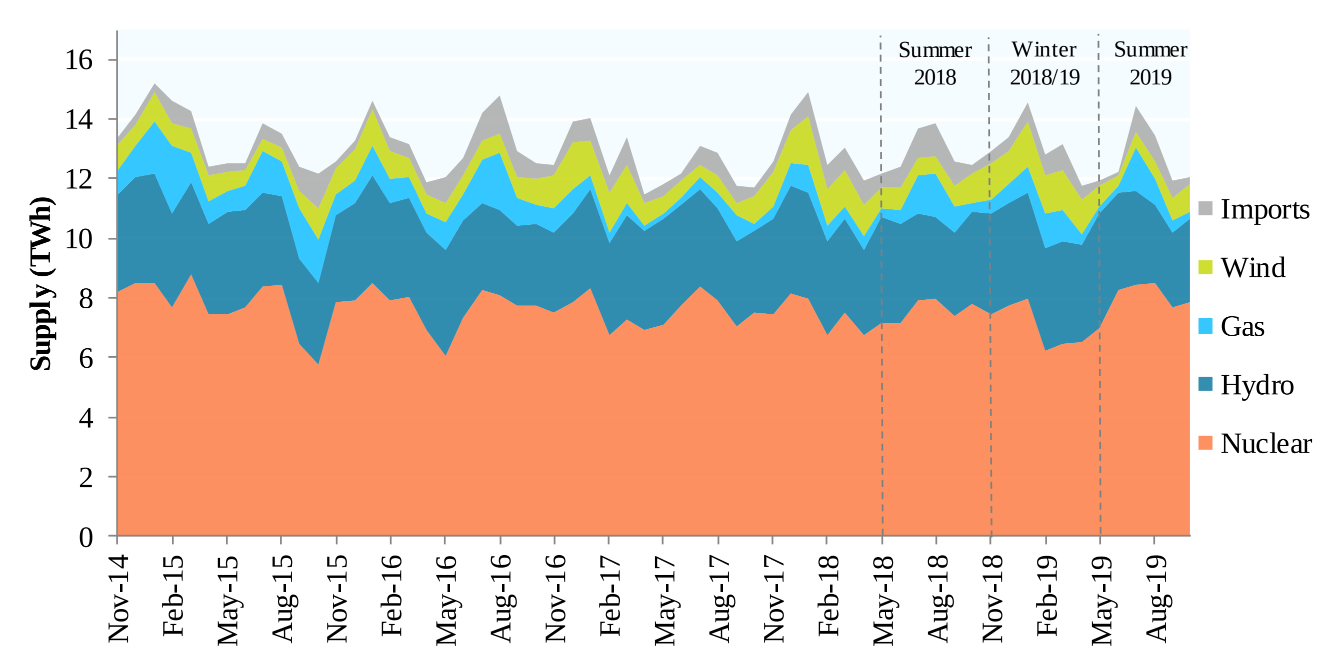


Figure B-21 displays the real-time unconstrained production schedules from November 2014 to October 2019 by resource or transaction type: imports, wind, gas-fired, hydroelectric and nuclear.[99] Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand 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 2018 Period, the Summer 2019 Period showed an increase in the output of nuclear generators from 45.4 TWh to 47.8 TWh. Most other types of supply had lower output. Production from wind generators was 3.9 TWh, down more than 10% from 4.3 TWh in the previous summer.

[99] Solar and biofuel are excluded from the figure as these fuel types 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 Ontario 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.

Gas generation and imports have higher marginal costs than nuclear, hydro, or wind resources. Because nuclear output was higher for the Summer 2019 Period, gas generators were less likely to be scheduled. Gas generator output decreased from 4.7 TWh to 3.4 TWh in the Summer 2019 Period, and imports decreased from 4.4 TWh to 2.9 TWh. Production from these resources was particularly low in May, June and October with average HOEP below $10/MWh.

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

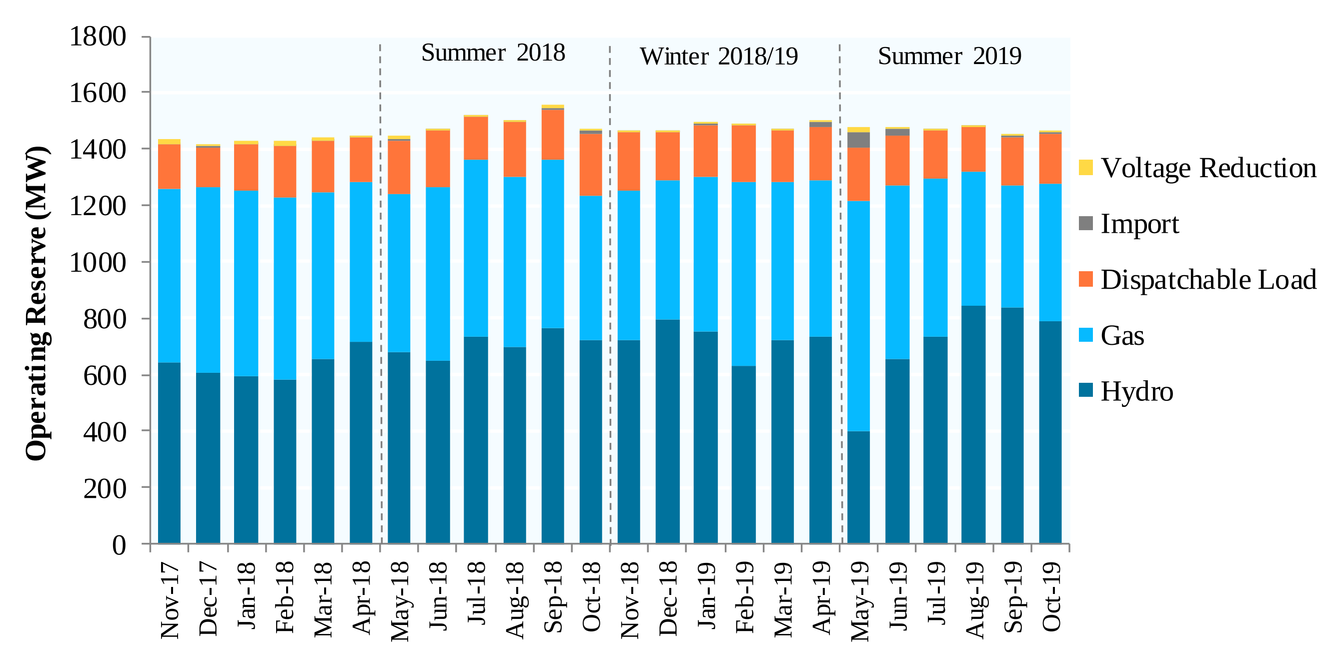


Figure B-22 displays the real-time unconstrained OR schedules from November 2017 to October 2019 by resource or transaction type: hydroelectric, gas-fired, dispatchable loads, imports and voltage reduction (taken as a control action by the IESO).[100] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

[100] 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 B-9: Average Hourly OR Scheduled by Resource Type and Season, 3 Periods

Quantity	Summer 2018	Winter 2018/19	Summer 2019
Average OR Scheduled (MW)	1,497 MW	1,484 MW	1,472 MW
Dispatchable Load Share	13%	13%	12%
Natural Gas Share	39%	38%	38%
Hydro Share	47%	49%	48%
Other Share	1%	1%	2%

Table B-9 reports the seasonal average quantity of hourly OR scheduled and the fraction of total OR that is provided by resource or transaction type. It is based on the same data as Figure B-22. "Other" is the sum of OR from imports and voltage reduction.

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

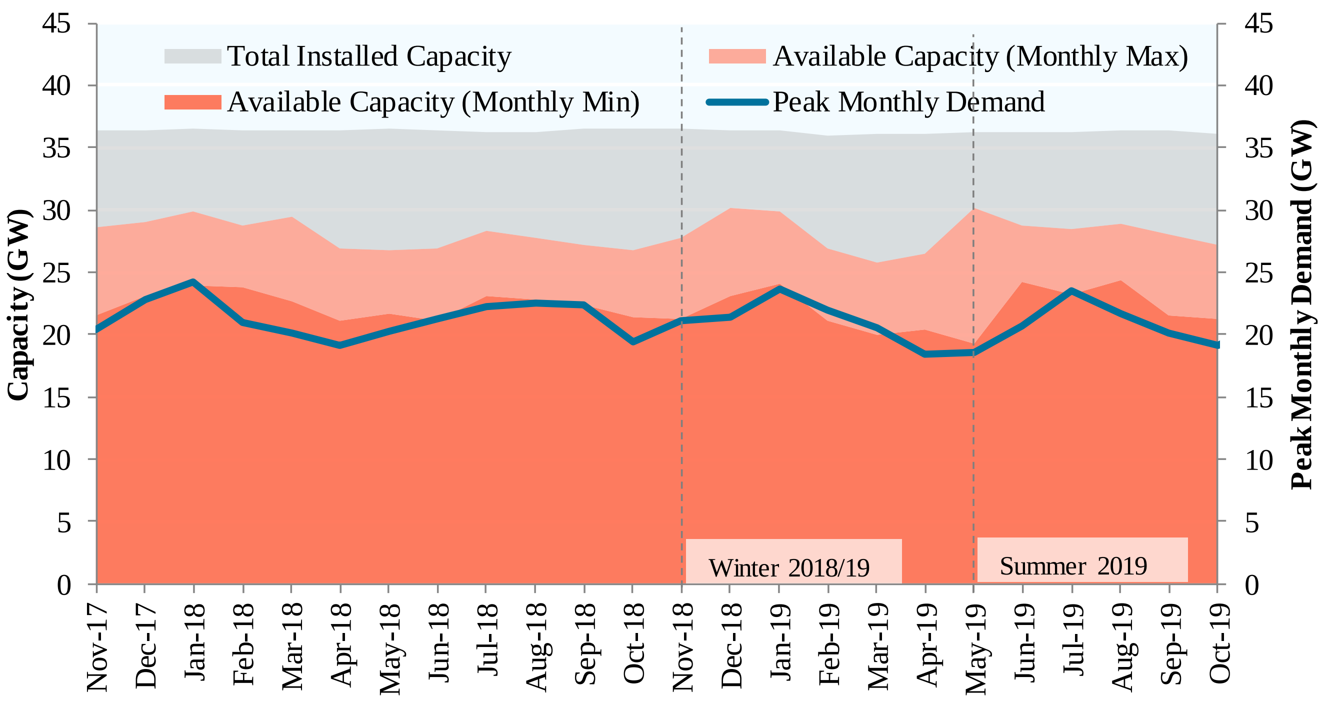


Figure B-23 plots the monthly minimum and maximum available generation capacity, accounting for unavailable capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from November 2017 to October 2019. 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.[101]

The Summer 2019 Period had, on average, 11.1 GW of unavailable capacity, which is 5% less than the average of 11.7 GW of capacity that was unavailable in the Summer 2018 Period. This difference was primarily driven by less outages of nuclear capacity in the Summer 2019 Period. Minimum and maximum available capacity were higher in the Summer 2019 Period by 0.2 GW and 1.31 GW on average compared the Summer 2018 Period, respectively.

[101] 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

B.4 Imports, Exports and Net Exports

This section examines import and exports transactions in the unconstrained sequence, as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[102]

Figure B-24: Monthly Imports and Exports, and Average Net Exports (Unconstrained), 2 Years

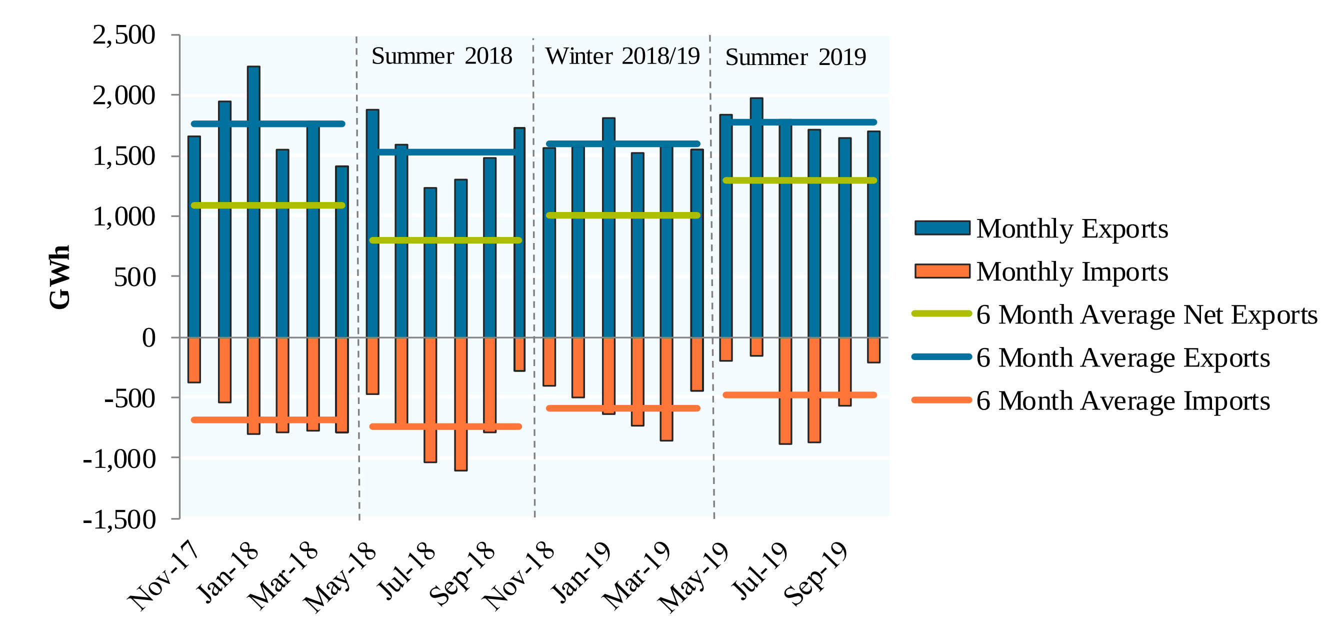


Figure B-24 plots total monthly imports and exports from November 2017 to October 2019, as well as the average monthly imports, exports and net exports calculated over each 6-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Ontario remained a net exporter in the Summer 2019 Period, with net exports of 7.78 TWh, up from 4.76 TWh in the Summer 2018 Period. Compared to the Summer 2018 Period, exports rose by 1.48 TWh, and imports fell by 1.54 TWh. The increase in net exports over the Summer 2019 Period was primarily driven by a large increase in exports to Michigan and the large decrease in imports from Québec, compared to the Summer 2018 Period. These

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

changes in imports and exports are consistent with the usually low HOEP in the Summer 2019 Period.

Figure B-25: Exports by Intertie, 2 Years

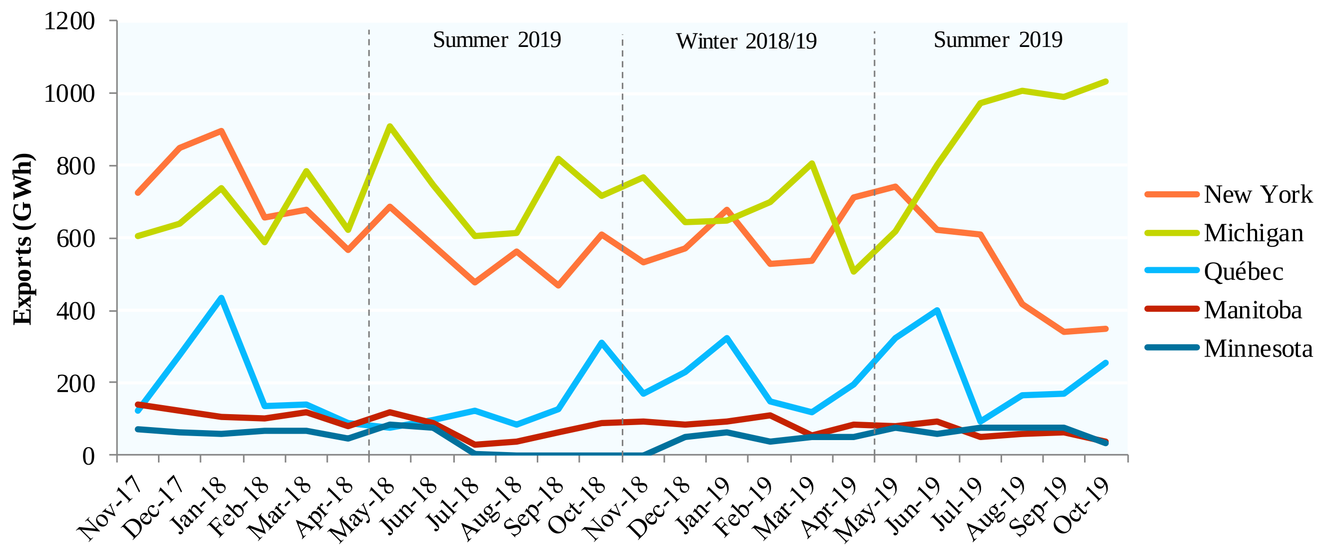


Figure B-25 presents a breakdown of exports from November 2017 to October 2019 to each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly export quantities over the Summer 2019 and Winter 2018/19 Periods are given for each intertie in Table B-10.

