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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2016 – October 2016

February 2018

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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, 2016 to October 31, 2016 (Summer 2016 Period). Certain portions of this report, notably Chapters 1 and 3, discuss noteworthy issues that are not necessarily linked to events in the Summer 2016 Period. Except where otherwise noted, developments occurring after October 31, 2017 are not reflected in this report.

The report is divided into the following four chapters:

- Chapter 1: Market Developments and Status of Recent Panel Recommendations;
- Chapter 2: Market Outcomes;
- Chapter 3: Analysis of Anomalous Market Outcomes; and
- Chapter 4: Matters to Report in the Ontario Electricity Market Place

Immediately below is a summary of each chapter.

Chapter 1: Market Developments and Status of Recent Panel Recommendations

Chapter 1 provides an update on recent developments related to the IESO-administered markets and the Panel's comments on the Independent Electricity System Operator's (IESO) responses to the recommendations contained in the Panel's previous semi-annual report.

The most significant development in the IESO-administered markets remains the IESO's Market Renewal initiative. If successful, Market Renewal will represent a fundamental redesign of Ontario's electricity market, which should address a number of known and enduring deficiencies with the existing design. The IESO is currently engaging stakeholders in preliminary design discussions, with final design decisions for the single schedule market and the incremental capacity auction expected in the first half of 2018. The Panel is supportive of the Market Renewal initiative and participates in the stakeholder efforts through its participation on the IESO's Market Renewal Working Group.

Chapter 1 also provides an update on the implementation of the expansion of the Industrial Conservation Initiative (ICI) to include certain consumers with peak demand between 500 kW and 1 MW, the suspension of renewable energy procurements, and an update on the IESO's stakeholder engagement dealing with system flexibility. Each one of these initiatives has potential short-term or long-term implications for participants in the IESO-administered markets and Ontario ratepayers.

With respect to the Panel's recommendations in its previous semi-annual monitoring report, the IESO agreed with most of the recommendations and has identified steps that it intends to take in relation to them. However, the Panel believes that in some instances the IESO's response does not fully address the Panel's concerns. First, although the Panel recommended that that the IESO stop disbursing funds from the Transmission Rights Clearing Account until revisions are made to the disbursement methodology, the IESO has proceeded with a $76 million disbursement in June 2017. Of the $11.3 million that was paid to exporters, the Panel believes $9 million ought to have been for the benefit of Ontario ratepayers. In addition, while the IESO has stated that it is committed to improving the efficiency of the demand response auction, the IESO has not responded directly to the Panel's concern that there appears to be no need to procure any demand response capacity at this time given current and projected supply conditions. Upwards of $73 million has been paid to demand response resources through the 2016 and 2017 auctions.

Chapter 2: Market Outcomes

Chapter 2 presents data from the Summer 2016 Period including pricing, demand, supply, imports and exports. The data is accompanied by written commentary that puts the data in context.

Notable observations include the steady increase in overall system costs leading to increases in the prices paid by all classes of consumers, with the Global Adjustment continuing to be a significant component of total system costs.

Chapter 3: Analysis of Anomalous Market Outcomes

As part of its monitoring mandate the Panel regularly reviews market outcomes for results that fall outside expected norms. In recent monitoring reports the Panel has expanded its analysis of anomalous events beyond those which meet or exceed its historic price and uplift thresholds. The Panel now also reports on market outcomes it considers to be anomalous relative to the Market Objective and the Market Rules, outcomes it considers to be novel or infrequent, as well as outcomes that are relevant to current IESO initiatives and stakeholder engagements. As part of its analysis of anomalous outcomes for the Summer 2016 Period, the Panel has identified a market design deficiency related to the operation of dispatchable loads.

This deficiency relates to the opportunity for dispatchable loads to earn unwarranted Congestion Management Settlement Credit (CMSC) payments as a result of conditions at their facilities. As a general rule, all dispatchable facilities (loads and generators) are required to follow the IESO’s dispatch instructions. However, dispatchable facilities may request alternate dispatch instructions when following the IESO’s initial instructions would endanger the safety of any person, damage equipment or violate any applicable law (referred to as SEAL-related constraints). While a SEAL-related constraint is a valid basis for requesting alternate dispatch instructions, the Panel views any CMSC payment attributable to such a circumstance as unwarranted. The existing Market Rules reflect this view by providing the IESO with the authority to recover SEAL-related CMSC payments from generators; however, these rules do not apply to dispatchable loads. The Panel is recommending that the IESO amend the Market Rules to enable the recovery of CMSC payments made to a dispatchable load where the payments are the result of operational constraints arising from conditions at the dispatchable load’s facility. The Panel is also recommending that the IESO examine whether the scope of the current CMSC recovery provisions in the Market Rules in relation to generators should be expanded to cover CMSC payments made as a result of facility-specific operational constraints beyond SEAL-related constraints.

Recommendation 3-1:

The Independent Electricity System Operator should implement rules that allow it to recover Congestion Management Settlement Credit payments made to dispatchable loads when those payments are the result of an operational constraint arising from conditions at the dispatchable load’s facility. The IESO should also examine whether the scope of the current provisions that allow it to recover CMSC payments from generators in relation to SEAL-related constraints should be expanded to cover any other operational constraints arising from conditions at the generator’s facility.

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

In Chapter 4 the Panel analyses potential market design deficiencies or concerns related to market participant conduct or activities of the IESO. Unlike Chapter 3, however, the issues discussed in in Chapter 4 are not necessarily linked to events that occurred during the Summer 2016 Period.

The Panel has identified concerns related to the payment of constrained-on CMSC to exporters, as well as to the IESO's administration of the claw back mechanism that targets market participants that fail to respond to operating reserve activations.

Constrained-on CMSC for Exporters

The Panel has long expressed concerns that intertie traders can bid strategically to exploit the artificially low prices in the Northwest zone of the province. In particular, the enduring presence of negative prices creates an opportunity for exporters to obtain significant amounts of constrained-on CMSC payments to export power from Ontario. In January 2010 the Panel recommended that the IESO implement a floor price of $0/MWh for the purposes of calculating CMSC when market participants bid at negative prices. While exporters could receive power for free (prior to transaction costs), they would not be paid to export power from Ontario.

The IESO agreed with the Panel's assessment that a replacement bid price was warranted, but opted to implement a replacement price of -$125/MWh; meaning that exporters may be paid up to $125/MWh (prior to transaction costs) to take power from Ontario. The rationale for this choice was a desire to minimize the potential loss of efficient export transactions that may occur between jurisdictions with negative prices. The Panel's analysis reveals, however, that the loss of any potentially efficient export transactions associated with a replacement bid price of $0/MWh would be insignificant. The Panel has concluded that over an almost five-year period since the implementation of the -$125/MWh replacement bid price, Ontario consumers paid approximately $2.1 million more in uplift charges than would have been the case if the IESO had adopted a $0/MWh replacement price, with little or no corresponding efficiency benefit.

Recommendation 4-1:

The Independent Electricity System Operator should set the replacement bid price to $0/MWh, or slightly negative, when it calculates constrained-on Congestion Management Settlement Credit payments for exports bid at negative prices.

Failure to Provide Operating Reserves when Activated

The IESO, like other system operators in North America, is required to carry operating reserve (OR) to protect the power system against contingencies, such as the sudden loss of a large generating station. OR represents back-up power that is available when needed but is seldom called upon. In Ontario, the IESO usually carries about 1,500 MW of OR in any given hour. In exchange for committing to provide this back-up power, OR providers receive OR payments from the IESO.

If an OR provider fails to fully honour its commitment to the IESO, the Market Rules make provision for the IESO to implement a claw back of OR payments. The claw back is intended to ensure that the OR service provider will not receive payments for a service that it did not provide.

The Market Rules require the IESO Board of Directors to establish a materiality threshold below which no OR payments would be clawed back. Notionally, this threshold could be set from anywhere between 0 (i.e. all failures are subject to a claw back) to infinity (no failures are subject to a claw back). From market opening in May 2002 to June 2016, no threshold was established by the IESO and no claw backs were undertaken. In June 2016, the IESO Board of Directors set the threshold at infinity, effectively ensuring the claw back provision remains inoperative. The Panel believes an inoperative claw back provision is inappropriate. Moreover, the Panel's analysis reveals that had a 0 threshold been used, OR participants would have been subject to over $6 million in claw backs for OR services that they failed provide between January 2012 and October 2016. The Panel is therefore recommending that the materiality threshold value be revised such that OR payments are clawed back when a market participant fails to fully respond to its OR activation.

Recommendation 4-2A:

The Independent Electricity System Operator's Board of Directors should revise the materiality threshold value such that operating reserve payments are clawed back when a market participant fails to fully respond to its operating reserve activation.

The Panel has also identified what it believes to be a flaw in the formula for establishing the claw back amount. The existing formula assesses the degree to which a participant has failed to honour its OR commitment as a function of that facility's total energy output. This inappropriately favours OR providers that, by happenstance, were producing energy at the time of the OR activation. The Panel believes that the claw back should instead be based on the ratio of energy not provided relative to the energy required by the activation, and is also recommending that this change be implemented.

Recommendation 4-2B:

When a market participant fails to fully respond to an operating reserve activation, the Independent Electricity System Operator should calculate the claw back based on the ratio of the energy not provided in response to the activation relative to the energy required by the activation.

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

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. In support of the Market Renewal initiative, the IESO launched the public Market Renewal stakeholder engagement, and appointed a Market Renewal Working Group consisting of 23 stakeholder representatives. The group includes generators, consumers, energy traders, emerging technology companies and a representative of the Panel.

In April 2017 the IESO published a commissioned study entitled *The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project.* The study estimated that Market Renewal would result in efficiency benefits to Ontario (net of implementation costs) totalling approximately $3.4 billion.[1] Electricity consumers will be the primary beneficiary of these efficiency gains, with estimated benefits of $180 million per year in 2021, increasing to $700 million per year in 2030.

Given the significant potential benefits associated with Market Renewal, the IESO has proceeded, with the assistance of the Working Group, to the high-level design phase of the project. The goal of the design phase is to consult with stakeholders in order to develop a high-level design for each of the five initiatives the IESO has identified as being part of Market Renewal:

- Single Schedule Market;
- Day-Ahead Market;

[1] See page vi of the report, available at: http://www.ieso.ca/en/sector-participants/market-renewal/overview-of-market-renewal

- Enhanced Real-Time Unit Commitment;
- More Frequent Intertie Scheduling; and
- Incremental Capacity Auction.

The IESO intends to use stakeholder engagements as the primary vehicle for developing the design elements for each initiative. To date, the IESO has launched stakeholder engagements related to the single schedule market and incremental capacity auction initiatives. These engagements have progressed past the fundamental education phase and into the preliminary design phase, to be followed by the final decisions phase (Q1 2018 for single schedule market and Q2 2018 for incremental capacity auction).[2]

Expansion of the Industrial Conservation Initiative

Effective July 2017, the Ontario Government again expanded the Industrial Conservation Initiative (ICI). When introduced in 2010, only customers with peak demand greater than 5 MW were eligible to participate; since then, the eligibility threshold has been reduced from time to time such that today all consumers with a peak demand of more than 1 MW can opt in, as can certain consumers with a peak demand of more than 500 kW. [3]

Each ICI customer's share of Global Adjustment charges is based on their consumption during the five coincident peak demand hours during a year. As ICI customers shift their consumption to minimize their Global Adjustment charges, those charges accrue to lower volume consumers.[4] However, the effect of that shift is currently mitigated as a result of the government's Fair Hydro Plan initiative.

Reduction in Renewable Energy Procurements

In September 2016 the Minister of Energy directed the IESO to suspend Ontario's Large Renewable Procurement II process for the procurement of over 1,000 MW of wind, solar,

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[2] For more information on Market Renewal, including estimated timelines, consult the IESO's Market Renewal webpage, available at: http://ieso.ca/en/sector-participants/market-renewal/overview-of-market-renewal

[3] Resources with peak demand exceeding 500 kW but not more than 1 MW are eligible to participate in the ICI only if they are part of targeted manufacturing and industrial sectors; all resources over 1 MW may participate. For more information see the IESO's *Global Adjustment Class A Eligibility* webpage, available at: http://www.ieso.ca/en/sector-participants/settlements/global-adjustment-class-a-eligibility

[4] For more information on the Global Adjustment costs and their allocation amongst different groups of consumers, see Chapter 2.

hydroelectric and biomass generating capacity.[5] The decision to suspend the procurement process was informed by the IESO's *Ontario Planning Outlook* report, which concluded that Ontario has sufficient generating capacity to meet projected demand over the coming decade.

