ONTARIO ENERGY BOARD

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

For the period from
May 2017 – October 2017

December 2019

Ontario

Table of Contents

List of Tables

List of Figures

Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board. 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:

- inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
- activities of the IESO that may have an impact on market efficiencies or effective competition;
- actual or potential design or other flaws and inefficiencies in the Market Rules and procedures; and
- 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 report of the Market Surveillance Panel (Panel) covers the six-month period from May 1, 2017 to October 31, 2017 (Summer 2017 Period). Certain portions of this report discuss noteworthy issues that are not necessarily linked to events in the Summer 2017 Period. Except where otherwise noted, market events occurring after October 31, 2017 are not reflected in this report.

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

- Chapter 1: Market Developments and the Status of Recent Recommendations
- Chapter 2: Analysis of Anomalous Market Outcomes
- Chapter 3: Matters to Report in the Ontario Electricity Marketplace
- Appendix: Market Outcomes

Chapter 1: Market Developments and Status of Recent Panel Recommendations

Through the Market Renewal Program (MRP), the Independent Electricity System Operator (IESO) may address many of the Panel's longstanding concerns regarding systemic issues and deficiencies of the Ontario wholesale electricity market, many of which have been in place since the market first opened. The Panel has previously expressed its support for the MRP and its goal of limiting known deficiencies that hinder the economic efficiency of the wholesale market or eliminating them altogether, and reiterates that support.

The IESO has now released high-level design (HLD) documents for each of the four main initiatives for the MRP: the Single Schedule Market (SSM), the Day-Ahead Market (DAM), Enhanced Real-Time Unit Commitment (ERUC) and the Incremental Capacity Auction (ICA). The Panel has submitted comments on two of these initiatives, the SSM and the ICA.

For SSM, the Panel highlighted that zonal pricing – where prices paid by customers vary across different zones in Ontario based on the cost of serving demand in each zone – is an important contributor to improving the economic efficiency of the wholesale market by encouraging price-responsiveness by loads. Some stakeholders oppose zonal pricing on the grounds that the greater price variability in a zonal system produces little or no benefit and that uniform pricing reduces prices for consumers outside northern Ontario. The IESO has proposed to limit zonal pricing to 'active loads', which are primarily dispatchable loads. The Panel has expressed serious concern about this vastly reduced scope of zonal pricing for loads as a retreat from the efficiency goals of market renewal.

With regards to the ICA, the Panel has highlighted its concerns over the expansion of multi-year commitments in the capacity auction, the use of "other" mechanisms to procure large generation assets and the possibility that overlapping incentives may result in "double counting." These concerns became moot when the IESO announced on July 16, 2019 that it was ending work on the ICA program.

In August 2018, the IESO's Board of Directors approved market rule amendments that create a framework to enable Ontario-based resources to export surplus capacity in excess of Ontario's needs to neighbouring jurisdictions. Currently, the IESO only allows capacity exports to the New York (NYISO) market, but expects to expand this opportunity to the Québec, MISO and PJM markets. Capacity exports may help defray the cost of generating assets that may otherwise remain idle or be decommissioned in the province.

In late 2018, the IESO completed its auction for 2019 Demand Response (DR) capacity – procuring 818 MW and 854 MW of DR capacity for the summer and winter periods, respectively. The 2019 DR auction added 268 MW of DR capacity in the summer and 156 MW of capacity in the winter, with an average clearing price of $52,810 per MW – bringing total DR costs in 2019 to more than $44 million. In total, ratepayers have paid $165 million for DR capacity since the DR auction was introduced in 2016.

The IESO recently made changes to the DR program to improve the availability of Hourly DR resources when they are needed, as detailed in the Panel's April 2019 Monitoring Report. Nevertheless, as of July 2019, none of the hourly DR resources (embedded loads not directly connected to the IESO-controlled grid) – which account for the majority of DR capacity – have been activated.

Chapter 2: Analysis of Anomalous Market Outcomes

The long-term trend of lower wholesale prices in Ontario continued, with the number of negative priced hours in the Summer 2017 Period hitting a high of 1,584 – more than double the number of negative priced hours during the summer period in the previous year. The average weighted Hourly Ontario Energy Price (HOEP) for Class B consumers in the current reporting period was $12.72/MWh, compared to $21.32/MWh in the same period last year. The average weighted HOEP for Class A ratepayers dropped to $10.13/MWh in the Summer 2017 Period, down from $16.45/MWh the previous year. The increase in negative priced hours and the decrease in the average HOEP is largely a result of low demand and surplus capacity, with demand in the Summer 2017 Period falling to 67.0 TWh from 70.7 TWh in the preceding summer period.

This report examines the increase in extreme congestion prices – when the price at the intertie is greater than $1,000 or less than -$1,000 – on the Québec interties. Extremely low intertie prices result in significant costs to the market. The Panel estimates that in the 21 hours of extreme congestion prices examined, there were total Intertie Offer Guarantee payouts of $30.2 million.

The Panel also analyzes what appears to be nodal price chasing by a trader selling Operating Reserve (OR) in Ontario – meaning the market participant may be bidding strategically on the difference between market and nodal prices in an effort to receive out-of-market payments. Nodal price chasing, as discussed at length by the Panel in previous Monitoring Reports, leads to the inefficient use of Ontario's interties with neighbouring markets and additional costs to consumers and exporters.

<u>Recommendation 2-1:</u>

The IESO should consider ways and means of deterring the Intertie Operating Reserve nodal price chasing behaviour described in this report.

Finally, the Panel examines a payout by the IESO to Transmission Rights (TR) holders on the Ontario-to-Minnesota intertie when the intertie's export limit was reduced to zero. The Market Rules stipulate that the IESO should stop making TR payouts when there is an outage on an intertie. In this case, the intertie's limit was reduced to zero due to maintenance on a circuit outside of the intertie. In the Panel's view, based on the Market Rules these TR payouts should not have been made.

Recommendation 2-2:

The IESO should ensure its procedure for determining an outage when administering Transmission Rights aligns with the Market Rules.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

The integration of distribution-connected DR resources in the IESO's system model resulted in an unintended consequence, adding in some hours as much as 220 MW of fictitious demand to the market over an 11-month period from May 2016 to April 2017 (although the average over that period would have been lower) and inflating the market price and certain uplifts.

The unintended consequence began after the introduction of the first Demand Response (DR) auction in May 2016. At that time, the IESO's scheduling algorithm had a mechanism to account for dispatchable loads – active participants in the wholesale market, capable of adjusting load in response to 5-minute prices – who may be consuming when not bidding into the market. However, the addition of DR resources that are embedded at the distribution level resulted in the IESO double-counting their demand in hours when they were not bidding: once as part of the IESO forecast generally and again by including them in a separate scheduling calculation akin to the mechanism applied to dispatchable loads.

This unintended consequence produced both higher wholesale prices, as well as higher payments for uplifts that are calculated as a direct function of the HOEP. In one hour, the fictitious demand pushed the HOEP to $1,619/MWh – the fourth highest since the market opened. Over the 11-month period in question, the estimated impact on the HOEP and transmission loss uplift combined could have ranged as high as between $450 million to $560 million, although a simulation accounting for additional potential variables could yield lower estimates.

For some market participants, this was offset in large part by a corresponding decrease in Global Adjustment payments. However, exporters, who do not pay the Global Adjustment, and Class A market participants, who pay less (or no) Global Adjustment by virtue of the Industrial Conservation Initiative, would have felt a larger impact.

The IESO discovered and resolved the unintended consequence in April 2017. However, as of September 2019 the IESO had not disclosed the unintended consequence, or its impact on HOEP and uplift, to market participants.

<u>Recommendation 3-1A</u>

The Panel recommends that—when implementing changes to the market—the IESO audit the pre-deployment testing process to ensure that sufficient controls are in place to identify errors and unintended consequences.

<u>Recommendation 3-1B</u>

The Panel recommends that, as soon as possible after the IESO detects an error or unintended consequence that significantly impacts the wholesale electricity market, it publically discloses details of the error or unintended consequence, the impact on the market and the actions taken or to be taken to address the matter.

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 Developments Related to the IESO-Administered Markets

This section summarizes developments related to the IESO-administered markets that the Panel considers noteworthy.

Market Renewal Progresses into the Detailed Design Phase

In March 2016, the IESO launched the Market Renewal initiative to address known challenges with the existing market design, and to create a foundation for a more dynamic energy market to meet future needs. The IESO has since released a number of high-level design documents for the various streams of Market Renewal. The Panel has participated in the Market Renewal process, including membership on the Market Renewal Working Group, and the submission of written feedback to the IESO regarding the design options under consideration.

The Panel's submissions have addressed both zonal pricing and the Incremental Capacity Auction (ICA).

The Panel believes that zonal pricing, whereby prices paid by customers vary across different zones in Ontario based on the cost of serving demand in each zone, is an important contributor to the efficiencies to be achieved by Market Renewal by encouraging price-responsiveness by loads.[1] Since 2002, the Panel has frequently noted the economic inefficiency associated with uniform pricing, whereby the province-wide price is divorced from the cost of meeting electricity demand in a given zone.[2]

The IESO's initial proposal that all consumers pay zonal prices met vigorous resistance from some stakeholders. Large industrial loads were concerned about the greater price volatility

[1] The High Level Design of the Single Schedule Market, provided that generators would be paid a locational marginal price for output, which is set at particular nodes across the grid. Loads would be charged a zonal price, which is a load-weighted average of locational prices in a particular zone.

[2] For example, in its first major review of the electricity market completed in 2003, the Panel concluded that it continued to "favour the introduction of locational marginal pricing as was contemplated in the original market." Report available at: https://www.oeb.ca/documents/msp/panel_mspreport_imoadministered_171203.pdf

associated with zonal pricing and about the small increase in price for loads outside the northeast and northwest zones if the uniform price is abandoned. LDCs were concerned about the mechanics of implementation when most small consumers are on the provincial Regulated Price Plan. The Panel commented in February, 2018, that any mitigation of zonal price volatility should preserve incentives to respond to short-term zonal price excursions. The IESO's High Level Design of September 2018 proposed to mitigate the impact of the difference in prices between zones by distributing congestion rents and loss residuals back to loads that suffer cost increases.[3] The Panel commented in December, 2018, calling for the maintenance of zonal pricing for all loads, and for a distribution of residuals that did not substantially reduce incentives to respond to short-term zonal price excursions. In June of 2019, the IESO released a Load Pricing Alternative Design that abandoned locational pricing for all but 'active loads', primarily dispatchable loads. The Panel submitted comments disagreeing with this design, stating that the absence of zonal pricing for most loads would lead to higher prices for all consumers because of lost incentives to reduce consumption during zonal price excursions. We called for a detailed design that would facilitate the migration of loads to zonal pricing.

The ICA was originally forecast to account for the vast majority of the proposed benefits of Market Renewal: $2.5 billion out of $3.4 billion in total benefits.[4]

The Panel commented on three aspects of the ICA in its November 16, 2018 and May 17, 2019 submissions to the IESO stakeholder engagement. First, it questioned the consideration of five-year commitment periods because such long commitments may negate the potential benefit of shifting risks from ratepayers to bidders. Second, it expressed concern that the statement that large, capital-intensive generation assets may be built through "other mechanisms" outside the ICA would increase uncertainty for investors and reduce the efficiency benefits of the ICA auctions. Third, it expressed concern that if large loads are allowed to bid in the ICA while participating in the Industrial Conservation Initiative, they will, in effect be paid twice for the same thing.

---

[3] Congestion on transmission lines and energy lost during transmission cause the price paid by loads at times to be higher than the price paid to generators. That price difference is classified as either a congestion rent (transmission congestion) or a loss residual (energy lost in transmission).

[4] See http://www.brattle.com/news-and-knowledge/publications/the-future-of-ontarios-electricity-market-a-benefits-case-assessment-of-the-market-renewal-project.

These issues have become moot with the IESO's announcement on July 16, 2019 that it was ceasing work on the High Level Design of the ICA project. However, they might still be relevant to the Transitional Capacity Auction as its design develops.

Market Rule Amendments Regarding Capacity Exports

In August 2018, the IESO's Board of Directors approved market rule amendments that create a framework to enable Ontario-based resources to export capacity in excess of Ontario's needs to neighbouring jurisdictions. Currently, the IESO only allows capacity exports to the New York (NYISO) market, but expects to expand this opportunity to the Québec, MISO and PJM markets.[5] While only two Ontario market participants have sold export capacity, other market participants may consider similar sales in the future.

Ontario's electricity market is expected to have sufficient capacity to meet peak demand periods in Ontario until the mid-2020s, according the IESO's most recent forecasts.[6] Selling surplus capacity, particularly if it is rate-regulated, may benefit Ontario consumers, as they should receive some portion of the revenue generated from these sales in the form of lower regulated rates. Generators subject to contracts may or may not also be required to use some portion of this revenue to reduce costs to ratepayers. Currently, it is not clear to what extent if at all the revenues earned from these capacity exports will benefit ratepayers.

As part of the market rule amendments approved by the IESO's Board of Directors, all market participants wishing to sell surplus capacity outside of Ontario must submit a request to the IESO no earlier than six months prior to the commitment period, no later than 15 weeks prior to the close of the external auction, and for a commitment period of no longer than one year. The IESO may accept the request in full, partially approve or reject the request outright if it determines that the capacity export will have a negative impact on Ontario's capacity requirements, produce congestion or occur during a planned transmission outage, among other criteria.[7]

[5] See the April 2018 presentation entitled "Enabling Capacity Exports: Detailed Design and Project Update", available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ce/ce-20180416-presentation.pdf?la=en.
[6] See the September 2018 technical planning conference presentation, available at: http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Technical-Planning-Conference.
[7] See the Market Rule Amendments, available at: http://www.ieso.ca/en/Sector-Participants/Change-Management/Market-Rule-Amendment-Archive.

The Panel will continue to monitor capacity exports to determine what impact, if any, they are having on the IESO-administered market.

Demand Response Procurement

In December 2018, the IESO completed its auction for 2019 Demand Response (DR) capacity. The IESO procured 818 MW and 854 MW of DR capacity for the summer and winter periods, respectively. The 2019 auction amounts to a 268 MW increase in summer DR capacity and a 156 MW increase in winter DR capacity compared to 2018 (see Table 1-1). The average annual clearing price for DR capacity was $52,810 per MW, bringing the total DR costs to be recovered from ratepayers in 2019 to more than $44 million.

Ratepayers have paid $165 million for DR capacity since the DR auction was first introduced in 2016.[8]

Table 1-1: Demand Response Procurement & Costs
2016-2019
(MW & $ Millions)

	2016	2017	2018	2019
Summer (MW)	391.5	448.4	550.4	818.4
Winter (MW)	403.7	451.2	689.9	854.2
Cost ($ Millions)	36	36	49	44

In the Panel's May 2017 Monitoring Report, it concluded that resources procured in the DR auction are unlikely to contribute to conservation or demand reductions. Since that time, hourly DR resources—embedded DR participants that are not active in the wholesale market as dispatchable loads—have yet to be called upon to reduce consumption ("activated") during periods of high demand or tight supply conditions. Hourly DR participants accounted for more than 78% of all capacity procured in the most recent DR auction. The IESO recently made changes to the DR program to improve the availability of Hourly DR resources when they are needed, as detailed in the Panel's March 2019 Monitoring Report. These changes have not resulted in any activations.

[8] This amount excludes non-performance charges and capacity buy-outs.

The Role of Energy Storage in the IESO-Administered Market

Energy storage, which includes everything from small-scale batteries to large-scale pumped hydro, is playing an increasing role in wholesale electricity markets. The IESO has already launched a number of storage pilot projects to test their effectiveness and the ability to integrate them into the wholesale market. The IESO, like other system operators across North America, is now focused on ensuring that the wholesale electricity market is fully capable of economically integrating new energy storage technologies into its day-to-day operations. Better utilizing storage technology may increase the efficiency of the grid and mitigate the need for new capacity or other infrastructure investments.

In April 2018, in order to improve the integration of energy storage, the IESO established the Energy Storage Advisory Group (ESAG). With the help of the ESAG, the IESO released a report, *Removing Obstacles for Storage Resources in Ontario*, that identified a number of barriers to energy storage in the wholesale market and provided recommendations on how to move forward.

For the recommendations that pertain to the IESO-administered markets, the IESO has proposed reviewing and amending its Market Rules—which currently do not specifically refer to energy storage—to "clarify the participation of storage resources in IESO-administered markets."[9] According to the IESO, the lack of clarity in the Market Rules regarding energy storage creates a number of systemic issues that limits the ability of storage to participate in the operating reserve market, provide other ancillary services or potentially offer multiple non-overlapping services.

The IESO also agreed to further examine whether energy storage facilities should be charged uplift payments. Currently, any market participant—including energy storage facilities—withdrawing energy from the system pays uplift charges, which recover the cost of reliability and ancillary services as well as other out-of-market payments. Energy storage participants have argued that they should be exempt from such charges, as the requirement to pay them may result in them not being economic to dispatch and increase total costs to the system.

[9] See the IESO's December 2018 report entitled *Removing Obstacles for Storage Resources in Ontario*, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esag/Removing-Obstacles-for-Storage-Resources-in-Ontario_20181219.pdf?la=en.

The Panel recognizes that energy storage may play an increasing role in the wholesale market and, as such, will continue to monitor and review its integration and impact.

2 Status of Recent Panel Recommendations

Below are the recommendations made in the Panel's March 2019 Monitoring Report and the IESO's responses to them.[10]

Recommendation	IESO Response
Recommendation 3-1A *The IESO should formalize the process by which it determines when to disable and re-enable the variable forecasting tool, and should communicate that process to market participants to increase transparency.*	The IESO agrees with the Panel's recommendation that the process used by the IESO to disable and re-enable the variable generation forecasting tool as a control action to maintain reliability should be formalized and communicated to market participants. The IESO will incorporate the process for enabling and disabling the variable forecasting tool into the applicable IESO market manuals by the end of 2019 and this will be communicated to market participants through the IESO Change and Baseline Management process.
Recommendation 3-1B *When a variable generator is on mandatory dispatch and the forecasting tool is disabled, the IESO should set the generator's unconstrained schedule at its forecasted output rather than its maximum offered capacity.*	The IESO agrees with the Panel's analysis that the current process of disabling the variable forecasting tool under certain conditions may lead to instances of lower real-time Ontario energy prices than market conditions should reflect. With respect to the Panel's recommended solution, the IESO understands and agrees with the Panel's intent and would like to clarify that the IESO does not actively "set" the unconstrained schedules of generators. Rather, the IESO establishes an upper bound limit to which a generator could be scheduled. This distinction is important because when variable generators are the marginal resource, only the economic megawatt amounts will be scheduled and this would not be the case if the [Panel's] recommendation is implemented verbatim. With that clarification, the IESO will endeavor to implement the intent of the Panel's recommendation. In order to address the recommendation, the IESO will first undertake an assessment of solutions that best reflect a variable generator's capability during periods when the variable forecasting tool is disabled. The IESO will then report back to the Panel by the end of Q3 2019 on its findings and estimated timelines for implementing a solution.

[10] See the April 29, 2019 letter from Peter Gregg, President and CEO of the IESO, to Rosemarie Leclair, Chair and CEO of the Ontario Energy Board, available at: https://www.oeb.ca/sites/default/files/IESO-MSP-Ltr-OEB-20190429.pdf

3 Panel Commentary on IESO Response

The Panel acknowledges the IESO’s commitment to address these recommendations and looks forward to the IESO’s proposed solutions.

Chapter 2: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments during the period from May 1, 2017 to October 31, 2017 (Summer 2017 Period), making comparisons to the May 1, 2016 – October 31, 2016 period (Summer 2016 Period) as appropriate.

Traditionally, the Panel's analysis of anomalous events has focused on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of high uplift, such as Congestion Management Settlement Credit (CMSC) payments, Operating Reserve (OR) payments and Intertie Offer Guarantee (IOG) payments. All of the above payments are recovered from consumers and exporters through uplift charges.

The Panel has established a number of thresholds to identify anomalous events. Table 2-1 displays the number of events that exceeded the Panel's thresholds during the Summer 2017 Period, with comparisons to the Summer 2016 Period.

Table 2-1: Summary of Anomalous Events
May 2017 – October 2017 & May 2016 – October 2016
(Number of Events)

Anomalous Event Threshold	Number of Events May 2017 to October 2017	Number of Events May 2016 to October 2016
HOEP > $200 (high priced hours)	3	13
HOEP ≤ $0 (negative priced hours)	1,584	735
Energy CMSC > $1 million/day	2	7
Energy CMSC > $500,000/hour	0	1
OR Payments > $100,000/hour	16	20
IOG > $1 million/day	1	0
IOG > $500,000/hour	2	0

During the Summer 2017 Period, the three high priced hours occurred on May 1 in hour ending (HE) 12, on July 7 in HE 10, and on October 3 in HE 17, all hours with significant variable generation shortfalls of more than 200 MW on average. Both May 1 HE 12 and July 7 HE 10 had demand under-forecasts averaging 62.6 MW and 232.5 MW respectively, while demand in October 3 HE 17 was over-forecast by 62.1 MW, meaning that the supply shortfall was significantly less than in the other two hours. Demand was modest in all three hours—between 15,000 and 18,000 MW—so that few gas generators were online in pre-dispatch, requiring more expensive hydro generators to be brought online in real-time when supply was inadequate. In all intervals with a market clearing price (MCP) greater than $200 in these three high priced hours, the marginal resource was hydro.

During the Summer 2017 Period, the number of negative priced hours reached an all-time high at 1,584 hours, which can be explained generally by low demand during the Period.