Figure B-26: Imports by Intertie, 2 Years

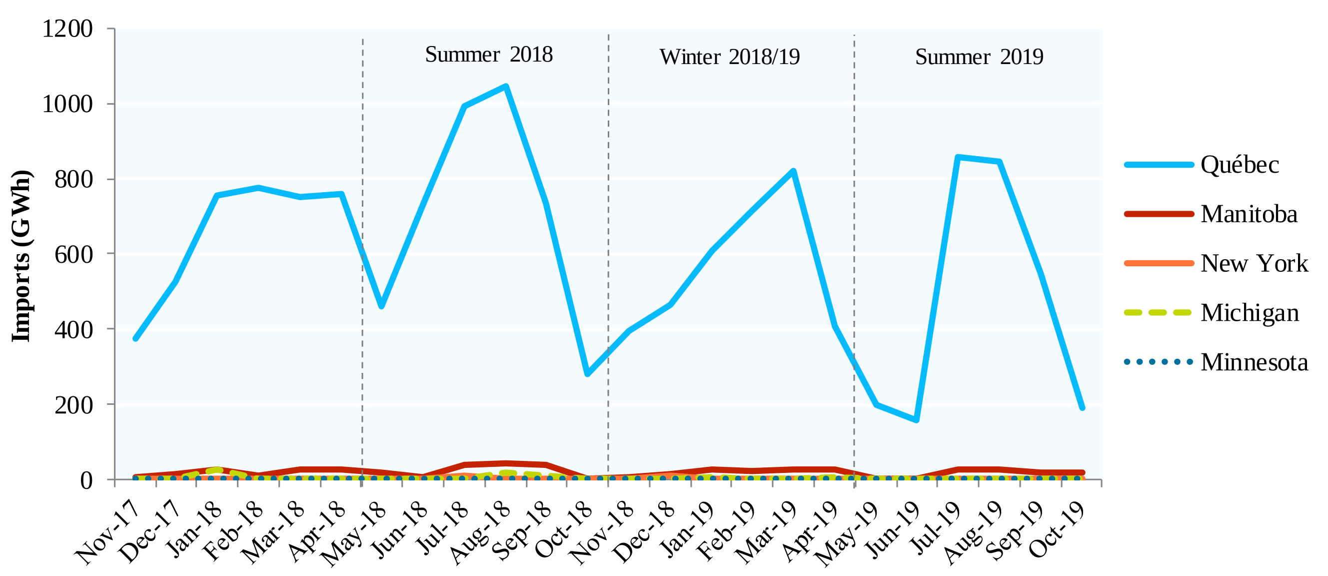


Figure B-26 presents a breakdown of imports from November 2017 to October 2019 from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly import quantities over the Summer 2019 and Winter 2018/19 Periods are given for each intertie in Table B-11.

Exports to Québec were much higher than usual for the summer season, particularly in May and June 2019 when the average HOEP was below $10/MWh. There was a very strong inverse correlation between the HOEP and exports to Québec in the Summer 2019 Period, which indicates that Québec consistently purchased more energy from Ontario when prices were low. The correlation between the HOEP and exports was not as clear for Ontario's other trading partners.

Exports to Michigan were characterized by high volume and sustained congestion. The volume increased considerably in the Summer 2019 Period compared to the Summer 2018 Period, rising by 23% or 168 GWh per month on average. Average monthly energy prices in Michigan remained above CAD$30/MWh throughout the summer season despite the low prices in Ontario. As shown in Figure B-16, there was export congestion more than 90% of the time on the Michigan intertie in the Summer 2019 Period.

Exports to New York decreased in the Summer 2019 Period compared to the Summer 2018 Period, falling by 9% or 50 GWh per month on average. Energy prices in New York were much closer to the HOEP in the Summer 2019 Period compared to the previous summer, which may explain the decrease in exports. As shown in Figure B-16, there was export congestion slightly more than 50% of the time, which is more than in the Summer 2018 Period. Export congestion to New York became more frequent later in the summer, mirroring the decrease in exports.

Imports from Québec greatly decreased in the Summer 2019 Period compared to the Summer 2018 Period, falling from an average of 707 GWh per month to an average of 465 GWh per month. This decrease was price-driven, with particularly low imports in May, June and October 2019.

Failed or curtailed exports reduce demand between pre-dispatch (PD-1) and real-time. The Market Participant (MP) percentage failure rate of exports on the Manitoba intertie increased substantially in the Summer 2019 Period and remained much higher than on other interties. Almost 30 GWh per month of exports to Manitoba were curtailed by MPs on an average export volume of 81 GWh per month. There were no large changes in the rate of Independent System Operator (ISO)-curtailed exports.

Table B-10: Average Monthly Exports and Export Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		Market Participant (MP) Failure		ISO Curtailment		Market Participant (MP) Failure	
	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19
New York	523	588	2.2	2.4	9.8	5.9	0.4%	0.4%	1.9%	1.0%
Michigan	835	618	3.5	3.5	4.9	7.4	0.4%	0.6%	0.6%	1.2%
Manitoba	81	103	2.4	1.2	29.9	23.5	3.0%	1.2%	37.0%	22.8%
Minnesota	53	33	1.4	0.4	1.3	1.1	2.7%	1.2%	2.5%	3.4%
Québec	248	202	3.8	8.0	2.8	2.1	1.5%	4.0%	1.1%	1.0%

Table B-10 reports average monthly export curtailments and failures over the Summer 2019 and Winter 2018/19 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.[103] 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 rate of MP Failures for Michigan and Minnesota imports fell in the Summer 2019 Period from the high rates in the Winter 2018/19 Period. The rate of ISO Curtailments for imports notably increased in the Summer 2019 Period compared to the Winter 2018/19 Period for the Manitoba intertie.

[103] 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 B-11: Average Monthly Imports and Import Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate			
			ISO Curtailment		Market Participant (MP) Failure		ISO Curtailment		Market Participant (MP) Failure	
	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19	Summer 2019	Winter 2018/19
New York	2	3	0.1	0.0	0.1	0.1	2.9%	0.4%	7.0%	1.6%
Michigan	12	6	0.5	0.1	0.9	1.2	4.0%	2.0%	7.5%	21.7%
Manitoba	52	42	9.6	1.1	0.3	0.5	18.5%	2.6%	0.5%	1.3%
Minnesota	4	8	0.6	0.3	0.4	1.5	13.9%	3.3%	10.1%	18.5%
Québec	402	477	10.3	2.4	0.3	0.6	2.6%	0.5%	0.1%	0.1%

Table B-11 reports average monthly import failures and curtailments the Summer 2019 and Winter 2018/19 Periods by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Appendix C: Market Outcomes for the Winter 2019/20 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Winter 2019/20 Period (November 1, 2019 to April 30, 2020), with comparisons to previous reporting periods as appropriate.

C.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.

HOEP and GA

Table C-1: Average Effective Price by Consumer Class and Period ($/MWh), 3 Periods

Customer Class	Average Weighted HOEP ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Average Effective Price ($/MWh)
Class A – Winter 2019/20	13.76	60.21	2.01	75.97
Class A – Summer 2019	10.04	63.78	2.62	76.43
Class A – Winter 2018/19	22.31	53.30	3.07	78.68
Class B – Winter 2019/20	16.21	111.78	2.17	130.16
Class B – Summer 2019	13.38	123.20	2.82	139.40
Class B – Winter 2018/19	26.46	89.77	3.27	119.51
All Consumers – Winter 2019/20	*N/A*	*N/A*	*N/A*	114.65
All Consumers – Summer 2019	*N/A*	*N/A*	*N/A*	120.39
All Consumers – Winter 2018/19	*N/A*	*N/A*	*N/A*	107.79

Table C-1 summarizes the average effective price in dollars per MWh by consumer class for the Winter 2019/20 Period (November 1, 2019 to April 30, 2020), Summer 2019 Period (May 1, 2019 to October 31, 2019) and Winter 2018/19 Period (November 1, 2018 to April 30, 2019).

The 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.[104] 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 distribution. Results are reported for three consumer groups: "Class A consumers", "Class B consumers" and "All Consumers".[105, 106]

Starting with the Panel's Monitoring Report 29 (May 2016-Oct 2016) published in March 2018, the Panel moved embedded Class A consumers from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table C-1.[107]

[104] 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.

[105] 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

[106] 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 total consumption by all consumers in each of those hours. To the extent that Class A consumers reduce their demand during those hours, their share of GA is reduced. The remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel's Industrial Conservation Initiative (ICI) Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[107] Following past practice, the Panel assumes that embedded Class A consumers have the same average load profile as directly-connected Class A consumers. Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and from "Class B & Embedded Class A" to just "Class B"), there is no direct comparison to be made between effective prices reported in this report and those from reports issued before the Panel's Monitoring Report 29 published March 2018. All references to effective price in the Panel's reports going forward – including all tables and figures – reflect the Panel's updated methodology.

The average effective price for all consumers increased by 6% between the Winer 2018/19 Period and the Winter 2019/20 Period. This overall increase was composed of a 3% decrease in the average effective price for Class A consumers and a 9% increase in the average effective price for Class B consumers. A reduction in the total demand for energy in the Winter 2019/20 Period compared to the Winter 2018/19 Period (see Figure C-20) caused the effective HOEP for both Class A and B consumers to decrease in the Winter 2019/20 Period, while a decrease in the frequency of Congestion Management Settlement Credit (CMSC) payments, transmission loss payments, Intertie Offer Guarantee (IOG) payments and cost guarantee payments (see Figure C-12) caused the effective uplift for both Class A and B consumers to decrease. As explained in further detail below, the HOEP and GA costs tend to be inversely related. The GA makes up a smaller portion of the average effective price of Class A consumers compared to Class B consumers. Therefore, the absolute increase in the average GA for Class A consumers was smaller than the decrease in the average weighted HOEP for Class A consumers, causing the average effective price for Class A consumers to decrease in the Winter 2019/20 Period, when compared to the Winter 2018/19 Period. Conversely, the absolute increase in the average GA for Class B consumers was significantly higher than the increase in average weighted HOEP for Class B consumers, causing the average Class B effective price to significantly increase in the Winter 2019/20 Period.

In March 2018, the Ontario Energy Board (OEB) issued a Payment Amounts Order for Ontario Power Generation's (OPG's) rate regulated hydroelectric and nuclear facilities for 2017-2021.[108] As a result of this Order, an annual increase in the price of OPG's nuclear energy production occurred in January 2020. There was a more modest increase in the payments made to OPG's hydroelectric facilities. Similar to the Winter 2018/19 Period and the Summer 2019 Period, this Order likely contributed to the rise in Class B GA, which significantly increased the average Class B effective price observed in the Winter 2019/20 Period.

[108] See the OEB Payment Amounts Order dated March 29, 2018 (EB-2016-0152): http://www.rds.oeb.ca/HPECMWebDrawer/Record/603940/File/document

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

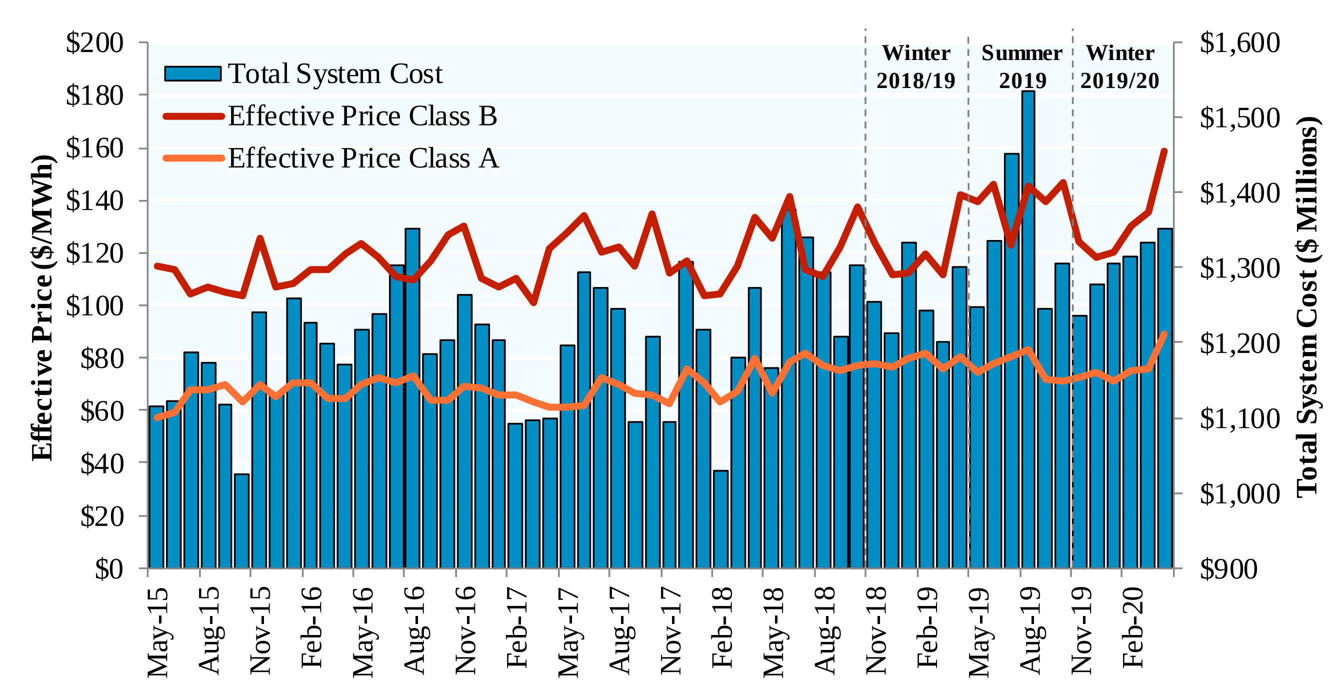


Figure C-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five years.

The total system cost borne by Ontario consumers in the Winter 2019/20 Period rose 3.6% compared to the Winter 2018/19 Period although the total system cost declined by 3.8% compared to the Summer 2019 Period. This change in the total system cost across winter reporting periods is above average: over the last five years, the total system cost has grown by about 2.9% per year. The total system cost rose by about $272 million, with about a $700 million decrease in the HOEP, about a $1,046 million increase in GA, and about $83 million decrease in uplift. The increase in the total system cost at the end of the Winter 2019/20 Period coincided with the decline of Ontario demand due to the onset of the COIVD-19 pandemic. The increase in the total system cost observed in the Winter 2019/20 Period compared to the Winter 2018/19 Period was caused by a significant increase in GA for Class A and B consumers. This effect is expected as both the HOEP and demand decreased during the Winter 2019/20 Period, requiring more payments to be recovered through GA.

The average effective price for Class B consumers remained significantly higher than the average effective price for Class A consumers in the Winter 2019/20 Period. The average Class A effective price decreased slightly by $2.71/MWh to $75.97/MWh, and the average Class B effective price increased notably by $10.65/MWh to $130.16/MWh. The increase in the average effective price for Class A was slightly below the increase in the average Class A effective price over the last five years, which was slightly more than $3/MWh per year. The increase in the average effective price for Class B was almost double the average increase over the last five years, which was just above $5/MWh per year.

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

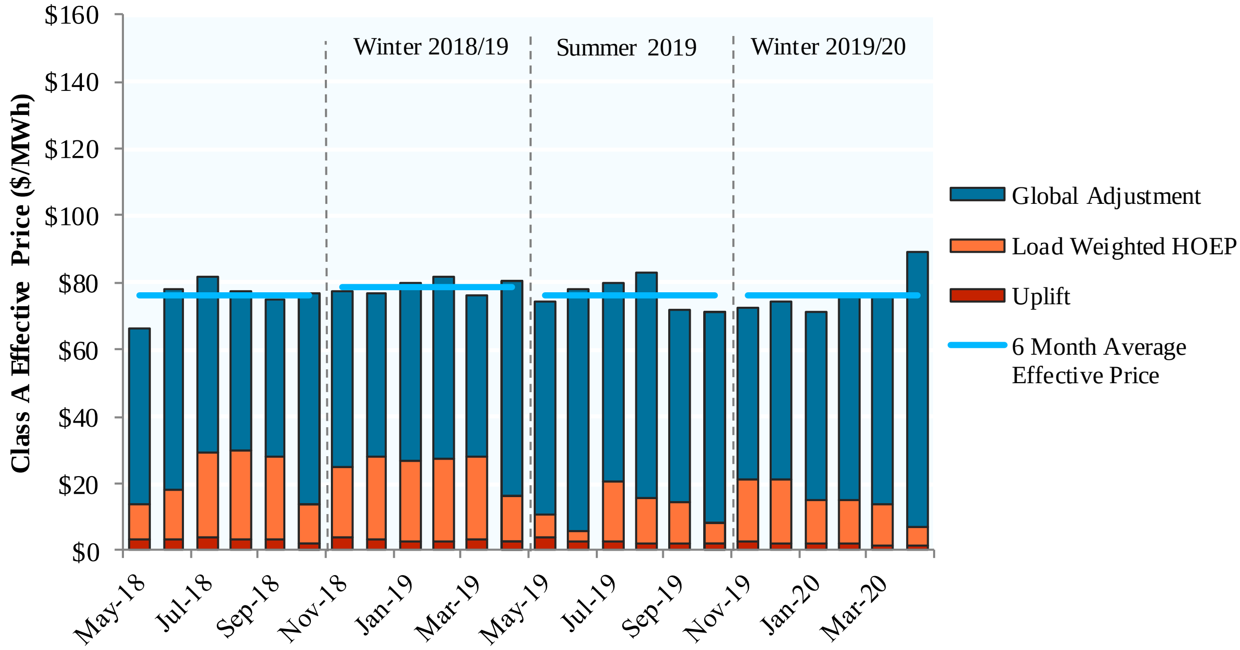


Figure C-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period.[109, 110]

The GA is the guaranteed revenue less the HOEP and uplift payments for Class A and B consumers. 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. A higher GA tends to increase the average effective price more for Class B than Class A consumers because the

[109] 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 demand), and their contracted rates of revenue or regulated rates set by the OEB. 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

[110] The six-month average Class A 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.

current GA allocation methodology has the effect of allocating to Class A consumers a lower share of GA per MWh consumed than Class B consumers pay.