In December 2016 the Minister of Energy directed the IESO to suspend the remaining 150 MW of renewable generating capacity planned to be procured under the sixth round of the Feed-In Tariff program, given the proposed evolution of the microFIT program to net metering.[6]

Enabling System Flexibility

The IESO has identified the need to increase system flexibility in response to the forecast uncertainty associated with wind and solar generators. In June 2016 the IESO launched a stakeholder engagement to explore possible solutions.

The IESO's *2016 Operability Assessment* concluded that, in the short term, the system requires 1,000 MW of additional flexibility by 2018; that number has since been revised down to 740 MW in light of the suspension of Large Renewable Procurement II and reduced Feed-in Tariff targets.[7]

At its August 2017 stakeholder engagement meeting the IESO proposed a solution to the short-term flexibility need: increase the 30-minute Operating Reserve (OR) requirement when potential wind and solar forecast error exceeds the projected availability of flexible resources.[8] By increasing the OR requirement ahead of real-time, the IESO hopes to signal the upcoming need for additional flexibility while increasing the likelihood of committing additional non-quick start resources to provide that flexibility.

The IESO intends to address the longer term need for system flexibility through changes to be developed through its Market Renewal initiative.

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[5] See the Minister of Energy's letter of direction to the IESO dated September 27, 2016, available at: http://www.ieso.ca/corporate-ieso/ministerial-directives

[6] See the Minister of Energy's letter of direction to the IESO dated December 16, 2016, available at: http://www.ieso.ca/corporate-ieso/ministerial-directives

[7] See slide 18 of the IESO's August 1, 2017 presentation to the *Enabling System Flexibility* stakeholder engagement, available at: http://www.ieso.ca/-/media/files/ieso/document-library/engage/esf/esf-20170801-presentation.pdf?la=en

[8] *Ibid*, slide 21-27.

2 *IESO Responses to Panel Recommendations in Last Monitoring Report*

Below are the recommendations made in the Panel's May 2017 Monitoring Report, and the IESO's responses to them.[9]

Recommendation	IESO Response
Recommendation 3-1 *The IESO should take steps to ensure that dispatchable loads are only compensated for the amount of operating reserve they were capable of providing in real-time. More fundamentally, the IESO should explore options for ensuring unavailable OR is not scheduled in the first instance.*	The IESO agrees that market participants should not be compensated for services that they are unable to provide. The Market Rules require all market participants, including dispatchable loads, to maintain accurate dispatch data and respond to IESO dispatch instructions for both energy and operating reserve. The IESO will assess what remedies are available to respond to the Panel's recommendation in 2017. These remedies could include but are not limited to changes to market design through Market Rules or investigations of non-compliance.
Recommendation 3-2 *The IESO should revise the methodology used to set the intertie failure charge to include the congestion rents that an intertie trader avoids when it fails a scheduled transaction for reasons within its control.*	The IESO agrees with the Panel's recommendation on intertie transaction failures; an intertie trader should not benefit by avoiding congestion rents when failing intertie transactions for reasons within its own control. Market Rules are in place that allow for the recovery of congestion rents that have been avoided, or Transmission Rights payments, when the intertie trader fails its transactions for illegitimate reasons. The IESO will consider the structure of intertie failure charges in 2017 and determine an appropriate avenue to address the issue identified by the Panel.

[9] See the May 30, 2017 letter from Bruce Campbell, then 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-Reply-to-OEB-MSP-Report-20170530.pdf

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Recommendation 4-1

a) *The IESO should revise the manner in which it allocates disbursements from the Transmission Rights Clearing Account such that disbursements are proportionate to transmission service charges paid over the relevant accrual period.*
b) *The IESO should not disburse any further funds from the Transmission Rights Clearing Account until such time that Recommendation 4-1(A) has been addressed.*

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The current disbursement methodology of the Transmission Rights Clearing Account is to allocate disbursements to both internal and external loads based upon their share of demand. In 2017 the IESO will initiate a review of the disbursement allocation methodology to ensure it is both consistent with the intent and purpose of the Transmission Rights Clearing Account, and is aligned with current market and system needs. The outcome of the review, which will be completed and communicated to the Panel by the end of 2017, could also inform the Transmission Rights discussions that will take place as part of the IESO's Market Renewal Program. Given that the allocation method is Market-Rule based, the outcome of the review will also inform whether changes to the Market Rule are required.

Meanwhile, until the review of the disbursement allocation methodology is completed, the IESO will continue with the semi-annual disbursements, as directed by the IESO Board and as detailed in Market Manual 5.5: Physical Markets Settlement Statements.

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Recommendation 4-2

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

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The IESO was assigned responsibility for developing Demand Response (DR) in Ontario in 2013 with a mandate to develop DR to meet system and policy objectives in the short and longer term. Since that time, the IESO has developed a comprehensive work plan to ensure contracted resources are integrated cost effectively into the market. As a result of these initiatives, the annual cost of maintaining DR has dropped by almost 30%, while participation has increased significantly and new innovative approaches are continuing to emerge.

In the short term, DR is contributing to the reliability of the Ontario grid as an integrated resource that is dispatched when it is economic relative to other resources. Over the longer term, the IESO agrees with the MSP that a technology-neutral capacity auction is a more cost effective way to procure capacity. The IESO has launched a stakeholder engagement to design such a mechanism as part of the Market Renewal Program. The learnings from the DR auction will help inform the design of a future incremental capacity auction and demonstrate how such a mechanism could work in Ontario.

The IESO is also working together with stakeholders through the DR Working Group (DRWG). The IESO and the DRWG are committed to continuously improving the efficiency of the DR auction and working together to assess priorities for 2017. The DRWG work plan includes a number of projects to improve the efficiency of the DR auction, including a review of how DR is activated in the market.

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3 *Panel Commentary on IESO Responses*

Recommendations 3-1 and 3-2

With respect to recommendations 3-1 and 3-2, the IESO agreed that action should be taken to address the inappropriate outcomes identified by the Panel, and committed to assessing potential solutions in 2017. In both cases, the Panel believes that the optimal solution would be one that prevents these inappropriate outcomes from arising in the first instance, rather than relying on after-the-fact payment recoveries or compliance actions.

Recommendation 4-1

The IESO committed to reviewing the current disbursement methodology for the Transmission Rights Clearing Account (TR Clearing Account) in 2017, to ensure that it is consistent with the intent and purpose of the TR Clearing Account, and aligned with current market and system needs.

With respect to the Panel's recommendation that the IESO stop disbursing funds from the TR Clearing Account until such time as revisions are made to the disbursement methodology, the IESO indicated that it would proceed with semi-annual disbursements as directed by the IESO Board of Directors and as detailed in the relevant Market Manual. The IESO has since made an additional disbursement of $76 million from the TR Clearing Account (in July 2017) using the existing methodology.[10] As a result, $11.3 million has been paid to exporters, $9 million of which ought in the Panel's view to have been for the benefit of Ontario ratepayers

Recommendation 4-2

The IESO was not directly responsive to the Panel's recommendation, as it has not indicated an intention to reassess the value provided by the capacity procured through its Demand Response (DR) auction. In the Panel's view, the IESO is procuring capacity through the DR auction at a time when additional capacity is not needed. Upwards of $73 million has been paid to demand response resources through the 2016 and 2017 auctions.

[10] See the IESO's June 1, 2017 News Release, available at: http://www.ieso.ca/en/sector-participants/ieso-news/2017/06/transmission-rights-clearing-account-disbursement.

While the IESO's response did not address the Panel's primary concern, it is consulting stakeholders about potential changes to the DR activation criteria. The changes being considered could increase the frequency with which DR resources are activated, and better align activations with system needs.[11]

[11] For more information, see the IESO's July 18, 2017 presentation entitled *Improved Utilization of DR*, available at: http://www.ieso.ca/en/sector-participants/engagement-initiatives/working-groups/demand-response-working-group

Chapter 2: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between May 1, 2016 and October 31, 2016 (Summer 2016 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 auction prices.

Table 2-1: Average Effective Electricity Price by Consumer Class
Summer 2015, Winter 2015/16 & Summer 2016 Periods
($/MWh)

Description:

Table 2-1 summarizes the average effective price in dollars per megawatt hour by consumer class for the Summer 2016 Period, the period from November 1, 2015 to April 30, 2016 (Winter 2015/16 Period) and the period from May 1, 2015 to October 31, 2015 (Summer 2015 Period). The effective price is the sum of the HOEP, the GA and uplift charges. Accordingly, it captures the hourly market price, payments under IESO reliability and other programs, prices payable for contracted and regulated generation and the costs of conservation and demand response programs. The effective price 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”.

Customer Class	Period	Average HOEP	Average Global Adjustment	Average Uplift	Effective Price
Class A	Summer 2016 Period	16.45	49.73	2.68	68.86
	Winter 2015/16 Period	8.32	57.44	1.72	67.48
	Summer 2015 Period	19.25	42.55	2.63	64.43
Class B	Summer 2016 Period	21.33	92.65	3.16	117.14
	Winter 2015/16 Period	10.31	102.14	1.91	114.37
	Summer 2015 Period	22.84	82.05	2.92	107.81
All Consumers	Summer 2016 Period				107.55
	Winter 2015/16 Period				105.05
	Summer 2015 Period				99.26

Relevance:

In Ontario, different consumer groups pay different effective prices. Consumers are divided into two groups: Class A, being consumers with an average monthly peak demand greater than 3 MW; and Class B, being all other consumers.[12]

The "All Consumers" group in Table 2-1 represents what the effective electricity price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. As of January 2011, the GA payable by Class A consumers is determined based on their peak demand factor, which is 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 and proportionately larger share of the GA, which includes the GA avoided by Class A consumers who reduced their consumption during the five peak hours of the year, is allocated on a monthly basis to Class B consumers based on their total consumption in that month.[13]

[12] The peak demand threshold for Class A consumers was 3 MW during the Summer 2016 Period; the threshold has since been lowered to 500 kW for certain consumers, and to 1 MW for all consumers (see section 1 of Chapter 1). For more information on the Global Adjustment allocation methodology, 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

[13] For more information on the GA allocation methodology and its effect on each consumer class, see pages 69-92 of the Panel's June 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

In previous Panel reports, Class A consumers that are embedded within a distribution system (as opposed to being directly-connected to the IESO-controlled grid) were combined with Class B consumers for the purposes of the Panel's effective price calculations and analyses. Starting in this report, the Panel has moved embedded Class A consumers from the Class B consumer class to the Class A consumer class for the purposes of its reporting, including Table 2-1. This change allows for a clearer delineation between Class A and Class B consumers.

The Panel has also adopted a new assumption regarding the behaviour of embedded Class A consumers. Starting in this report the Panel assumes that embedded Class A consumers behave like directly-connected Class A consumers (and thus have the same load profile). Previously the Panel made no such assumptions about the behaviour of Class A consumers (hence the use of a "Class B & Embedded Class A" group in previous reports).

The Panel must make assumptions with respect to the behaviour of embedded Class A consumers due to data limitations. These data limitations preclude an assessment of exactly how effective embedded Class A consumers are at shifting or curtailing consumption to avoid GA costs, and the degree to which any net consumption reductions are being achieved through increased behind-the-meter generation. [14]

The Panel's April 2015 Monitoring Report explained the need to obtain generation and consumption data at an hourly level of granularity, specifically for embedded generation, behind-the-meter generation and embedded Class A consumption.[15] The Panel noted that assessing the impacts of certain market changes – such as the 2011 change to the methodology for allocating the GA – loses precision without access to this data. In addition, assessing the province's overall demand for electricity becomes increasingly difficult as a larger portion of that demand is no longer served by the province's high-voltage power system. The need for this data is even more pronounced today given recent changes in the Class A eligibility threshold and the increase in the number of embedded Class A consumers.

[14] Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and "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 earlier reports. All references to effective price in this report – including all tables and figures – reflect the Panel's new methodology.