The two days when CMSC payments were more than $1 million were July 8 and September 22. A number of hydro resources were constrained on extensively in the early hours of July 8 in response to transmission contingencies. The circumstances of September 22 were more conventional, with one resource having been constrained on extensively during peak hours on a day when there were substantial amounts of forecasted variable generation. This was done to ensure reliability in case less variable generation was available than had been forecast.

IOG payments are made to guarantee that importers will, at a minimum, recover their as-offered prices on import transactions whether those are scheduled day-ahead or in pre-dispatch. On June 12, there were payments of more than $1.6 million in each of HE 20 and HE 21. Previously, the daily IOG threshold had not been surpassed since the November 2013 to April 2014 period, and the hourly IOG threshold has not been surpassed in the last ten years, for as long as the MSP has been tracking this threshold in its Monitoring Reports.

The Panel's March 2019 Monitoring Report noted a significant increase in the frequency of hours with substantial IOG payments—in the range of $5,000-$70,000—due to increases in imports, increases in imports scheduled in the Day Ahead Commitment Process (DACP), and increases in the variation between one-hour ahead pre-dispatch (PD-1) and real-time prices. The high IOG payments on June 12 are distinct from this trend: they were paid on account of imports on the Outaouais interface and resulted from an Intertie Zonal Price (IZP) that was around -$2,000 throughout the two hours involved. In these hours, imports were offered at a positive price day-ahead, and were committed in the DACP. Offers for committed imports were subsequently reduced to a significantly negative number in pre-dispatch to ensure the energy would be scheduled in real-time. However, only 87% of committed imports could flow in real-time due to a limitation on the interface that reduced the import scheduling limit. This change drove down the IZP and IOG payments were made to ensure the original offer price was paid. This event is discussed in greater detail below.

2 Analysis of Other Anomalous Events

Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. Since its report covering the Summer 2016 Period, the Panel has expanded its analysis of anomalous events beyond those which meet or exceed pre-determined thresholds. Other criteria for assessing events include: the appropriateness of the market outcome relative to the Market Objective[11] and the Market Rules, the novelty and frequency of an event, as well as the relevance of the outcome to current IESO initiatives and stakeholder engagements.

In the sections that follow, the Panel reports on three anomalous outcomes during the Summer 2017 Period: a series of extreme congestion prices on multiple Québec interties, nodal price chasing in relation to Operating Reserve imports, and a planned outage when unwarranted Transmission Rights (TR) payouts were made.

2.1 Extreme Congestion Prices over the Interties

In its March 2019 Monitoring Report, the Panel noted that the vast majority of the significant increase in volume of DACP imports scheduled was attributable to Hydro-Québec, which has an agreement with the IESO that provides for electricity trade between the provinces over a seven-year period from 2017 to 2023.[12] Among other things, under that agreement Québec sells 2 TWh of electricity per year to Ontario at a set contract price. The increase in imports from Québec into

[11] The Market Objective of the IESO-administered markets is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

[12] The counterparty to the agreement is HQ Energy Marketing Inc., a wholly owned subsidiary of Hydro-Québec that is also a registered market participant (intertie trader) in the IESO-administered markets. For convenience, this report refers simply to Hydro-Québec.

Ontario scheduled in the DACP contributed to the increase in IOG payments that was observed at the time.

In this section, the Panel analyzes 21 hours with extreme congestion prices that are attributable to the significant increase in the volume of DACP imports scheduled. In these hours, a reduction in the intertie scheduling limit led to import congestion, highly negative congestion prices and large IOG payments and TR payouts for transactions over the Québec interties. This resulted in significant costs to the market with little to no corresponding benefit beyond the reliability benefit of respecting intertie limits. In addition, the resulting extreme price signals in the wholesale market did not reflect underlying costs.

Intertie Congestion and Scheduling Limits

Intertie scheduling limits consider the physical capacity of the tie-lines to transfer energy between external jurisdictions and Ontario. They are specific to each intertie zone and may be different for imports versus exports. For example, imports from Michigan could be limited to 1300 MW while exports are limited to 1500 MW.

Congestion on the interties occurs when the scheduling limit restricts the selection of competitive offers. When an intertie is congested in the import direction, the IZP—the price at which intertie traders are settled for transactions in both directions—will be lower than the MCP. The opposite is true when an intertie is export-congested. When the IZP is equal to the MCP, there is no congestion. The difference between the MCP and the IZP—which is a negative number when an intertie is import-congested and a positive number when it is export-congested—is known as the Intertie Congestion Price (ICP).

The Effect of Reduced Scheduling Limits on Day Ahead Imports

The reduction of an intertie's import scheduling limit after day-ahead imports have been scheduled can lead to high congestion costs. Importers scheduled day-ahead are guaranteed their day-ahead offer price if the scheduled MWs flow in real-time. This guarantee provides an incentive for traders to lower import offers to -$2,000/MWh (the lowest allowable offer price) after they have been scheduled in the day-ahead. Lowering the offer price increases the likelihood that the MWs will flow in real-time and that the trader will receive, at the minimum, their day-ahead offer price.

If the import scheduling limit is subsequently reduced[13] below the total amount scheduled day-ahead—and there are insufficient exports bid to cancel out the excess imports—the intertie will become congested, often with an IZP of -$2,000/MWh. Imports that do flow are subject to paying the extremely negative IZP. However, due to the day-ahead IOG, their losses are offset by a payment that makes them whole with their day-ahead offer price. The day-ahead IOG effectively removes[14] the financial risk associated with lowering offer prices to ensure MWs flow in real-time

Extreme Transmission Rights Payouts

Intertie congestion can be difficult to predict and introduces financial risk to intertie traders. To hedge against this risk, traders can purchase TRs. TRs are sold through an IESO-administered auction in units of megawatts by intertie and direction (import or export) for periods of one month or one year. When congestion occurs, owners of TRs are entitled to a payment equal to the ICP for each megawatt of TRs they own for that intertie and direction.

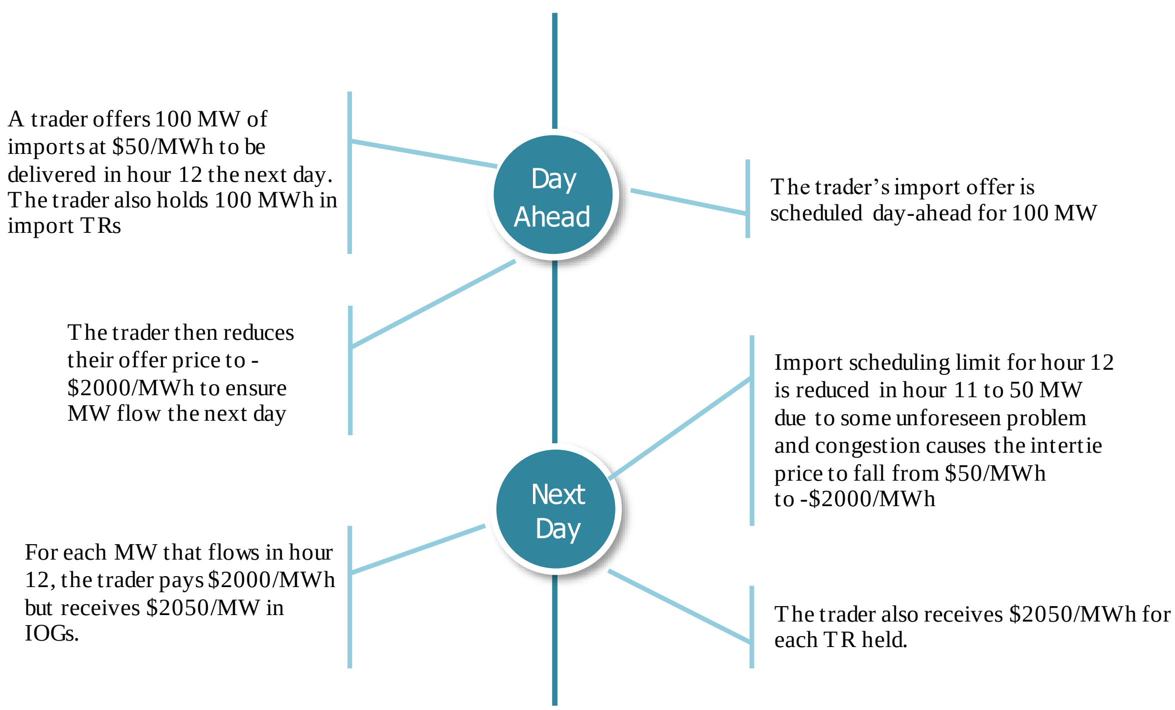
An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is considered perfectly hedged against congestion, as TR payouts will exactly offset the ICP. Extreme ICPs trigger considerable TR payouts, the costs of which are ultimately borne by Ontario consumers in the form of reduced disbursements from the TR Clearing Account if payouts exceed the congestion rent paid by traders. Table 2-2 and Figure 2-1 both illustrate the effect of extreme congestion on IOG payments and TR payouts. In this simplified[15] example, had the intertie remained uncongested, the payment to the trader for the 100 MW of imports would have been $5000. With congestion, the payout for the limit reduced flow of 50 MW is $102,500 in IOGs and $205,000 in TRs. The trader would pay $100,000 in real-time costs, for a net payment to the trader of $207,500.

[13] Reduced at a time when the trader is often unable to respond due to offer change restriction rules and congestion price setting latency close to real-time.
[14] IOGs are paid on net imports. If a trader is simultaneously exporting, then IOGs are offset by the MW amount being exported.
[15] This example assumes the price without congestion is $50/MWh in day ahead and in real-time with no IOG offsetting exports.

Table 2-2: Example of the Effect of Reduced Scheduling Limits on Day-Ahead Imports (MW and $/MWh)

Time Period	Import Scheduling Limit (MW)	Offered Quantity (MW)	Offered Price ($/MWh)	Scheduled (MW)	PD Ontario Price ($/MWh)	Intertie Price ($/MWh)	Congestion Price ($/MWh)
Day-ahead	100	100	50	100	N/A	N/A	N/A
Pre-dispatch before scheduling limit reduction	100	100	-2,000	100	50	50	0
Pre-dispatch after scheduling limit reduction	50	100	-2,000	50	50	-2,000	-2,050.00

Figure 2-1: A Timeline Illustrating IOG Payments and TR Payouts in the Presence of Day-Ahead Imports



Extreme Congestion Events

From the start of 2017 until September 2018, there were 21 hours when the congestion price of an Ontario intertie was more than $1,000/MWh or less than negative $1000/MWh. All of these events occurred on the Québec interties (either Outaouais or Beauharnois). In the previous two years there were no such events on any of Ontario's interties. Each time, Hydro-Québec offered a large amount of imports day-ahead, and reduced[16] the associated offer price to a significantly negative number after the imports were scheduled, in line with the common practice to ensure imports flow. When the scheduling limit was subsequently reduced to below the import quantity scheduled day-ahead, not all the negative-priced imports could be accommodated and, in all but one of the hours, the intertie became congested with an IZP of -$2,000/MWh. In one of the hours, exports bid at a higher but still negative price were scheduled and set the IZP.

IOG payments for these 21 hours totalled $30.2 million. For reference, IOG payments averaged $2,340 per hour between January 1, 2017 and September 3, 2018, compared to an average of $1,440,000 in IOG payments made in each of the 21 hours examined by the Panel. Taking into account IOG payments to Hydro-Québec, TR payouts on the affected intertie, payments for energy imported, and payments made to exporters for buying energy at a negative intertie price, these 21 hours led to a total net payout of nearly $31.7 million, which corresponds to about $1,900/MWh for imports during these hours.

Events in the 21 hours in question resulted in significant costs to the market with little to no corresponding benefit beyond the reliability benefit of respecting intertie limits, and sent price signals that did not reflect underlying costs. Although the events were largely attributable to increased DACP import volumes due to Hydro-Québec's obligations under its electricity trade agreement with the IESO, they could arise on any intertie since the IOG effectively provides an incentive to reduce the offer price on imports scheduled day-ahead to ensure they actually flow in real-time.

The Panel recognizes that the financially binding Day-Ahead Market proposed under Market Renewal has the potential to address the issue of significant payouts that are due to extreme congestion and have little or no market benefit. It will likely remove the need for importers to reduce their day-ahead offer prices to ensure their transactions are completed. However, Market

[16] The electricity trade agreement referred to earlier obliges Hydro-Québec to submit import offers to the Ontario market using offer prices and quantities specified in the agreement.

Renewal is a longer-term endeavour, and the financial outcomes of this issue in the near term may be substantial.

2.2 *Intertie Operating Reserve Nodal Price Chasing*

Theory of Nodal Price Chasing

In its April 2015 and March 2018 Monitoring Reports, the Panel identified various situations in which intertie traders offer and bid strategically to increase the CMSC payments they receive, a behaviour the Panel has characterized as "nodal price chasing". Nodal price chasing often results in inefficient utilization of Ontario's interties and increased uplift costs for Ontario consumers and exporters. The Panel has more recently observed a market participant engaging in what appears to be nodal price chasing through its import offers into Ontario's OR markets.

Nodal price chasing involves aiming to have one's transaction either constrained on or constrained off. Transactions are constrained on when the offer/bid price is economic in the constrained sequence but not the unconstrained sequence. In the case of imports, this occurs when the offer price is lower than the constrained sequence's nodal price[17] but higher than the unconstrained sequence's IZP. As shown in Figure 2-2, CMSC payments allow a market participant that is constrained on to be paid its offer price, up to the nodal price, not the lower market clearing IZP. This encourages nodal price chasing.

The Panel has long observed nodal price chasing behaviour on Ontario's interties, making a number of recommendations aimed at mitigating or eliminating the associated CMSC payments. The IESO has taken a number of steps to address the Panel's concerns. Most of the focus has been on constrained-off CMSC payments. In 2005, the IESO introduced its Constrained-off Watch Zone framework to mitigate constrained-off CMSC payments to intertie traders,[18] before eliminating the payments entirely in 2014.[19] While these changes largely alleviated concerns

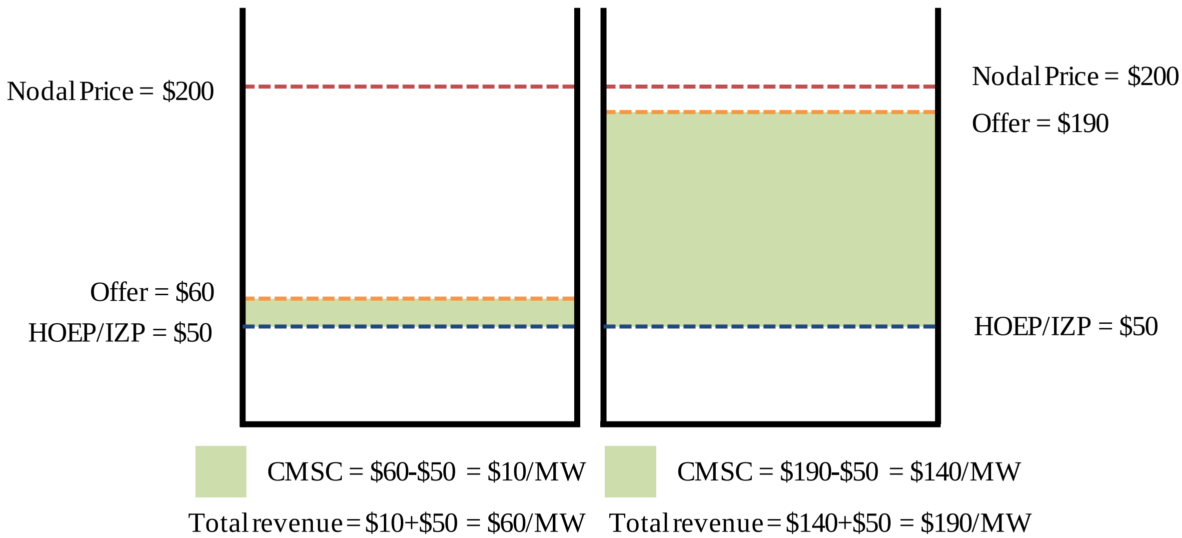
[17] Nodal prices approximate the marginal value of electricity in each region of Ontario and reflect the Province's internal transmission constraints. Additional nodal price data and trends for the Summer 2017 Period are provided in Figure A-13 in the Appendix.

[18] A Constrained-off Watch Zone is an area where nodal prices diverge regularly from the market clearing price, giving rise to frequent constrained-off dispatches and providing market participants with the opportunity to receive unwarranted CMSC payments. Resources in these zones found to receive persistent and significant constrained-off CMSC may be subject to CMSC recalculations by the IESO.

[19] A small percentage of constrained-off intertie transactions are still eligible for CMSC payments, specifically those that are manually curtailed by the IESO in real-time.

over nodal price chasing that targets constrained-off CMSC payments, nodal price chasing that targets constrained-on CMSC payments remains a concern.

Figure 2-2: Demonstration of Nodal Price Chasing ($/MW)



Participant Behaviour

The participant whose behaviour is discussed below is frequently constrained on to provide OR: between June 1, 2014 and September 30, 2018, it was scheduled for over 200 GWh of 10-minute non-spinning (10N) OR in the unconstrained schedule, but for over 500 GWh in the constrained schedule. Over the same period, it was also scheduled for over 40 GWh of 30-minute (30R) OR in the unconstrained schedule and for over 100 GWh in the constrained schedule.[20] Over this period, it received approximately $20 million in OR CMSC payments.

The opportunity to nodal price chase arises when there is a divergence between market clearing OR prices and nodal OR prices. The OR nodal prices at the intertie used by the market participant in question generally spike relative to market clearing OR prices when area reserve limits in Northern Ontario are reduced. This reduction limits the amount of OR from Northern Ontario that can be scheduled in the constrained sequence (but not the unconstrained sequence), pushing nodal prices up throughout Southern Ontario relative to the market clearing OR price.

[20] As an importer, the participant is unable to participate in the 10-minute spinning (10S) OR market.

When a market participant is scheduled for OR, it must stand by to provide power, forgoing the opportunity to sell that power into the wholesale electricity market. Accordingly, a market participant should only be willing to stand by if the price it receives for OR exceeds the profit it could have earned selling that electricity. It follows that an efficient OR offer price is determined by the opportunity cost of not selling that electricity.

The participant in question typically offers a considerable amount of 10N OR and small amount of 30R OR into Ontario at a price well over the IZP. These offers are normally revised or deleted closer to dispatch, often immediately before bids and offers are finalized two hours in advance of dispatch. When the market participant revises its offers, the prices on its OR offers are usually changed to just below the prevailing nodal price, or to a value substantially higher than the nodal price.

An example of the first type of behaviour is an afternoon hour in late May, 2017, when the market participant reduced its OR offer price to just under the nodal price after the three-hour ahead pre-dispatch (PD-3) nodal price was published. For the very next hour, it increased its offer price to more than 20 times as much, just less than the PD-3 nodal price after it was published. Of the over 10,000 hours in which the market participant's offer price was changed to below the nodal price in the period under consideration, 60% had a final offer price that was more than 80% of the nodal price. In other words, offers were regularly changed to a price just below the nodal price.

In the hours when nodal price chasing for constrained-on CMSC was possible (i.e. hours where the nodal price exceeded the market clearing price for the relevant type of OR), the correlation between the market participant's final offer price and the IZP was not statistically significant. In contrast, the correlation between the offer price and the nodal price in those hours was highly significant. This suggests that the market participant considered nodal prices rather than OR market clearing prices or opportunity cost when determining its OR offer prices.

The second type of behaviour, where offers were revised to be greater than the nodal price, appears to fall into two categories. Many such revisions appear to be attempts at avoiding receiving a schedule: on average, offer revisions that exceeded the prevailing nodal price were priced at more than 200 times the nodal price at the time of the offer revision. Some revisions, however, occurred when the market participant was the marginal resource for the relevant type of OR. With these revisions, the market participant increased the nodal price by increasing its offer price when it remained marginal. In a subset of these cases, it increased its offer price to the extent that it ceased to be the marginal resource before revising it back down. For example, for an afternoon hour in late May, 2017, the participant set the 10N nodal price for three pre-dispatch runs before tripling its offer, which doubled the nodal price. It then revised its offer to just below the nodal price in the last hour in which it could modify its offers, becoming marginal again and setting the PD-2 and PD-1 nodal price much higher than in earlier pre-dispatch runs. Since it was constrained on for its full 10N offer throughout that hour, the participant received $25,500 in additional OR CMSC payments by revising its offer.

Not only do nodal price chasing and strategic offering to increase nodal prices result in higher CMSC payments and thus higher uplift for Ontario consumers and exporters, they can also impact market efficiency.

Specifically, offer prices driven by nodal price chasing and offer prices intended to raise the nodal price can fall in a different place in the OR supply stack than if they were based on opportunity cost. This may re-order the OR supply stack, making it less representative of the actual costs of supplying OR. Moreover, when these offers set a price, that price is not reflective of the marginal cost of supplying OR. This sends an incorrect market signal to other providers of OR.

Resolving the problem of nodal price chasing for constrained-on CMSC presents a real challenge, since it is difficult to distinguish definitively between pricing that indicates marginal cost and pricing designed to chase nodal prices. Reducing or eliminating constrained-on CMSC payments could lead to resources being dispatched to operate at a loss, and for that reason is not feasible. By contrast, the elimination of constrained-off CMSC payments only leads to resources forgoing profits they otherwise could have made but for the congestion. That is to say, eliminating constrained-on CMSC, as was done for constrained-off energy CMSC over the interties, is not feasible.

It is likely that the Single Schedule Market expected to be introduced through Market Renewal will eventually address this problem. By implementing a locational marginal price that serves as both nodal price and market clearing price at each node, the opportunity to nodal price chase would be eliminated. Even then, the design should include strong market power mitigation measures to ensure that participants with market power may are not able to inflate the locational marginal price and thus the payments they receive by offering above marginal price. This may be a particular concern over the interties, where market power mitigation is expected to take place only after-the-fact.[21]

Recommendation 2-1:

The IESO should consider ways and means of deterring the Operating Reserve nodal price chasing behaviour described in this report.