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

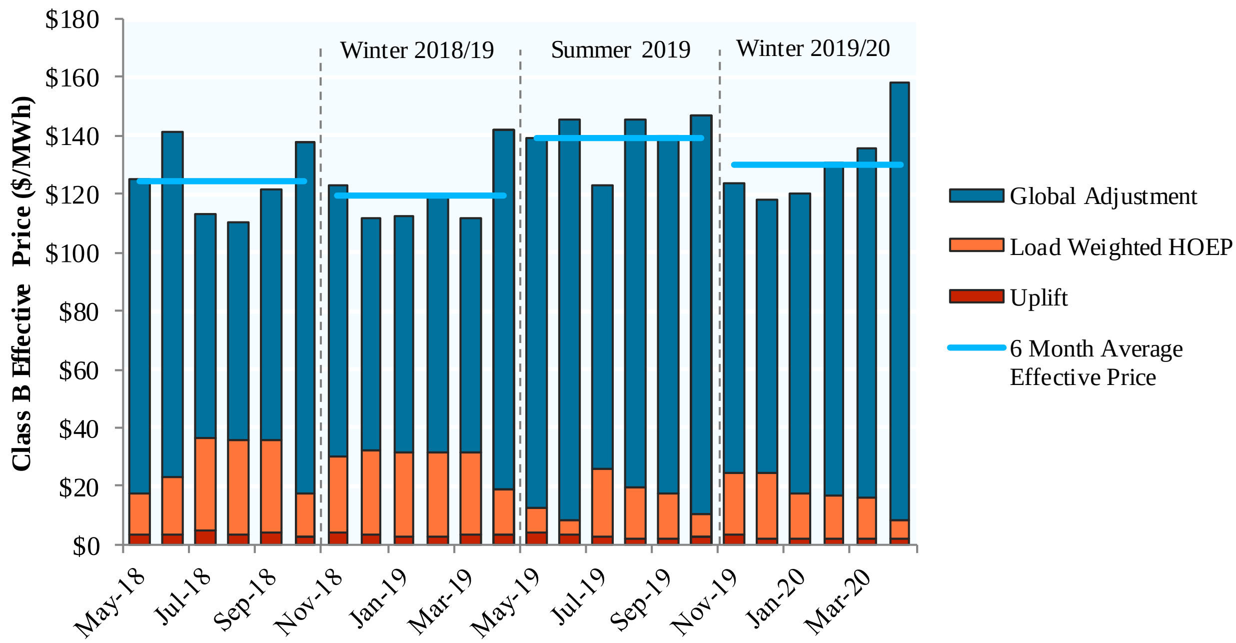


Figure C-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period.[111]

The 6-month average effective price for Class A consumers decreased from $78.69/MWh in the Winter 2018/19 Period to $75.97/MWh. On a monthly basis, higher Class A prices did not necessarily occur during the months when the HOEP was the highest during the Winter 2019/20 Period. The Class A effective price increased significantly between March and April 2020, peaking in April 2020. The rise in the Class A effective price toward the end of the Winter 2019/20 Period coincided with the onset of the COVID-19 pandemic when demand for

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

all consumers fell significantly as a response to the public health measures implemented at the end of the Winter 2019/20 Period.

Generally, most Class B consumers are subject to the Regulated Price Plan (RPP) and pay prices that are reviewed by the Ontario Energy Board (OEB) twice a year and reset if required.[112] As a result, Class B consumers are usually less affected by monthly effective price variations in comparison to Class A consumers who do not pay RPP. The 6-month average effective price for Class B consumers increased from $119.51/MWh in the Winter 2018/19 Period to $130.16/MWh in the Winter 2019/20 Period. As detailed previously, the increase in the average Class B effective price was partly driven by increased rates paid to OPG's regulated hydroelectric and nuclear resources. The extraordinarily low HOEP associated with the COVID-19 pandemic also caused a greater share of the total system cost to be allocated to Class B consumers.

There was a significant decrease in the 6-month average HOEP from $24.19/MWh in the Winter 2018/19 Period to $14.56/MWh in the Winter 2019/20 Period. The drop in average price was driven by the decrease in demand for energy in the Winter 2019/20 Period compared to the Winter 2018/19 Period. The highest HOEPs in the Winter 2019/20 Period occurred in November and December 2019 and HOEPs steadily declined for the rest of the season. In April 2020 there was a drastic drop in the HOEP, during which hydroelectric and wind resources set the real-time Market Clearing Price (MCP) most frequently and the average Ontario demand was lowest in the season. This effect also coincided with the onset of the COVID-19 pandemic when Ontario demand began to decline.

[112] More information on the RPP is available at: https://www.oeb.ca/industry/policy-initiatives-and-consultations/regulated-price-plan-rpp

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

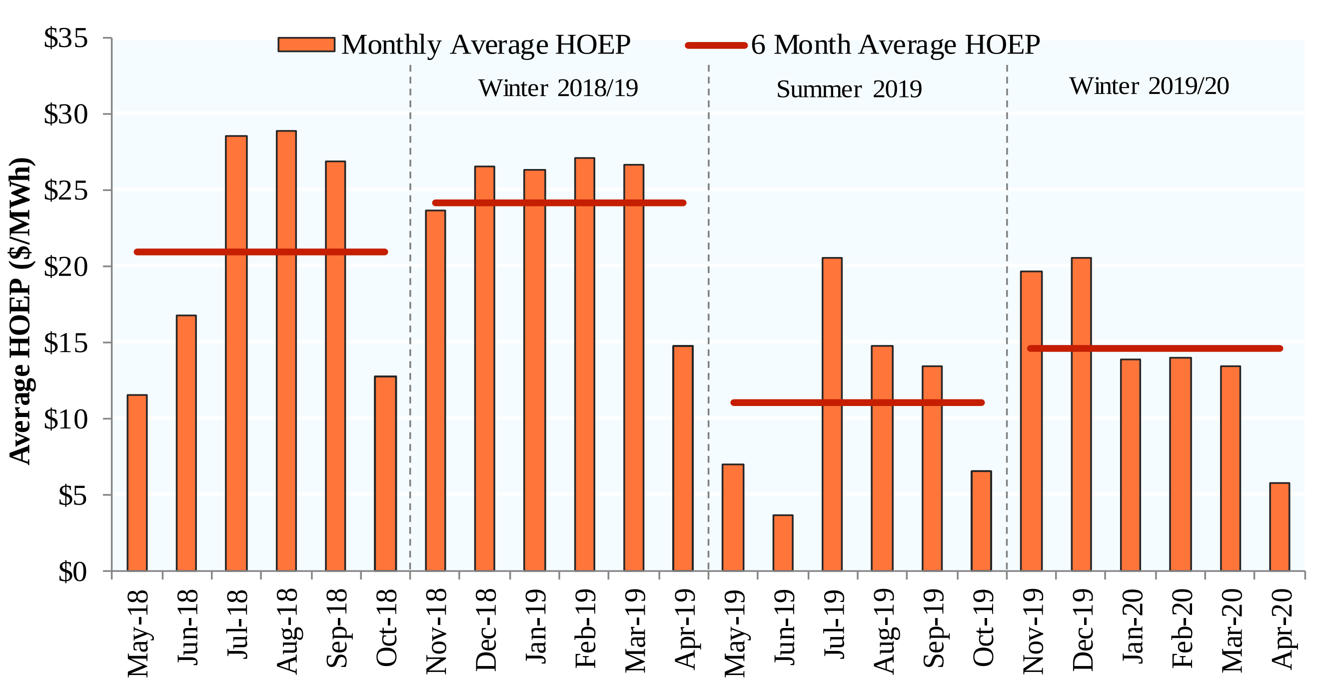


Figure C-4 displays the monthly average HOEP unweighted by the volume of energy consumed in any given interval (the "simple HOEP"), for each month between May 2018 and April 2020. Figure C-4 also displays the simple monthly average HOEP for each 6-month period since May 2018. The HOEP is the unweighted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

The average gas price during on-peak hours was $2.76/MMBtu in the Winter 2019/20 Period, well below the $4.33/MMBtu in the Winter 2018/19 Period, compared to $3.21/MMBtu in the Summer 2019 Period and $3.87/MMBtu in the Summer 2018 Period.

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

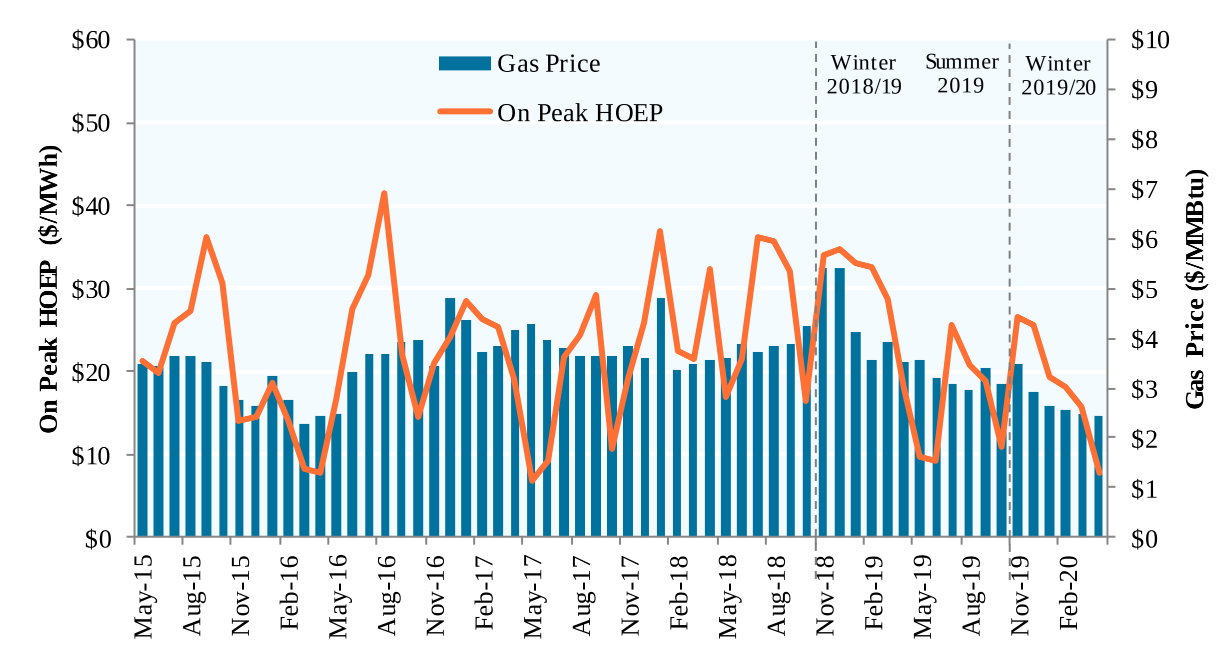


Figure C-5 plots the average monthly HOEP during on-peak hours and the monthly average of Henry Hub natural gas spot prices for days with on-peak hours for the previous year.[113] Natural gas prices are compared to the HOEP for on-peak hours as gas-fired facilities frequently set the price during these hours. Gas-fired facilities typically purchase gas day-ahead.

A correlation coefficient of 0.38 was observed between average daily natural gas prices and daily averages of on-peak HOEP values during the Winter 2019/20 Period, which is much lower than in the Winter 2018/19 Period and the Summer 2019 Period. When the supply of generation is tight, or when the demand for energy is high, high-priced (that is, high marginal cost) resources tend to set the MCP more frequently. As nuclear, wind and hydro resources all typically offer energy at lower prices than natural gas resources, natural gas resources often set the MCP under these conditions. A high correlation between natural gas prices and the

[113] 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

HOEP would be expected, as both natural gas prices and the on-peak HOEP were highest between November 2019 – January 2020, with a drop in both prices as the season continued. During these months of the Winter 2019/20 Period, the monthly Ontario demand was above average and natural gas resources generally set the real-time MCP more frequently than in comparison to other months in the Winter 2019/20 Period. A higher correlation between natural gas prices and the HOEP was likely not observed as monthly HOEPs declined much quicker than the average monthly price of natural gas towards the end of the Winter 2019/20 Period.

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

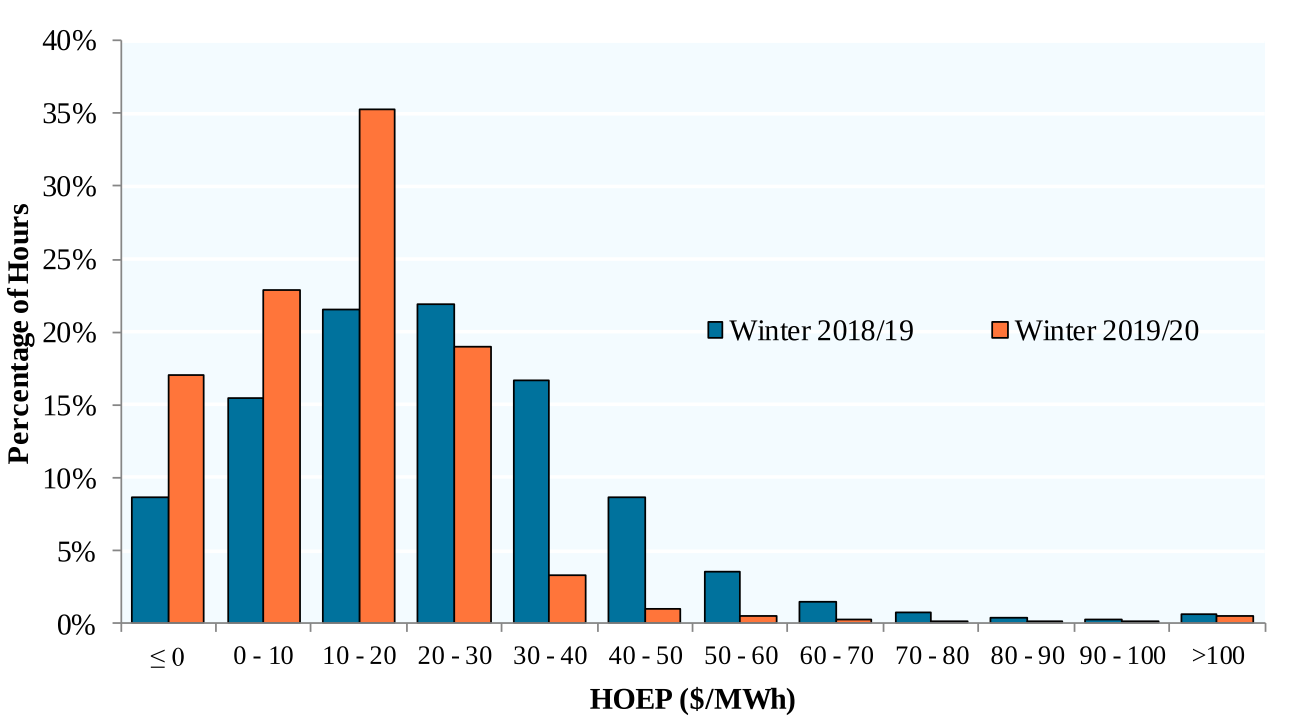


Figure C-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Winter 2019/20 and Winter 2018/19 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh values.

In the Winter 2019/20 Period, there was a large increase in the frequency of hours when the HOEP was negative or zero, and a significant decrease in the frequency of hours with a more expensive HOEP. Only 9% of hours in the Winter 2018/19 Period had a negative HOEP, compared to 17% in the Winter 2019/20 Period, while only 25% of hours had HOEPs of at least $20/MWh in the Winter 2019/20 Period, a notable decline from 54% in the Winter 2018/19 Period. This is likely because demand was lower on average in the Winter 2019/20 Period than it was in the Winter 2018/19 Period, causing MCPs to be lower on average. Available supply may have also been a factor; the Winter 2019/20 Period had less resources on outage than the Winter 2018/19 Period on average (see Figure C-23). A decrease in supply from natural gas resources coupled with an increase in supply from nuclear resources during the Winter 2019/20 Period in comparison to the Winter 2018/19 Period, likely contributed to the drop in the HOEP along with the demand trends observed during the period. As a result, higher priced gas resources had less opportunity to set the MCP during the Winter 2019/20 Period (see Figure C-7).

The percentage of hours that natural gas resources set the real-time MCP decreased notably from 45% in the Winter 2018/19 Period to 32% in the Winter 2019/20 Period, while the percentage of hours that wind resources set the real-time MCP increased from 12% to 24% between the Winter periods. This effect was likely the result of the drop in the average Ontario demand between the Winter 2018/19 Period and the Winter 2019/20 Period, minimizing the use of more expensive resources to set the real-time MCP, thus lowering market prices. The percentage of hours that nuclear resources set the real-time MCP decreased rapidly and from 0.13% to 0.02% despite the increase in supply and decrease in outages from nuclear facilities during the Winter 2019/20 Period. Similar to the Winter 2018/19 Period, nuclear resources were marginal in April 2020 only when the HOEP and demand fell significantly, and did not set market prices at all in any other month during the Winter 2019/20 Period. The percentage of hours that hydroelectric resources set the real-time MCP during the Winter 2019/20 Period remained constant. Hydroelectric resources set the real-time MCP for most of the hours during the Winter 2019/20 Period.