[15] For more information on data limitations 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

Commentary and Market Considerations:

The average effective price increased for both Class A and B consumers during the Summer 2016 Period relative to the previous two reporting periods. Compared with the Summer 2015 Period, the average effective price for Class A and Class B consumers increased by $4.43/MWh and $9.33/MWh respectively. The primary driver of the increase in effective prices was an increase in total system costs, as opposed to a significant decrease in the consumption volumes over which these costs are recovered.

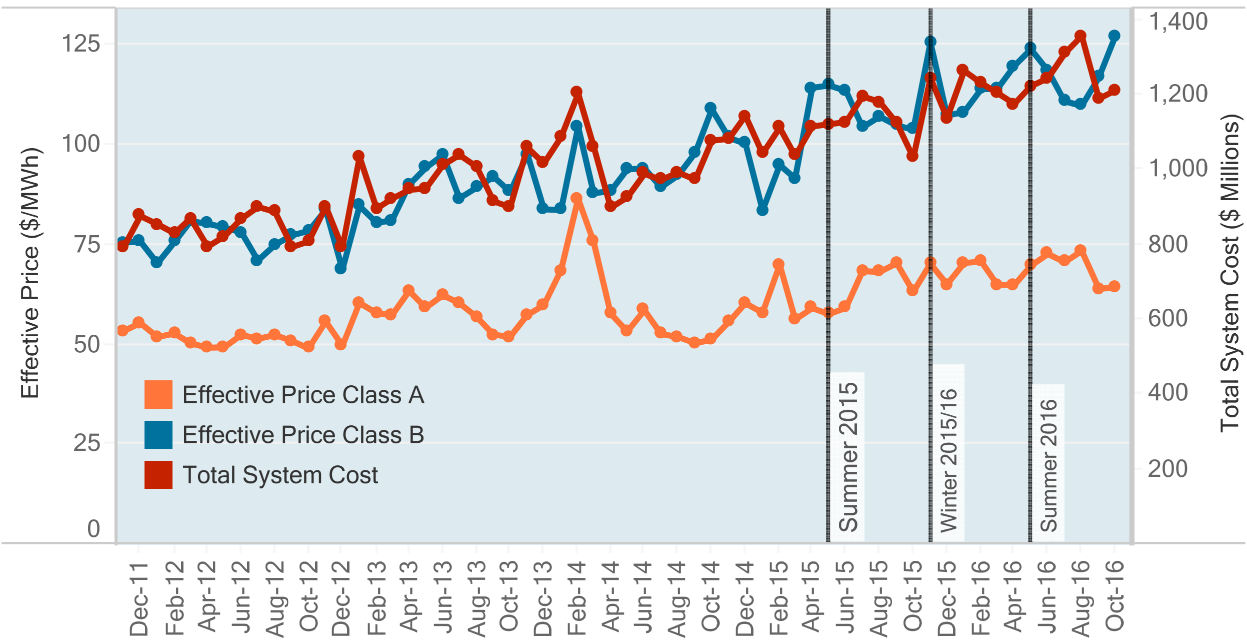
The HOEP and the GA have an inverse relationship because the GA is primarily composed of payments to contracted and regulated generating resources that are intended to make up for shortfalls between market revenues and the contracted or regulated rates of those resources.[16] Compared to the Winter 2015/16 Period, the HOEP rose during the Summer 2016 Period while the average GA fell for all consumer classes.

Figure 2-1: Monthly Average Effective Electricity Price and System Costs November 2011 – October 2016 ($/MWh & $)

Description:

Figure 2-1 plots the monthly average effective price for Class A and Class B consumers, as well as the monthly system cost for the previous five years.

[16] The costs associated with compensating loads under the IESO's demand response pilots and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges



Relevance:

This figure highlights the changes in the effective price paid by each consumer class over the past five years, as well as the steady increase in total system costs.

Commentary and Market Considerations:

In the Summer 2016 Period, there were both record high total system costs ($1.35 billion in August 2016) and a record high effective price for Class B consumers ($127.10/MWh in October 2016). The Class A effective price increased modestly from the Winter 2015/16 Period.

Class A consumers can avoid GA costs by minimizing their consumption during peak system hours. The GA that is avoided by Class A consumers is payable by Class B consumers. As a result, over the past 5 years Class A effective prices have not risen in step with system costs and Class B consumers continue to bear the majority of increased system costs.

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

Description:

Figures 2-2A and 2-2B separate the monthly average effective price into its three components (average HOEP, average GA and average uplift charges) for Class A and Class B consumers for the previous two years.

As previously explained, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases, albeit not necessarily one-for-one. The GA allocation methodology and the extent to which Class A consumers respond to the incentives it provides are responsible for the significant difference in the average effective price paid by each consumer class. When the average GA makes up an increasing portion of system cost, the average effective price paid by Class B consumers increases proportionately more than the average effective price paid by Class A consumers. This relationship is readily apparent in the Summer 2016 Period, as it has been in past reporting periods.

Figure 2-2A: Average Effective Price for Class A Consumers by Component November 2014 – October 2016 ($/MWh)

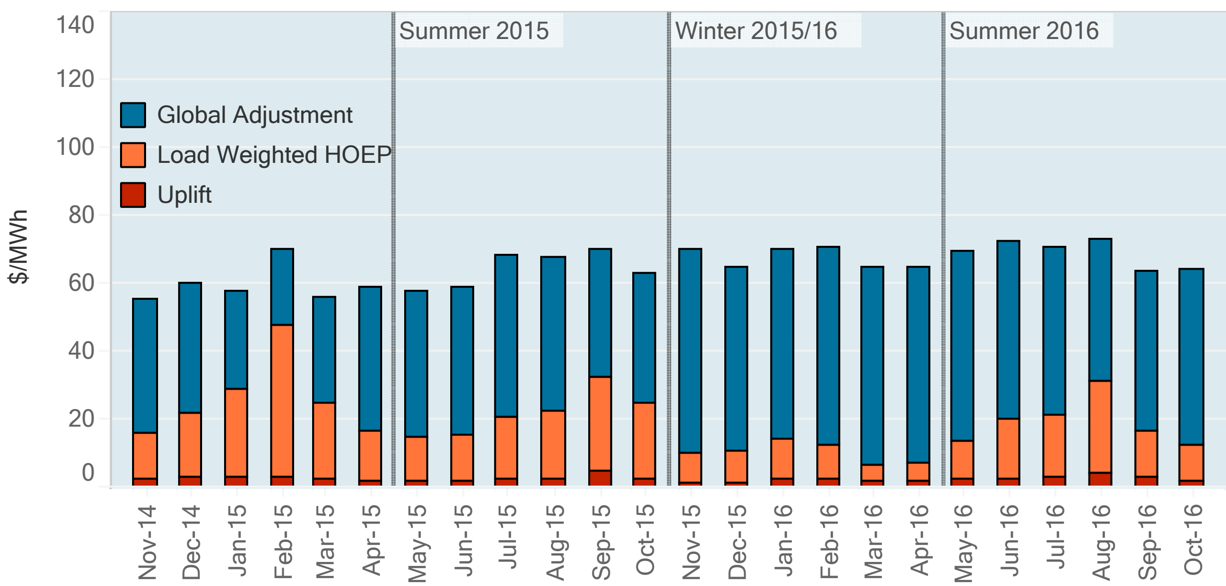
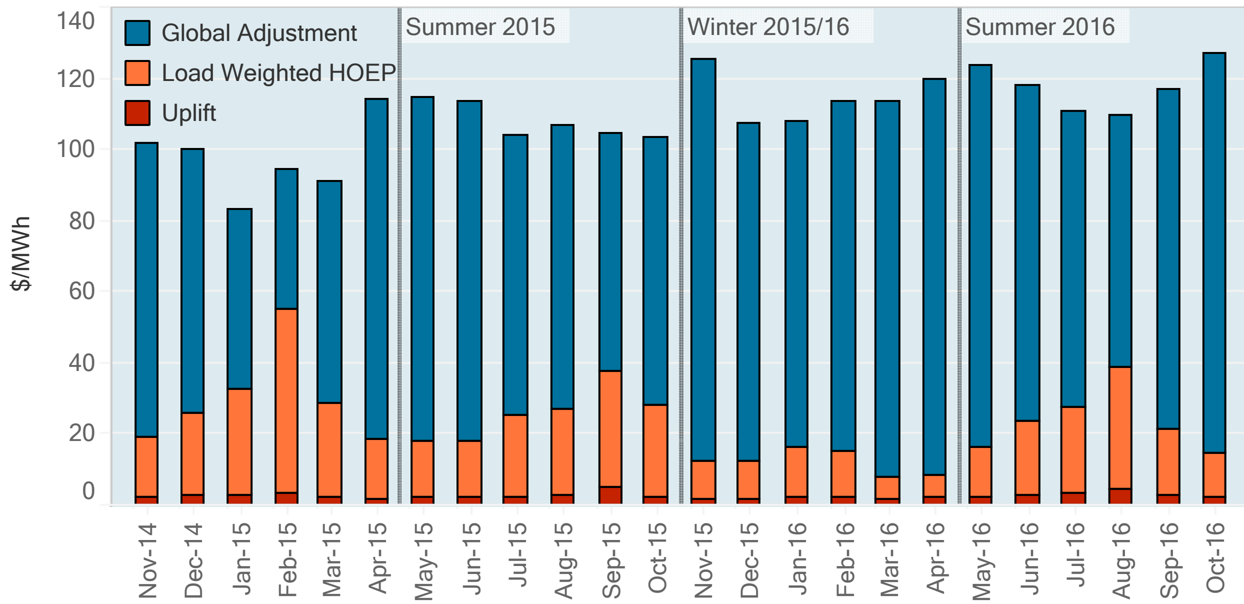


Figure 2-2B: Average Effective Price for Class B Consumers by Component November 2014 – October 2016 ($/MWh)



Relevance:

These two figures illustrate how changes in the individual components of the effective price affect the average effective price paid by each consumer class.

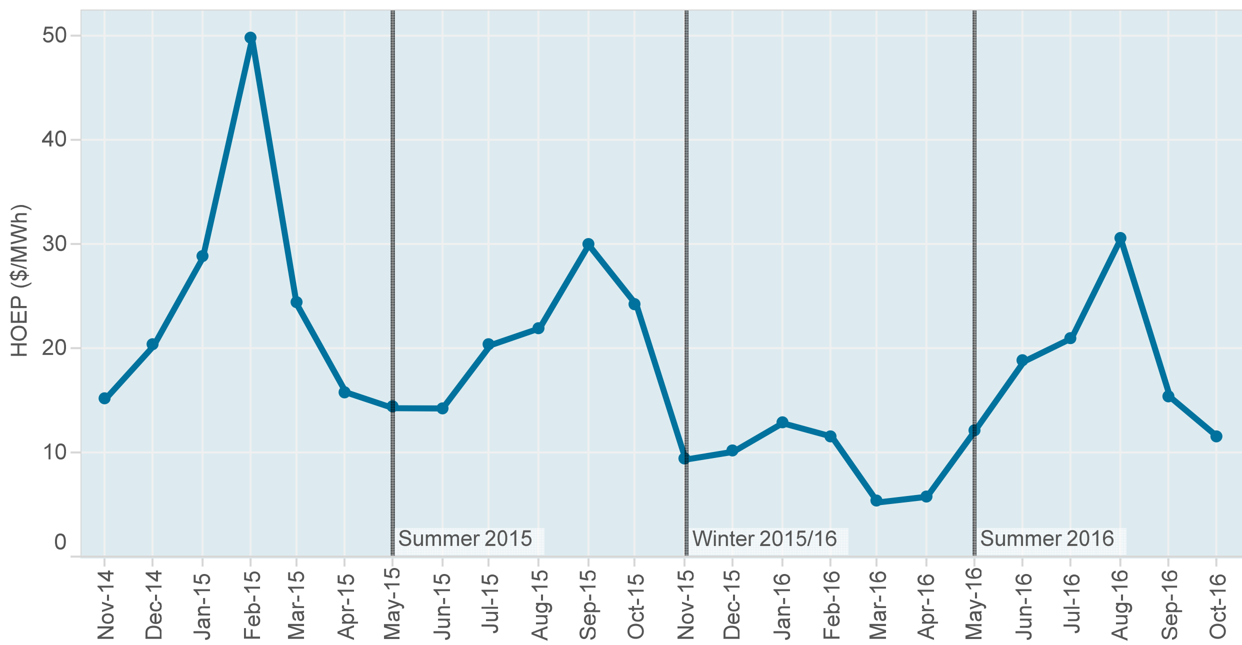
Commentary and Market Considerations:

The average effective price for Class B consumers continues to be significantly higher than that of Class A consumers, a trend that began with the change in the GA allocation methodology introduced in 2011.