2.3 *TR Payouts Made during a Planned Outage*

Between May 20, 2017 and May 23, 2017, the IESO made payouts totalling $220,000 to Transmission Rights (TRs) holders on the Ontario-to-Minnesota intertie, even though the transfer capability of the intertie was reduced to zero due to planned work on a line outside of Ontario. The IESO stopped making payouts halfway through the planned outage once all bids by traders were removed, and resumed making payouts when the intertie returned to service. According to the Market Rules, the IESO should stop making TR payouts in hour after "the transmission transfer capability on an intertie has been reduced to zero by reason of the outage of the relevant intertie." [22] The IESO is to resume making TR payouts in the hour after the intertie is returned to service.

Theory of TRs and TR Auctions

Ontario's electricity market is connected with neighbouring jurisdictions, allowing for trade from one market into and out of other electricity markets. The difference in prices between electricity

[21] The high-level design of the Single Schedule Market under Market Renewal is available at http://www.ieso.ca/Sector-Participants/Market-Renewal/Single-Schedule-Market-High-Level-Design.
[22] See section 4.4.2 of Chapter 4 of the Market Rules, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-rules/mr-chapter8.pdf?la=en.
For a narrative explanation, see page 10 of Market Manual 4: Market Operations Part 4.4: Transmission Rights Auction, available at: http://www.ieso.ca/-/media/files/ieso/document-library/market-rules-and-manuals-library/market-manuals/market-operations/mo-transmissionrights.pdf.

markets—Ontario compared to New York, for example—creates a trading opportunity. Electricity traders can import and export power through the interties connecting markets as an arbitrage opportunity—buying power in a low-priced market and selling it in a higher-priced market. In 2018, Ontario exported and imported 18.6 TWh and 8.4 TWh of electricity, respectively.[23]

The interties connecting Ontario to neighbouring jurisdictions each have their own intertie zonal price. If the intertie zonal price is less than the Ontario market price, the intertie is import congested, meaning more traders want to import power into Ontario than the intertie can physically handle. When this happens, traders importing power into Ontario are paid an amount below Ontario's wholesale price, which would reduce—or eliminate altogether—the arbitrage opportunity. The reason the arbitrage opportunity is mitigated, or eliminated altogether, is that the importer is paid the lower intertie zonal price, but the buyer in Ontario's wholesale market continues to pay the higher market price. The difference between these two amounts is known as "congestion rent" and is a credit to the IESO's TR Clearing Account. Periodically, excess funds in the TR Clearing Account are disbursed to Ontario wholesale loads and exporters.

The opposite is true when the intertie is export congested. When this occurs, the intertie zonal price will be higher than the Ontario market price. In this case, a generator in Ontario will deliver power to the intertie and will be paid Ontario's market price for their output. The exporter, meanwhile, pays the higher intertie zonal price to take the power out of Ontario, with the IESO collecting the difference in the form of congestion rent.

Traders can hedge against the risk of intertie congestion by purchasing TRs through the TR auctions administered by the IESO. TRs are sold per MW for each intertie in Ontario, for both directions (import or export) and for periods of one month (short-term) or one year (long-term). A TR owner will receive a payment – equal to the Intertie Congestion Price (ICP) multiplied by the number of TRs they hold – when there is congestion on the intertie in the direction for which they hold TRs. TRs act as a hedge against congestion, ensuring traders settle their transactions on the Ontario market price, not the lower/higher intertie price. As an example, an importer that

[23] See http://www.ieso.ca/power-data/supply-overview/imports-and-exports.

owns TRs will be paid the Ontario market price for power being delivered, not the lower intertie price that the importer would receive without TRs. The proceeds from selling TRs to market participants are placed into the TR Clearing Account. Auction prices for TRs will move higher if traders expect congestion to increase in the future, but will decrease if traders expect less congestion.

TR payouts should, in theory, completely offset any congestion rent collected, as the TRs simply pay out the difference between the market price and the intertie price. But that is often not the case in practice, as the number of TRs held by market participants may not match the number of imports and exports flowing during times of congestion. Due to Ontario's two-schedule price system, transaction failures and intertie de-ratings, the IESO may make more payouts to TR holders than it collects in congestion rent. When the IESO pays out more TR payouts than it collects in congestion rent, the TR Clearing Account is drawn down. When the opposite is true, congestion rent will exceed TR payouts and the TR Clearing Account grows.

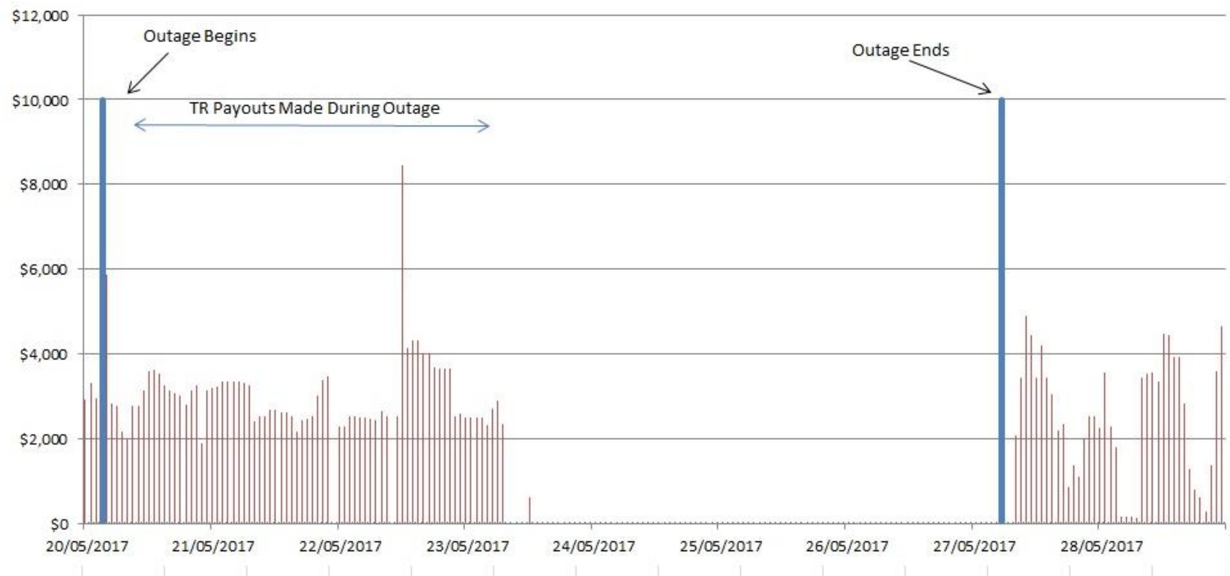
As an example, the Ontario-to-Minnesota intertie typically has an export transfer capacity (also known as the scheduling limit) of 130 MW in a particular month. Now, assume the IESO sold 200 MW of TRs. If the ICP in a given hour were $15/MWh, the IESO would collect 130 MW times $15/MWh in congestion rent (or $1,950), but would have an obligation to pay out 200 MW times $15/MWh in TR payouts (or $3,000). In this case, the amount available for disbursement from the TR Clearing Account would be reduced.

IESO Payouts

As shown in Figure 2-3, the IESO made a total of $220,000 in TR payouts between May 20, 2017 and May 23, 2017 to TR holders on the Ontario-to-Minnesota intertie at times when the transfer capability of the intertie was reduced to zero due to a planned outage in Manitoba. Market participants holding TRs to export power from Ontario on the Minnesota intertie would have been aware of the reduced transfer capability, given the reports that the IESO published in the weeks leading up to the event. As early as May 3, 2017, the IESO listed the reduced capability in its transmission outage report for the next 30 days, and identified it as beginning on

May 20th and lasting for more than 8 days.[24] The IESO also detailed the event in its short-term report released on May 18, 2017, which provides information on outages scheduled to take place over the next two days.[25]

Figure 2-3: TR Payouts Made During the May 20 – May 27, 2017 Outage ($)



In this case, the IESO appears to have taken the view that, for the purposes of stopping TR payouts, an outage is a situation when the intertie itself is taken out of service. In the Panel's view, however, the Market Rules contemplate that TR payouts will be stopped when the transfer capability of an intertie is reduced to zero by reason of any outage of the intertie – whether the outage is to the intertie itself or is due to outside restraints or limitations.

Specifically, section 4.4.2 of Chapter 8 of the Market Rules contemplates that TR payouts will be suspended when the transfer capability of an intertie is reduced to zero by reason of the outage of

[24] See the IESO's May 3, 2017 Transmission Facility Outage Limits Report (Days 3 to 34) for outages occurring between May 6, 2017 and June 06, 2017.
[25] See the IESO's May 18, 2017 Transmission Facility Outage Limits Report (Days 0 to 2) for outages occurring between May 18, 2017 and May 20, 2017.

the intertie. An "outage" is, in turn, defined in Chapter 11 of the Market Rules as follows (emphasis added):

> *outage means the removal of equipment from service, unavailability for connection of equipment or* ***temporary derating, restriction of use, or reduction in performance of equipment for any reason including, but not limited to****, to permit the performance of inspections, tests or repairs on equipment, and shall include a planned outage, a forced outage and an automatic outage.*

In the Panel's view, under the Market Rules the $220,000 in TR payouts made to market participants as shown in the above Figure should not have been made.

Outage Information Not Provided in TR Auction or Reflected in the Number of TRs Auctioned

Traders would not have been aware of the outage in question when they bid on short-term TRs, as the IESO did not notify market participants about the outage in its short-term TR pre-auction reports published on March 10, 2017 and April 10, 2017[26] despite having been notified of it on March 2, 2017 and having entered the information in its outage request system. The pre-auction reports typically provide market participants with information on any planned outages and may impact bidding strategies. Outages reduce the number of hours an intertie will be available for trading and thus have the potential to be congested.

The IESO also did not adjust the number of TRs offered in the relevant short-term auction. According to the Market Manual, the number of TRs offered on each path at a short-term auction is limited to the lowest of:

- The financial upper limit, which allows the IESO to adjust the amount of TRs based on the cumulative balance between congestion rents and TR payouts. If, for example, congestion rents are consistently higher than TR payouts, the number of TRs may be increased.

[26] See the IESO's March 10, 2017 and April 10, 2017 Pre-Auction Reports for Short Term Transmission Rights.

- The expected available transfer capability, with consideration for outages that last more than 2.5 days.
- The expected available transfer capability, with consideration for non-tieline or operational constraints (for example, a constraint on an internal/external interface that imposes a limit on imports or exports). [27]

The number of TRs for sale in both short-term and long-term auctions is determined using the "simultaneous feasibility test", which ensures "that the congestion rents collected by the IESO…shall, under most circumstances, be sufficient to cover any payment obligations owing by the IESO to TR holders…"[28] In conducting simultaneous feasibility test, the IESO is to use a forecast of available transmission transfer capability that takes into account prolonged outages that are scheduled for or likely to occur for the time during which the TRs that are to be sold at the auction will be valid. In other words, the simultaneous feasibility test takes into consideration, among other factors, any outages that are expected to occur at the intertie when TRs sold at the auction are valid. If there is a planned outage, the IESO would be expected to adjust the quantity of TRs offered up to the day when the final pre-auction report is published.

As noted earlier, in this case the IESO neither notified market participants of the outage prior to the relevant short-term TR auction or materially reduce the number of short-term TRs for auction.

It then paid TR holders $220,000 in payouts when the transfer capability on the Ontario-to-Minnesota intertie was reduced to zero due to an external limitation. This is contrary to the IESO's own rules. According to its Market Manual, the IESO should have ceased making TR payouts during the outage. The IESO is only expected to resume making payouts to TR holders in the hour after the outage has been resolved.

[27] See page 5 of Market Manual 4: Market Operations Part 4.4: Transmission Rights Auction, available at: http://www.ieso.ca/-/media/files/ieso/document-library/market-rules-and-manuals-library/market-manuals/market-operations/mo-transmissionrights.pdf.
[28] See Chapter 8, Section 4.6.1 of the Market Rules, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-rules/mr-chapter8.pdf?la=en.

Recommendation 2-2:

The IESO should ensure its procedure for determining an outage when administering Transmission Rights aligns with the Market Rules.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 *Introduction*

In this chapter, the Panel examines the market impact of a flaw in the IESO's integration of Demand Response resources.

2 *New Matters*

2.1 *Fictitious Demand: the Unintended Consequence of Integrating Demand Response Resources*

In May of 2016, the IESO introduced the Demand Response (DR) auction. Unlike DR resources procured through past procurement mechanisms,[29] resources procured through the DR auction actively participate in the wholesale electricity market. They do so by submitting bids that specify the amount of consumption they are willing to reduce and the price at which they are willing to do so. These resources are activated to provide DR (i.e. reduce consumption) when the market price exceeds their bid price.[30]

Resources participating in the DR auction are either directly connected to the transmission grid or are connected at the distribution level. The IESO has direct visibility over transmission-connected resources, meaning it can observe their consumption levels and send them dispatch instructions, but has no such visibility over distribution-connected resources. As mentioned above, DR resources procured through the auction must participate in the wholesale electricity market. For transmission-connected resources, this involves bidding into the market in the normal course. Conversely, distribution-connected DR resources are not represented in the IESO's model of the transmission system and had not previously participated in the wholesale electricity market.[31]

[29] Prior to May of 2016, DR resources were manually activated by the IESO through mechanisms outside the wholesale electricity market, primarily based on a target market price or low supply cushion levels.
[30] For more detailed information on the obligations of resources procured through the DR auction, and how they are activated, see pages 96-106 of the Panel's May 2017 Monitoring Report, available at: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf.
[31] Furthermore, distribution-connected DR resources are often an amalgamation of many smaller resources, committed to providing coordinated DR as a single resource. Despite the amalgamated resources potentially being located at different points on the transmission grid, they need to be modelled as a single resource at a single location in order to be dispatched as one DR resource.

To allow distribution-connected DR resources to bid into the wholesale electricity market and meet their DR auction obligations, the IESO needed to create virtual representations of these resources in its model of the transmission system. In May 2016 the IESO did just that, integrating the virtual DR resources into the software responsible for optimizing supply and demand. Unfortunately, the way in which these resources were integrated created an unintended consequence whereby, at times, up to 220MW of fictitious demand was added to the market (although the average over the period would have been lower). This unintended consequence only impacted the unconstrained sequence of optimizing supply and demand, which is where the market price and resource market schedules are determined. For the duration of the 11 months during which this issue went undetected and unresolved, the addition of fictitious demand regularly inflated the Hourly Ontario Energy Price (HOEP) as well as uplifts that are calculated as a direct function of the HOEP. Over the 11-month period in question, the estimated impact on the HOEP and transmission loss uplift combined could have ranged as high as between $450 million to $560 million, although a simulation accounting for additional potential variables could yield lower estimates. For some market participants, this was offset in large part by a corresponding decrease in Global Adjustment payments. However, exporters, who do not pay the Global Adjustment, and Class A market participants, who pay less (or no) Global Adjustment by virtue of the Industrial Conservation Initiative, would have felt a larger impact.

The sections below describe in greater detail the circumstances that triggered the unintended consequence and quantify its impact on the HOEP and certain uplift.

The IESO discovered and resolved the unintended consequence in April 2017. However, as of September 2019, it had not disclosed the existence of the unintended consequence or its impact to market participants.

Circumstances that Triggered the Addition of Fictitious Demand

The IESO's scheduling algorithm has a mechanism designed to account for dispatchable loads who may be consuming without a bid in the current hour.[32] This 'no-bid mechanism' is triggered when a dispatchable load has no bid in the current hour, but has a future bid within in the scheduling algorithm's forecast window. Under such circumstances, the no-bid mechanism adds

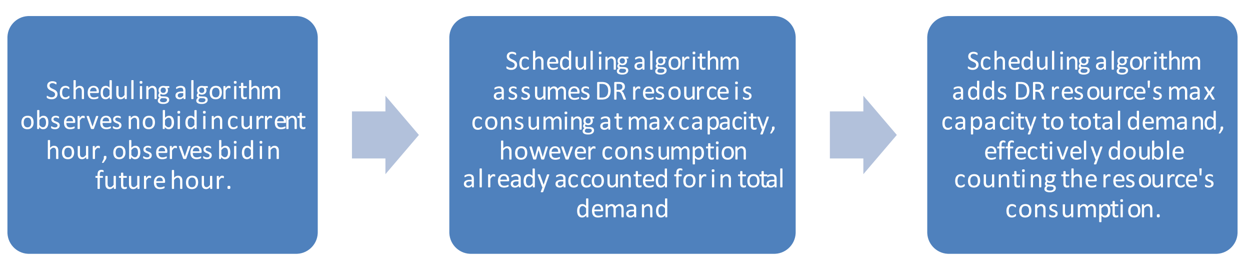
[32] Dispatchable loads are price takers when they consume energy without a bid in the system.

the dispatchable load's meter value (its current consumption) to total system demand to ensure sufficient generation is scheduled to meet demand.

The no-bid mechanism started applying to virtual DR resources when they entered the market in May of 2016. However, virtual DR resources are typically an aggregation of a number of smaller loads embedded within a distribution network; as such, they have no meter for the no-bid mechanism to read. Without that reading, the scheduling algorithm assumes (by reading a manually set value) that the virtual DR resource is consuming at its maximum capacity, which is equal to the megawatts it cleared in the DR auction. As far as the virtual representation of these loads on the transmission system is concerned, these loads are consuming at maximum capacity.

The consumption of these loads is not just accounted for on the transmission network by way of the virtual DR resource, but on the distribution network as well. Because the loads themselves are embedded within the distribution network, their consumption is accounted for in the IESO's forecast of non-dispatchable demand. Hence, when the no-bid mechanism is triggered, the loads' consumption is accounted for twice: once by the IESO's forecast, and again by its virtual representation on the transmission system.[33] This double counting of consumption adds fictitious demand to the system.

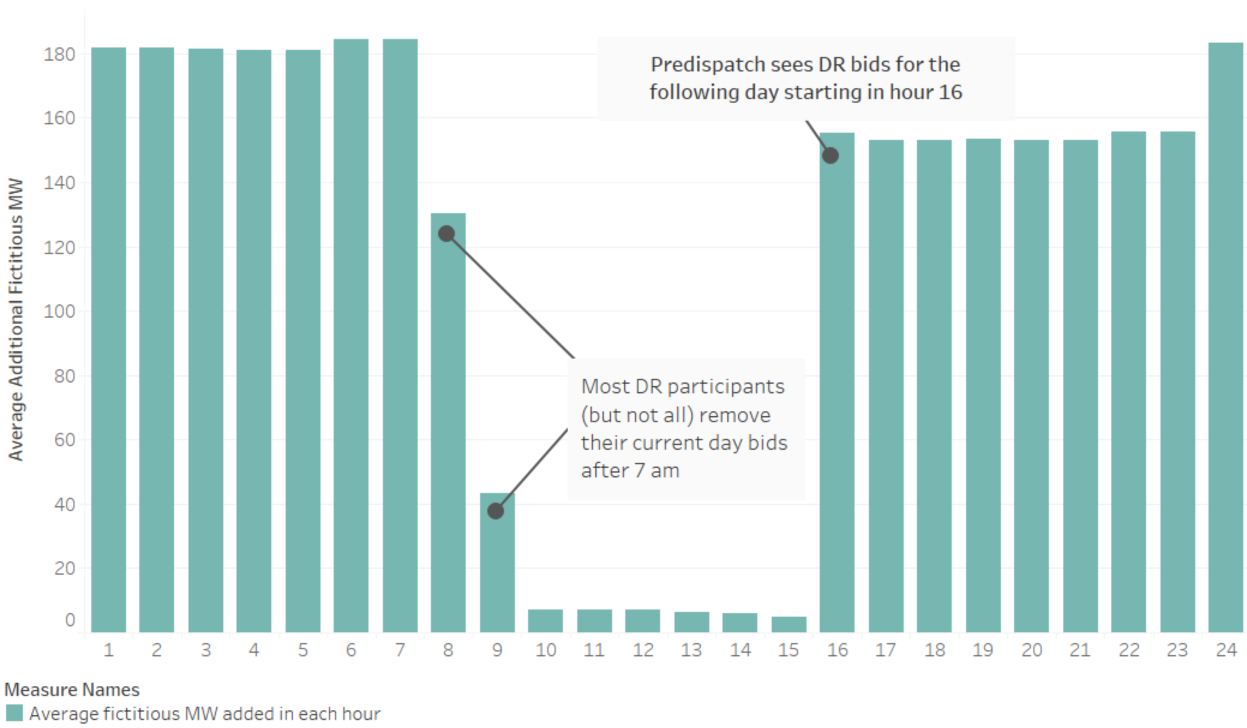
This chain of events makes up the unintended consequence associated with the integration of distribution-connected DR resources into the wholesale electricity market.[34]



[33] When the virtual DR resource has a bid in the current hour, its demand is removed from the IESO's forecast of distribution network demand; this does not occur when there is no bid in the current hour and the no-bid mechanism is triggered.
[34] The addition of fictional MW is dependent on the bid/offer reading process which occurs at the top of each hour during the first interval. Therefore, this chain of events plays out in intervals 2 through 12 of the relevant period hours.

The addition of fictitious demand is far more likely to impact the early morning, late afternoon and evening hours. The scheduling algorithm forecasts prices for the hours up until the end of the current day; in hour ending (HE) 15 (i.e. 2 p.m. to 3 p.m.) the scheduling algorithm extends its forecast to include all hours of the following day as well. Given that virtual DR resources generally remove the entirety of that day's bids around HE 8,[35] from HE 9 to HE 15 there are no future bids for the scheduling algorithm to observe. Accordingly, no fictitious demand is added during those hours. In HE 16, when the scheduling algorithm extends its forecasting period to include the following day, the scheduling algorithm observes the bids the virtual DR resource has made for the next day. As a result, fictitious demand is added in each of the hours between HE 16 of the current day and HE 7 of the next day when virtual DR resources typically to remove their bids once again.