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

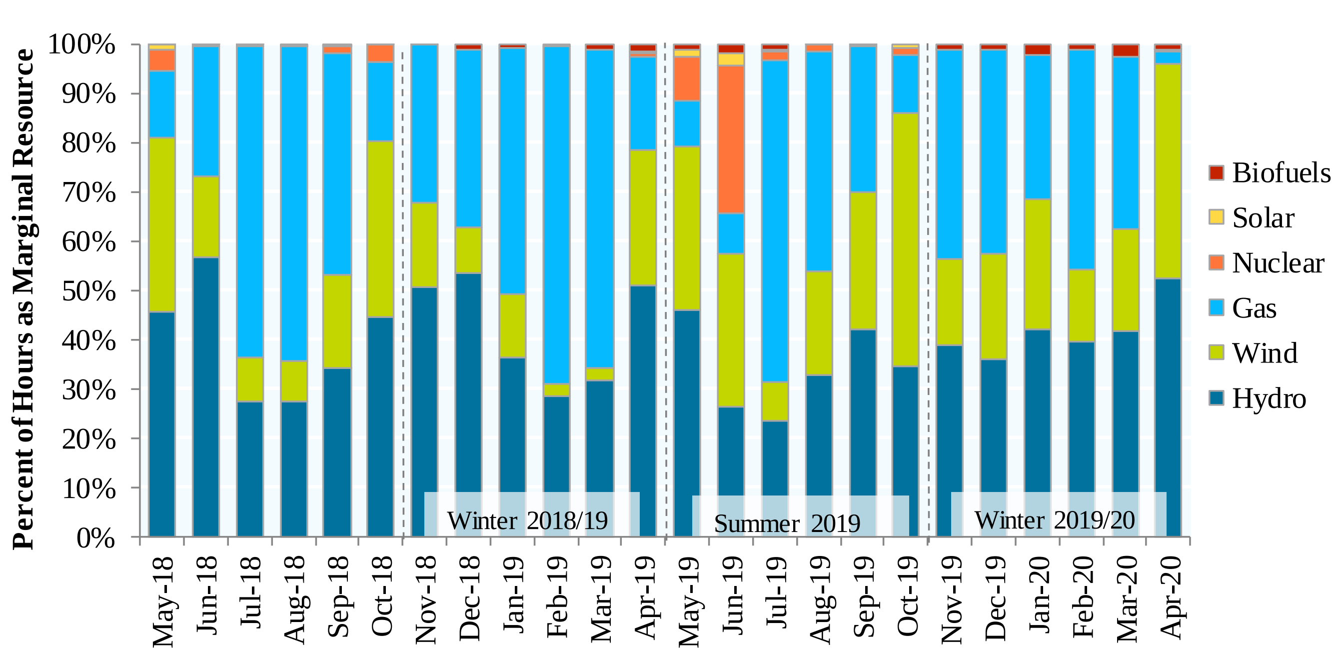


Figure C-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the previous two years. The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

The frequency with which imports and exports set the pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[114] 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.

[114] 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.

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

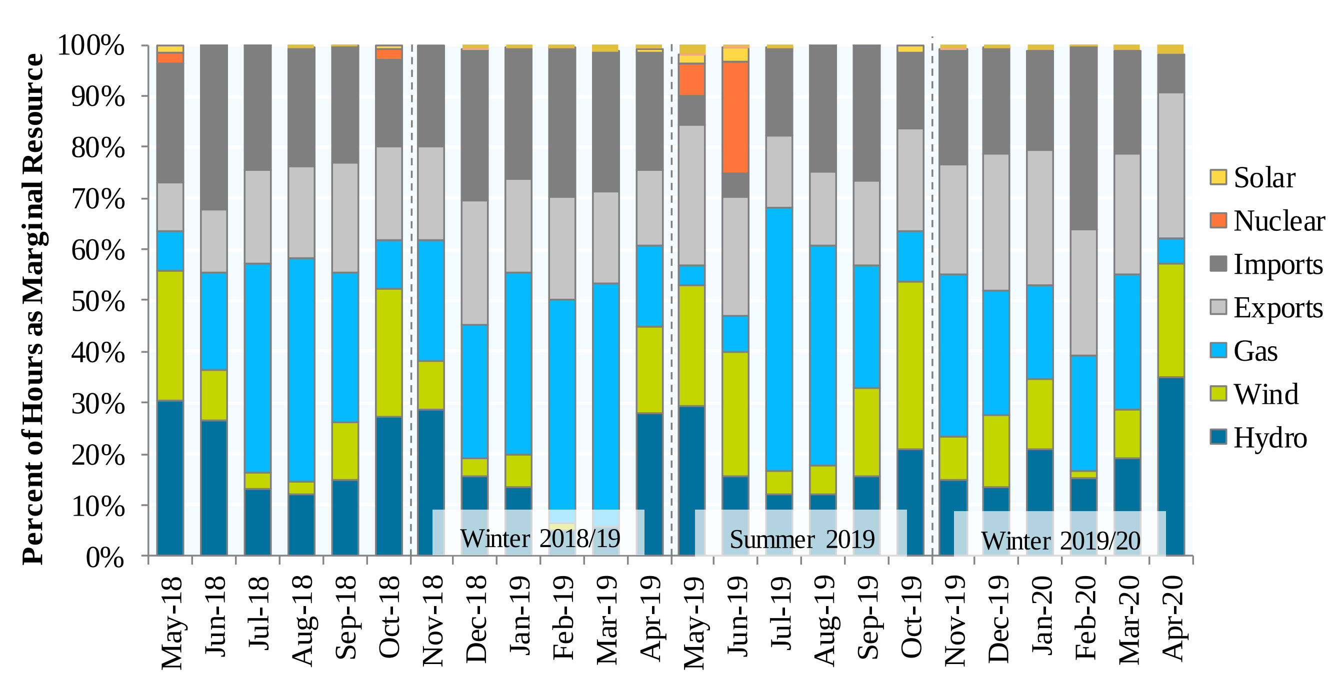


Figure C-8 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP in each month of the previous two years. When compared with Figure C-7, Figure C-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

Natural gas resources set the PD-1 MCP in 21% of hours in the Winter 2019/20 Period, compared to 32% in the Winter 2018/19 Period. The decrease in the frequency of natural gas resources setting the PD-1 MCP in the Winter 2019/20 Period compared to the Winter 2018/19 Period was likely driven by a lower output from gas resources as a result of the decline in Ontario demand. The drop in the frequency of gas resources setting the PD-1 MCP closely aligns with the decline in the frequency of natural gas resources setting the real-time MCP (see Figure C-7). Similar to the trends observed in real-time, the frequency with which wind resources set the PD-1 MCP doubled from 6% in the Winter 2018/19 Period to 12% in the Winter 2019/20 Period. Notably, nuclear resources did not set PD-1 prices at all during the Winter 2019/20 Period, a similar behavior from nuclear resources is apparent in real-time as well. The frequency with which hydro resources set the PD-1 MCP increased steadily from

16% of hours in the Winter 2018/19 Period to 20% of hours in the Winter 2019/20 Period, which follows the trends observed in real-time.

Imports set the PD-1 MCP in 21% of hours in the Winter 2019/20 Period, compared to 26% of hours in the Winter 2018/19 Period. Exports set the PD-1 MCP in 25% of hours in the Winter 2019/20 Period, compared to 19% of hours in the Winter 2018/19 Period. These trends are expected as there was a decrease in imports and increase in exports during the Winter 2019/20 Period in comparison to the Winter 2018/19 Period as a result of the decline in Ontario demand.

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, these transactions are settled based on the Intertie Zonal Price (IZP), which is the sum of the real-time MCP and the Intertie Congestion Price (ICP). 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 Winter 2019/20 Period, there was a variation of less than $10/MWh between PD-1 and real-time prices for 86% of hours, down notably from 71% in the Winter 2018/19 Period. The average absolute deviation between PD-1 and real-time prices in the Winter 2019/20 Period of $5.88/MWh was also significantly lower than the Winter 2018/19 Period average deviation of $9.87/MWh.

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time.[115] Identifying the factors that lead to deviations between the PD-1 MCP and the

[115] The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the 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 offers and bids are entered into the market.

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

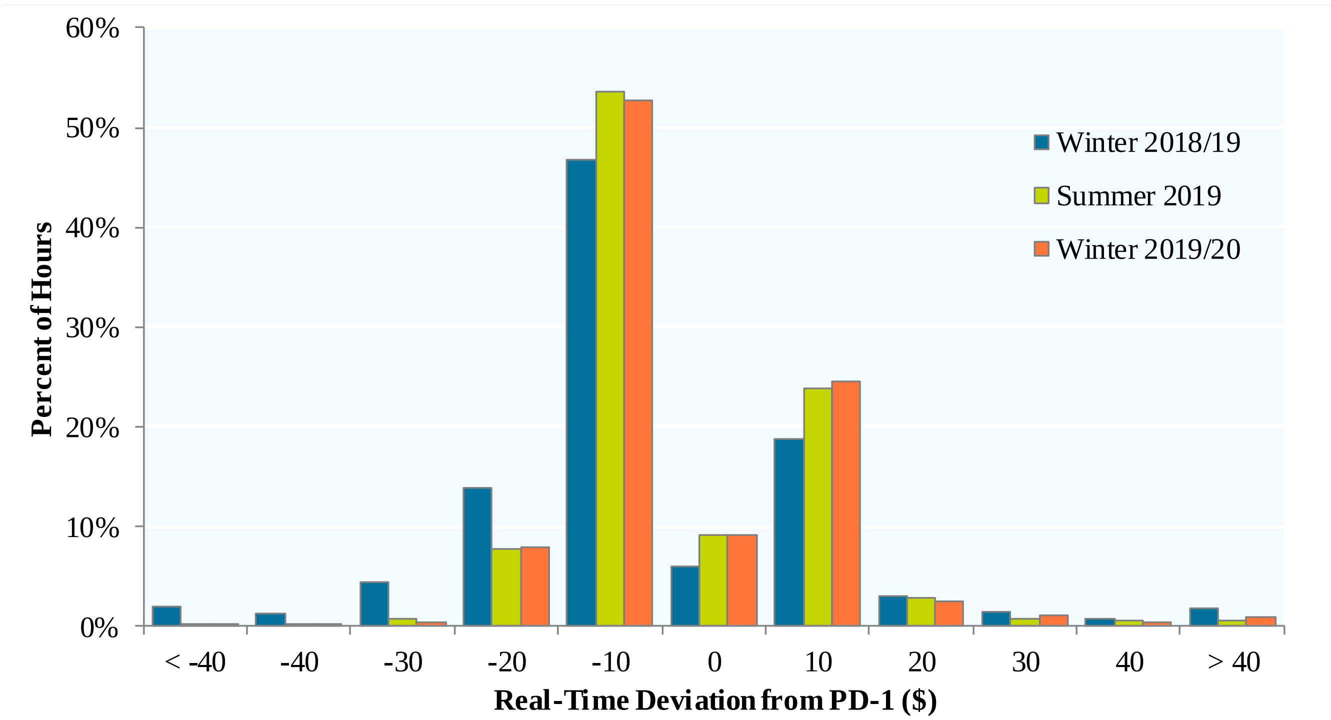


Figure C-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Winter 2019/20, Summer 2019 and Winter 2018/19 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the 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 demand forecast deviation, the most significant source of deviation between the PD-1 MCP and the HOEP, decreased in the Winter 2019/20 Period relative to the Winter 2018/19 Period. The next most significant source of deviation, wind forecasts, decreased as well during the Winter periods. Although the output from wind generators increased during the Winter 2019/20 Period, wind deviation decreased. However, the decrease in average energy demand between the Winter 2018/19 and Winter 2019/20 Periods resulted in the amount of wind forecast deviation relative to demand for energy to remain about the same between periods. Self-scheduling and intermittent forecast deviation, as well as net export curtailments, both worsened during the Winter 2019/20 Period relative to the Winter 2018/19 Period.

Table C-2: Factors Contributing to Differences between PD-1 MCP and HOEP, 3 Periods

Factor	Winter 2019/20: Average Absolute Difference		Summer 2019: Average Absolute Difference		Winter 2018/19: Average Absolute Difference	
	MW	% of Ontario Demand	MW	% of Ontario Demand	MW	% of Ontario Demand
Ontario Average Demand	15,386 MW		14,947 MW		15,979 MW	
Forecast Deviation	216 MW	1.40%	213 MW	1.43%	226 MW	1.41%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	29 MW	0.19%	27 MW	0.18%	20 MW	0.12%
Wind Forecast Deviation	166 MW	1.08%	148 MW	0.99%	175 MW	1.09%
Net Export Failures/Curtailments	78 MW	0.51%	79 MW	0.53%	74 MW	0.46%

Table C-2 displays the average absolute difference between PD-1 and real-time for all of the factors identified by the Panel as contributing to the difference between PD-1 and real-time, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

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 the PD-3 MCP 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.[116] Price changes are

[116] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that these facilities 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.

also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

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

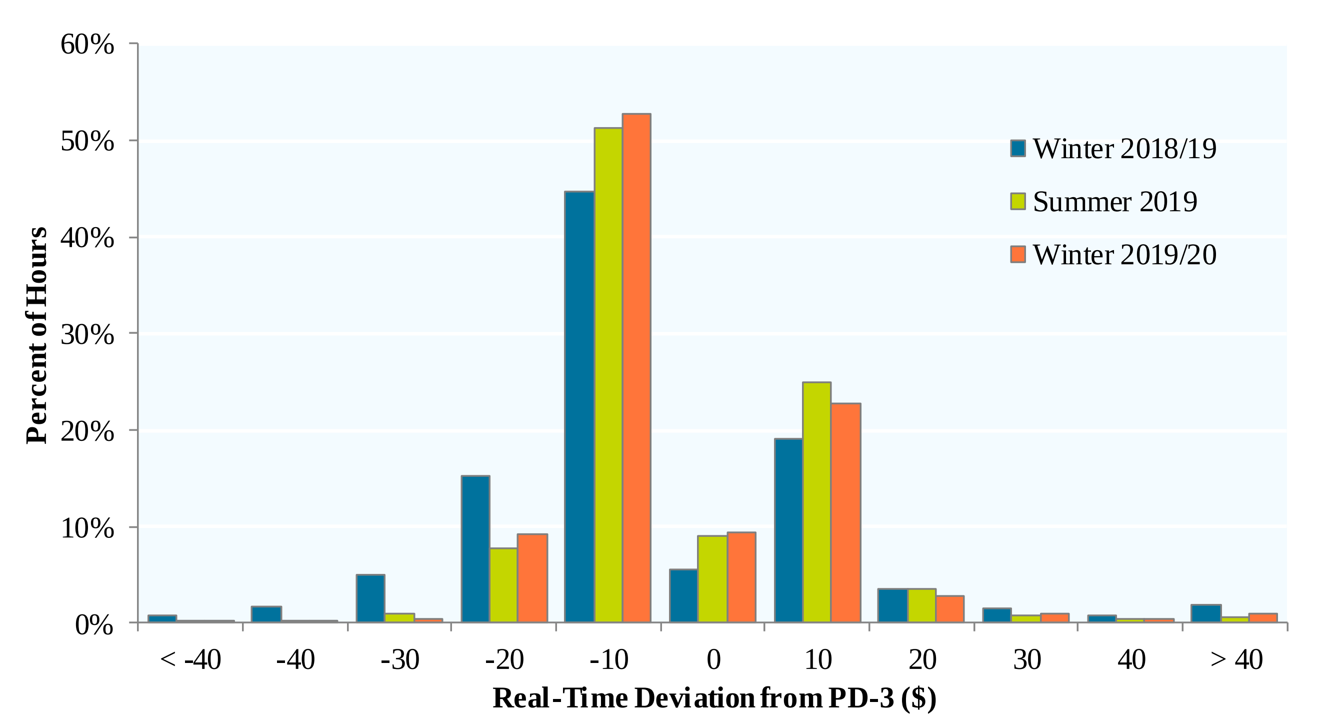


Figure C-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Winter 2019/20, Summer 2019 and Winter 2018/19 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and 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.

PD-3 prices were within $10/MWh of the real-time MCP in 85% of hours in the Winter 2019/20 Period, up from 70% of hours in the Winter 2018/19 Period. The average absolute deviation between PD-3 and real-time MCPs was also lower in the Winter 2019/20 Period ($6.22/MWh) compared to the Winter 2018/19 Period ($9.15/MWh). These trends are closely aligned with the deviations observed in relation to PD-1 prices.