Figure 2-3: Monthly (Simple) Average HOEP November 2014 – October 2016 ($/MWh)

Description:

Figure 2-3 displays the simple monthly average HOEP for the previous two years.



Relevance:

The HOEP is the market price for a given hour and is one component of the effective price paid by consumers. The HOEP is the simple average of the twelve market clearing prices (MCPs) set every five minutes within an hour. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay Regulated Price Plan prices set by the Ontario Energy Board.

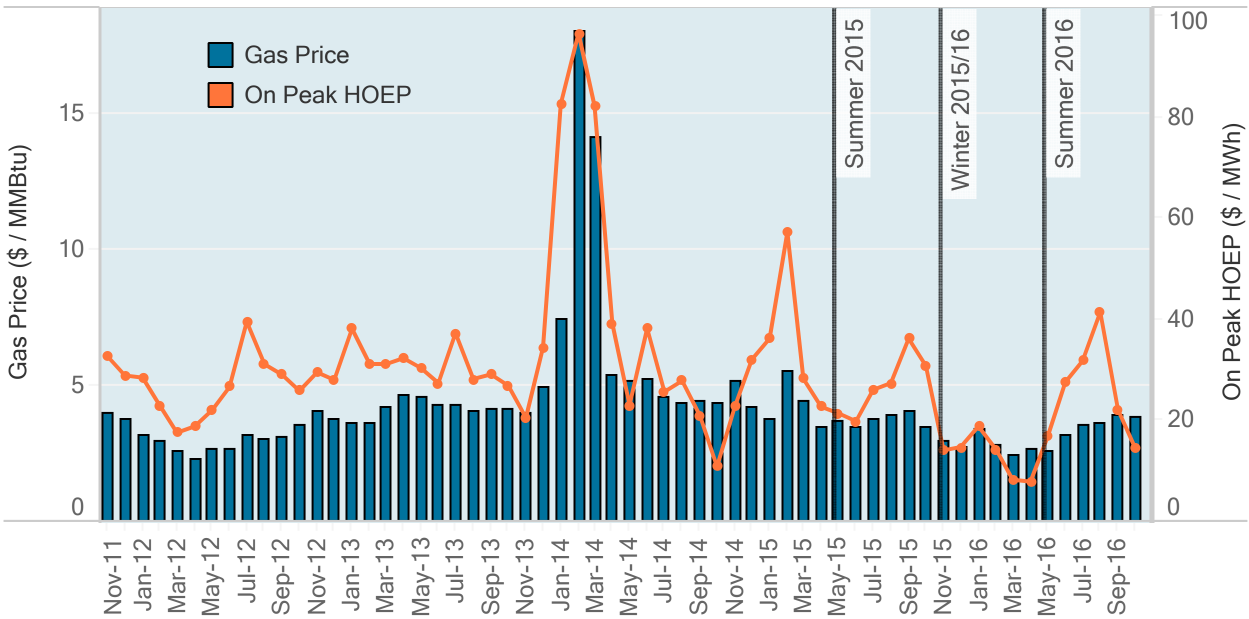
Commentary and Market Considerations:

Demand in the Summer 2016 Period was nearly 2 TWh higher than in the Summer 2015 Period. Despite higher demand, the average HOEP was lower by over $2/MWh. The lower average HOEP is partially attributed to 829 MW of low marginal cost wind and solar capacity that was added to the grid following the Summer 2015 Period.

***Figure 2-4: Natural Gas Price and On-peak HOEP
November 2011 – October 2016
($/MWh & $/MMBtu)***

Description:

Figure 2-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours[17] for the previous five years.



Relevance:

The Dawn Hub is the most active natural gas trading hub in Ontario, and has the largest gas storage facility in the province. Gas-fired facilities can typically purchase gas day-ahead in order to ensure sufficient time to arrange for transportation; for that reason, the Dawn Hub day-ahead gas price is a relevant measure of the cost of natural gas in Ontario. Natural gas prices are compared to the HOEP during on-peak hours, as gas-fired facilities frequently set the price during these hours.

[17] On-peak hours are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays). Off-peak hours are all other hours.

Commentary and Market Considerations:

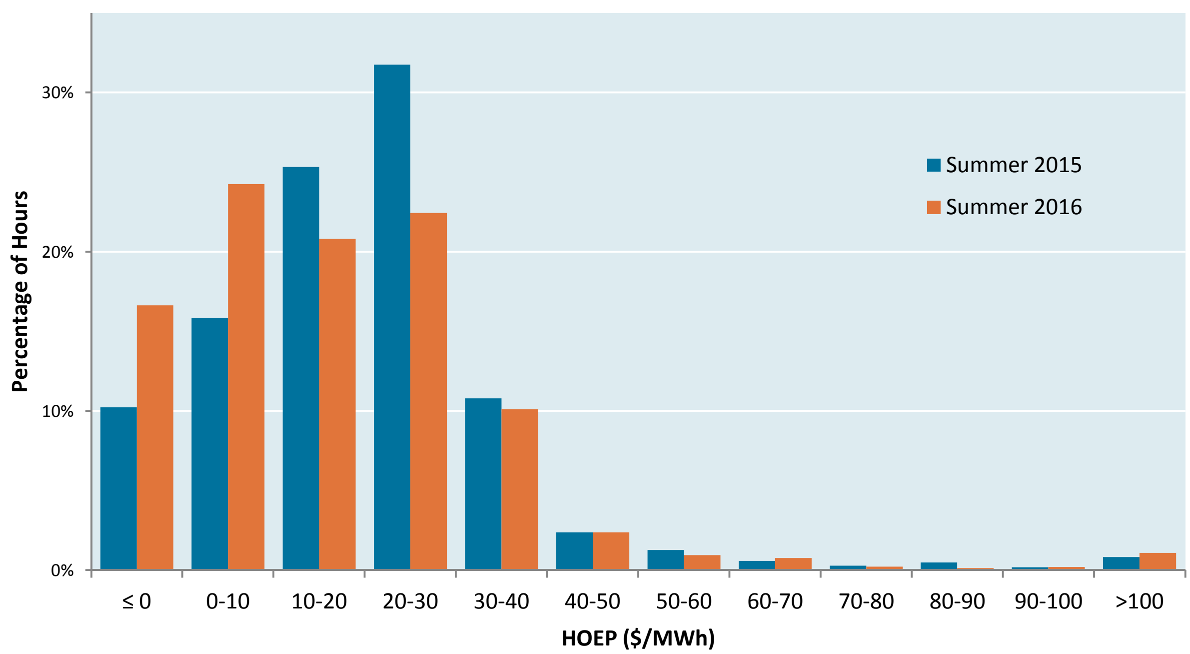
Dawn Hub gas prices, which had been in decline since the Winter 2013/14 Period, rose modestly in the Summer 2016 Period (average day-ahead gas price of $3.42/MMBtu, compared to $2.84/MMBtu in the Winter 2015/16 Period).

In the past, changes in natural gas prices have been positively correlated with movements in the on-peak HOEP. The correlation in the Summer 2016 Period was very weak, which can be attributed to a significant increase in wind and hydro replacing gas facilities as the marginal resource (see Figure 2-6).

Figure 2-5: Frequency Distribution of the HOEP
Summer 2015 & Summer 2016 Periods
(% of hours & $/MWh)

Description:

Figure 2-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Summer 2016 and Summer 2015 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-price hours which are grouped together with all $0/MWh values.



Relevance:

The frequency distribution of the HOEP illustrates the proportion of hours that the HOEP falls into a given price range, and provides information regarding the frequency of high and low prices.

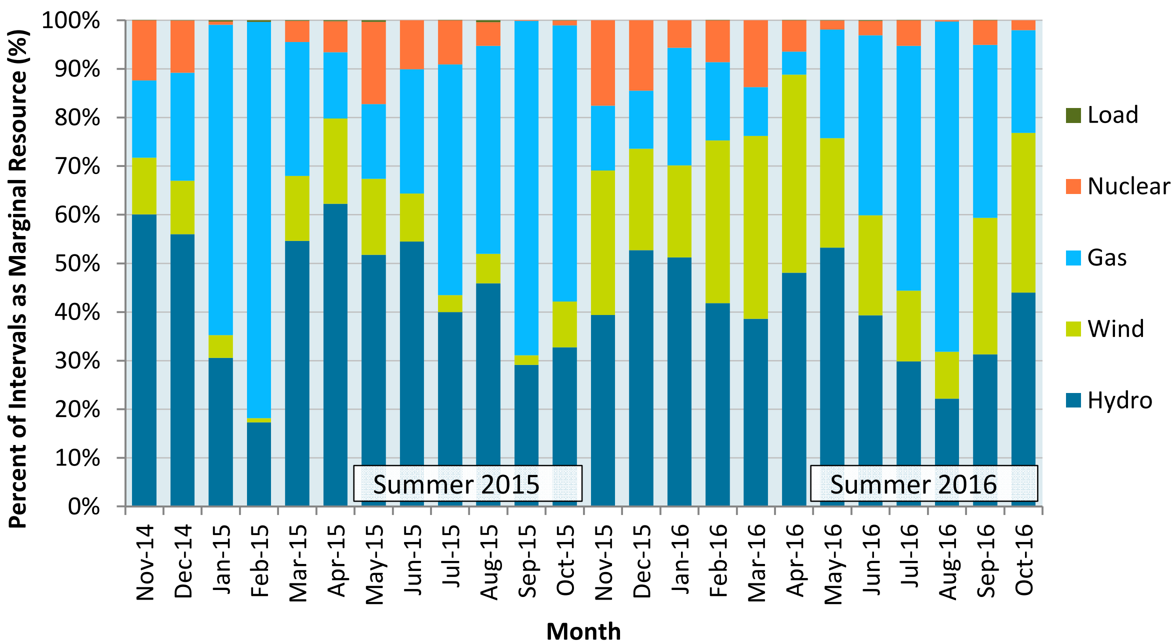
Commentary and Market Considerations:

The frequency distribution of the HOEP shows an increase in the amount of non-positive price hours (zero and negative) in the Summer 2016 Period relative to the Summer 2015 Period. Overall, the HOEP was lower than in the Summer 2015 Period, despite higher demand. The addition of 829 MW of renewable energy capacity to the grid after the end of the Summer 2015 Period contributed to the increased frequency of lower prices.

Figure 2-6: Share of Resource Type setting the Real-Time MCP
November 2014 - October 2016
(% of intervals)

Description:

Figure 2-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



Relevance:

The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

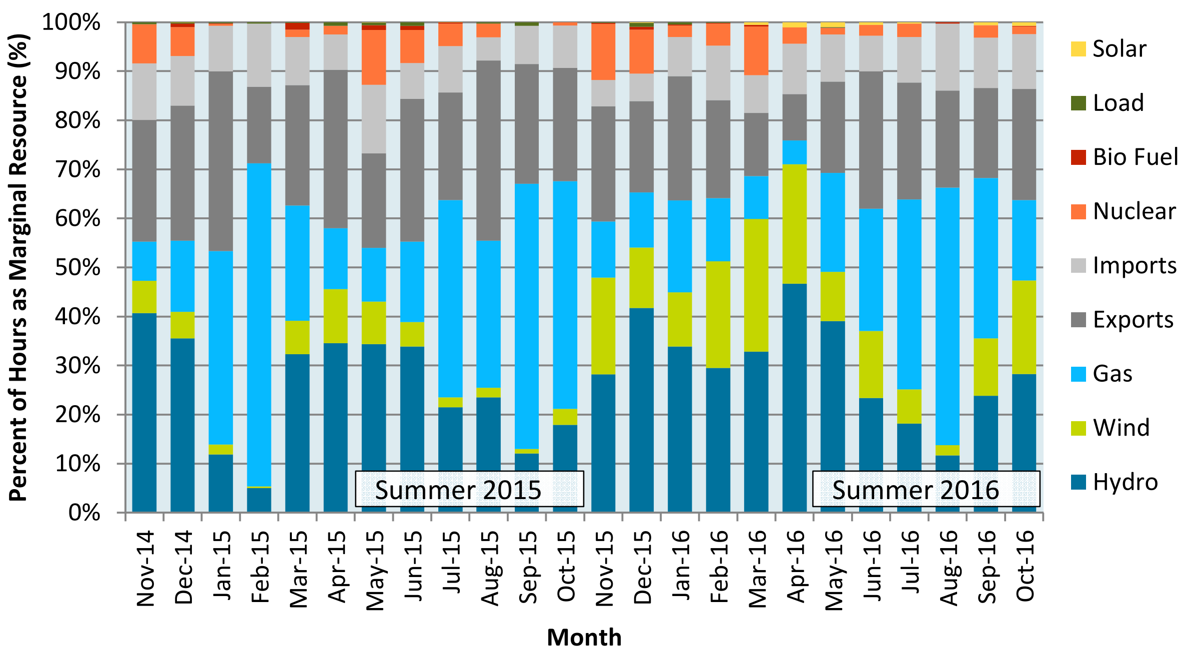
Commentary and Market Considerations:

Wind set the MCP in 21% of all intervals in the Summer 2016 Period, which is more frequent than in any previous summer period. As installed wind capacity continues to increase in Ontario, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. There was a decrease in the share of gas generators setting the MCP compared to the Summer 2015 Period (from 42% to 38% of all intervals).