Figure 3-1: Average Fictitious Demand by Hour
May 2016 – April 2017
(MW)



[35] Virtual DR resources may remove their current day bids after 7 am if their capacity has been deemed unlikely to be needed that day.

Impact on Market Prices and Uplift

The unintended consequence that added fictitious demand to the market was active for a period of 11 months and 6 days; from May 18, 2016 when DR resources were integrated to the market, until April 24, 2017 when the IESO applied an interim fix (the "relevant period"). The IESO's interim fix involved changing each virtual DR resource's cleared DR auction megawatts—the assumed consumption level when the unintended consequence is in effect—to zero. The IESO applied an enduring fix on July 12, 2017.

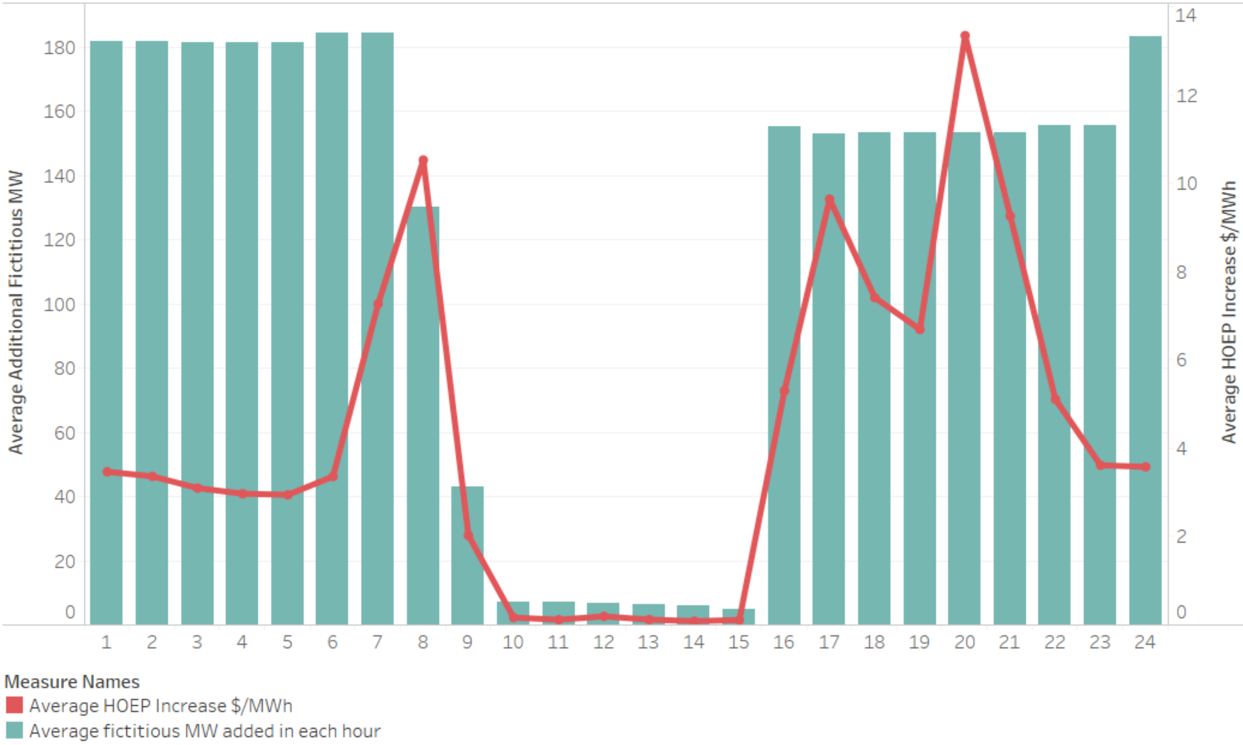
Of the 8,184 hours in which the unintended consequence was operative, 6,281 hours were impacted by the addition of fictitious demand. In those hours, fictitious demand was added to the unconstrained sequence of optimizing supply and demand, which is where the market price and market schedules are determined. Some of those hours experienced up to 220 MW of fictitious demand, although the average over the period would have been lower. Additional demand is met by scheduling increasingly expensive supply, thus increasing the market price. In instances where supply is tight and the supply stack is steep, small increases in demand can cause significant increases in the market price.

To assess how the market price (the Hourly Ontario Energy Price or HOEP) was impacted during these hours, the Panel ran a simulation of the unconstrained scheduling algorithm, removing the fictitious demand in each hour during the relevant period. Use of this methodology reveals the highest estimated market price and uplift impacts that resulted from the unintended consequence. A simulation that accounts for additional potential variables could yield lower estimates.

Figure 3-2 displays the estimated average increase in the HOEP resulting from the addition of fictitious demand over the relevant period, grouped by each hour of the day.

The estimated average increase in HOEP during the relevant period was as much as $4.50/MWh, though the impact is estimated to have been far more significant in many hours. Hours with higher than average HOEP increases coincide with hours that typically have tighter supply such as the mid-morning ramp up period and the early evening when consumption in the province is often the highest.

Figure 3-2: Simulated Average HOEP Increase versus Average Fictitious Demand (MW & $/MWh)



The most direct impact of the increase in HOEP was felt by Ontario consumers and exporters of electricity, who paid an artificially high HOEP, to the benefit of generators and importers.

However, the artificially high HOEP did not result in an equivalent increase in total system costs, which the Panel defines as the sum of HOEP, the Global Adjustment and uplift. This is due to the inverse relationship between the HOEP and the Global Adjustment in which any change in HOEP is to some degree offset by an inverse change in the Global Adjustment. It is difficult to estimate exactly how much of the increase in wholesale electricity costs was offset by a corresponding decrease in the Global Adjustment. This is due to the fact that there are many different contract structures as well as rate regulation that determine the payments to be recovered through the Global Adjustment, each of which interact with the HOEP in different ways. Nonetheless, in reviewing a sample of the contract structures and rate regulation, it is clear that a dollar increase in the HOEP results in less than a dollar reduction in the Global Adjustment.[36]

Although the impact of the unintended consequence on the Global Adjustment is difficult to estimate with precision, the impact on uplift is less ambiguous. Many uplifts are calculated as a direct function of the HOEP, increasing or decreasing as does the HOEP, and adding to or reducing total system costs. One such example is transmission losses, which occur when electricity is transmitted across long distances. Over the relevant period, the estimated increase in HOEP associated with the addition of fictitious demand resulted in a corresponding estimated increase ranging as high as between $10 million to $13 million in transmission loss uplift.

Another uplift—for Congestion Management Settlement Credit (CMSC) payments—also increased as a result of the unintended consequence. CMSC payments are made to generators, dispatchable loads, importers and exporters when the schedule they receive from the constrained sequence (which determines actual production and consumption schedules) differs from the schedule they receive from the unconstrained sequence (which determines the market price). The larger the megawatt difference in schedules, the more CMSC payments they receive. The estimated impact of the unintended consequence was twofold: a quantity and price impact. The unintended consequence increased the quantity of megawatts eligible to receive CMSC payments as it added fictitious demand to the unconstrained sequence but not the constrained sequence. Furthermore, as noted above the unintended consequence increased the HOEP, which, on average, tends to increase the CMSC payments per megawatt.

In times of tight supply, the addition of fictitious demand often had a dramatic inflationary impact on the HOEP. To illustrate this impact, consider HE 20 on June 9, 2016. This hour had an HOEP of $1,619/MWh, the fourth highest in the history of the Ontario wholesale electricity market.

There are also fairness concerns related to the impact of the unintended consequence on wealth transfers amongst market participant groups. Class A market participants who take advantage of

[36] For example, payments under the Clean Energy Supply contracts held by many of Ontario's gas fired resources decrease when the HOEP increases, but only if the generator is deemed to be online under the terms of the contract. The Panel has observed generators regularly operating when not deemed. During such hours, the generator is receiving the higher HOEP, but there is no reduction in their contract payment, thus no reduction in the Global Adjustment.

the Industrial Conservation Initiatives pay less (or no) Global Adjustment and exporters do not pay the Global Adjustment at all. These market participants do not see any (or only a partial) offset to their total costs when the HOEP increases.

Conclusion

The unintended consequence had a significant impact on the wholesale electricity market, in the form of higher HOEP and higher uplifts that are calculated as a direction function the HOEP (the impact of which was offset in large part by a reduction in the Global Adjustment for some market participants), and wealth transfers amongst market participant groups.

Recommendation 3-1A

The Panel recommends that—when implementing changes to the market—the IESO audit the pre-deployment testing process to ensure that sufficient controls are in place to identify errors and unintended consequences.

As of September 2019, the IESO had not yet disclosed the existence of the unintended consequence or its impact to market participants, despite having at least one good opportunity to do so. At the Market Operations Awareness Session in May 2017, the IESO explained the reasons behind the prevalence of recent high prices but made no mention of the unintended consequence, despite knowledge of its impact on the high price hours in question.[37] In instances where an IESO error or unintended consequence has a significant impact on the wholesale electricity market, the Panel believes it appropriate that the IESO publicly disclose such information as soon as reasonably possible. This ensures that market participants have correct and up-to-date information on which to base decisions.

Recommendation 3-1B

The Panel recommends that, as soon as possible after the IESO detects an error or unintended consequence that significantly impacts the wholesale electricity market, it publically discloses details of the error or unintended consequence, the impact on the market and the actions taken or to be taken to address the matter.

---

[37] See slides 21-33 of the IESO's May 2017 *Operations Awareness Session* presentation, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2017/Operations-Awareness-May-3-2017.pdf?la=en.

Appendix: Market Outcomes

This Appendix reports on outcomes in the IESO-administered markets for the period between May 1, 2017 and October 31, 2017 (Summer 2017 Period), with comparisons to previous reporting periods as appropriate.

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.

Table A-1: Average Effective Price by Consumer Class Summer 2016, Winter 2016/17 & Summer 2017 ($/MWh)

Customer Class	Average Weighted HOEP	Average Global Adjustment	Average Uplift	Effective Price
Class A – Summer 2017	10.13	54.27	2.38	66.78
Class A – Winter 2016/17	17.17	45.96	2.41	65.55
Class A – Summer 2016	16.45	49.73	2.68	68.86
Class B – Summer 2017	12.72	110.17	2.77	125.66
Class B – Winter 2016/17	20.14	90.01	2.66	112.81
Class B – Summer 2016	21.33	92.65	3.16	117.41
All Consumers – Summer 2017				110.31
All Consumers – Winter 2016/17				103.26
All Consumers – Summer 2016				107.55

Description:

Table A-1 summarizes the average effective energy price in dollars per MWh by consumer class for the Summer 2017 Period, the period between November 1, 2016 and April 30, 2017 (Winter 2016/17 Period) and the period between May 1, 2016 and October 31, 2016 (Summer 2016 Period). The effective price is the sum of the HOEP,[38] the GA and uplift charges. Accordingly, it

[38] 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.

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 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".

Class A consumers are those 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. Class B are all other consumers.[39]

The "All Consumers" group in Table A-1 represents what the effective electricity price would have been for all consumers if they all paid GA on a volumetric basis. However, 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. The remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month.[40]

Starting with its March 2018 Monitoring Report covering the Summer 2016 Period, the Panel moved embedded Class A consumers (those connected at the distribution level) from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table A-1.[41] For this purpose, the Panel assumes that embedded Class A consumers have a similar load profile to that of directly-connected Class A consumers.

[39] See Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998,* available at: http://www.ontario.ca/laws/regulation/040429.
[40] For more information on the GA allocation methodology and its effect on each consumer class, see pages 4-12 of the Panel's December 2018 report entitled "The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches," available at: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.
[41] 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 March 2018 Monitoring Report. All references to effective price in this report — including all tables and figures—reflect the Panel's updated methodology.

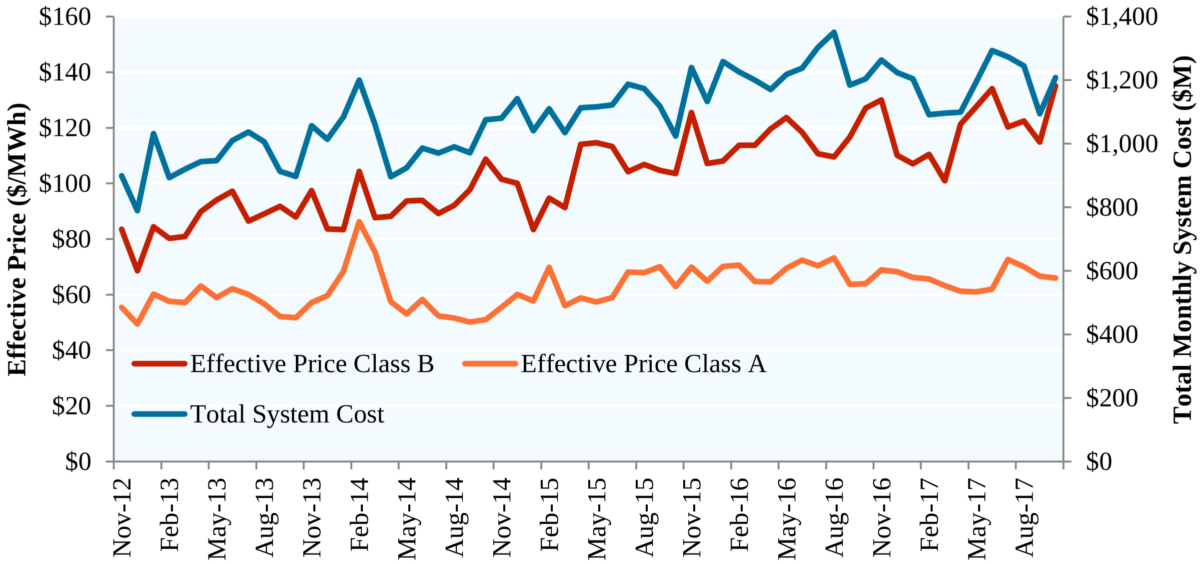
Commentary:

The average effective price for Class A remained fairly constant while the Class B effective price increased considerably. Comparing the Summer 2016 and Summer 2017 Periods, the Class A effective price decreased by $2.08/MWh, while the Class B effective price increased by $8.25/MWh. Few Class B consumers will feel the direct impact of this increase in effective price as the commodity prices payable by most Class B consumers have been set under the "Fair Hydro Plan" introduced by the previous Ontario government in mid-2017.[42]

The increase in the Class B effective price compared to the Summer 2016 Period is mostly due to three factors: an increase in the size of Class A, a decrease in the size of Class B, and an increase in the magnitude of the GA. The size of Class A was increased and the size of Class B was decreased by the decision to lower the threshold for participation in Class A from 1 MW to 500 kW for certain industrial sectors. Meanwhile, the GA was higher due to the low demand and associated low HOEP in the Summer 2017 Period, which led to a greater shortfall between market revenues and the rates for contracted and rate-regulated generators.[43]

[42] The current government is taking steps to wind down the Fair Hydro Plan – see the *Fixing the Hydro Mess Act, 2019*.
[43] The Global Adjustment also includes costs associated with various IESO conservation programs. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges.

Figure A-1: Monthly Average Effective Electricity Price & System Cost November 2012 – October 2017 ($/MWh & $)



Description:

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.

Commentary:

Total system cost in the Summer 2017 Period fell modestly when compared to the Summer 2016 Period but showed a slight increase from the Winter 2016/17 Period. This reduction in cost is due to lower demand in the Summer 2017 Period compared to the Summer 2016 Period. The effective price faced by Class B consumers increased, as previously noted.

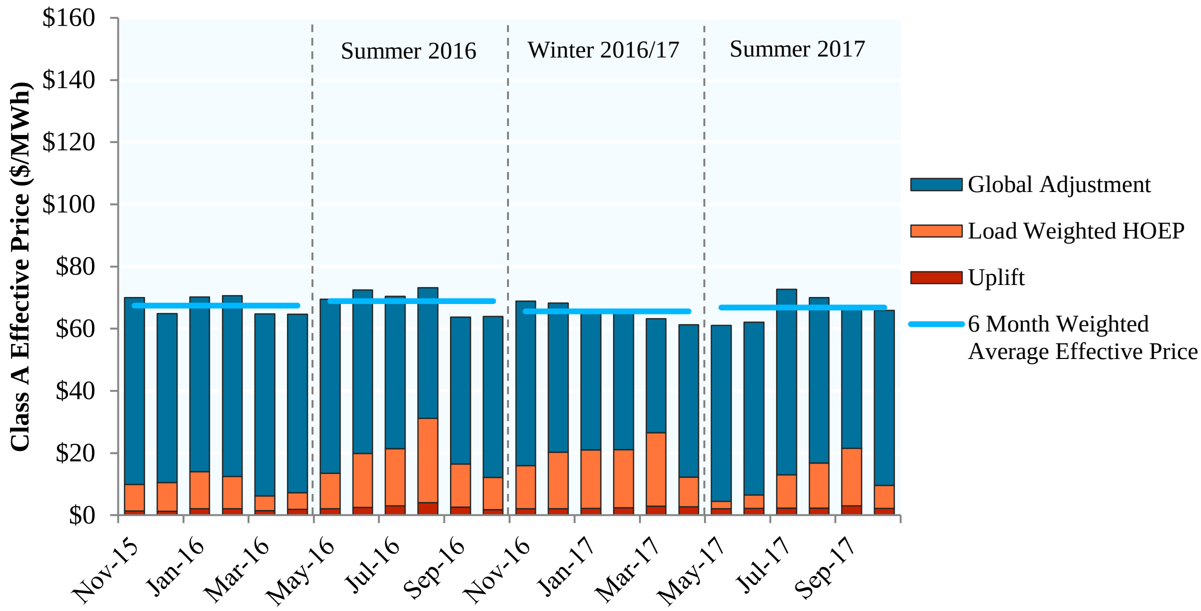
Figures A-2A & A-2B: Average Effective Price by Consumer Class & by Component

Description:

Figures A-2A and A-2B separate the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A and Class B consumers for the previous two years. They also show the total effective price averaged over each six-month period for each consumer class.

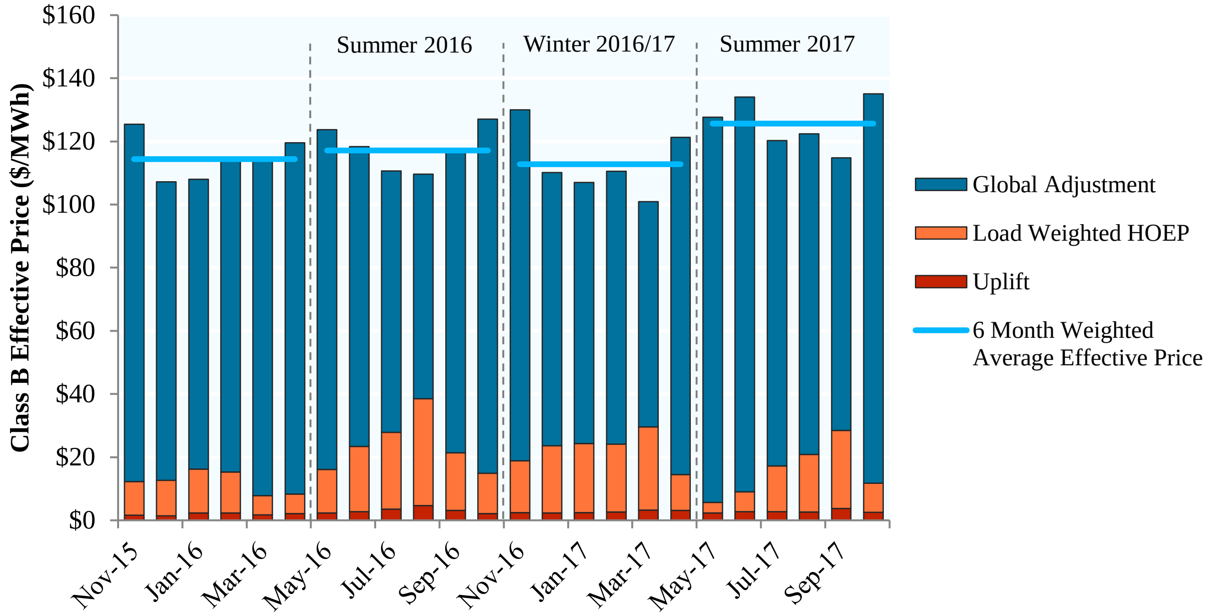
The GA is primarily[44] composed of payments to rate-regulated and contracted generators to make up the shortfall between market revenues, which are related to HOEP and demand, and regulated or contracted rates. In short, the GA is the revenue need less HOEP and uplift payments. The GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases, but this is not necessarily a one-for-one relationship. 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, a higher GA tends to increase the effective price more for Class B than Class A consumers.

Figure A-2A: Average Effective Price for Class A Consumers by Component November 2015 – October 2017 ($/MWh)



[44] As noted above, the GA also includes costs associated with various IESO conservation programs.