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

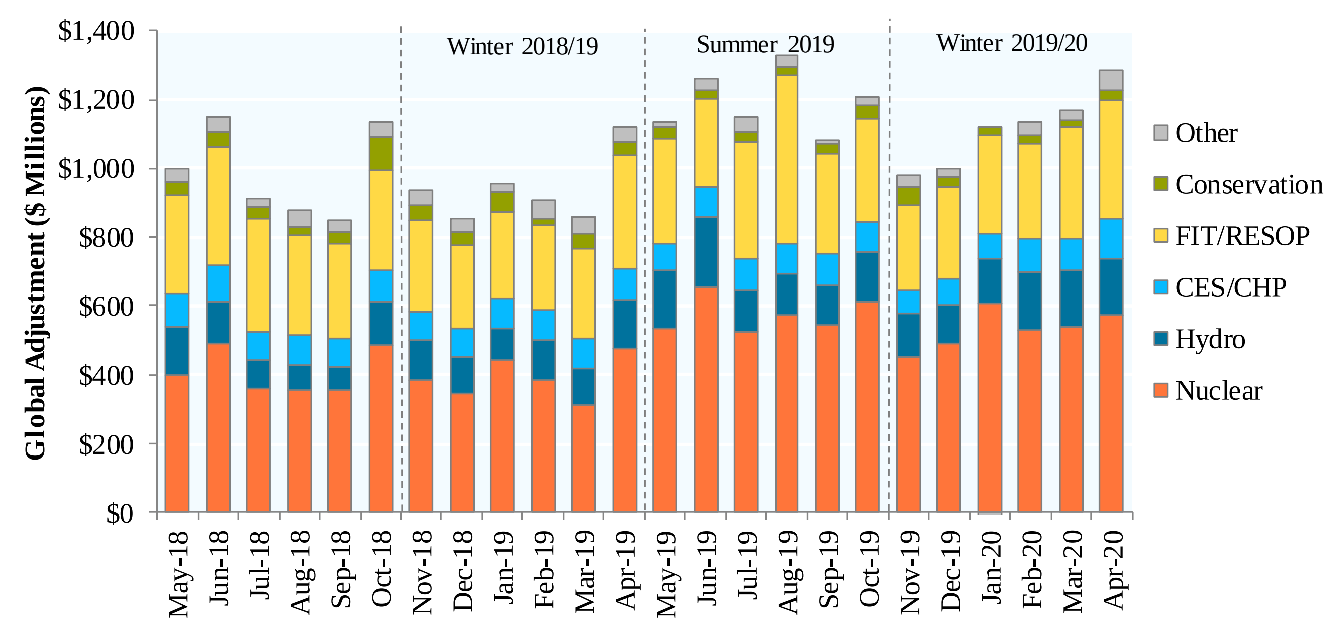


Figure C-11 plots the payments to various resources and recovered through the GA each month by component for the previous two years.

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 OPG's Lennox Generating Station).

The total GA throughout the Winter 2019/20 Period was about 19% more than the total GA during the Winter 2018/19 Period, rising from $5.6 billion to $6.7 billion. The overall increase in GA is mainly in the nuclear and hydroelectric components. From the Winter 2018/19 Period to the Winter 2019/20 Period, GA payments to regulated hydro and nuclear facilities increased notably by 29% and 36% respectively. This was due to the combined effects of higher nuclear production, substantially higher regulated nuclear rates for 2020, and a lower HOEP. Since GA and the HOEP are usually inversely related, the decrease in demand and the HOEP between the Winter Periods caused higher payments recovered through GA. Excluding payments to nuclear, which increased from 42% to 48% of total GA Payments between the Winter 2018/19 Period and the Winter 2019/20 Period, the relative contribution of each component of GA remained relatively constant.

Regulatory Charges

Regulatory charges include the cost of services provided by the Independent Electricity System Operator (IESO) to operate the wholesale electricity market and maintain the reliability of the high voltage power grid 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".[117] Regulatory charges include both amounts set or approved by the OEB (e.g. IESO Administration Charge and the Rural or Remote Electricity Rate Protection (RRRP) charge) and amounts that are not set or approved by the OEB such as charges associated with reliability or transmission losses.[118]

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

[118] 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.[119]

Table C-3 below summarizes a number of the amounts captured by regulatory charges, the majority of which are “uplift” costs for wholesale market participants.[120] 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 (PCG)[121] 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 C-12 shows the regulatory charges by month.[122]

Total regulatory charges in the Winter 2018/19 Period were $285 million, a 27% decrease from the Winter 2018/19 Period ($359 million). Notable decreases since the previous winter period include: CMSC (53% decrease or $35.9 million), Losses (42% decrease or $15.6 million), PCG (70% decrease or $13.7 million) and IOG (74% decrease or $12.8 million).

[119] This applies to all monthly and daily uplifts with the exception of costs associated with Demand Response (DR). The costs of DR 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.

[120] The Panel has not previously provided this information in tabular form. 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.

[121] 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.

[122] For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge have been omitted from Figure C-12.

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

Settlement Resolution	Regulatory Charges	Winter 2019/20 ($ million)	Summer 2019 ($ million)	Winter 2018/19 ($ million)
Hourly	Congestion Management Settlement Credits (CMSC)	31.4	49.1	67.3
	Transmission Losses	21.4	17.5	37.1
	Intertie Offer Guarantee (IOG)	4.5	5.9	17.3
	Operating Reserve: 10-minute spinning reserve	7.4	17.8	10.4
	Operating Reserve: 10-minute non-spinning reserve	8.7	14.2	9.0
	Operating Reserve: 30-minute reserve	5.6	11.3	8.0
	Hourly Reactive Support and Voltage Control	9.0	12.4	7.5
	Hourly Charges Subtotal	**88.1**	**128.1**	**156.5**
Monthly	Cost Guarantee: RT-GCG program	15.5	15.9	17.0
	Cost Guarantee: PCG program	5.8	9.1	19.5
	Ancillary Services: Black Start	0.9	0.9	0.9
	Ancillary Services: Regulation	30.8	31.2	29.6
	Ancillary Services: Monthly Reactive Support and Voltage Control	0.7	1.0	0.9
	Demand Response Capacity Payments	17.7	18.1	21.6
	IESO Administration Charge	92.0	90.7	91.2
	Rural or Remote Electricity Rate Protection	32.9	32.4	20.2
	Other: Additional Compensation for Admin Pricing	0.0	0.0	0.0
	Other: Station Service Reimbursement	1.1	1.5	1.7
	Other: Local Market Power	0.0	0.0	0.0
	Monthly Charges Subtotal	**197.4**	**200.8**	**214.5**
Total Regulatory Charges		**285.5**	**328.9**	**371.1**

Table C-3 compares the regulatory charges for the Winter 2019/20, Summer 2019 and Winter 2018/19 Periods, separated by hourly and monthly charges.

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

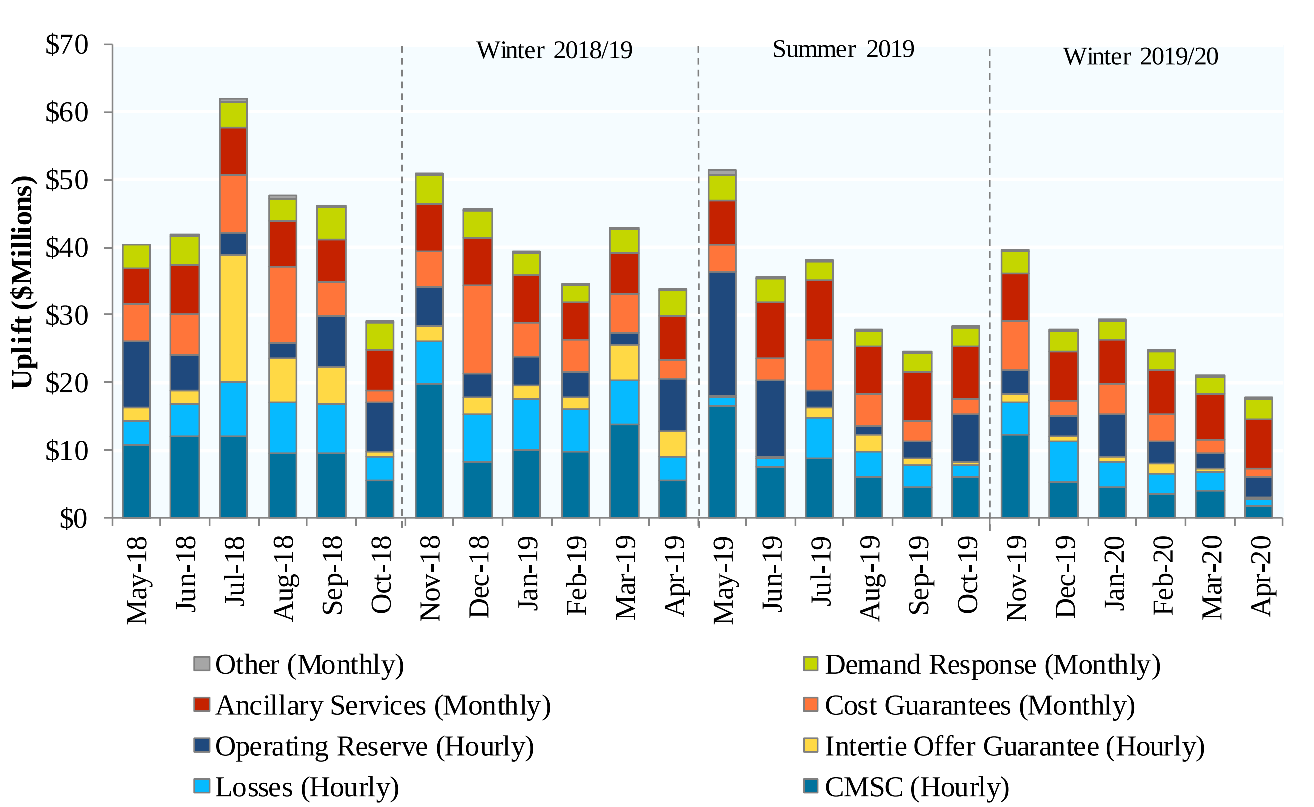


Figure C-12 presents the total uplift charges by component on a monthly basis for the previous two years. This includes both hourly and monthly uplift, which were displayed in separate figures in previous Panel reports. In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee Program (RT-GCG) payments are combined as Cost Guarantees. For consistency with previous reports, the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge have been omitted from Figure C-12.

Operating Reserve Prices

The three OR markets are co-optimized with the energy market, so prices in these markets tend to be subject to similar dynamics. 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 been used to increase the scheduled amount of 30-minute OR by 200 MW to enable system flexibility.[123,124]

The increased procurement of 30-minute OR may have increased the uplift and higher average 30-minute OR price for this period.

Uplift from OR was $22 million for Winter 2019/20 Period, down from $27 million in the Winter 2018/19 Period. Average OR prices for all class types were between $3-$5/MW, a decrease of 10-15% compared to the Winter 2018/19 Period as seen in Table C-3.

Table C-4: Average Operating Reserve Prices by Period, 2 Years

Operating Reserve Markets	Winter 2019/20 ($/MW)	Summer 2019 ($/MW)	Winter 2018/19 ($/MW)	Summer 2018 ($/MW)
10-minute spinning (10S)	4.67	8.02	5.30	8.10
10-minute non-spinning (10N)	3.79	7.32	4.44	5.65
30-minute reserve (30R)	3.04	5.01	3.55	3.68

Table C-4 presents the average OR prices by period for the past 2 years for the three OR markets.

Figure C-13 illustrates the monthly fluctuations of OR prices. Because OR prices are usually low, a single high-priced hour can lead to an increased monthly average price. During the Winter 2019/20 Period, prices remained both low and steady.

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

[124] This Market Rule Amendment and its justification was discussed in the Panel’s Monitoring Report 32 published July 2020, pages 76-88: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

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

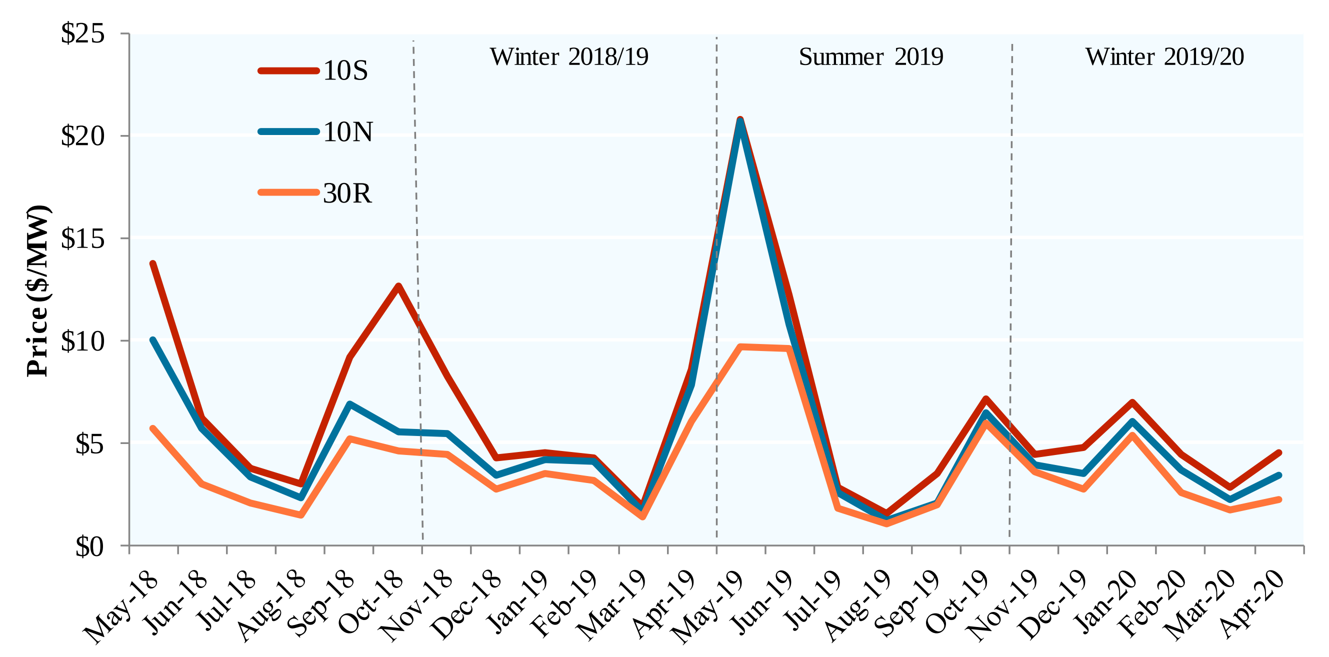


Figure C-13 plots the monthly average OR price for the previous two years for the three OR markets: 10--minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).

Nodal Prices

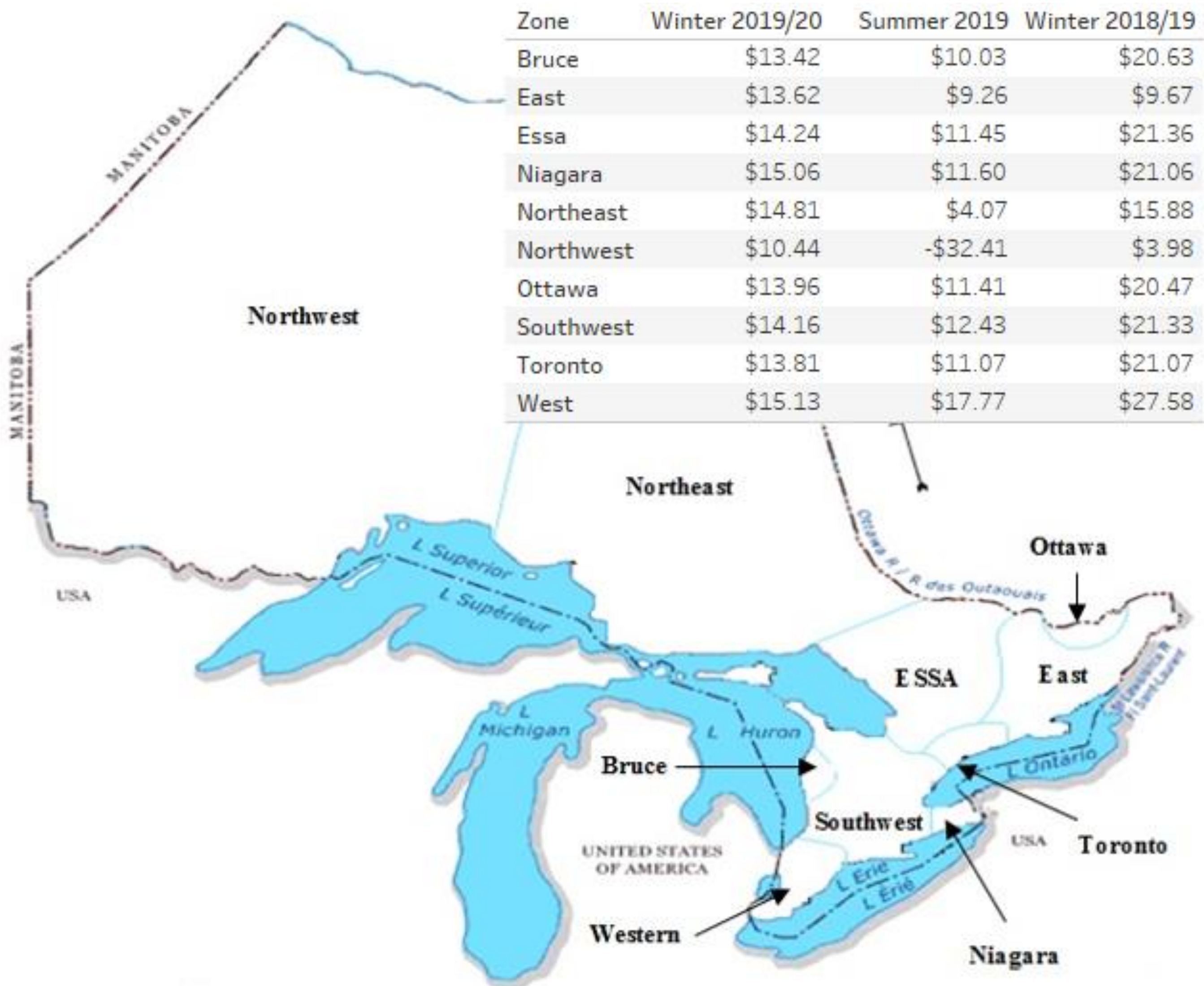
Nodal prices approximate the marginal cost of electricity in each region and reflect Ontario's internal transmission constraints. High average nodal prices are generally caused by expensive or limited supply while low average nodal prices are generally caused by cheaper or abundant supply.