Figure 2-7: Share of Resource Type setting the One-Hour Ahead Pre-Dispatch MCP
November 2014 – October 2016
(% of hours)

Description:

Figure 2-7 presents the monthly share of hours in which each resource type set the hour-ahead pre-dispatch (PD-1) MCP, for the previous two years.



Relevance:

When compared with Figure 2-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[18] 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 and Market Considerations:

Wind set the PD-1 MCP in 11% of all hours in the Summer 2016 Period, compared to 4% of all hours during the Summer 2015 Period. As noted above, installed wind capacity continues to increase in Ontario as contracted resources are still coming online. Therefore, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. Gas-fired resources set the PD-1 MCP 31% of all hours in the Summer 2016 Period, down from 33% of the time during the Summer 2015 Period.

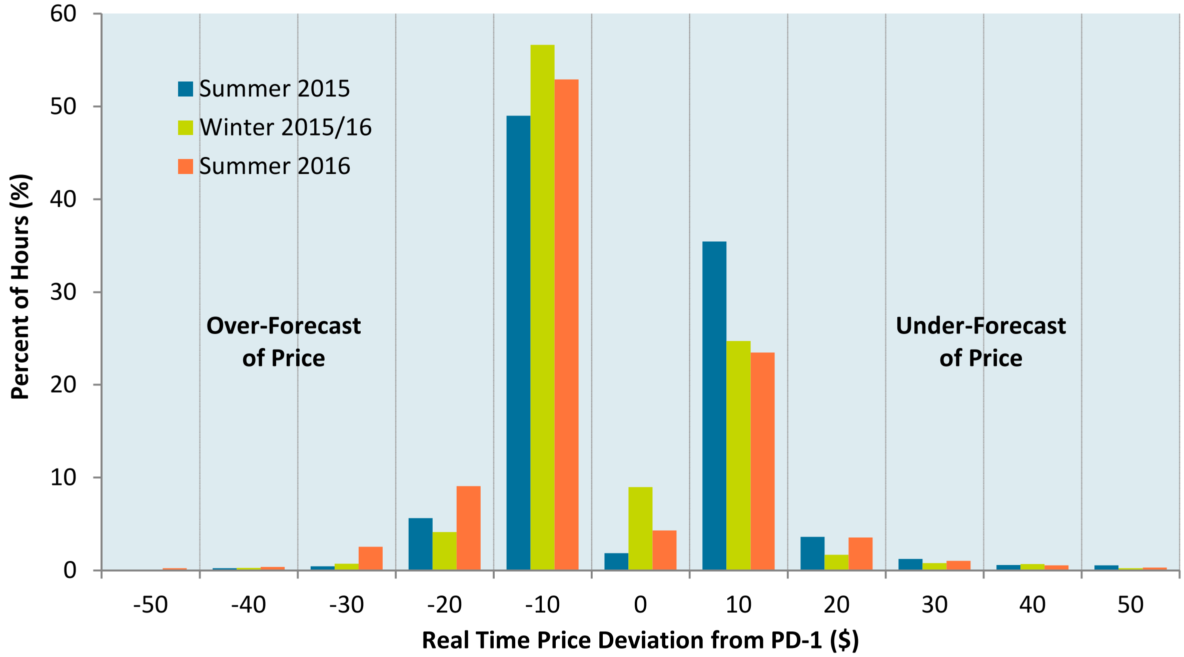
Figure 2-8: Difference between the HOEP and the PD-1 MCP
Summer 2015, Winter 2015/16 & Summer 2016 Periods
(% of hours, $)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2016, Winter 2015/16 and Summer 2015 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. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $50/MWh is negligible in the context of this graph, and so is not included in Figure 2-8. The same is true of Figure 2-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease.

[18] Due to scheduling protocols, imports and exports are scheduled an hour ahead of real-time. In real-time, import and export quantities are fixed for a given hour and their prices are adjusted to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time and cannot set the MCP.



Relevance:

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. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher, but would be required to do so. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

PD-1 prices in the Summer 2016 Period were a less accurate predictor of real-time prices than in the previous two reporting periods. In the Summer 2016 Period, the pre-dispatch sequence was within +/- $10/MWh of the HOEP 81% of the time compared, to 86% in the Summer 2015 Period and 90% in the Winter 2015/16 Period. The average absolute price difference was $8.39/MWh, up from $6.58/MWh in the Summer 2015 Period and $5.20/MWh in the Winter 2015/16 Period. As in periods past, the PD-1 MCP was far more likely to be over-forecast than under-forecast.

Table 2-2: Factors Contributing to Differences between PD-1 MCP and HOEP Summer 2015, Winter 2015/16 & Summer 2016 Periods (MWh)

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:

Supply

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

Demand

- Pre-dispatch to real-time demand forecast deviation; and
- Export failures/curtailments.

Imports or exports setting the PD-1 MCP can result in price divergences as these transactions cannot set the price in real-time. Table 2-2 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, 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.

Factor	Average Hourly Absolute Difference (MWh)		
	Summer 2015 Period	Winter 2015/16 Period	Summer 2016 Period
Ontario Demand	15,205	15,435	15,602
Demand Forecast Deviation	211	219	209
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	20	17	21
Wind Forecast Deviation	124	140	185
Net Export Failures/Curtailments	82	90	78

Relevance:

Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of price risks that participants, particularly importers and exporters, face as they enter offers and bids into the market.

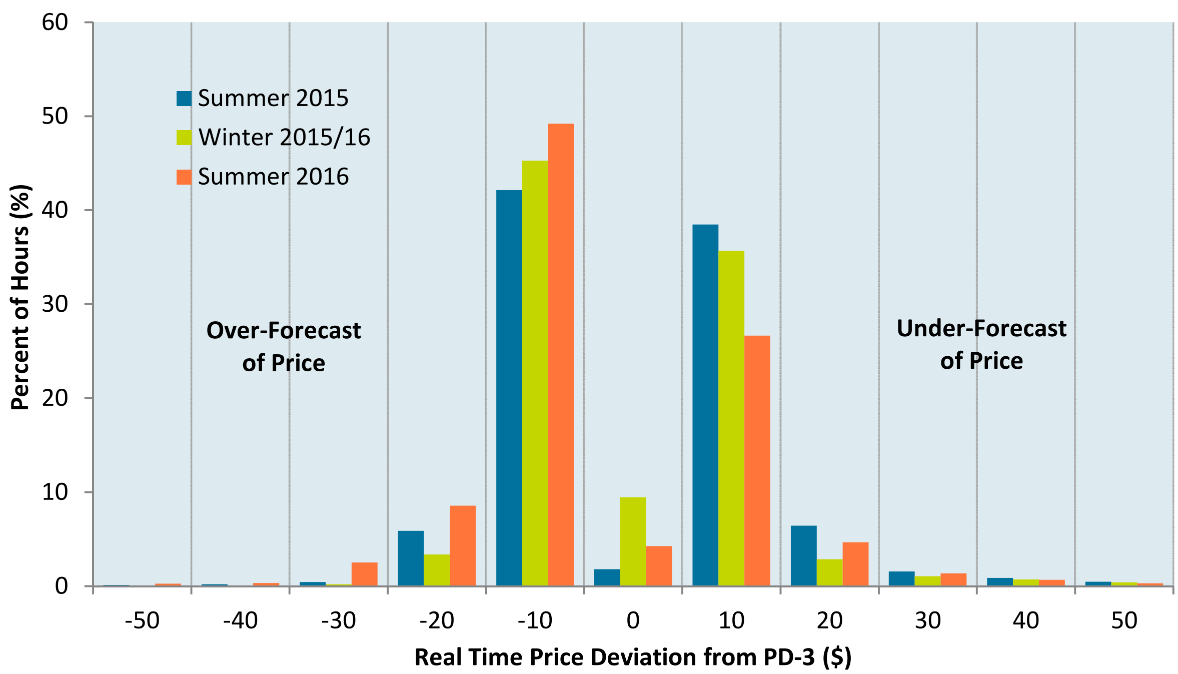
Commentary & Market Considerations:

Wind forecast deviation increased significantly over the last three reporting periods, primarily due to the increase in installed wind capacity. All other factors have varied as well, although to a significantly lesser degree.

Figure 2-9: Difference between the HOEP and the PD-3 MCP
Summer 2015, Winter 2015/16 & Summer 2016 Periods
(% of hours, $)

Description:

Figure 2-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP during the Summer 2016, Winter 2015/16 and Summer 2015 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. Positive differences on the horizontal axis represent a price increase from PD-3 to real-time, while negative differences represent a price decrease.



Relevance:

The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window, after which offers and bids may only be changed under limited circumstances with the approval of the IESO.

Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[19] 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.

Commentary and Market Considerations:

In the Summer 2016 Period the PD-3 MCP was within +/- $10/MWh of the HOEP 80% of the time, compared to 82% for the Summer 2015 Period and 90% in the Winter 2015/16 Period.

When comparing PD-3 to PD-1 (Figure 2-8), the forecast accuracy was similar during the Summer 2016 Period, and the PD-3 MCP was similarly far more likely to be over-forecast than under-forecast.

Figure 2-10: Monthly Global Adjustment by Component
November 2014 – October 2016
($)

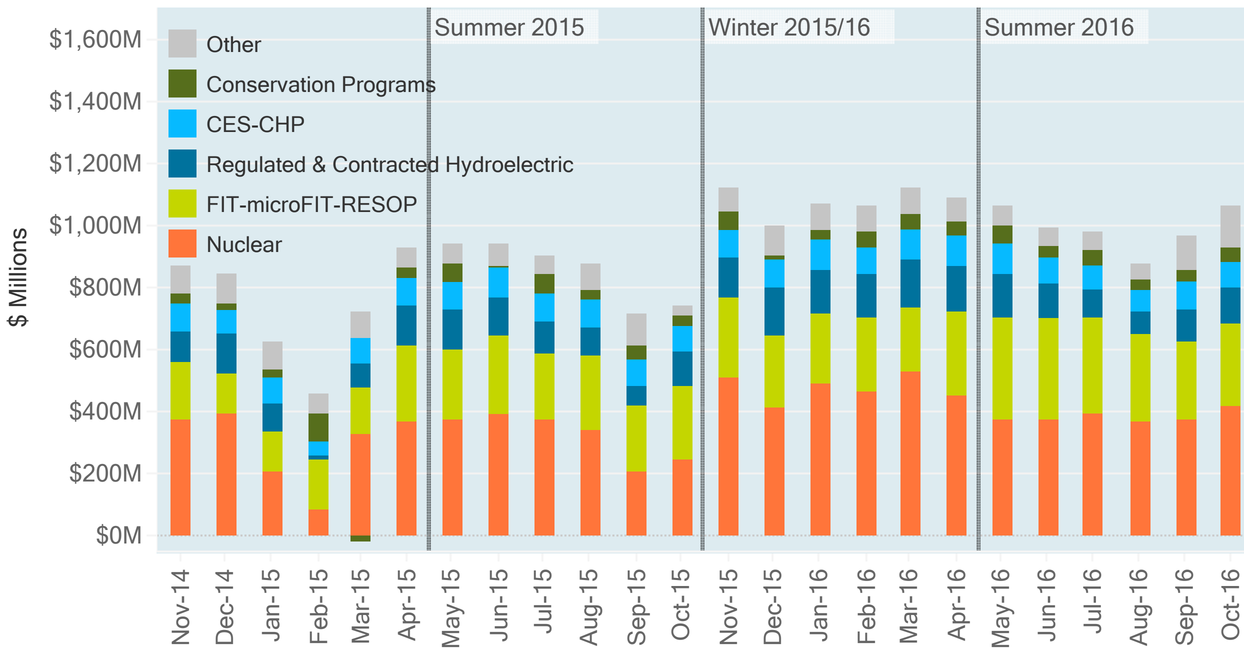
Description:

Figure 2-10 plots the payments to various resources and recovered through the GA each month, by component, for the previous two years. For this purpose, the total GA is divided into the six following components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's (OPG) nuclear assets);
- Payments to holders of Clean Energy Supply contracts and Combined Heat and Power (CES-CHP) contracts;

[19] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions that prevent them from operating at full capacity at all times. Energy limited resources differ from intermittent resources (such as wind) in that they have the ability to store fuel, thus allowing them to optimize production over their storage horizons. For example, a hydroelectric facility with limited water availability and a storage pond may store water during relatively lower priced hours, and use it to generate and sell electricity during relatively higher priced hours.