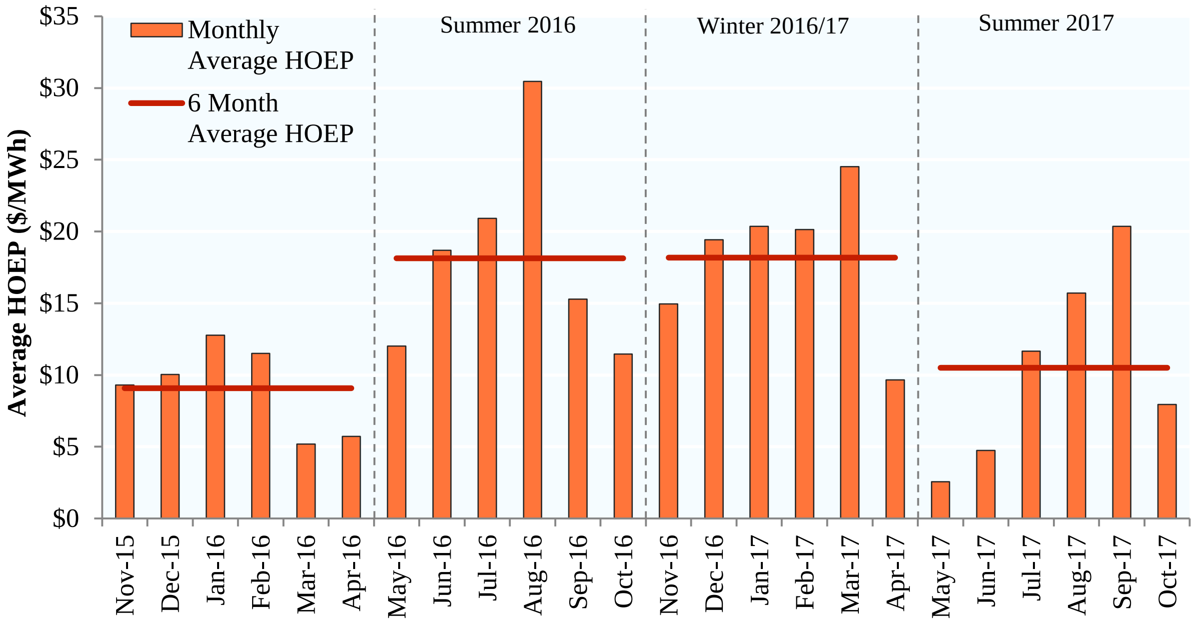
***Figure A-2B: Average Effective Price for Class B Consumers by Component
November 2015 – October 2017
($/MWh)***



Commentary:

The Class B effective price remained significantly higher than the Class A effective price. The Summer 2017 Period saw an average Class A effective price of $66.78/MWh and an average Class B effective price of $125.66/MWh. Class A effective prices remained relatively constant compared to previous periods, while Class B effective prices reached a record high. The two highest monthly Class B effective prices to date occurred during the Summer 2017 Period: $134.11/MWh in June and $135.09/MWh in October. These were both months with particularly low HOEPs, resulting in higher GA charges for Class B.

Figure A-3: Monthly & 6 Month (Simple) Average HOEP
November 2015 – October 2017
($/MWh)



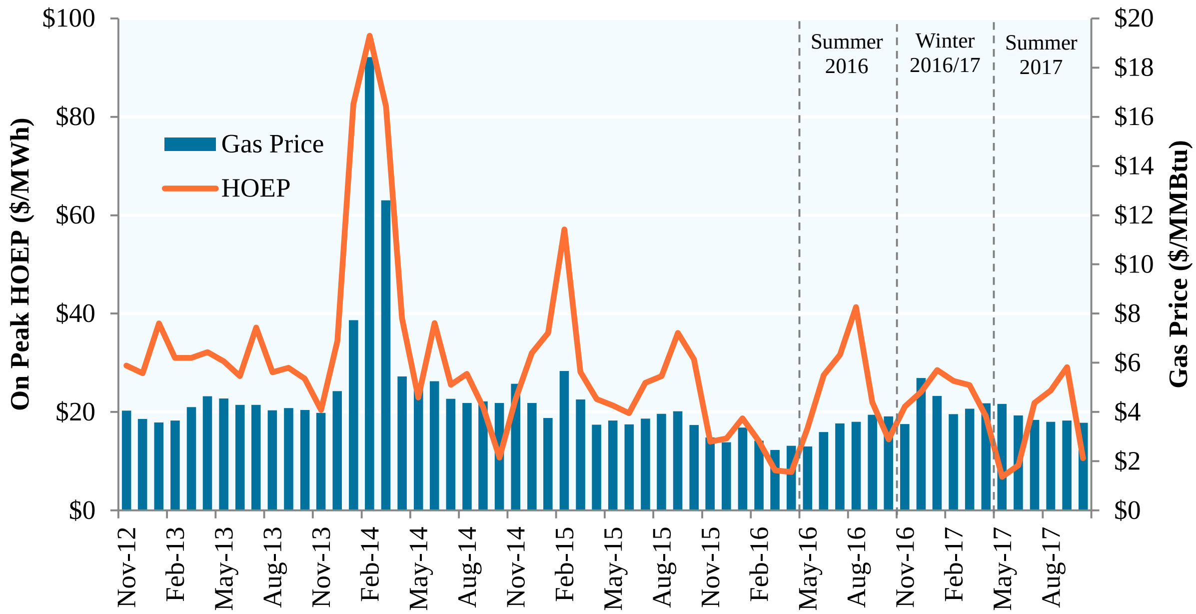
Description:

Figure A-3 displays the simple monthly average HOEP as well as the simple monthly average for each six-month period since November 2015. The HOEP is the simple average of the twelve market clearing prices (MCPs) set every five minutes within an hour.

Commentary:

The Summer 2017 Period saw an average HOEP of $10.47/MWh, much lower than the Summer 2016 Period average HOEP of $18.15/MWh. Lower market prices were predominantly driven by demand which was 5.3% lower than in the Summer 2016 Period.

Figure A-4: Natural Gas Price & HOEP during On-Peak Hours
November 2012 – October 2017
($/MWh & $/MMBtu)



Description:

Figure A-4 plots the average monthly HOEP during on-peak hours[45] and the monthly average of Dawn Hub day-ahead natural gas prices for days with on-peak hours for the previous five years. 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.

Commentary:

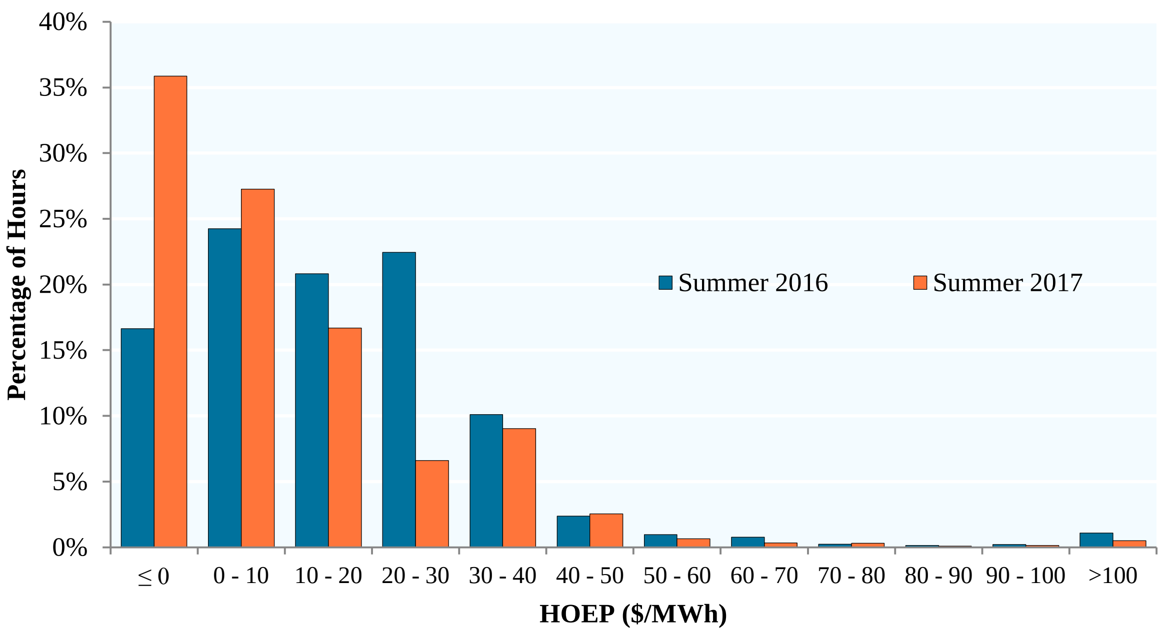
The average gas price over days containing on-peak hours was $3.78/MMBtu in the Summer 2017 Period, compared to $4.31/MMBtu in the Winter 2016/17 Period and $3.43/MMBtu in the Summer 2016 Period. In the past, daily changes in gas prices were positively correlated with movements in the on-peak HOEP, as natural gas generators were frequently the marginal resource during those hours. In the Summer 2017 Period, as in the previous two reporting periods, however, no statistically significant correlation existed, perhaps because as new supply

---

[45] 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.

has been added to the grid, wind and hydro have displaced natural gas as principal on-peak marginal resources, as shown in Figure A-6 below.

Figure A-5: Frequency Distribution of Hourly Ontario Energy Price Summer 2016 & Summer 2017 (% of Hours)



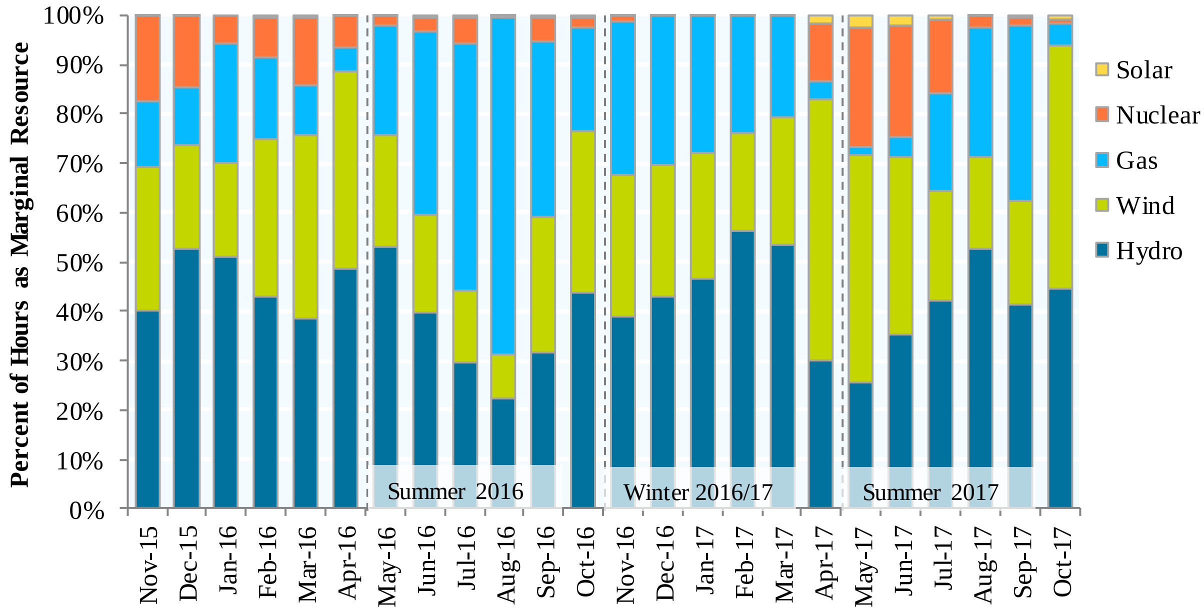
Description:

Figure A-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Summer 2017 and Summer 2016 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.

Commentary:

The Summer 2017 Period saw a significant increase in low HOEPs. In 80% of the hours, the HOEP was less than $20/MWh, and in 36% of hours the HOEP was $0/MWh or negative. Given that output from zero-marginal cost generators—primarily wind and solar—remained fairly constant, the increase in low-priced hours was primarily due to low demand resulting in surplus baseload generation. May 2017 was the month with the lowest prices since market opening in 2002; in 64% of the hours the HOEP was non-positive.

Figure A-6: Share of Resource Type Setting the Real-Time MCP
November 2015 – October 2017
(% of Intervals)



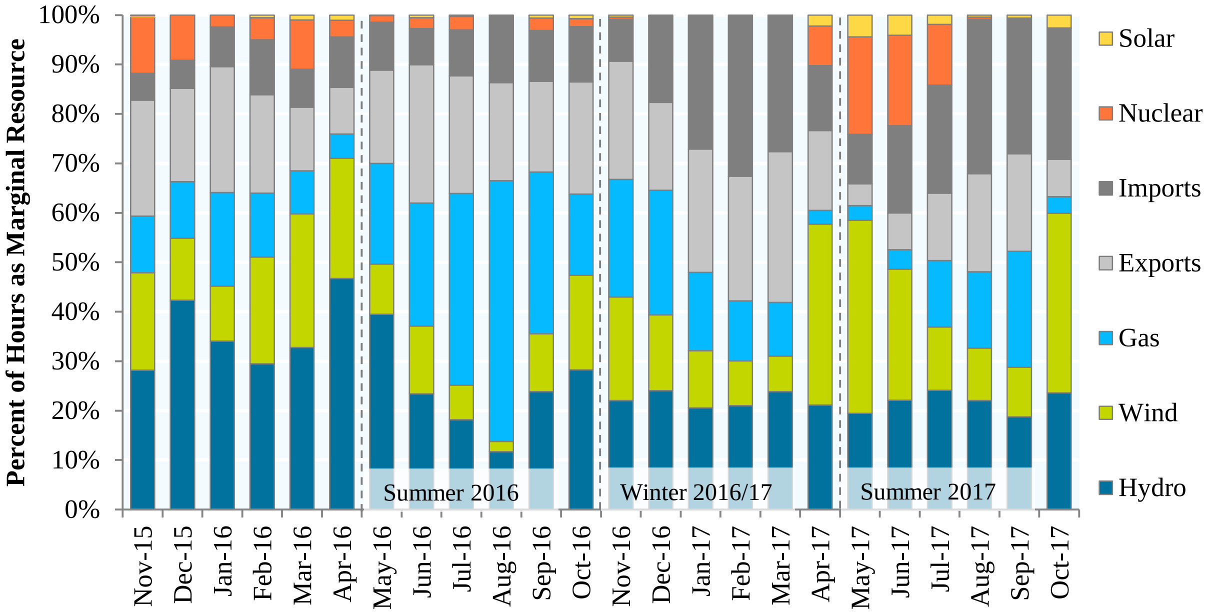
Description:

Figure A-6 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.

Commentary:

Lower demand in the Summer 2017 Period resulted in wind and nuclear resources setting the MCP more often and a significant reduction in the frequency of natural gas resources setting that price. Hydro, wind, and gas were most frequently the marginal resources, setting the MCP in 41%, 32% and 15% of intervals respectively.

Figure A-7: Share of Resource Type Setting the One-Hour Ahead Pre-Dispatch MCP November 2015 – October 2017 (% of Hours)



Description:

Figure A-7 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-6, Figure A-7 shows how the marginal resource mix changes from pre-dispatch to real-time. The frequency with which imports and exports set the PD-1 MCP is important, as these transactions are unable to set the real-time MCP.[46] 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.

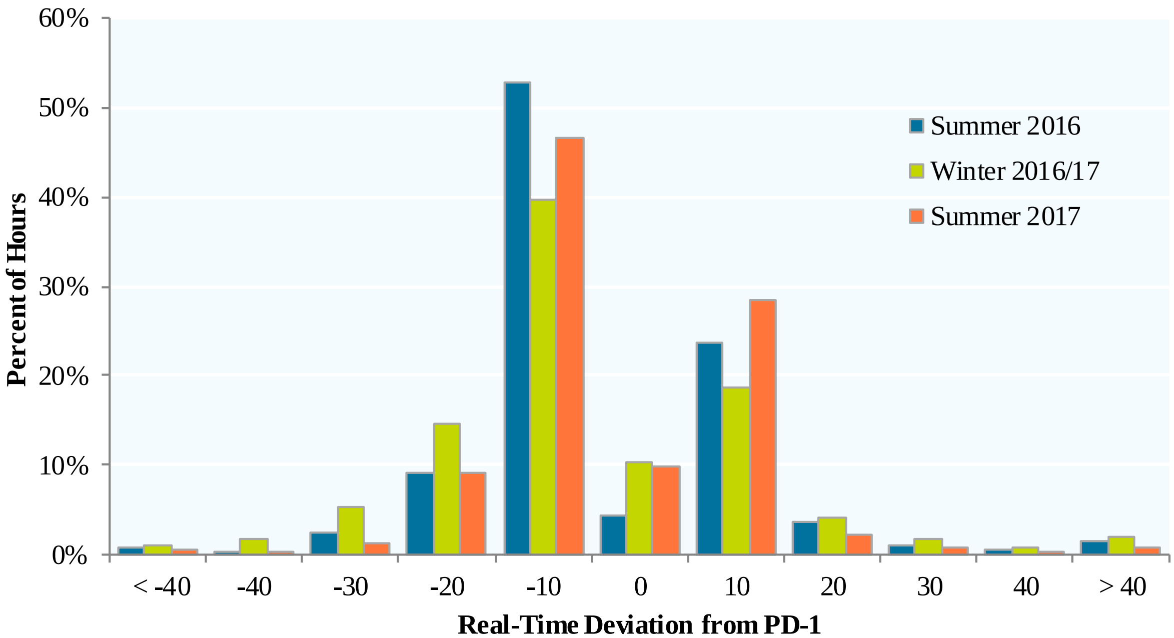
Commentary:

The mix of resources setting pre-dispatch prices in the Summer 2017 Period saw increases in wind and nuclear and a decrease in gas, parallel to changes in resources setting real-time prices. Wind resources set the PD-1 price in 23% of hours in the Summer 2017 Period, compared to 11% in the Summer 2016 Period. Nuclear set the price in 8% of hours in the Summer 2017

[46] 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.

Period, compared to 2% in the Summer 2016 Period. Gas saw a reduction from 31% of hours in the Summer 2016 Period to 10% of hours in the Summer 2017 Period. Some of this reduction in gas as the price-setting resource in pre-dispatch is due to the introduction of contracted imports from Québec, which contributed to an increase in imports as the marginal pre-dispatch resource. Imports set the pre-dispatch price 22% of hours in the Summer 2017 Period, compared to 10% in the Summer 2016 Period.

Figure A-8: Difference between HOEP & PD-1 MCP
Summer 2016, Winter 2016/17 & Summer 2017
(% of Hours)



Description:

Figure A-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2017, Winter 2016/17 and Summer 2016 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 and 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. The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. 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 HOEP.

Commentary:

81% of hours in the Summer 2017 Period saw a variation of less than $10/MWh between PD-1 and real-time prices, the same percentage as in the Summer 2016 Period.

Table A-2: Factors Contributing to Differences between PD-1 MCP & HOEP Summer 2016, Winter 2016/17 & Summer 2017 (MW & % of Ontario Demand)

Factor	Summer 2017: Average Absolute Difference		Winter 2016/17: Average Absolute Difference		Summer 2016: Average Absolute Difference	
	MW	% of Ontario Demand	MW	% of Ontario Demand	MW	% of Ontario Demand
Ontario Average Demand	14,629		15,420		15,602	
Demand Forecast Deviation	221	1.51%	195	1.26%	210	1.34%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	14	0.10%	18	0.12%	21	0.13%
Wind Forecast Deviation	131	0.90%	185	1.20%	185	1.19%
Net Export Failures/Curtailments	63	0.43%	88	0.57%	78	0.50%

Description:

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time. The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP:

<u>Supply</u>

- Self-scheduling and intermittent generation forecast deviation (other than wind),
- Wind generation forecast deviation,
- Generator outages and
- Import failures/curtailments.

<u>Demand</u>

- Pre-dispatch to real-time demand forecast deviation and

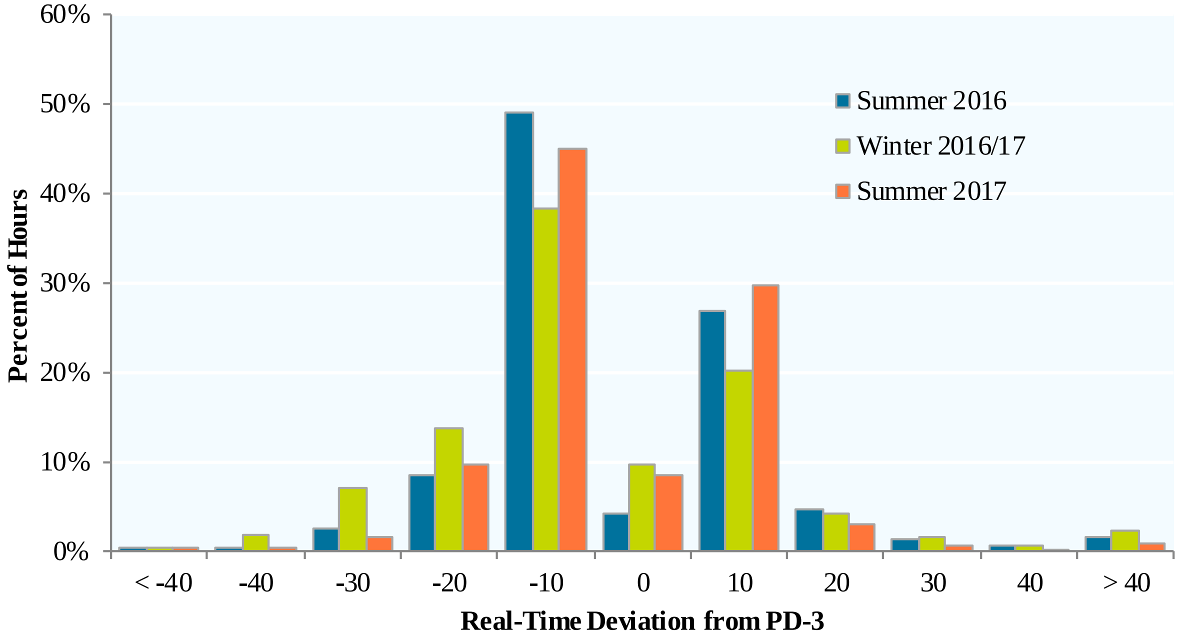
- Export failures/curtailments.