As shown in Figure C-14, most zones had similar and stable average prices across Ontario in the Winter 2019/20 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 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.

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.

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



Zone	Winter 2019/20	Summer 2019	Winter 2018/19
Bruce	$13.42	$10.03	$20.63
East	$13.62	$9.26	$9.67
Essa	$14.24	$11.45	$21.36
Niagara	$15.06	$11.60	$21.06
Northeast	$14.81	$4.07	$15.88
Northwest	$10.44	-$32.41	$3.98
Ottawa	$13.96	$11.41	$20.47
Southwest	$14.16	$12.43	$21.33
Toronto	$13.81	$11.07	$21.07
West	$15.13	$17.77	$27.58

Figure C-14 illustrates the average nodal prices of Ontario's ten internal zones for the Winter 2019/20, Summer 2019 and Winter 2018/19 Periods.[125]

[125] 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 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.

Figure C-15: Hours per Month of Import Congestion by Intertie, 2 Years

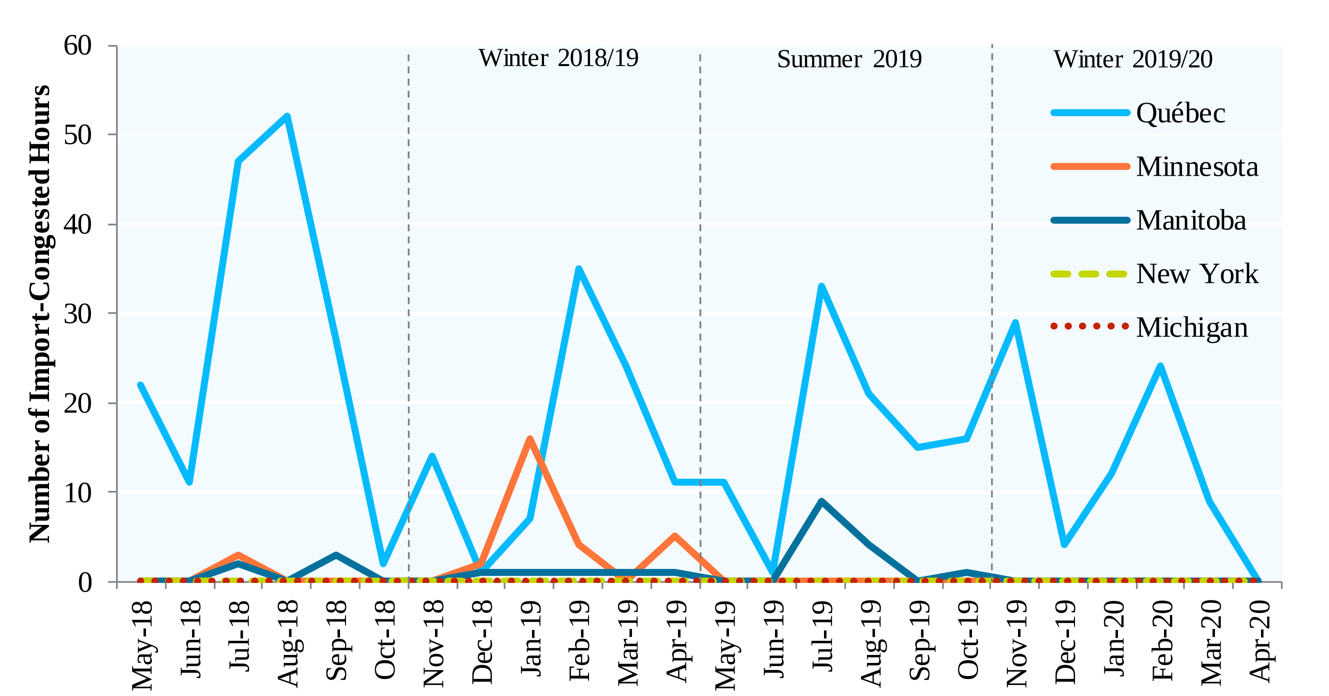


Figure C-15 reports the number of hours per month of import congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

Québec continued to experience the highest number of import congestion hours compared to other jurisdictions in the Winter 2019/20 Period. The Québec intertie did experience a decrease in the number of import-congested hours from 92 hours in the Winter 2018/19 Period to 78 hours in the Winter 2019/20 Period. Congestion on the Québec intertie was highest in November with 29 hours.

Figure C-16: Hours per Month of Export Congestion by Intertie, 2 Years

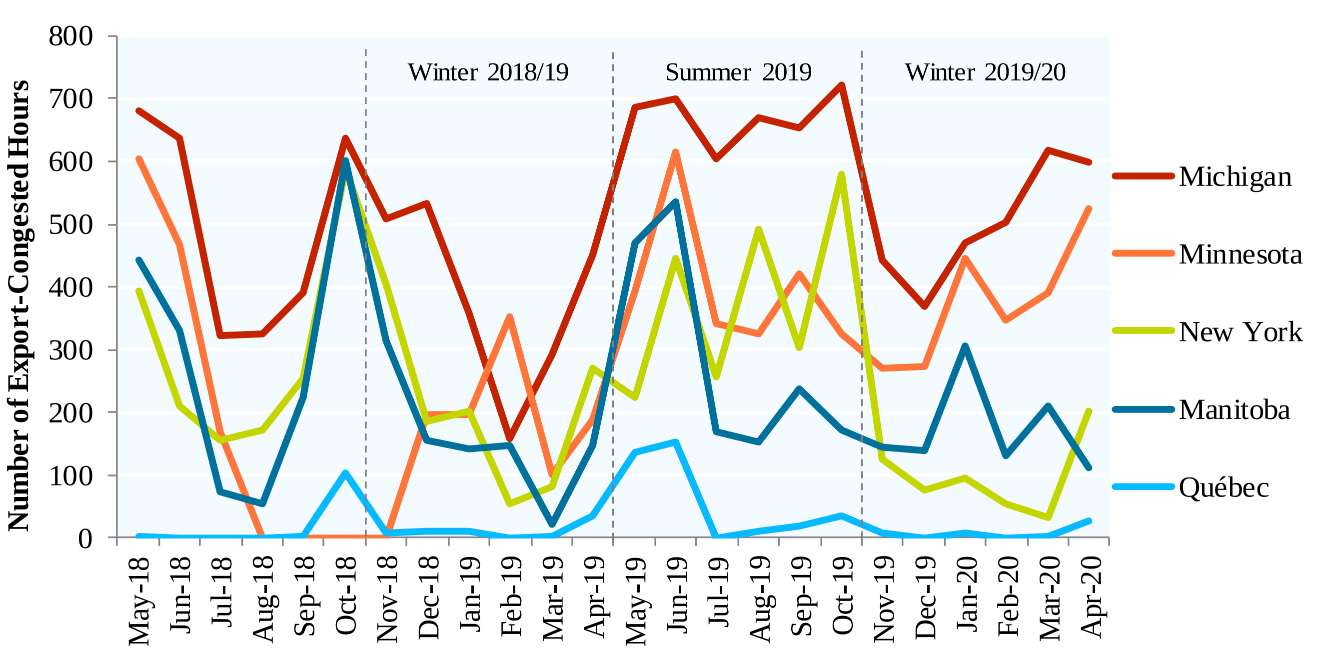


Figure C-16 reports the number of hours per month of export congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

There were 6,919 hours of export congestion in the Winter 2019/20 Period, a 25% increase compared to the previous winter period. Minnesota had the greatest increase in export-congested hours, more than doubling from 1,032 hours in the Winter 2018/19 Period to 2,248 hours in the Winter 2019/20 Period.

Table C-5: Monthly Electricity Spot Prices – Ontario & Surrounding Jurisdictions, 1 Period

Date	Ontario (HOEP) ($/MWh)	Manitoba ($/MWh)	Michigan (MISO[126]) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO[127]) ($/MWh)	PJM[128] ($/MWh)
Nov 2019	19.62	28.22	35.96	29.38	25.28	32.99
Dec 2019	20.59	25.08	29.72	26.28	25.59	29.57
Jan 2020	13.92	26.89	25.90	27.10	16.83	27.39
Feb 2020	14.00	18.47	26.70	22.25	19.39	24.84
Mar 2020	13.44	19.61	24.02	21.92	18.03	23.34
Apr 2020	5.78	17.28	18.28	21.92	13.09	22.75

Table C-5 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA or uplift. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table C-5. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs.

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.

The average HOEP continued to be the lowest market price as compared to Manitoba, Michigan, Minnesota, New York and Pennsylvania New Jersey Maryland (PJM). The price difference is mainly due to export congestion. In other words, there is not enough transmission available to move low cost energy from Ontario to other markets.

[126] Midcontinent Independent System Operator

[127] New York Independent System Operator

[128] Pennsylvania New Jersey Maryland

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

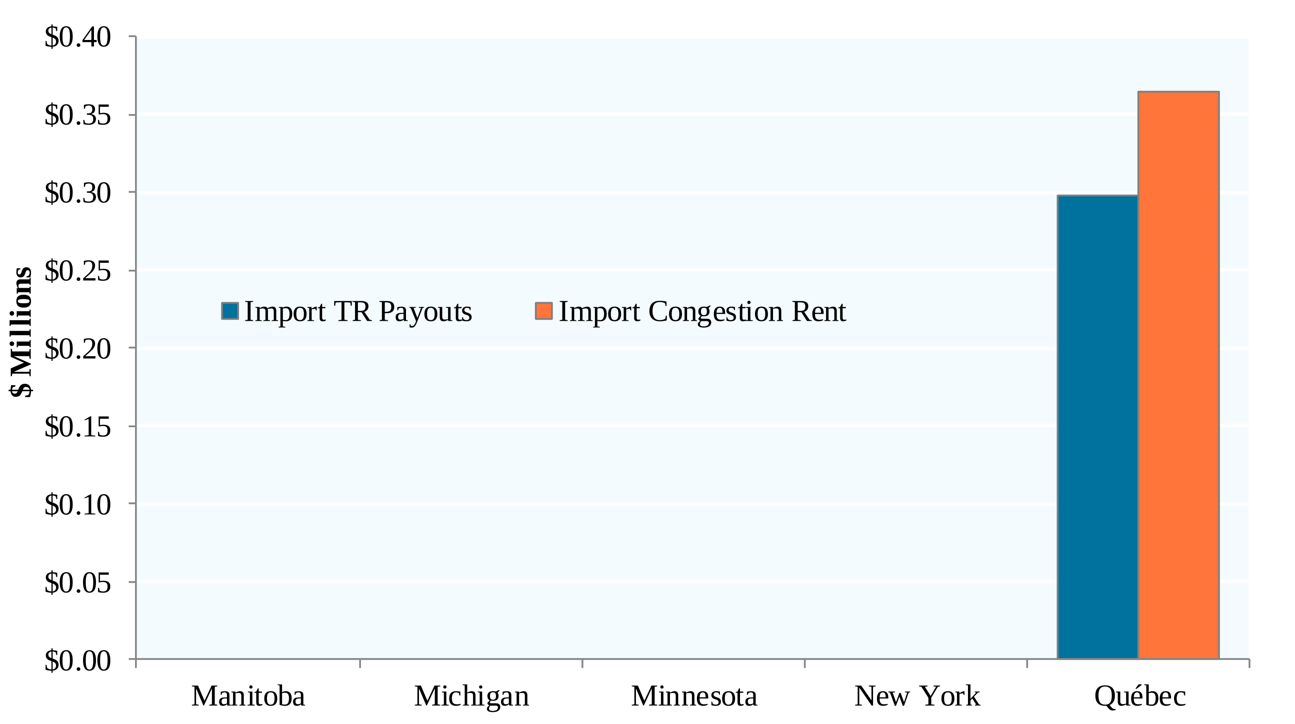


Figure C-17 compares the total import congestion rent collected to total TR payouts by intertie for the Winter 2019/20 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

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

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. 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 shortfalls are covered primarily by TR auction revenues, which are the proceeds from selling TRs (a payment into the TRCA).

Total import TR payouts in the Winter 2019/20 Period were $0.3 million, while total import congestion rent was $0.4 million, creating a congestion rent surplus of less than $0.1 million. This surplus was 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 Winter 2019/20 Period, causing congestion rent to outweigh TR payments collected during these hours.

Export TR payouts in the Winter 2018/19 Period totalled $30.9 million, while export congestion rent totalled $43.4 million. This $12.5 million surplus of congestion rent is primarily due to the $11.3 million imbalance between congestion rent and TR Payouts on the Michigan intertie.

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

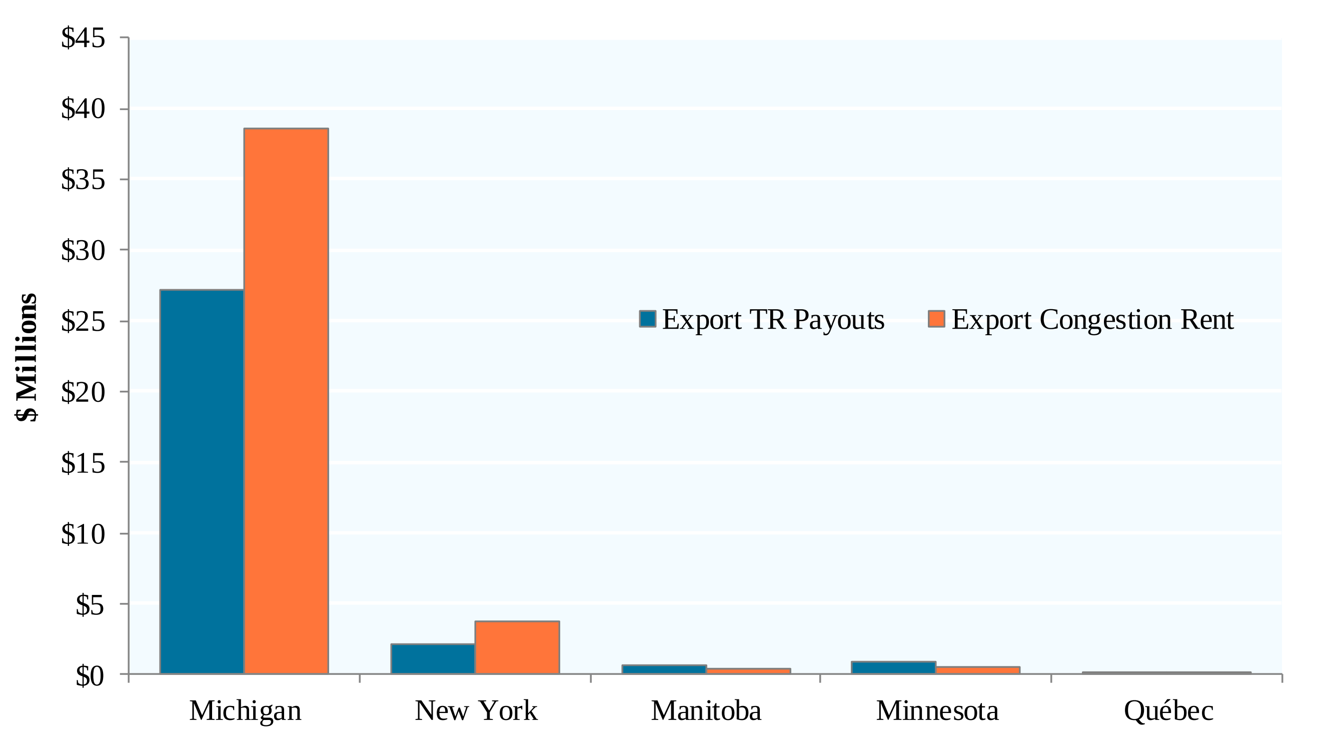


Figure C-18 compares the total export congestion rent collected to total TR payouts by intertie for the Winter 2019/20 Period. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

Long-term (12-month) import and export TR prices for the past four auction dates are shown in Table C-6. Generally, when long-term import and export TR prices increase from auction to auction – as an additional 3-month period is added to the 12-month term – it indicates that traders expect import congestion to increase, and vice versa.