- Payments to regulated or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff (FIT), microFIT and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including under the IESO's demand response pilots, to holders of non-utility generator contracts and under the contract with OPG's Lennox Generating Station).



Relevance:

Showing the GA by component identifies the extent to which each component contributes to the total GA. The high GA totals for a particular component may be the result of increases in contracted rates, increased production, increased capacity, or decreases in the HOEP.

Commentary and Market Considerations:

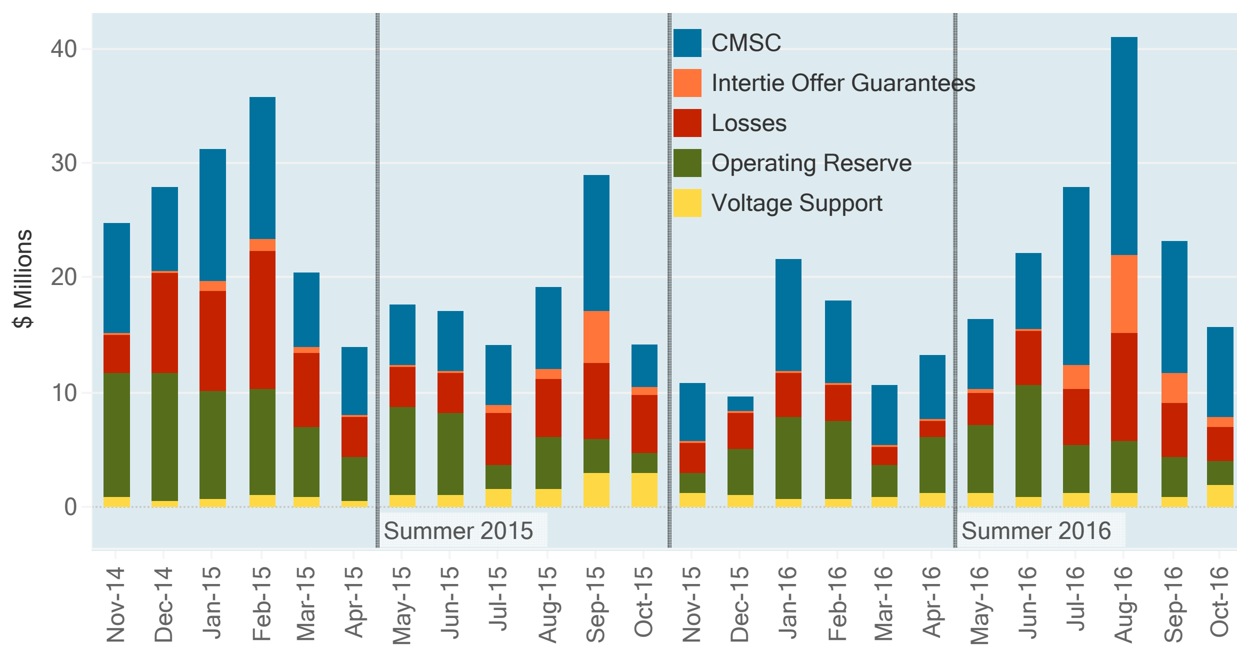
Two GA components, payments to "FIT-microFIT-RESOP" generators and payments in the "Other" category, increased in the Summer 2016 Period, while payments in the remaining four fell. FIT-microFIT-RESOP payments surpassed $300 million/month for the first time in May 2016. It is expected that these payments will continue to increase as renewable capacity in Ontario continues to come online. Payments in the "Other" category also reached a new high of

$133 million/month in October 2016, largely as a result of higher payments to non-utility generators.

Figure 2-11: Total Hourly Uplift Charge by Component and Month November 2014 – October 2016 ($)

Description:

Figure 2-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments, OR payments, voltage support payments and transmission losses.



Relevance:

Hourly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) – based on their share of total hourly demand – in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

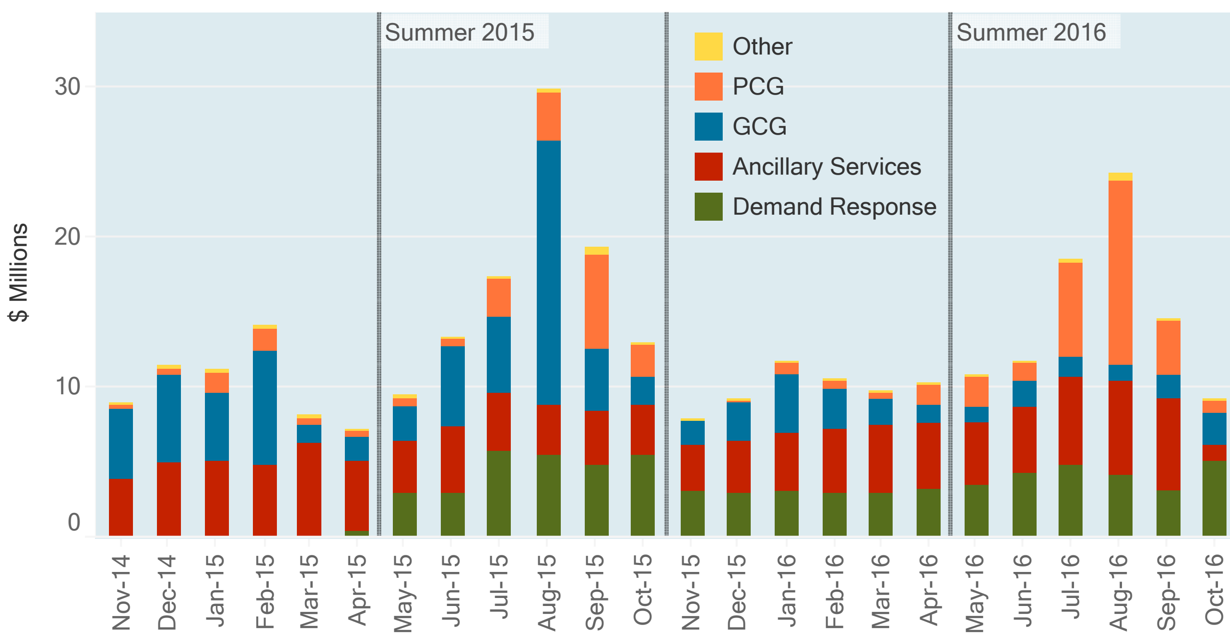
In August 2016, total Hourly Uplift exceeded $40 million for the first time since March 2014, primarily driven by an increase in CMSC payments ($18.9 million), losses ($9.6 million) and IOG payments ($6.8 million). Hourly Uplift tends to follow trends in the HOEP, as higher prices mean more costly losses and congestion and higher guarantees to importers. As shown in Figure 2-3, August 2016 had the highest average HOEP of the Summer 2016 Period, and the second highest average monthly HOEP of the two year period covered by the figure.

Figure 2-12: Total Monthly Uplift Charge by Component November 2014 – October 2016 ($)

Description:

Figure 2-12 plots the total monthly uplift charges (Monthly Uplift) by component, for the previous two years. Monthly Uplift has the following components:[20]

- Payments for ancillary services (i.e. regulation service, black start capability, monthly voltage support);
- 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 demand response auction; and
- Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.



[20] The figure includes all uplifts charged, except those charged on an hourly basis.

Relevance:

Monthly Uplift is a component of the effective price in Ontario. It is charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand, as applicable, in order to recover the costs associated with various market programs and design features.

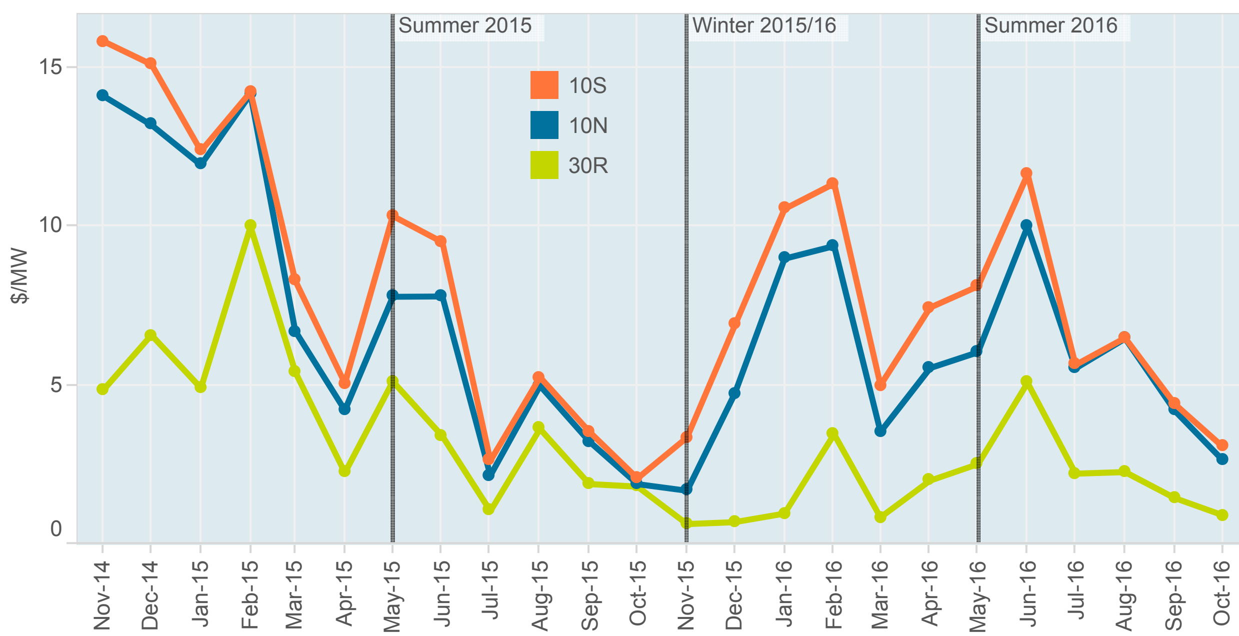
Commentary and Market Considerations:

PCG and GCG payments make up a substantial portion of Monthly Uplift and tend to trend with market demand (Figure 2-20); higher demand typically necessitates the commitment of more non-quick start facilities. Total Monthly Uplift in the Summer 2016 Period was down slightly from the Summer 2015 Period, with the majority of commitment costs shifting from the GCG program to the PCG program (i.e. from real-time to day-ahead).

Figure 2-13: Average Monthly Operating Reserve Prices by Category
November 2014 – October 2016
($/MW)

Description:

Figure 2-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).



Relevance:

The three OR markets are co-optimized with the energy market, meaning that resources are scheduled to minimize the combined costs of energy and OR. As such, prices in these markets tend to be subject to similar dynamics.