Imports or exports setting the PD-1 MCP can also result in price divergences as these transactions cannot set the price in real-time. Table A-2 displays the average absolute difference between PD-1 and real-time for all of the above-noted factors, 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. Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as they enter offers and bids into the market.

Commentary:

Average demand forecast deviation, the most significant source of deviation between PD-1 MCP and HOEP, was similar during the Summer 2017 Period and Summer 2016 Period, while the next most significant source of deviation, wind forecasts, improved. The reduction in wind forecast deviation is likely attributable to lower wind output during the Summer 2017 Period: it was 19% lower than the output in the Summer 2016 Period, and less than half of the output in the Winter 2016/17 Period.

Figure A-9: Difference between HOEP & PD-3 MCP
Summer 2016, Winter 2016/17 & Summer 2017
(% of Hours)



Description:

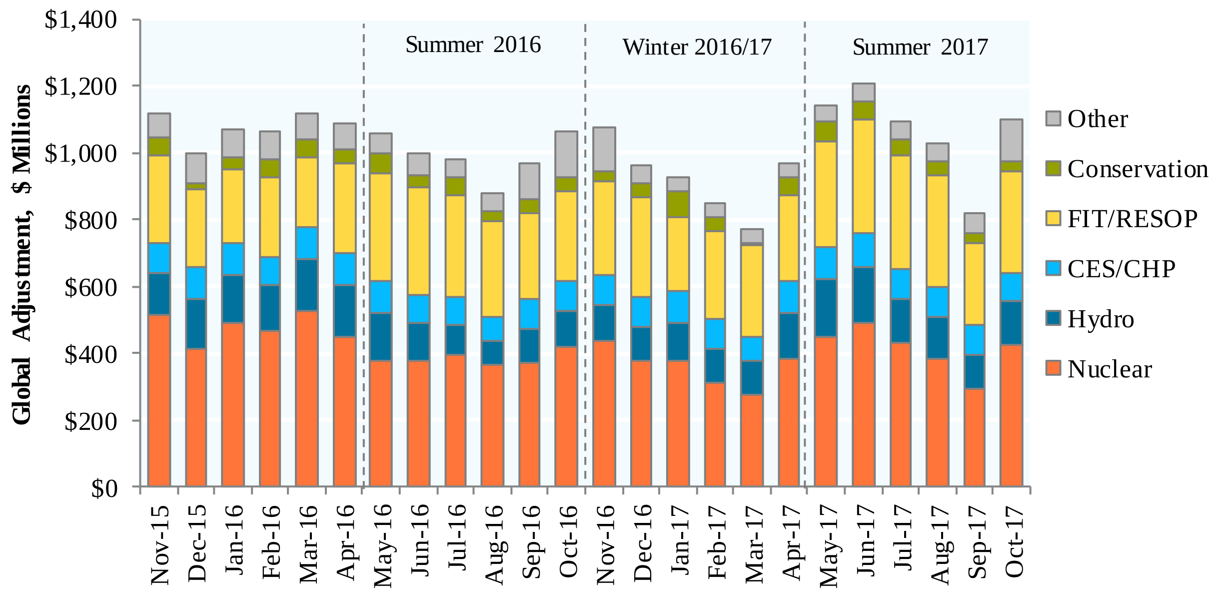
Figure A-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP during the Summer 2017, Winter 2016/17 and Summer 2016 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP, and the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$40/MWh. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time. The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window. Changes in price between PD-3 and HOEP are particularly relevant to non-quick start facilities and energy limited resources,[47] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

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

Commentary:

PD-3 prices were within $10/MWh of the real-time price in 80% of hours in the Summer 2017 Period, compared to 68% of hours in the Winter 2016/17 Period and 83% of hours in the Summer 2016 Period. The average absolute deviation between PD-3 and real-time prices was also lower in the Summer 2017 Period ($6.0/MWh) compared to the Winter 2016/17 Period ($11.4/MWh) and the Summer 2016 Period ($8.0/MWh). These trends are closely aligned with the deviations observed in relation to PD-1 prices.

Figure A-10: Monthly Global Adjustment by Component
November 2015 – October 2017
($)



Description:

Figure A-10 plots the payments to various resources and recovered through the GA each month, by component for the previous two years. We divide the total GA into six components:

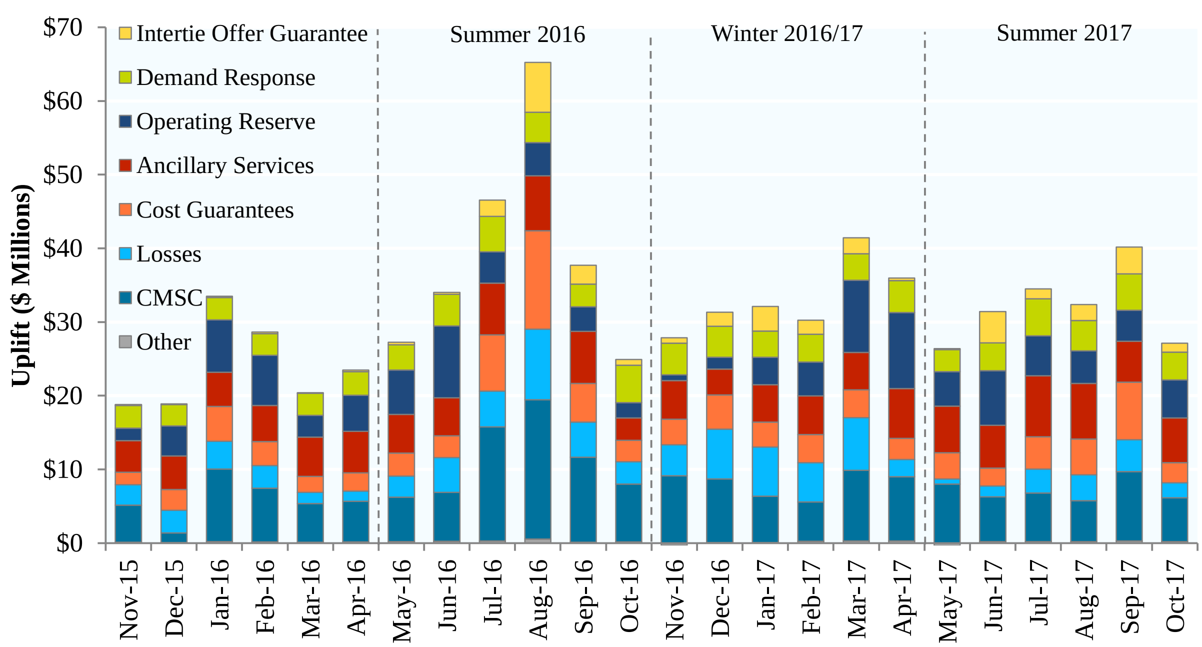
- Payments to nuclear facilities (Bruce Nuclear GS and OPG's nuclear assets);
- Payments to holders of Clean Energy Supply (CES) and Combined Heat and Power (CHP) contracts;
- Payments to regulated or contracted hydroelectric generation;

- 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 or NUG contracts and OPG's Lennox GS).

Commentary:

The GA during the Summer 2017 Period was $452 million larger than the GA during the Summer 2016 Period. This increase was largely driven by the lower HOEPs resulting from lower demand during the Summer 2017 Period, which led to lower market payments. When market payments are lower, higher payments are required to be recovered through the GA to meet generators' contracted or regulated rate revenues. The relative contribution of each component to the GA remained largely unchanged.

Figure A-11: Total Uplift Charge by Component on a Monthly Basis November 2015 – October 2017 ($)



Description:

Figure A-11 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. Hourly uplift components include:

- Congestion Management Settlement Credit (CMSC) payments;
- Intertie Offer Guarantee (IOG) payments;
- Operating Reserve (OR) payments;
- Voltage support payments; and
- Transmission losses.

Monthly uplift components include:

- Payments for ancillary services;
- Guarantee payments to generators under the Day-Ahead Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee (GCG) programs;
- Payments for the IESO's demand response capacity, such as capacity procured through the DR auction; and
- Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.

In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while PCG and GCG payments are combined as Cost Guarantees.

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.[48]

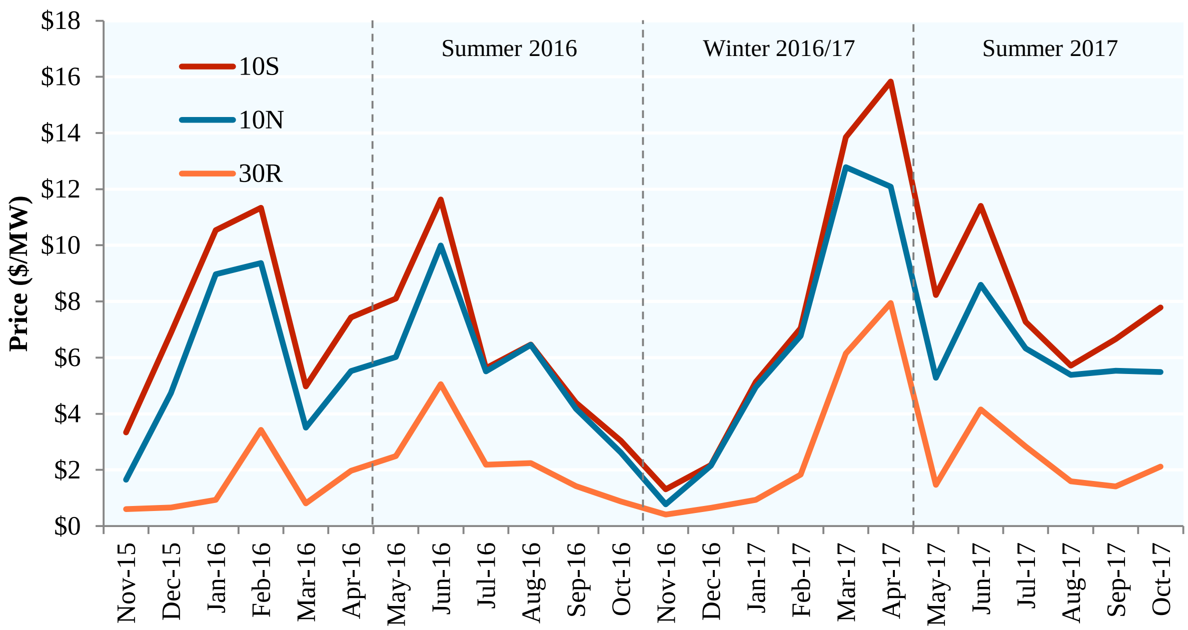
[48] This applies to all monthly and daily uplifts with the exception of costs associated with demand response. The costs of demand response are allocated with the same methodology as the GA, where Class A consumers pay the fraction of costs corresponding to their fraction of Ontario demand during the 5 highest demand peaks of the year, and Class B consumers are billed the remaining sum volumetrically.

Commentary:

Total uplift decreased in the Summer 2017 Period compared to the previous two reporting periods. Total uplift in the Summer 2017 Period was $191 million, compared to $200 million in the Winter 2016/17 Period and $235 million in the Summer 2016 Period.

The reduction in total hourly uplift was driven by significant reductions in both CMSC payments and losses, as would be expected during a period with lower demand and thus lower prices. The decrease in total monthly uplift was largely driven by a significant reduction in PCG payments resulting from lower demand and the resulting reduced use of gas-fired generators.

Figure A-12: Average Monthly Operating Reserve Prices by Category
November 2015 – October 2017
($/MW)



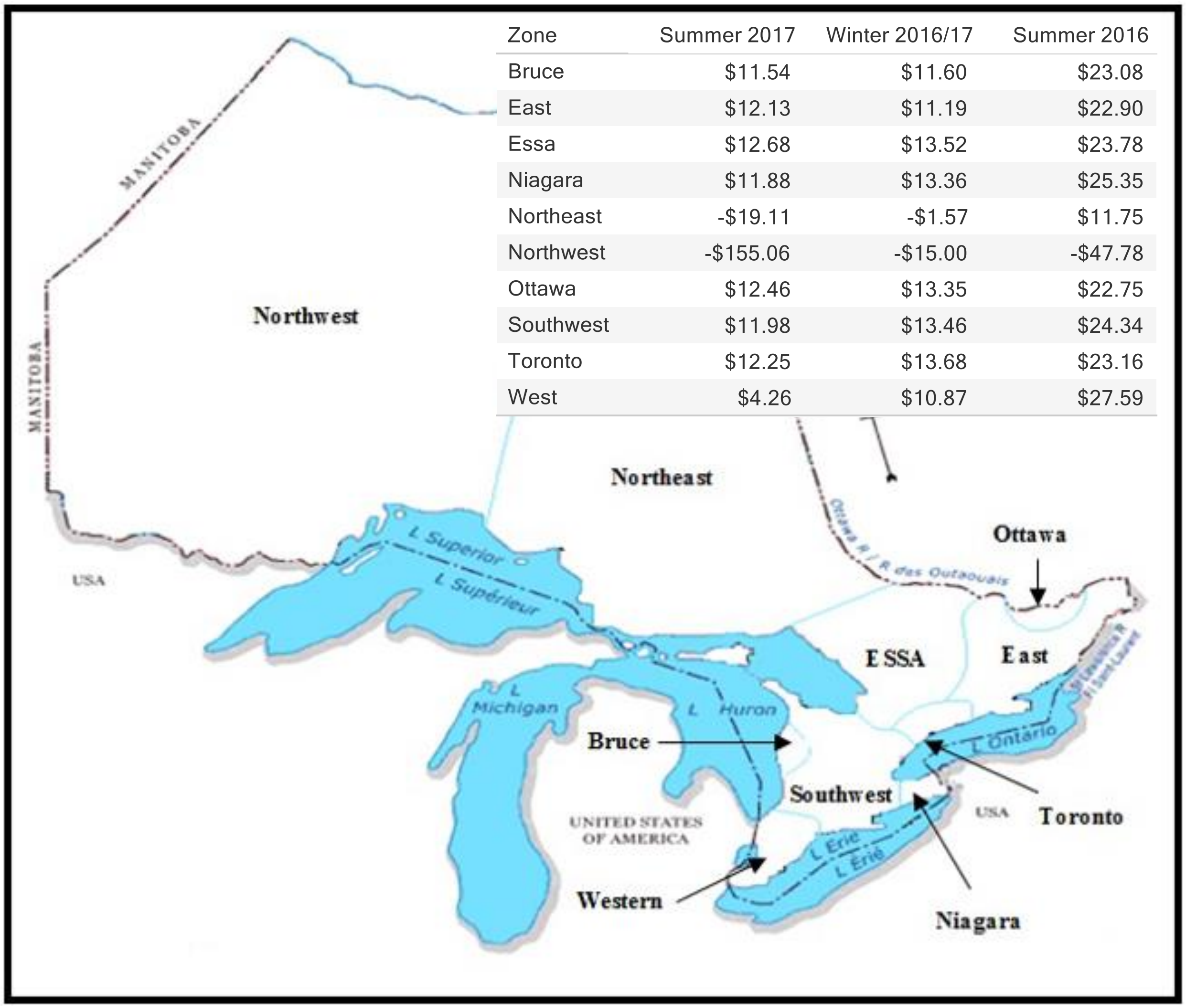
Description:

Figure A-12 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 three OR markets are co-optimized with the energy market, so prices in these markets tend to be subject to similar dynamics. OR demand is non-discretionary because of reliability standards set by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council. 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.

Commentary:

OR prices increased modestly in the Summer 2017 Period when compared to the Summer 2016 Period. Average OR prices in the Summer 2017 Periods were $7.84/MW, $6.10/MW and $2.26/MW for 10S, 10N and 30R respectively. In contrast, the average OR prices in the Summer 2016 Period were $6.54/MW, $5.80/MW and $2.38/MW for 10, 10N, and 30R. While the Summer 2017 Period had significantly lower energy market prices than the Summer 2016 Period, the modest increase in OR prices is likely due to the increase in the use of gas-fired resources as OR, which offer OR at higher prices.

Figure A-13: Average Internal Nodal Prices by Zone
Summer 2016, Winter 2016/17 & Summer 2017
($/MWh)



Zone	Summer 2017	Winter 2016/17	Summer 2016
Bruce	$11.54	$11.60	$23.08
East	$12.13	$11.19	$22.90
Essa	$12.68	$13.52	$23.78
Niagara	$11.88	$13.36	$25.35
Northeast	-$19.11	-$1.57	$11.75
Northwest	-$155.06	-$15.00	-$47.78
Ottawa	$12.46	$13.35	$22.75
Southwest	$11.98	$13.46	$24.34
Toronto	$12.25	$13.68	$23.16
West	$4.26	$10.87	$27.59

Description:

Figure A-13 illustrates the average nodal price of Ontario's ten internal zones for the Summer 2017, Winter 2016/17 and Summer 2016 Periods.

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.

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 in order to ensure that the units are economically selected and scheduled.

Commentary:

Nodal prices in all zones were lower in the Summer 2017 Period compared to the Summer 2016 Period, largely attributable to low demand. High river flows in 2017 increased hydroelectric generation at times, further depressing prices, particularly in the Northwest and Northeast zones.

Figures A-14 & A-15: Congestion by Intertie

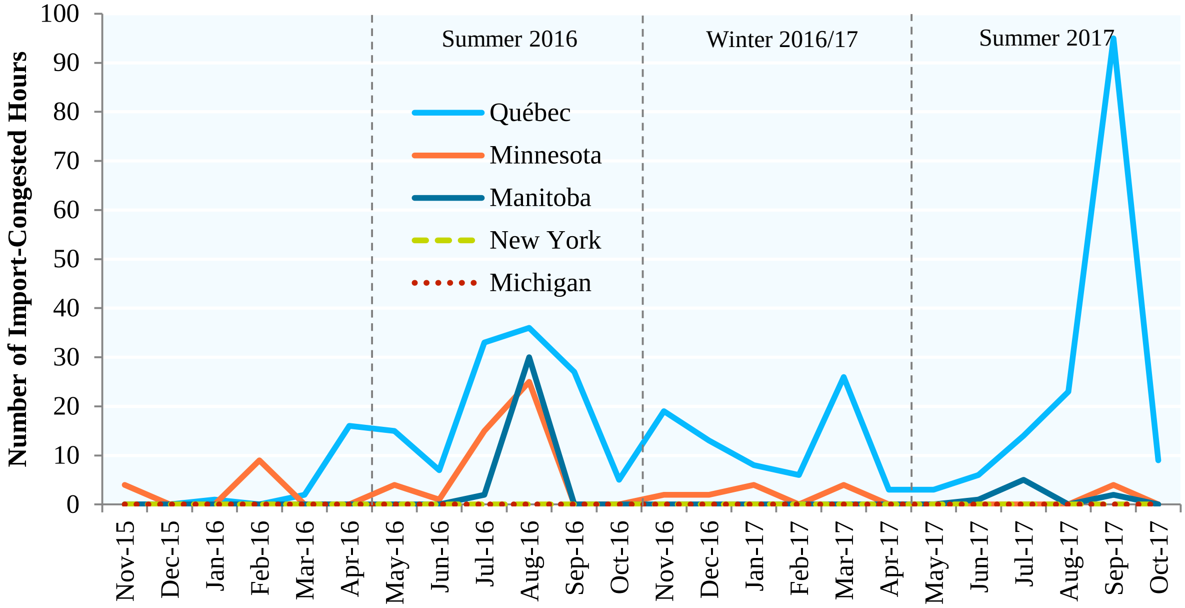
Description:

Figures A-15 and A-16 report the number of hours per month of import and export congestion, respectively, by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

When an intertie has a greater amount of economic net import offers (or economic net export bids) than its 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 when there are more economic transactions than the intertie transmission lines can accommodate. The ICP is positive when there is export congestion and negative when there is import congestion.

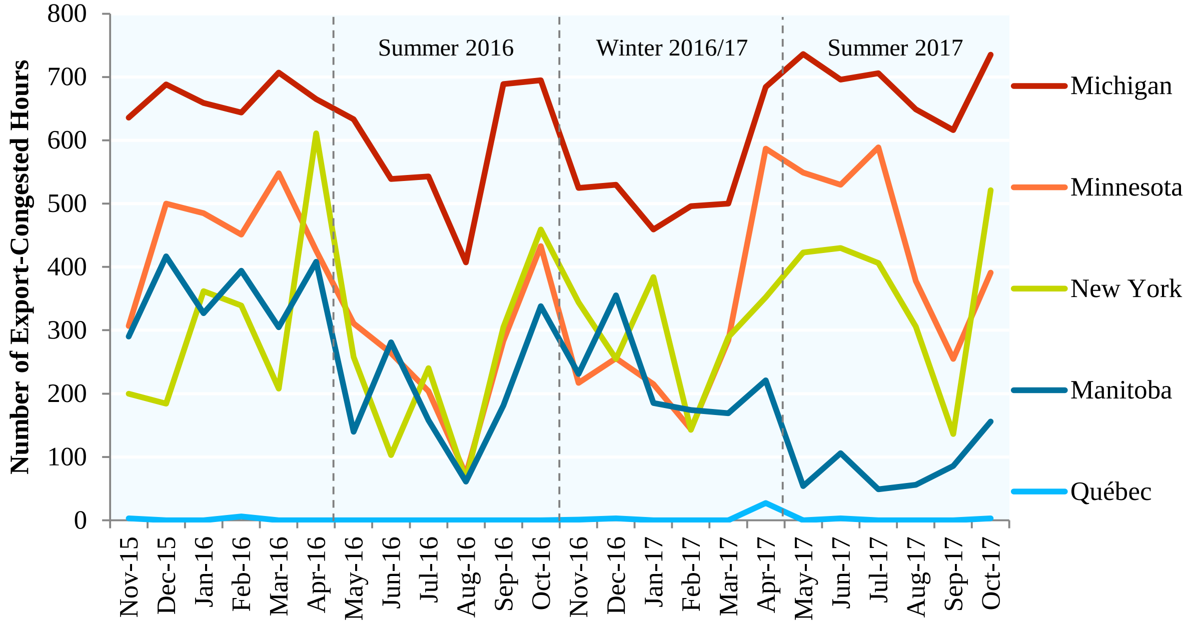
Figure A-14: Import Congestion by Intertie
November 2015 – October 2017
(Number of Hours in the Unconstrained Schedule)



Commentary:

Similar to the Summer 2016 Period, only the Québec, Minnesota, and Manitoba interties experienced import congestion during the Summer 2017 Period. The Québec intertie saw an increase in the number of import-congested hours from 123 hours in the Summer 2016 Period to 150 hours in the Summer 2017 Period, though these numbers still represent a small minority of hours. The increase in congestion on the Québec intertie was primarily driven by a period of more significant Québec imports in mid and late September 2017.