Table C-6: Average 12-Month TR Auction Prices by Intertie & Direction

Direction	Auction Date	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-19	Jul-19 to Jun-20	656	65	2,460	146	11,423
	Aug-19	Oct-19 to Sep-20	1,104	261	2,579	220	8,243
	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
Export	May-19	Jul-19 to Jun-20	40,089	84,032	39,792	54,878	2,966
	Aug-19	Oct-19 to Sep-20	40,779	80,146	47,656	36,933	3,493
	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

Table C-6 lists the average auction prices for 1 MW of long-term (12-month) TRs for each intertie in either direction for each auction since May 2019. 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 Winter 2019/20 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 C-7: Average One-Month TR Auction Prices by Intertie & Direction, 1 Year

Direction	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-19	13	2	-	7	558
	Jun-19	22	2	87	8	720
	Jul-19	26	4	100	4	558
	Aug-19	61	1	130	5	767
	Sep-19	26	6	223	2	612
	Oct-19	30	1	75	5	298
	Nov-19	35	2	97	-	185
	Dec-19	1,015	131	966	210	8,784
	Jan-20	31	0	375	19	543
	Feb-20	27	0	271	10	565
	Mar-20	28	0	-	12	655
	Apr-20	22	0	-	12	670
Export	May-19	3,841	10,788	-	3,906	186
	Jun-19	4,250	2,794	-	4,363	72
	Jul-19	4,873	7,901	4,873	4,070	103
	Aug-19	4,427	4,956	-	2,284	119
	Sep-19	3,082	7,063	3,679	2,735	70
	Oct-19	3,800	11,450	-	3,746	25
	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

Table C-7 lists the auction prices for 1 MW of short-term (one-month) TRs for each intertie in either direction for each auction during the Winter 2019/20 and Summer 2019 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 continue to be volatile from month-to-month. Minnesota continues to sell short-term TRs sporadically, while Manitoba has not sold short-term export TRs from January to April 2020.

The balance of the Transmission Rights Clearing Account (TRCA) decreased to $85.1 million at the end of the Winter 2019/20 Period (April 2020), a decrease from $94.4 million at the end of the Summer 2019 Period (October 2019).[129,130] The April 2020 balance was $65.1 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance for the 6-month monitoring period was composed of:[131]

1. $94.4 million in revenue, specifically:
    - $43.8 million in congestion rent
    - $49.5 million in total auction revenues
    - $1.0 million in interest
2. $103.7 million in debits, specifically:
    - $31.2 million in TR payouts
    - $72.5 million in disbursements to Ontario consumers and exporters.

[129] 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.

[130] For reference, the balance at the end of the previous Winter 2018/19 Period (April 2019) was $111.2 million.

[131] 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 Report because the settlement database records revenue on a cash flow basis and not an accrual basis.

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

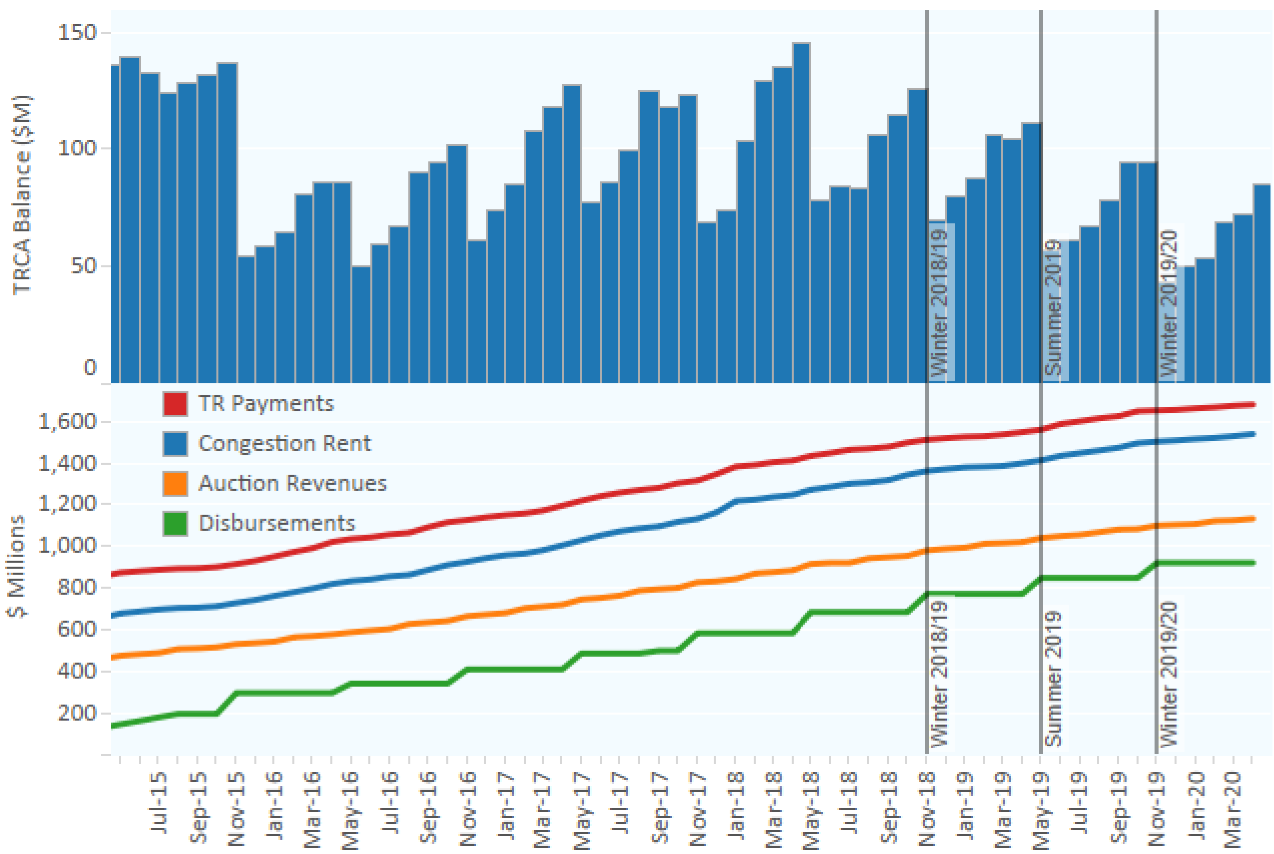


Figure C-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account.

C.2 Demand

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

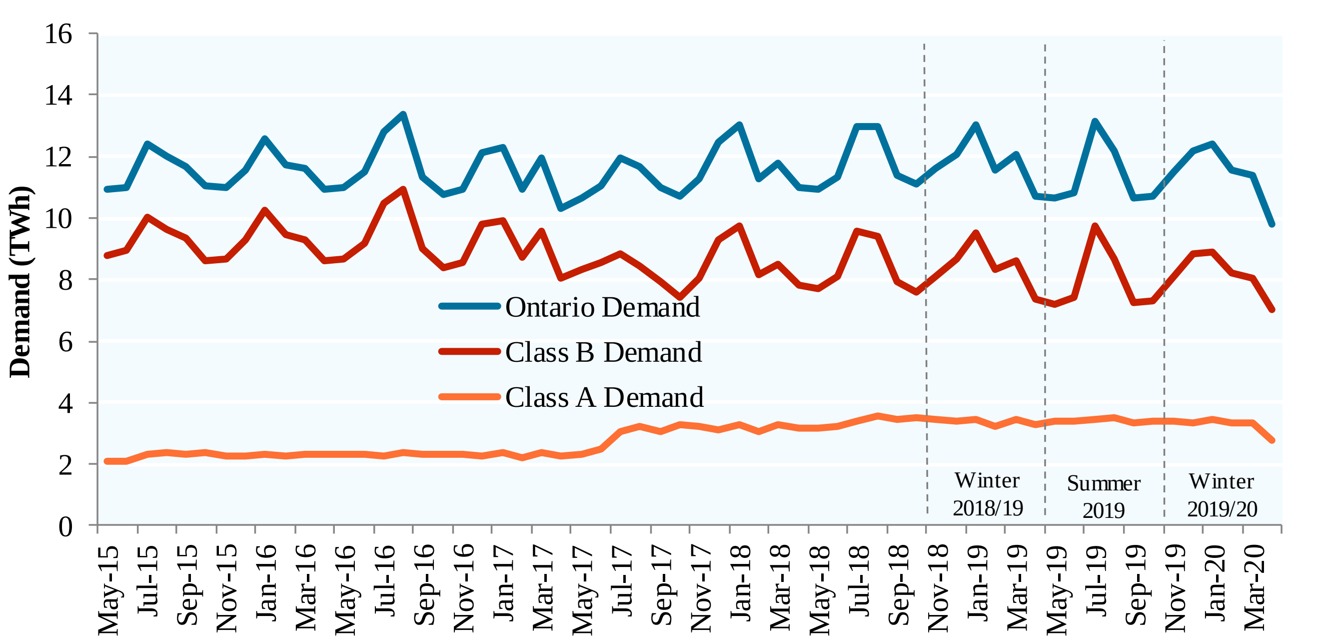


Figure C-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand–not grid-connected demand–in that it includes demand satisfied by embedded generators.[132]

Total demand in the Winter 2019/20 Period was 68.9 TWh – 3.0% lower than the total demand of 71.0 TWh in the Winter 2018/19 Period. This decrease in demand in the Winter 2019/20 Period was caused partly by the weather, which was milder than average in January and March 2020, and partly by the public health response to outbreaks of COVID-19 in Ontario. Measures such as the government-mandated closure of nonessential businesses on

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

March 23, 2020 quickly led to a substantial and ongoing reduction in demand. Total consumption for April 2020 was more than 8% lower than April 2019.

The percentage decline in Class A and Class B consumption for the Period was similar to the decline in overall demand. However, the impact of COVID-19 measures in April was greater on Class A consumers compared to Class B consumers. The year-over-year reduction in April demand was 16% for Class A consumers and only 5% for Class B customers. The decline in total Class B demand for the Winter 2019/20 Period was mostly due to milder weather.

C.3 Supply

This section presents data on generating capacity, actual generation, and Operating Reserve (OR) supply for the Winter 2019/20 Period relative to previous years.

Table C-8: Changes in Generating Capacity, Q4 2019 to Q1 2020

Generation Type	Grid-connected		Distribution-level (“Embedded”)	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	-	13,009	-	-
Natural Gas	993	11,270	-	-
Hydro	-	9,065	6	286
Wind	-	4,486	-1	590
Solar	54	478	1	2,166
Biofuel	-	295	-	110
Gas-Fired and Combined Heat and Power	-	-	25	299
Energy from Waste	-	-	-	24
Total	1,047	38,603	31	3,475

Table C-8 lists the quantity of nameplate generating capacity that completed commissioning and was added to the IESO-controlled grid's total capacity during the fourth quarter of 2019 and first quarter of 2020, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[133] Total capacity of each type at the end of the first quarter of 2020 is also shown.

The 993 MW increase in natural gas capacity is from Napanee Generating Station, a new combined-cycle gas plant in Eastern Ontario. Small amounts of embedded generation and

[133] 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 http://www.ieso.ca/power-data/supply-overview/transmission-connected-generation#Historical%20Quarterly%20Progress%20Reports%20on%20Contracted%20Electricity%20Supply

grid-connected solar were also added to the system in the fourth quarter of 2019 and first quarter of 2020.

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

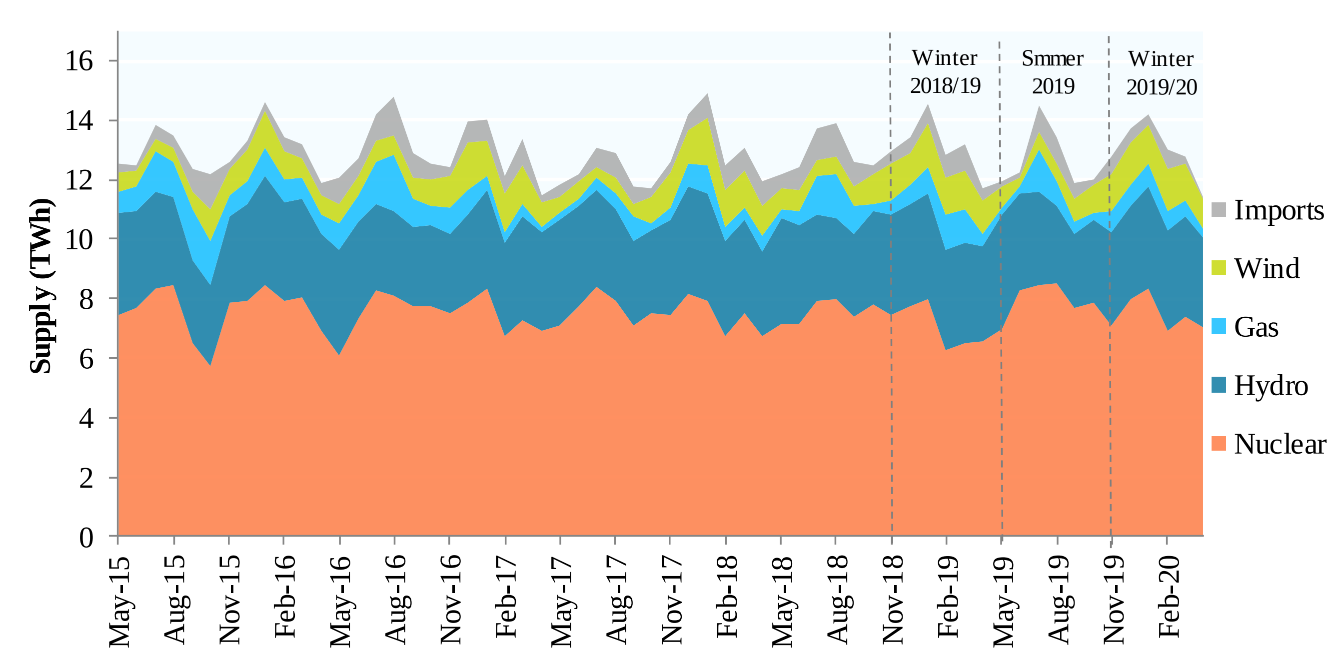


Figure C-21 displays the real-time unconstrained production schedules from May 2015 to April 2020 by resource or transaction type: imports, wind, gas-fired, hydroelectric and nuclear.[134] Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand or seasonal fuel variations (for example, during the spring snowmelt or freshet when hydroelectric plants have an abundant supply of water).

Compared to the Winter 2018/19 Period, the Winter 2019/20 Period showed an increase in nuclear generation from 42.5 to 44.7 TWh. With more baseload nuclear generation and lower demand compared to the previous winter, higher marginal cost resources were scheduled less,

[134] Solar and biofuel are excluded from the figure as these fuel types 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 Ontario 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.

Hydroelectric generation was down 1.0 TWh to 19.5 TWh, and gas-fired generation was down 0.9 TWh to 3.7 TWh. Imports also fell 1.3 TWh from 3.6 to 2.4 TWh.

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

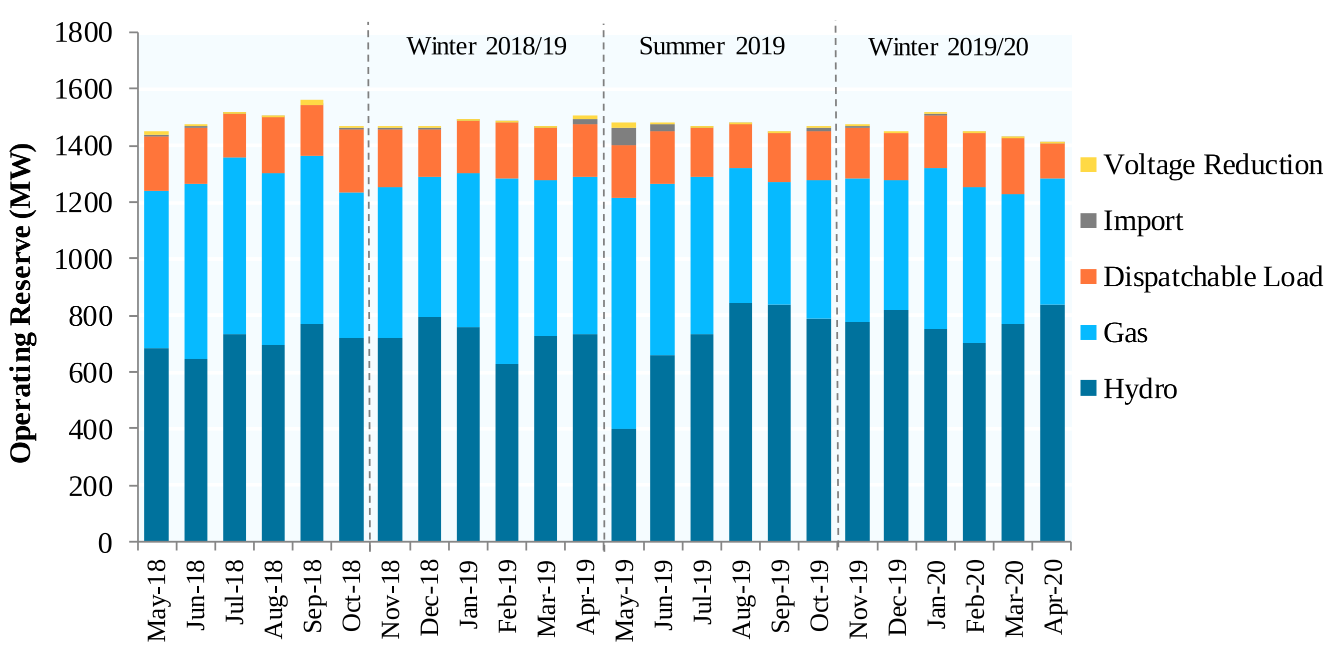


Figure C-22 displays the real-time unconstrained OR schedules from May 2018 to April 2020 by resource or transaction type: hydroelectric, gas-fired, dispatchable loads, imports and voltage reduction (taken as a control action by the IESO).[135] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

[135] 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 C-9: Average Hourly OR Scheduled by Resource Type and Season, 3 Periods

Quantity	Winter 2018/19	Summer 2019	Winter 2019/20
Average OR Scheduled (MW)	1,484 MW	1,472 MW	1,460 MW
Dispatchable Load Share	13%	12%	12%
Natural Gas Share	38%	38%	34%
Hydro Share	49%	48%	53%
Other Share	1%	2%	1%

Table C-9 reports the seasonal average quantity of hourly OR scheduled and the fraction of total OR that is provided by resource or transaction type. It is based on the same data as Figure C-22. "Other" is the sum of OR from imports and voltage reduction.