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The reliability standards set by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council stipulate that the IESO must schedule sufficient OR to allow the grid to recover from the single largest contingency (such as the largest generator tripping offline) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. These requirements ensure that the IESO-controlled grid can operate reliably.

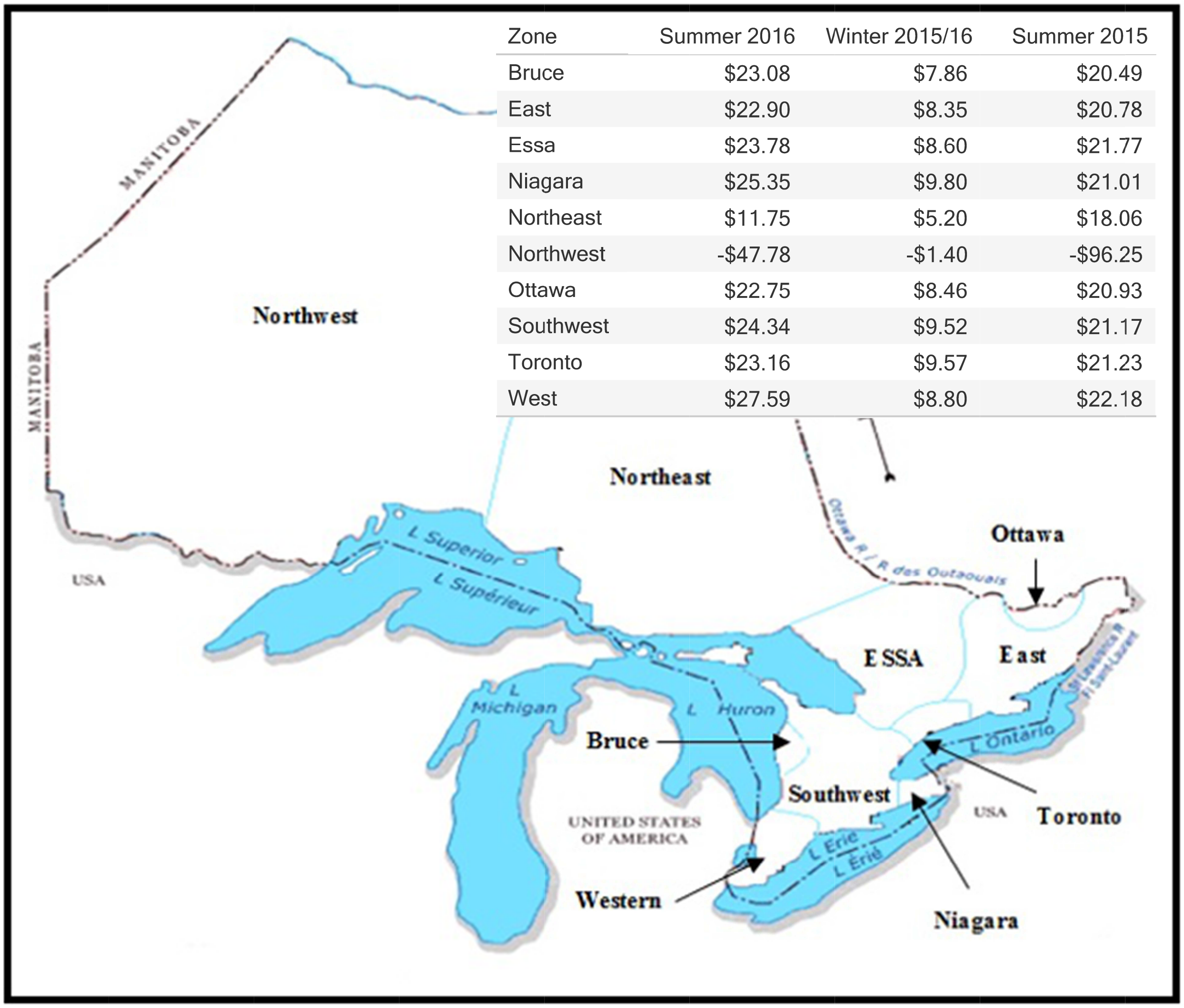
Commentary and Market Considerations:

OR prices in all three markets were moderately higher in the Summer 2016 Period relative to the Summer 2015 Period. The high OR prices in June 2016 reflect a single high price event occurring within a two-hour period. In that case, demand was under-forecast and wind resources were over-forecast, leaving an energy shortfall that could only be met with faster ramping, more expensive resources. Since energy and operating reserve are co-optimized, this energy shortfall translated into high OR prices.

Figure 2-14: Average Internal Nodal Prices by Zone
Summer 2015, Winter 2015/16 & Summer 2016 Periods
($/MWh)

Description:

Figure 2-14 illustrates the average nodal price of Ontario's ten internal zones for the Summer 2016, Winter 2015/16 and Summer 2015 Periods. In principle, nodal prices represent the cost of supplying the next megawatt-hour of energy at a given location.



Zone	Summer 2016	Winter 2015/16	Summer 2015
Bruce	$23.08	$7.86	$20.49
East	$22.90	$8.35	$20.78
Essa	$23.78	$8.60	$21.77
Niagara	$25.35	$9.80	$21.01
Northeast	$11.75	$5.20	$18.06
Northwest	-$47.78	-$1.40	-$96.25
Ottawa	$22.75	$8.46	$20.93
Southwest	$24.34	$9.52	$21.17
Toronto	$23.16	$9.57	$21.23
West	$27.59	$8.80	$22.18

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal cost[21] of electricity in each region and reflect Ontario's internal transmission constraints. Differences in average nodal prices identify zones that are separated by system constraints. In zones in which average nodal prices are high, supply is more expensive or the supply conditions are relatively tight; in zones in which average nodal prices are low, supply is cheaper or the supply conditions are relatively more abundant.

[21] There are instances where nodal prices do not reflect the marginal cost of electricity, such as those discussed in section 1.1 of Chapter 4.

In general, nodal prices outside the northern parts of the province move together. Most of the time the nodal prices in the Northwest and Northeast zones are significantly lower than the nodal prices in the rest of the province due primarily to two factors: first, in these zones, there is surplus low-cost generation (in excess of demand); and second, there is insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate 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 and Market Considerations:

Given the relatively static location of generators, loads and transmission lines over time, changes in nodal prices are largely driven by demand. With the exception of the Northeast, nodal prices within all zones were higher during the Summer 2016 Period relative to the Summer 2015 Period. These higher prices can be largely attributed to hotter summer conditions causing increased demand during the period.

Figures 2-15 & 2-16: Congestion by Interface Group

Description:

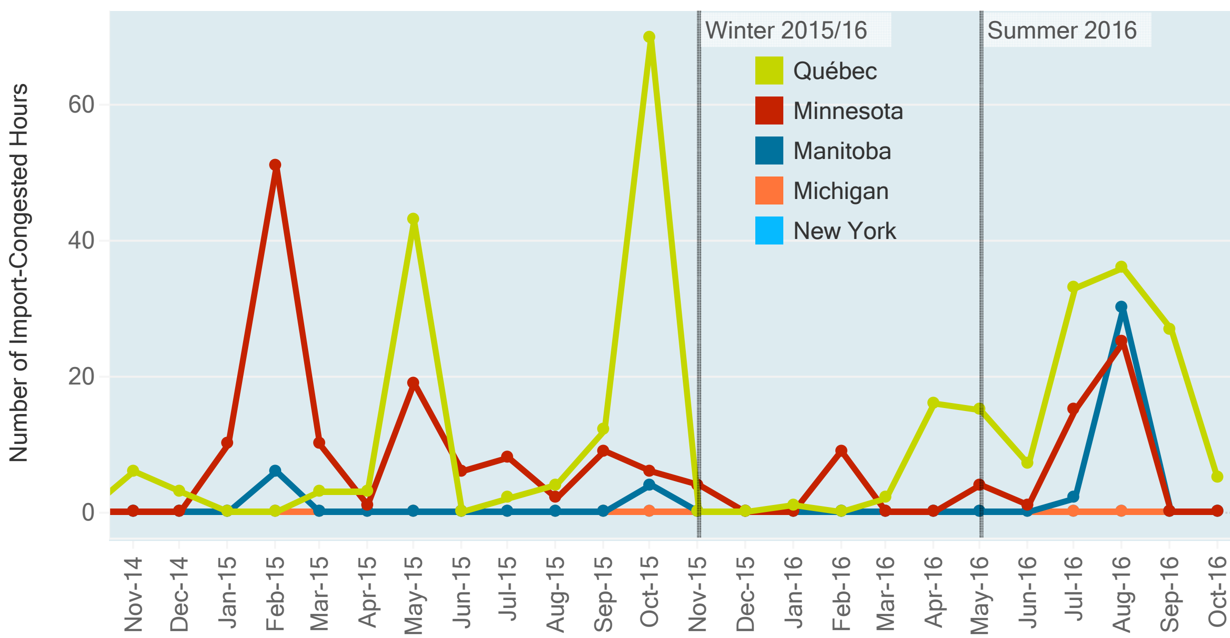
Figures 2-15 and 2-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. 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. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions.

The price for import and export transactions can differ from the MCP, as it is based on the intertie zonal price where the transaction is taking place. For a given intertie, importers are paid the intertie zonal price, while exporters pay the intertie zonal price. When there is import congestion, importers receive less for the energy they supply while exporters pay less for the energy they purchase—the intertie zonal price is lower than the MCP. When there is export congestion, importers receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zonal price is greater than the MCP. The difference between the intertie zonal price and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 depending on whether or not the PD-1 energy schedule has 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. This is discussed in more detail in the "Relevance" section associated with Figure 2-17.

Figure 2-15: Import Congestion by Interface Group
November 2014 – October 2016
(number of hours in the unconstrained schedule)

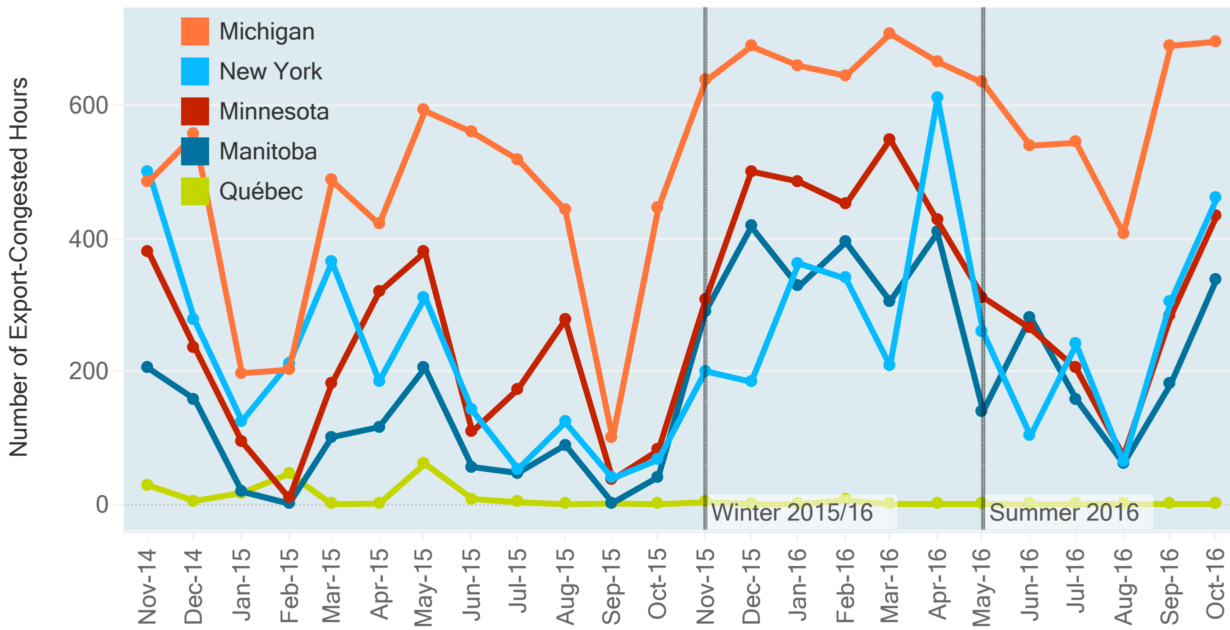


Commentary and Market Consideration:

Import congestion rose between June and August 2016 before declining in September and October. These variations were observed at the Manitoba, Minnesota and Québec interties. The higher HOEP in Ontario during August was a major cause of the increase in import congestion.