Figure A-15: Export Congestion by Intertie
November 2015 – October 2017
(Number of Hours in the Unconstrained Schedule)



Commentary:

Total export congestion increased in the Summer 2017 Period compared to the previous two reporting periods because of lower HOEPs in the Summer 2017 Period. May 2017 was the month with the most congested hours on the Michigan intertie since market opening, and also the month with the lowest average HOEP since market opening. This congestion is also attributable to the scheduling limit on Ontario's Michigan intertie being lower during the Summer 2017 Period than it was in the preceding two reporting periods.

Table A-3: Monthly Average Hourly Electricity Spot Prices – Ontario & Surrounding Jurisdictions May 2017 – October 2017 ($/MWh)

Month	Ontario (HOEP)	Manitoba	Michigan (MISO)	Minnesota (MISO)	New York (NYISO)	PJM
May	2.56	23.56	39.52	26.73	21.51	38.04
June	4.73	25.56	38.77	27.91	24.33	35.12
July	11.66	31.65	37.17	32.13	26.00	36.65
August	15.71	25.16	33.93	25.64	24.57	31.16
September	20.35	23.26	44.24	27.56	25.13	32.53
October	7.95	25.99	38.93	29.53	25.51	33.06

Description:

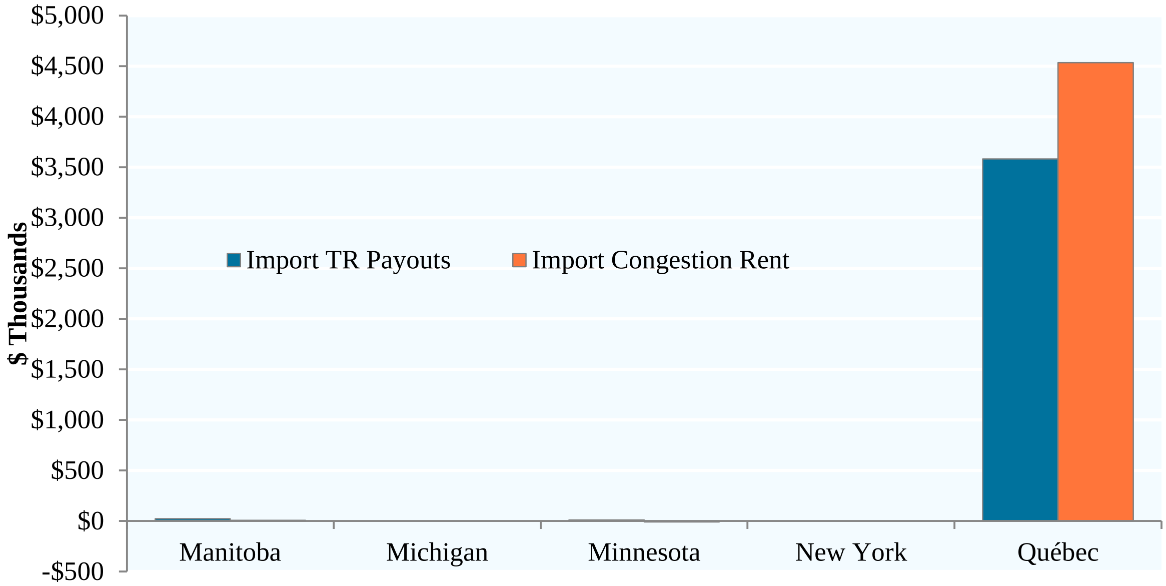
Table A-3 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA or uplift. 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. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table A-3. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs.

Commentary:

As it has been for several years, the average HOEP was lower than the market prices in all of Ontario's neighbouring jurisdictions in every month in the Summer 2017 Period. This is due in part to the capacity surplus in Ontario, and in part to characteristics in the Ontario market that artificially depress prices. Accordingly, Ontario remained a net exporter for every month in the Summer 2017 Period.

Figure A-16: Import Congestion Rent & TR Payouts by Intertie
May 2017 – October 2017
($)



Description:

Figure A-16 compares the total import congestion rent collected to total TR payouts by intertie for the Summer 2017 Period.

An IZP is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the 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 (TR Clearing Account).

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 they hold every time congestion occurs on the intertie in the direction for which they own a TR.

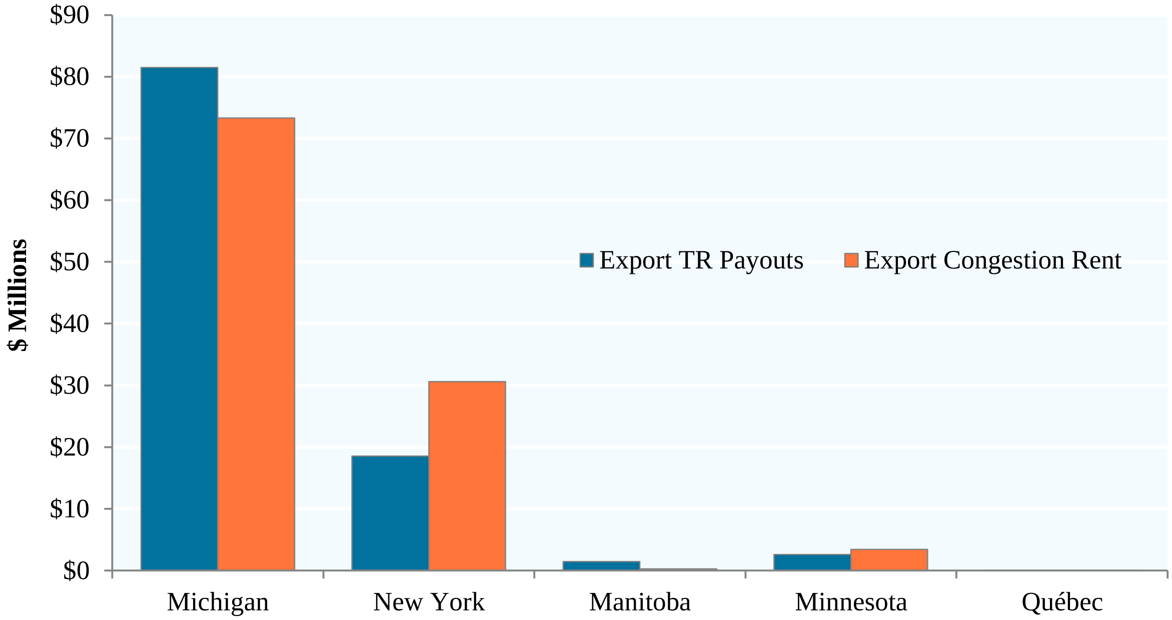
While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. Any shortfalls are covered primarily by TR auction revenues, which are the proceeds from selling TRs (a payment into the TR Clearing Account).

Interties with a high frequency of import congestion hours (see Figure A-14) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

Commentary:

Total import congestion rent in the Summer 2017 Period was $4.5 million, while total import TR payouts were $3.6 million. The Québec intertie saw a congestion rent surplus of approximately $950,000, while the Minnesota and Manitoba interties saw modest congestion rent shortfalls of less than $20,000. The surplus over the Québec intertie was largely due to more megawatts of transmission being available on the intertie than were sold as TRs throughout the period, which was also the case in the Winter 2016/17 Period. 615 MW of import TRs were sold each month, while on average 1143 MW of import transmission capacity was available. No significant financial settlements on the Minnesota and Manitoba interties were expected given these interties were import congested for only 4 and 8 hours respectively during the Summer 2017 Period.

Figure A-17: Export Congestion Rent & TR Payouts by Intertie
May 2017 – October 2017
($)



Description:

Figure A-17 compares the total export congestion rent collected to total TR payouts by intertie for the Summer 2017 Period.

Commentary:

Export TR payouts in the Summer 2017 Period totalled $104.2 million, while export congestion rent totalled $107.6 million. This $3.4 million surplus of congestion rent shows that, province-wide, the TR market was very close to balanced.

Table A-4: Average Long-Term (12-Month) TR Auction Prices by Intertie & Direction November 2016 – October 2017 ($/MW)

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-16	Jan-17 to Dec-17	2,117	175	1,840	383	3,989
	Feb-17	Apr-17 to Mar-18	1,421	78	1,603	128	1,463
	May-17	Jul-17 to Jun-18	1,480	47	1,707	148	2,280
	Aug-17	Oct-17 to Sep-18	560	132	1,779	188	3,632
Export	Nov-16	Jan-17 to Dec-17	35,203	113,394	40,466	43,017	4,425
	Feb-17	Apr-17 to Mar-18	28,353	108,664	34,175	47,840	3,013
	May-17	Jul-17 to Jun-18	29,008	131,418	46,357	56,743	2,473
	Aug-17	Oct-17 to Sep-18	20,148	123,254	52,842	56,204	1,927

Description:

Table A-4 lists the average auction prices for one megawatt of long-term (12-month) TRs for each intertie in either direction for each auction since November 2016. These are the TRs that would have been valid during the Summer 2017 Period. If an auction is efficient, the price paid for one megawatt 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.

Commentary:

Long-term export TR prices decreased noticeably for the two jurisdictions of Manitoba and Québec over the Summer 2017 Period and increased noticeably for New York, indicating that TR market participants expected export congestion to Manitoba and Québec to decline through to the 2018 summer period but expected export congestion to New York to worsen. The only significant change in long-term import TR prices was an increase for imports from Manitoba, indicating an expectation that import congestion will increase. Export TR prices broadly remained higher than import TR prices, indicating that traders expected export congestion to continue to surpass import congestion through to the 2018 summer period.

Table A-5: Average Short-Term (One-Month) TR Auction Prices by Intertie & Direction November 2016 – October 2017 ($/MWh)

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-16	115	14	140	22	233
	Dec-16	90	14	104	26	77
	Jan-17	68	3	157	37	135
	Feb-17	96	1	142	37	85
	Mar-17	62	4	35	5	37
	Apr-17	94	4	43	1	72
	May-17	20	4	45	22	86
	Jun-17	77	4	79	22	108
	Jul-17	82	6	-	24	260
	Aug-17	90	0	-	1	357
	Sep-17	65	7	64	2	265
	Oct-17	14	3	-	2	128
Export	Nov-16	3,633	13,102	3,319	2,904	79
	Dec-16	3,846	10,601	3,802	4,096	120
	Jan-17	4,204	10,475	4,205	5,275	1,123
	Feb-17	3,945	7,855	3,864	3,645	370
	Mar-17	2,655	8,201	2,512	4,208	18
	Apr-17	3,750	12,960	4,471	5,401	19
	May-17	2,983	14,962	5,820	6,002	5
	Jun-17	2,599	11,570	-	5,665	7
	Jul-17	3,802	12,649	-	5,385	8
	Aug-17	2,135	12,689	-	6,220	11
	Sep-17	1,320	11,887	-	4,680	19
	Oct-17	3,058	12,983	-	4,820	5

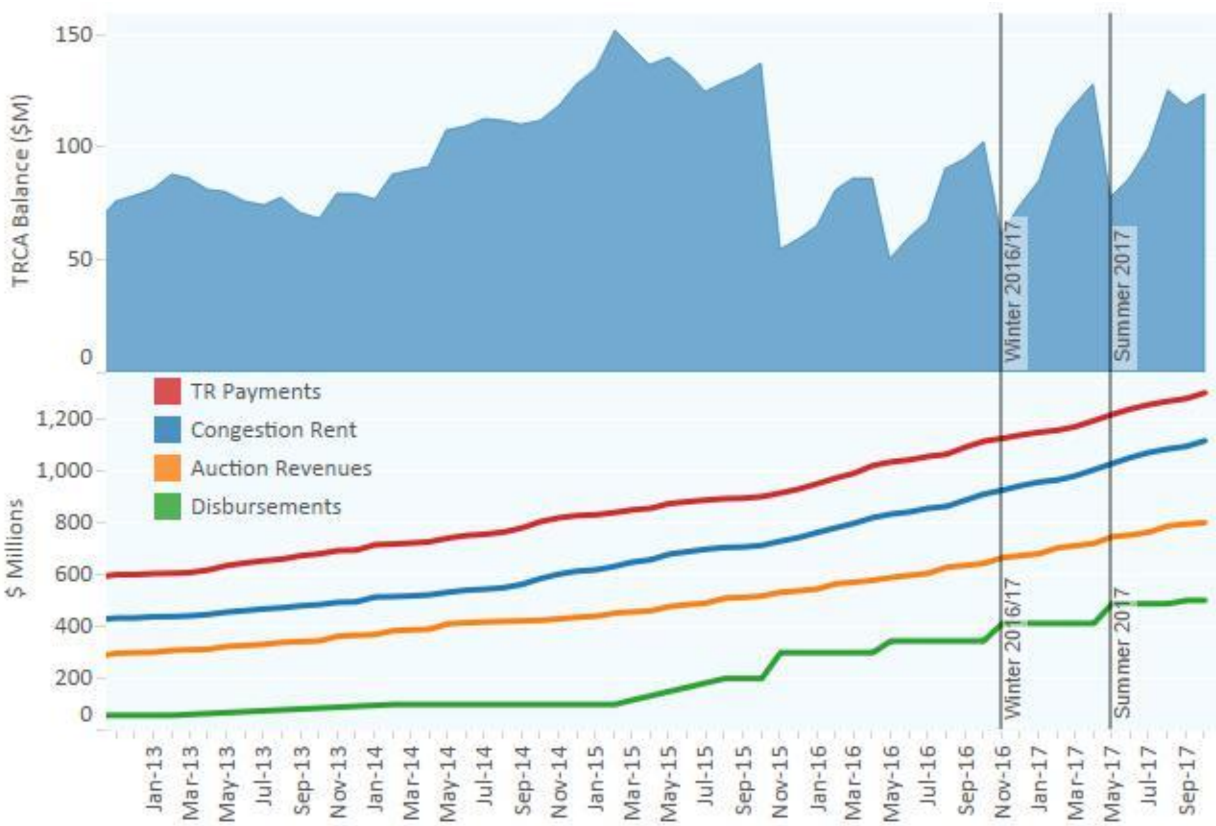
Description:

Table A-5 lists the auction prices for one megawatt of short-term (one-month) TRs for each intertie in either direction for each auction during the Summer 2017 and Winter 2016/17 Periods. Auction prices signal market participant expectations of intertie congestion conditions for the forward period.

Commentary:

Short-term TR prices were broadly stable in the Summer 2017 Period, with import TR prices having fallen in the preceding Winter 2016/17 Period and export TR prices having risen in the same period. Import TR prices for Québec peaked noticeably in August while export prices peaked in January, which is likely due to the significant differences in seasonal demand between Ontario and Québec. In several months, the Minnesota intertie had little to no capacity due to outages, as well as an outage arising from MISO, preventing TRs from being sold.

Figure A-18: Transmission Rights Clearing Account Month-end Balance November 2012 – October 2017 ($)



Description:

The TR Clearing Account is an account administered by the IESO to record credits and debits related to TRs. Figure A-18 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. Credits are congestion rent received from the market, TR auction revenues and interest earned on the TR Clearing Account balance. Debits are TR payouts to TR holders and disbursements to Ontario market participants. The account has a reserve threshold of $20 million set by the IESO Board of Directors: funds in excess of this threshold are intended to be disbursed to wholesale loads and exporters semi-annually or as directed by the IESO Board of Directors.

Commentary:

The balance of the TR Clearing Account decreased to $123.8 million at the end of the Summer 2017 Period, down from $127.3 million at the end of the Winter 2016/17 Period. The October 2017 balance was $103.8 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:

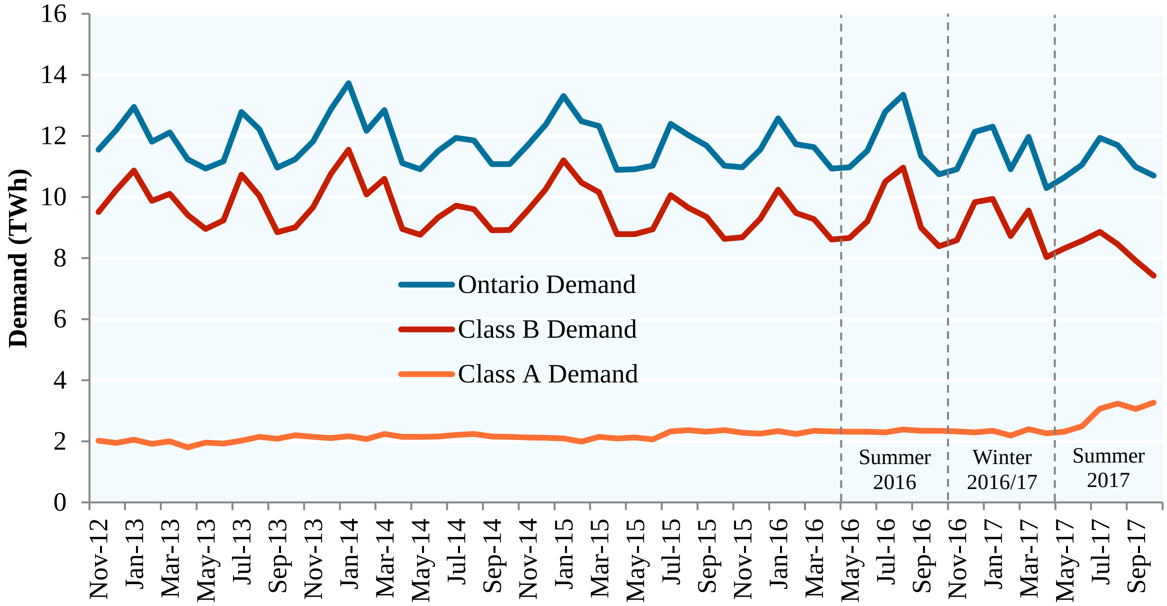
- $193.3 million in revenue, specifically:
    - $112.1 million in congestion rent
    - $80.5 million in auction revenues
    - $0.7 million in interest
- $196.8 million in debits, specifically:
    - $107.8 million in TR payouts
    - $89.0 million in disbursements to Ontario consumers and exporters

Compared to the Winter 2016/17 Period, there was an increase in both credits and debits in the Summer 2017 Period. This was largely due to higher congestion rent and TR payouts associated with significant export congestion in the Summer 2017 Period.

2 *Demand*

This section presents data on Ontario energy demand for the Summer 2017 Period relative to previous years.

Figure A-19: Monthly Ontario Energy Demand by Class A & Class B Consumers November 2012 – October 2017 (TWh)



Description:

Figure A-19 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.[49]

Commentary:

Demand in the Summer 2017 Period was 67.0 TWh, slightly less than the 70.7 TWh in the Summer 2016 Period. The summer in 2017 had more moderate temperatures than the summer of 2016, resulting in lower air conditioning load.

Class A demand grew significantly and Class B demand fell significantly, in part due to the lowering of the threshold for participation in Class A from 1 MW to 500 kW for certain

[49] 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 pages 105-109 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf and the Panel's December 2018 report entitled "The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches," available at: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.

industrial sectors. Between the Summer 2016 and Summer 2017 Periods, Class A demand grew by 3.4 TWh, or 25% of Class A demand, while Class B demand fell by 7.2 TWh.

3 Supply

This section presents data on generating capacity, actual generation, and OR supply for the Summer 2017 Period relative to previous years.

Table A-6: Changes in Generating Capacity Summer 2017 (MW)

Generation Type	Grid-connected		Distribution-level ("Embedded")	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	31	13,009	-	-
Natural Gas	-	10,277	-	-
Hydro	29	8,480	2	240
Wind	230	4,213	8	580
Solar	-	380	49	2,009
Biofuel	-	495	-	109
Gas-Fired and Combined Heat and Power	-	-	10	269
Energy from Waste	-	-	-	24
Total	290	36,854	69	3,231

Description:

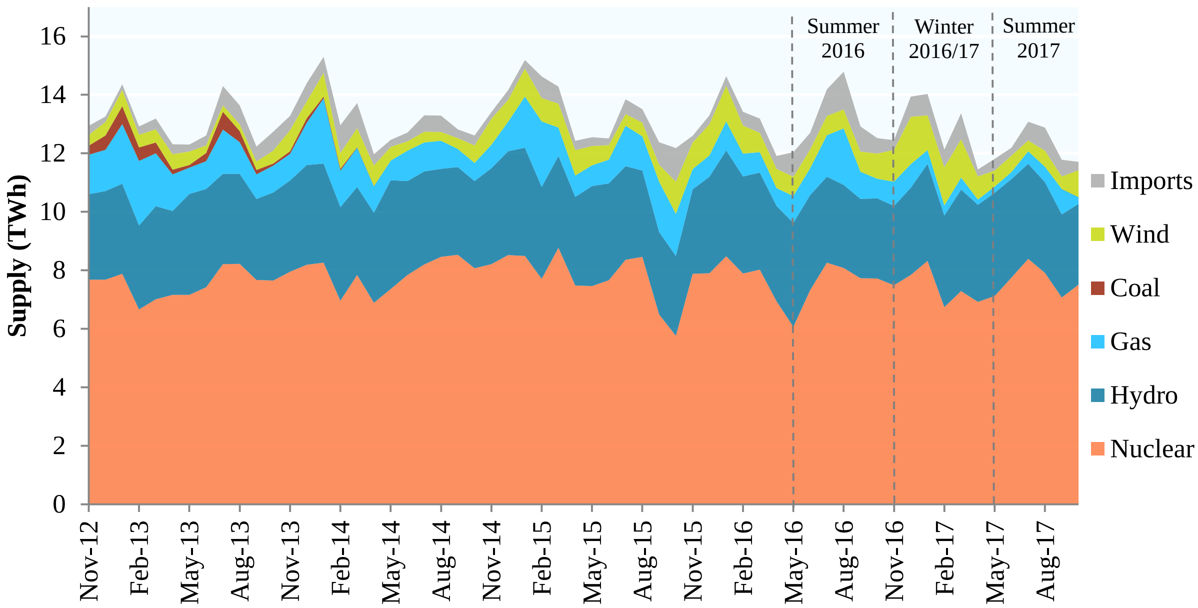
Table A-6 lists the quantity of nameplate generating capacity that completed commissioning and was added to the IESO-controlled grid's total capacity during the second and third quarters of 2017,[50] as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[51] Total capacity of each type at the end of the Summer 2017 Period is also shown.