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

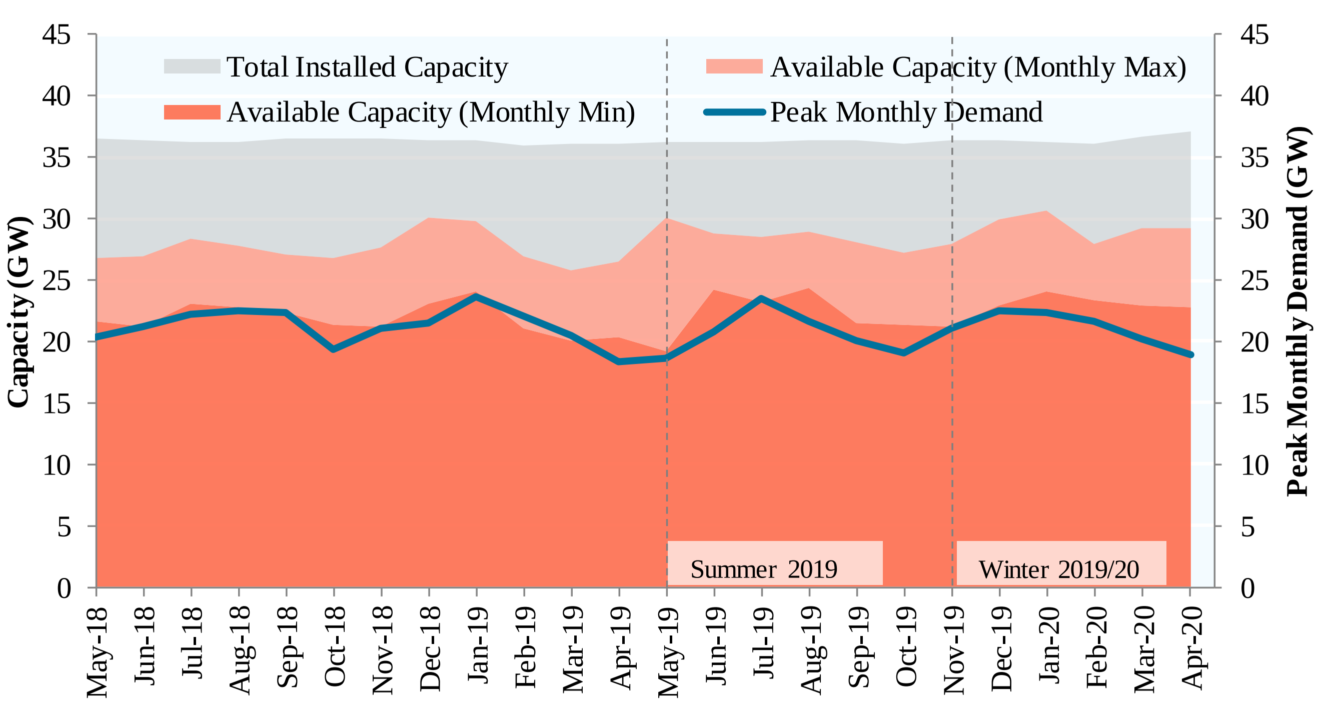


Figure C-23 plots the monthly minimum and maximum available generation capacity, accounting for unavailable capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from May 2018 to April 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.[136]

The Winter 2019/20 Period had, on average, 10.6 GW of unavailable capacity, which is 9% less than the average of 11.6 GW of capacity that was unavailable in the Winter 2018/19 Period. This difference was primarily driven by less outages of gas and nuclear capacity in the Winter 2019/20 Period. Minimum and maximum available capacity were lower in the Winter 2019/20 Period by 1.2 GW and 1.3 GW on average compared the Winter 2018/19 Period, respectively.

[136] 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

C.4 Imports, Exports and Net Exports

This section examines import and exports transactions in the unconstrained sequence, as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[137]

Figure C-24: Monthly Imports and Exports, and Average Net Exports (Unconstrained), 2 Years

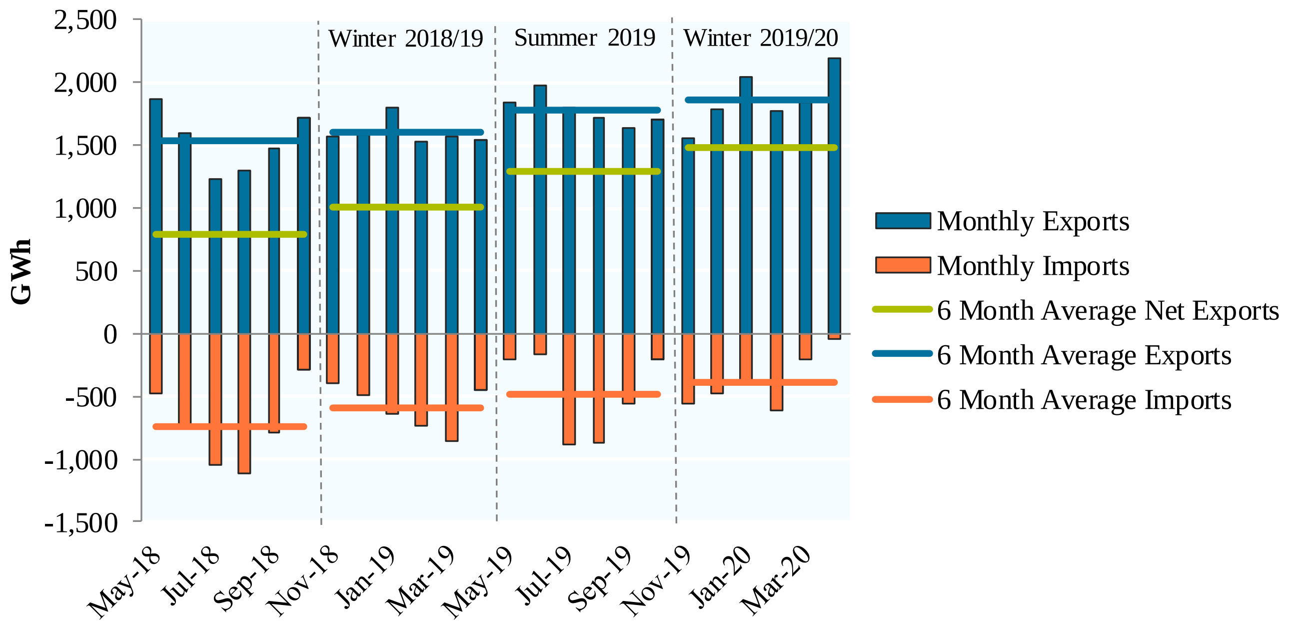


Figure C-24 plots total monthly imports and exports from May 2018 to April 2020, as well as the average monthly imports, exports and net exports calculated over each 6-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Ontario remained a net exporter in the Winter 2019/20 Period, with net exports of 8.88 TWh, up from 6.02 TWh in the Winter 2018/19 Period. Compared to the Winter 2018/19 Period, exports rose by 1.60 TWh, and imports fell by 1.26 TWh. The increase in net exports over the Winter 2019/20 Period was primarily driven by a large increase in exports to Michigan and the large decrease in imports from Québec, compared to the Winter 2018/19 Period. The reduction

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

in imports from Québec, along with perennially low imports from other jurisdictions, caused total imports to reach a low of 43 GWh in April 2020.

Figure C-25: Exports by Intertie, 2 Years

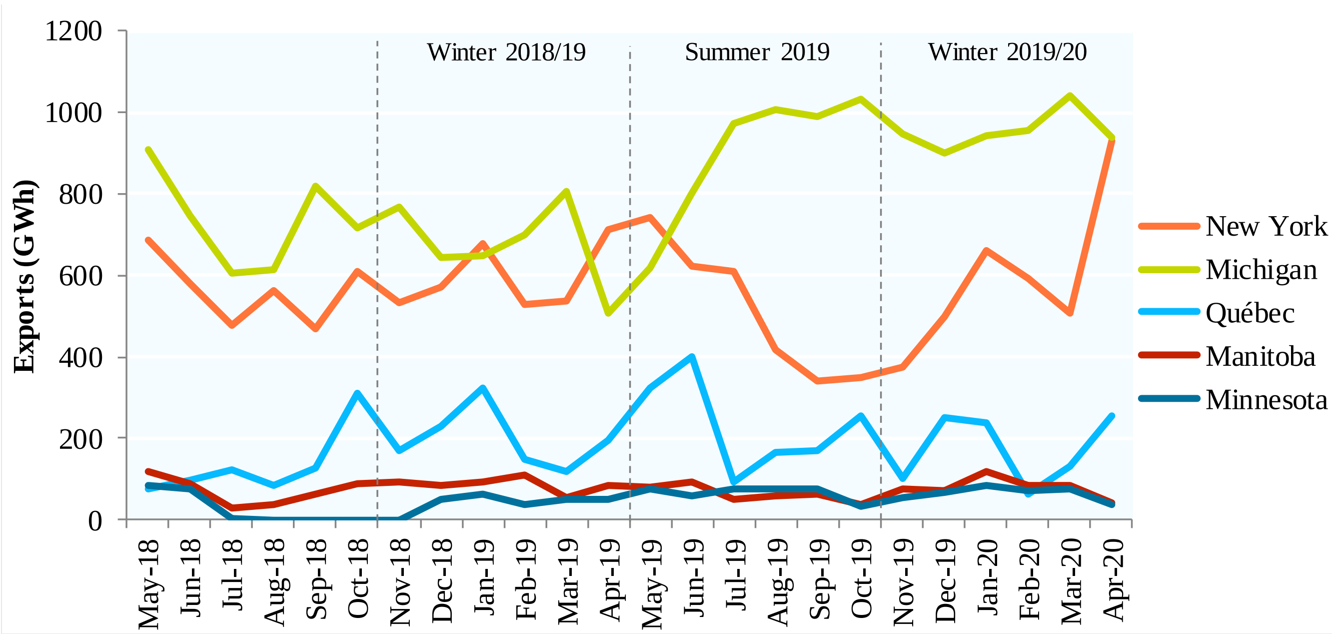


Figure C-25 presents a breakdown of exports from May 2018 to April 2020 to each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly export quantities over the Winter 2019/20 and Summer 2019 Periods are given for each intertie in Table C-7.

Figure C-26: Imports by Intertie, 2 Years

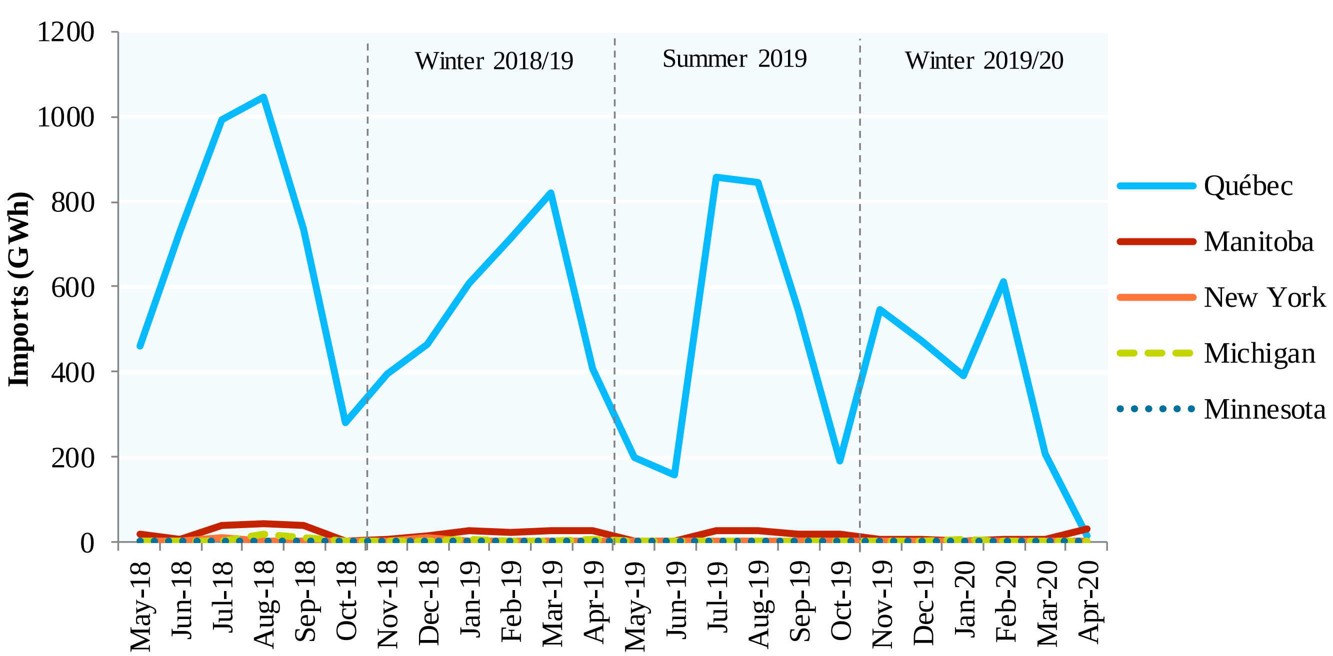


Figure C-26 presents a breakdown of imports from May 2018 to April 2020 from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly import quantities over the Winter 2019/20 and Summer 2019 Periods are given for each intertie in Table C-8.

Exports to Michigan increased considerably in the Winter 2019/20 Period compared to the Winter 2018/19 Period, increasing by 275 GWh per month on average. The high-level of exports was driven by sustained energy price differences between the Michigan and Ontario markets. Congestion on the Michigan intertie remained high, though not as frequent as in the Summer 2019 Period (see Figure C-16).

Exports to New York in the Winter 2019/20 period were similar to the Winter 2018/19 Period on average. For most of the Winter 2019/20 Period, the level of exports was lower than the same month in the previous Period. The trend was reversed in April 2020 as business shutdowns and other public health measures led to demand reductions, lower Hourly Ontario Energy Price (HOEP), and higher exports to New York.

Imports from Québec decreased in the Winter 2019/20 Period compared to the Winter 2018/19 Period, falling from an average of 568 GWh per month to an average of 374 GWh per month.

Imports were unremarkable for the first four months of the Winter 2019/20 Period. Most of this decrease for this Period is from exceptionally low imports in March and April 2020. With very a low demand and HOEP in Ontario due to the COVID-19 response, there were few opportunities for energy from Québec to be economically scheduled.

Failed or curtailed exports reduce demand between pre-dispatch (PD-1) and real-time. The Market Participant (MP) percentage failure rate of exports on the Manitoba intertie remained much higher than on the other interties in the Winter 2019/20 Period.

The rate of Independent System Operator (ISO)-curtailed exports in the Winter 2019/20 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 C-10: Average Monthly Exports and Export Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		Market Participant (MP) Failure		ISO Curtailment		Market Participant (MP) Failure	
	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019
New York	597	523	1.7	2.2	9.1	9.8	0.3%	0.4%	1.5%	1.9%
Michigan	942	835	3.1	3.5	10.9	4.9	0.3%	0.4%	1.2%	0.6%
Manitoba	93	81	1.2	2.4	24.0	29.9	1.2%	3.0%	25.9%	37.0%
Minnesota	39	53	0.5	1.4	1.0	1.3	1.2%	2.7%	2.5%	2.5%
Québec	172	248	2.6	3.8	2.0	2.8	1.5%	1.5%	1.2%	1.1%

Table C-10 reports average monthly export curtailments and failures over the Winter 2019/20 and Summer 2019 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.[138] 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 decrease in the Winter 2019/20 Period compared to the Winter 2018/19 Period for all intertie except Michigan. The rate of MP Failures for the New York, Michigan and Minnesota interties remained above 5%, although total import

[138] 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.

volume from these three areas is very low. Almost all imports were from Québec, which had fairly low ISO Curtailment and MP Failure rates.

Table C-11: Average Monthly Imports and Import Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate			
			ISO Curtailment		Market Participant (MP) Failure		ISO Curtailment		Market Participant (MP) Failure	
	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019	Winter 2019/20	Summer 2019
New York	1	2	0.0	0.1	0.2	0.1	0.0%	2.9%	29.8%	7.0%
Michigan	1	12	0.1	0.5	0.0	0.9	6.7%	4.0%	5.2%	7.5%
Manitoba	34	52	0.9	9.6	0.5	0.3	2.6%	18.5%	1.3%	0.5%
Minnesota	7	4	0.2	0.6	0.6	0.4	2.1%	13.9%	8.2%	10.1%
Québec	316	402	4.7	10.3	0.7	0.3	1.5%	2.6%	0.2%	0.1%

Table C-11 reports average monthly import failures and curtailments the Winter 2019/20 and Summer 2019 Periods by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.