[50] Capacity totals were obtained from the IESO's 18 month outlook reports, which can be found at http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook.
[51] Embedded capacity totals were obtained from the quarterly *Ontario Energy Report*, which can be found at http://www.ontarioenergyreport.ca/index.php.

Commentary:

Not much new capacity was added to the Ontario generation fleet at either the IESO-controlled grid or the distribution level. What capacity was added was mostly baseload or variable generation offered at low prices, potentially contributing to the continuation of the trend of prevailing low prices in Ontario.

Figure A-20: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule November 2012 – October 2017 (TWh)



Description:

Figure A-20 displays the share of monthly real-time unconstrained production schedules from November 2012 to October 2017 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.[52] Changes in the resources scheduled may be the result of a number of factors, such as changes in market

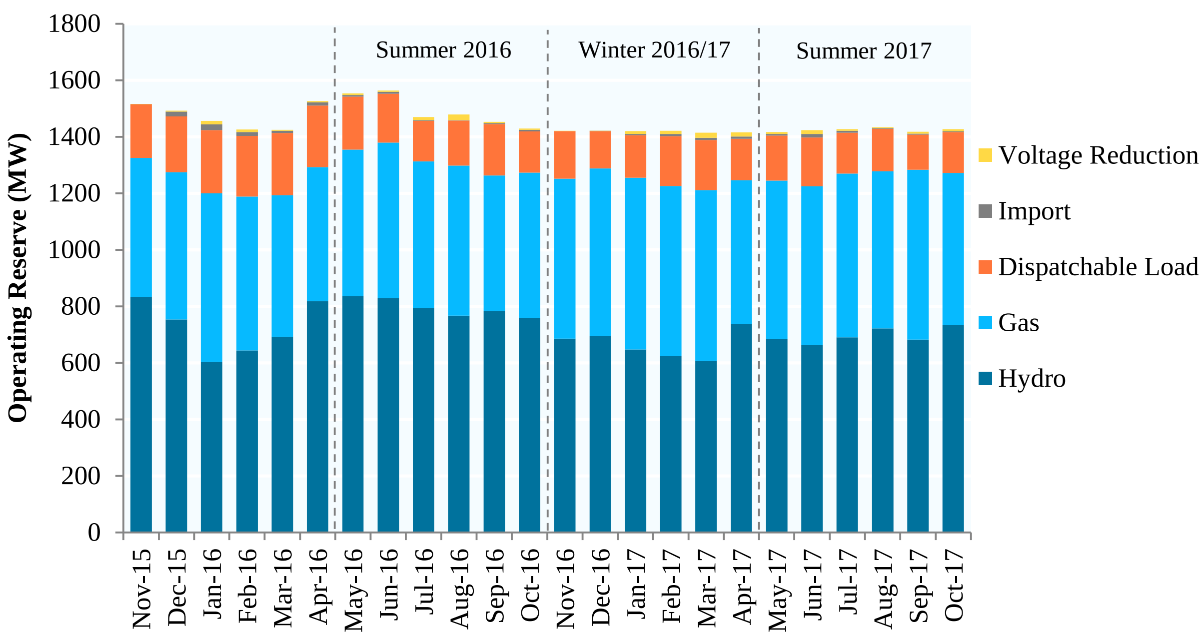
[52] Ontario has significant solar and wind generation connected at the distribution level that is not included in this figure. These embedded resources are not scheduled in IESO-administered markets. Average output from these embedded generators was approximately 0.5 TWh per month; due to data constraints, this quantity cannot be broken down by type of generation.

demand or seasonal fuel variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

Commentary:

Compared to the Summer 2016 Period, the Summer 2017 Period showed a significant reduction in the output of gas-fired generators from 6.8 TWh in the Summer 2016 Period to 2.5 TWh in the Summer 2017 Period. In the Summer 2016 Period, 15.5% of grid-connected gas capacity was in use on average notwithstanding outages and de-rates; this dropped to 5.5% in the Summer 2017 Period. There was also a significant decrease in imports from 5.0 TWh in the Summer 2016 Period to 3.0 TWh in the Summer 2017 Period, and more modest reductions in wind output and exports. Hydroelectric output increased modestly from 18.0 TWh in the Summer 2016 Period to 18.8 TWh in the Summer 2017 Period due to relatively high river flows. Larger reductions in the output of more expensive resources, typically gas and imports, are an expected outcome of the reduction in demand.

Figure A-21: Average Hourly Operating Reserve Scheduled by Resource Type November 2015 – October 2017 (MW)



Description:

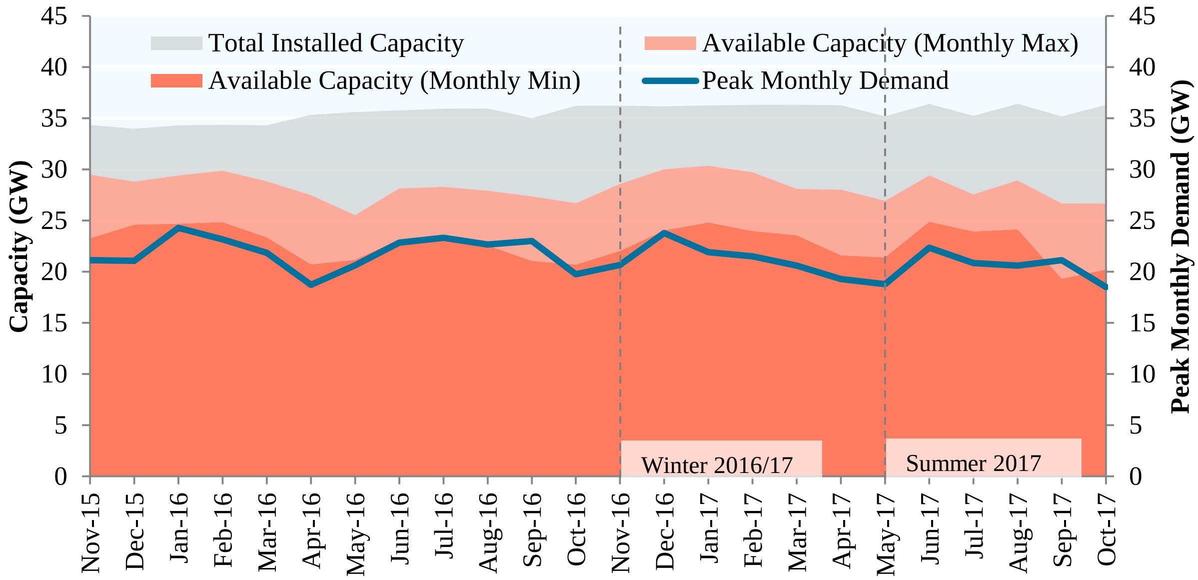
Figure A-21 displays the share of real-time unconstrained OR schedules from November 2015 to October 2017 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads, and voltage reduction (taken as a control action by the IESO).[53] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

Commentary:

The average quantity of OR scheduled remained relatively constant between 1,420 MW and 1,430 MW during the Summer 2017 Period. This is very similar to the Winter 2016/17 Period, but a modest reduction from the average of 1,492 MW in the Summer 2016 Period. The OR resource mix remained reasonably constant between the Summer 2016, Winter 2016/17, and Summer 2017 Periods. Gas generators were scheduled slightly more for OR (40% of OR in the Summer 2017 Period compared to 35% in the Summer 2016 Period), while hydroelectric generators were scheduled slightly less (49% of OR in the Summer 2017 Period compared to 53% in the Summer 2016 Period).

[53] 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.

Figure A-22: Unavailable Generation Relative to Installed Capacity November 2015 – October 2017 (GW)



Description:

Figure A-22 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from November 2015 to October 2017. 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.[54]

Commentary:

The Summer 2017 Period had, on average, slightly less capacity on outage than did the Summer 2016 Period. The Summer 2017 Period did, however, have more capacity on outage than was the case in the Winter 2016/17 Period. These changes in available capacity are largely caused by

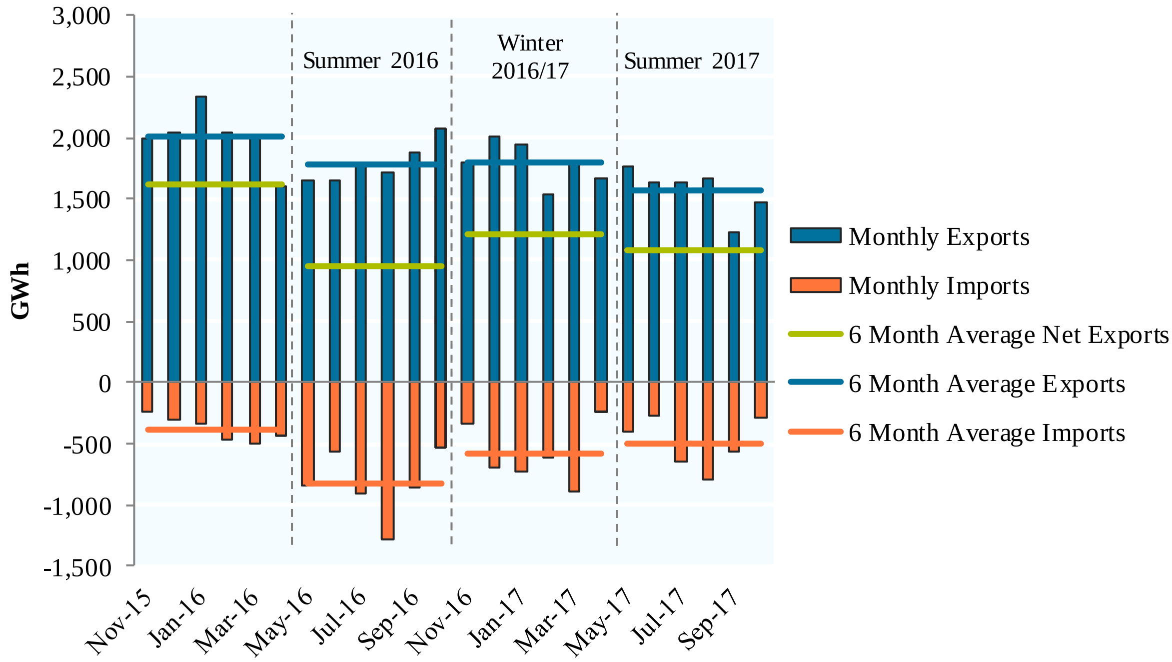
[54] Unavailable generation capacity data was obtained from adequacy reports published daily by the IESO. Daily, weekly and monthly market summaries published by the IESO can be found on the IESO website, available at: http://www.ieso.ca/power-data/market-summaries-archive.

changes in the amount of nuclear and gas capacity on outage between the two monitoring periods.

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.[55]

Figure A-23: Total Monthly Imports and Exports, and Average Monthly Net Exports (Unconstrained Schedule) November 2015 – October 2017 (GWh)



Description:

Figure A-23 plots total monthly imports and exports from November 2015 to October 2017, as well as the average monthly imports, exports and net exports calculated over each six month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

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

Commentary:

Ontario remained a net exporter in the Summer 2017 Period with net exports of 6.45 TWh, up from 5.74 TWh in the Summer 2016 Period. Both exports and imports decreased compared to the Summer 2016 Period. The reduction in exports was caused in part by the average export capability on Ontario's Michigan intertie being 500 MW lower in the Summer 2017 Period than in the Summer 2016 Period.

Figure A-24 & A-25: Interjurisdictional Transactions by Intertie

Description:

Figure A-24 and A-25 present breakdowns of exports and imports, respectively, from November 2015 to October 2017 to and from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly export and import quantities in the Summer 2017 and Winter 2016/17 Periods are given for each intertie in Tables A-7 and A-8.

Figure A-24: Exports by Intertie
November 2015 – October 2017
(GWh)

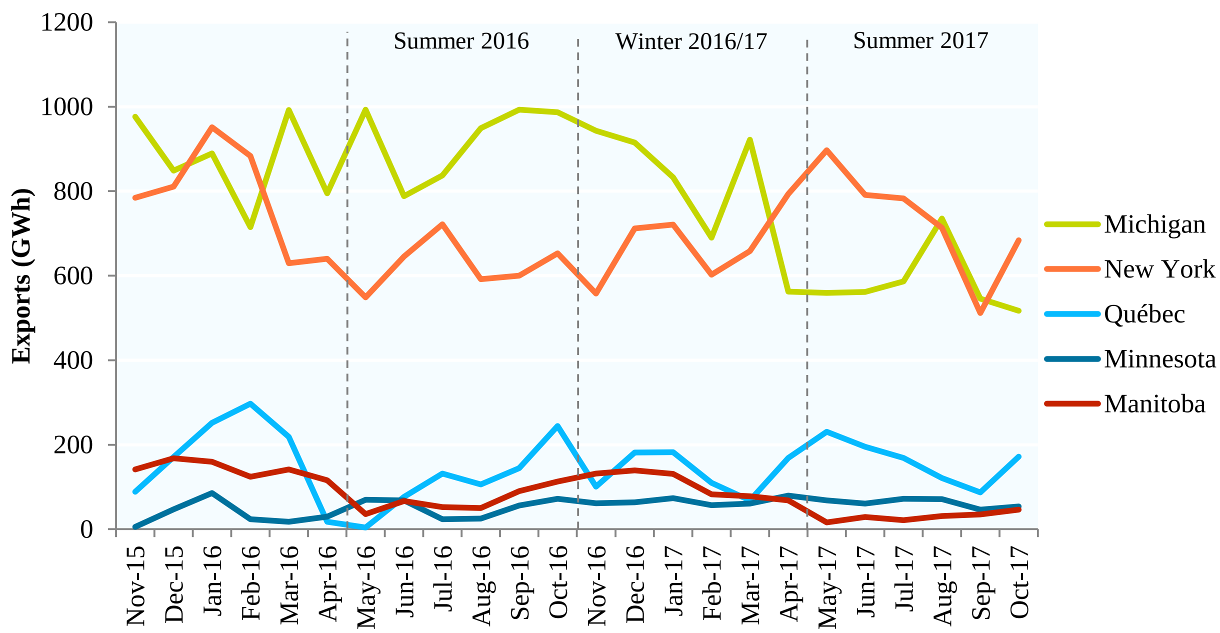
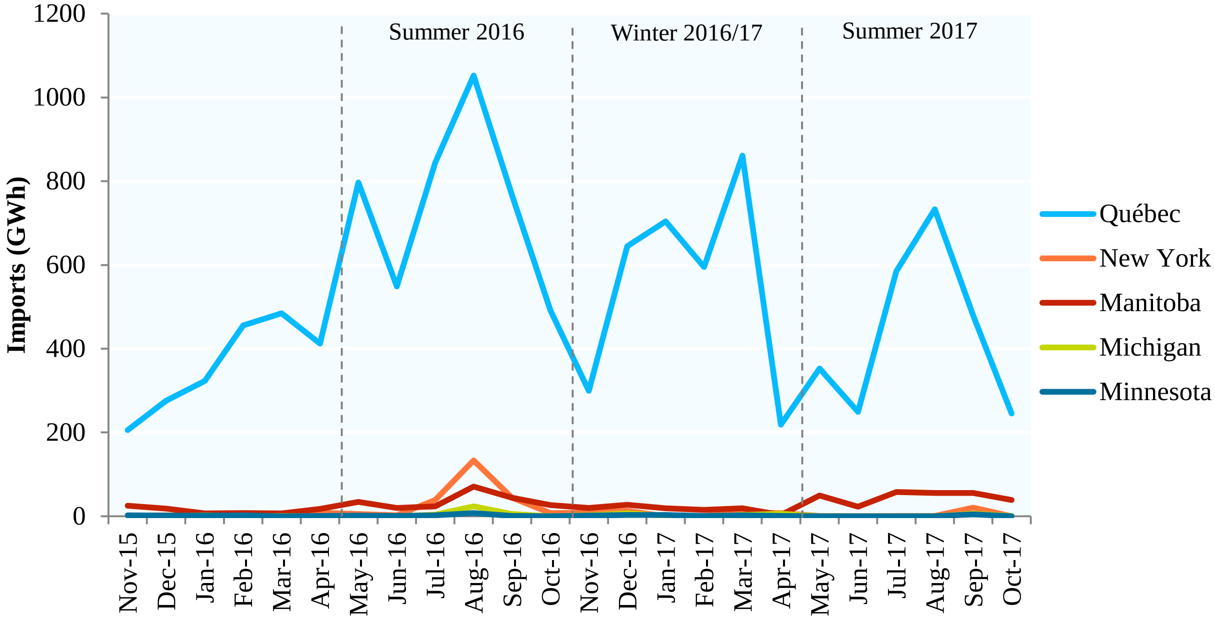


Figure A-25: Imports by Intertie
November 2015 – October 2017
(GWh)



Commentary:

Exports to Manitoba and Michigan were substantially lower in the Summer 2017 Period compared to the Winter 2016/17 Period, while exports to New York and Québec were slightly higher. The decreased Manitoba exports contributed to Manitoba becoming a net importer from Ontario in the Summer 2017 Period, an unusual outcome given the lower HOEPs during the Summer 2017 Period. The decreased Michigan exports are largely explained by the scheduling limit on the intertie being lower on average in the Summer 2017 Period than in the Winter 2016/17 Period, as previously mentioned.

Imports increased significantly on the Manitoba intertie, and decreased slightly over the New York and Québec interties. Thus, net exports were higher over the Summer 2017 Period than over the Winter 2016/17 Period on the New York, Minnesota and Québec interties, and lower on the Michigan and Manitoba interties.

Table A-7: Average Monthly Export Failures by Intertie & Cause Winter 2016/17 & Summer 2017 (GWh & %)

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17
New York	701	653	2.6	1.8	11.6	12.3	0.4%	0.3%	1.7%	1.9%
Michigan	456	672	1.8	2.2	6.3	9.4	0.4%	0.3%	1.4%	1.4%
Manitoba	43	125	3.0	4.1	15.7	26.7	7.0%	3.3%	36.4%	21.4%
Minnesota	50	41	1.2	1.3	0.7	0.7	2.5%	3.1%	1.4%	1.6%
Québec	176	149	2.5	11.4	2.0	2.2	1.5%	7.7%	1.1%	1.5%

Description:

Table A-7 reports average monthly export curtailments and failures over the Summer 2017 Period and the Winter 2016/17 Period 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.[56] 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 exports reduce demand between PD-1 and real-time.

Commentary:

The market participant percentage failure rate of exports on the Manitoba intertie, which had already been significantly above that of the other interties in previous reporting periods, rose significantly due to a greater decrease in the total volume of exports relative to failed exports. This decrease is at least partly seasonal: exports to Manitoba have been lower in the summer in past years compared to the winter.

Relative to the Winter 2016/17 Period, the Québec intertie experienced a reduction in ISO-curtailed exports in the Summer 2017 Period to 1.5%, which is in line with the 1.3% seen in the

[56] 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.

Summer 2016 Period. This is explained by the higher rate of reliability-related curtailments in the coldest months, as seen in the Winter 2016/17 Period.

Table A-8: Average Monthly Import Failures by Intertie & Cause Winter 2016/17 & Summer 2017 (GWh & %)

Intertie	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17	Summer 2017	Winter 2016/17
New York	5	6	0.5	0.1	0.1	0.1	8.9%	1.5%	1.4%	1.2%
Michigan	3	4	0.5	0.1	0.9	0.5	15.9%	2.6%	30.6%	11.2%
Manitoba	64	64	12.0	7.9	0.3	0.5	19.0%	12.4%	0.4%	0.7%
Minnesota	5	17	0.6	0.4	0.7	1.4	11.4%	2.2%	13.7%	8.3%
Québec	335	358	6.3	2.7	0.2	0.2	1.9%	0.8%	0.1%	0.1%

Description:

Table A-8 reports average monthly import failures and curtailments over the Summer 2017 Period and the Winter 2016/17 Period by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions. 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.

Commentary:

The percentage rate of ISO Curtailments for imports increased in the Summer 2017 Period compared to the Winter 2016/17 Period for all interties, due to various decreases in import volume and increases in average monthly volume of curtailments on these interties. In the case of Minnesota, this appears to be part of a pattern of higher winter imports and lower summer imports, while for New York, Michigan, and Québec it continues a trend of decreasing imports between the Summer 2016 Period and the Winter 2016/17 Period. The number of MP Failures was broadly stable, but the low volume of imports from Michigan and Minnesota relative to the volume of import failures led to higher percentage rates of failure.