As prices in Ontario came down during September and October, there were fewer profitable import opportunities available and consequently import congestion decreased.

***Figure 2-16: Export Congestion by Interface Group
November 2014 – October 2016
(number of hours in the unconstrained schedule)***



Commentary and Market Consideration:

Export congestion generally trended downwards between May and August 2016 before coming back up in September and October. At the Michigan intertie there were approximately 690 hours of export congestion in September and October; this is close to a two year high. The low HOEP in Ontario combined created greater potential for profitable export opportunities in these months.

***Table 2-3: Monthly Average Hourly Electricity Spot Prices – Ontario and Surrounding Jurisdictions
May 2016 – October 2016
($/MWh)***

Description:

Table 2-3 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.[22] Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario.

The external prices reported are the real-time locational-marginal prices that correspond with the node on the other side of Ontario's interface with each jurisdiction. Québec is a frequent trading partner, but does not operate a wholesale market and thus is not included.

Month	Ontario (HOEP)	Manitoba*	Michigan (MISO)*	Minnesota (MISO)*	New York (NYISO)*	Pennsylvania New Jersey Maryland Operator (PJM)*
May	12.01	18.66	26.65	20.51	18.87	28.36
Jun	18.69	25.69	33.20	27.35	22.97	32.36
Jul	20.92	30.10	40.27	32.00	28.30	36.95
Aug	30.45	32.06	47.44	34.17	31.91	39.33
Sep	15.29	25.15	39.74	27.48	23.64	33.05
Oct	11.46	26.46	38.29	28.72	23.72	31.12

* All prices listed for each jurisdiction reflect the marginal price of energy. Costs associated with capacity, such as Ontario's GA or NYISO, PJM, or MISO's capacity markets, are not considered in inter-jurisdictional trade.

Relevance:

One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will impact the direction of energy trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing conditions can lead to energy trade that at a given time appeared profitable or efficient but becomes unprofitable or inefficient later. However, average prices over longer time horizons are informative on expected trends in the direction of energy trade between jurisdictions.

As discussed in the Relevance section associated with Figures 2-15 and 2-16, importers and exporters in Ontario do not receive or pay the HOEP if congestion exists at an interface in a

[22] Exporters pay most uplifts charges, but do not pay the GA.

given hour. Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction's price. However, the HOEP and the spot price in the external jurisdiction remain two key pieces of information in determining whether to import to or export from Ontario.

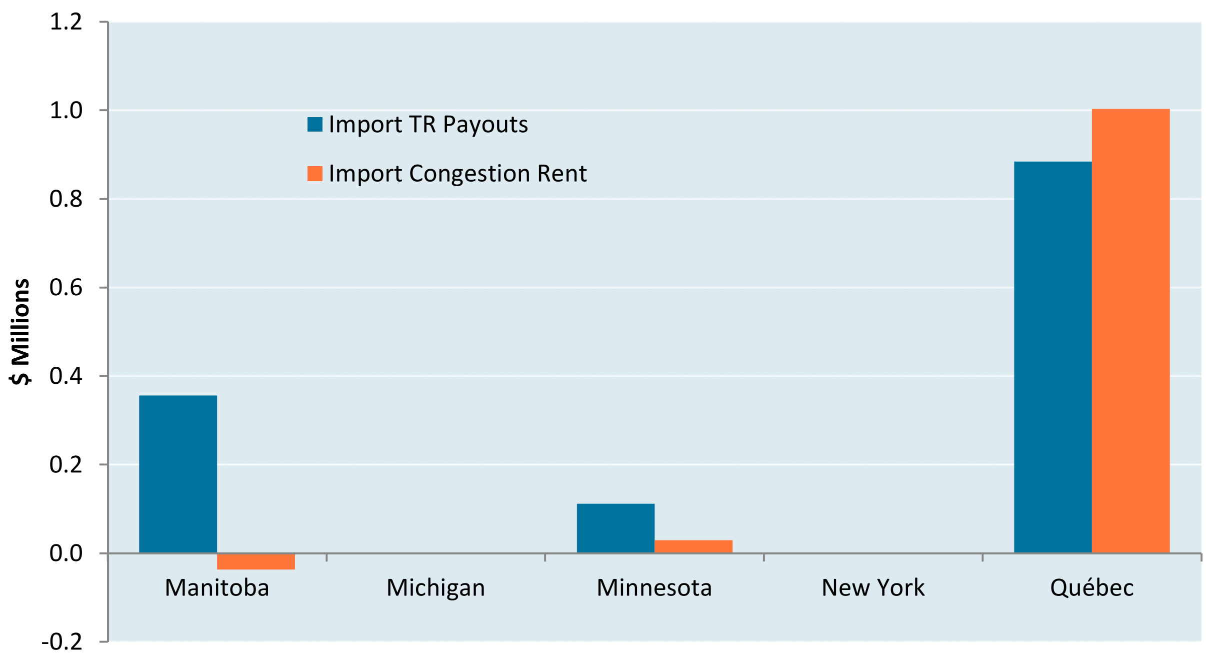
Commentary and Market Considerations:

During the Summer 2016 Period, the HOEP was significantly lower than the energy price in all of the surrounding jurisdictions. As expected, Ontario was a net exporter over the period (see Figure 2-24), often with congested interties in the export direction (see Figure 2-16).

Figure 2-17: Import Congestion Rent & Transmission Rights Payouts by Interface Group
May 2016 – October 2016
($)

Description:

Figure 2-17 compares the total import congestion rent collected to total transmission rights (TR) payouts by interface group for the Summer 2016 Period.



Relevance:

As discussed in the Relevance section associated with Figures 2-15 and 2-16, an intertie zonal price 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 intertie zonal price. While the importer is paid the lesser intertie zonal price, 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 is known as import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TR Clearing Account). This account is discussed in greater detail in the Relevance section associated with Figure 2-19.

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. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion, as TR payouts will exactly offset price differences between the HOEP and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. One of the main reasons for this is the difference between the number of TRs held by market participants and the number of net imports/exports flowing during hours of congestion. When TR payouts exceed congestion rent collected, the TR Clearing Account is drawn down; the opposite is true when congestion rent collected exceeds TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[23] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent

[23] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree that the pre-dispatch unconstrained schedule differs from the real-time constrained schedule, TR payouts may differ from congestion rent collected. In the extreme, congestion may occur in one direction (*e.g.* import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has net transactions in the opposite direction (*e.g.* export). In this case, import TR payouts are made and negative import congestion rents are "collected".

shortfall arises; instead of remaining revenue neutral, these events draw down the TR Clearing Account. These shortfalls are covered primarily by TR auction revenues. The Panel has previously expressed the view that TR auction revenues should be for the benefit of consumers in the form of a reduction in transmission charges.[24] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers.

Note that interties with a high frequency of import congestion hours (see Figure 2-15) 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 and Market Consideration:

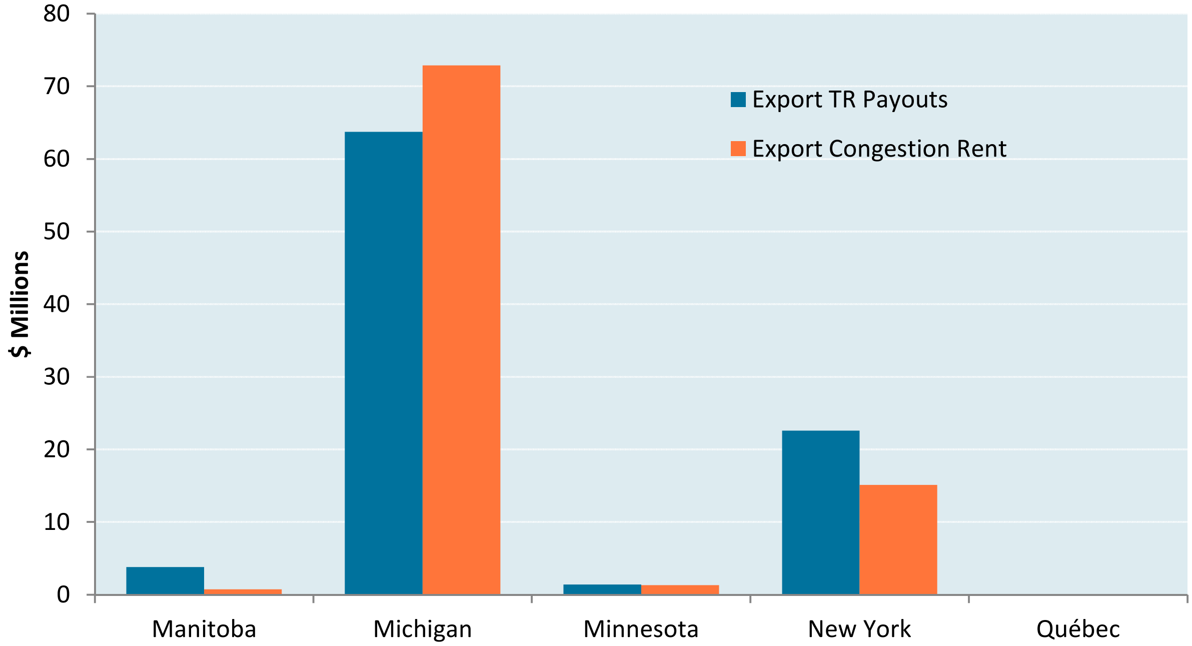
In the Summer 2016 Period, TR payouts exceeded import congestion rent collected by $350,000 across all interties; a relative balance when compared to past reporting periods. TR payouts exceeded congestion rents primarily at the Manitoba interface, in part due to the high failure rate of import transactions on the Manitoba interface (see Table 2-7).

Figure 2-18: Export Congestion Rent & TR Payouts by Interface Group May 2016 – October 2016 ($)

Description:

Figure 2-18 compares the total export congestion rent collected to total TR payouts by interface group for the Summer 2016 Period.

[24] If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that rents might be paid to transmission owners. But as the transmission companies are rate-regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario consumers) would benefit from congestion rents. For more information on the TR market and the basis for disbursing funds from the TR Clearing Account to offset transmission service charges, see pages 146-160 of the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf



Relevance:

When there is export congestion, the intertie zonal price is greater than the Ontario price. See the Relevance section associated with Figure 2-17 which describes the relationship between congestion rents and TR payments in regards to import congestion.

Commentary and Market Consideration:

Across all interfaces, export TR payouts were in excess of congestion rent collected by $1.5 million. The Michigan interface, which was the most heavily export-congested interface in the Summer 2016 Period (see Figure 2-16), saw congestion rents collected exceed TR payouts by $9.1 million, while conversely the New York interface saw TR payouts exceeding congestion rents collected by $7.5 million.

Manitoba experienced a shortfall in congestion rents of $3.1 million. Manitoba also experienced the highest rate of export failures during the Summer 2016 Period (see Table 2-6) which contributed to the under collection of congestion rents. If a scheduled export transaction fails in an hour where congestion existed, congestion rent goes uncollected as no energy is purchased, though the transaction contributed to congestion at the interface in pre-dispatch. The Panel has previously recommended that traders that fail transactions for reasons within their control should be required to pay the foregone congestion rent, thus maintaining the balance in the TR Clearing Account.[25]

Table 2-4: Average Long-Term (12-month) TR Auction Prices by Interface and Direction November 2015 – October 2016 ($/MW)

Description:

Table 2-4 lists the average auction prices for one megawatt of long-term (12-month) TRs sold for each interface, in either direction, since November 2015 (these TRs would have been valid during the Summer 2016 Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-15	Jan-16 to Dec-16	1,735	389	3,707	224	1,850
	Feb-16	Apr-16 to Mar-17	1,796	339	3,487	208	1,118
	May-16	Jul-16 to Jun-17	1,437	350	1,564	252	1,259
	Aug-16	Oct-16 to Sep-17	2,208	164	3,006	384	2,662
Export	Nov-15	Jan-16 to Dec-16	8,828	61,875	19,034	29,036	4,383
	Feb-16	Apr-16 to Mar-17	19,595	78,135	25,276	34,165	2,980
	May-16	Jul-16 to Jun-17	31,341	113,934	42,647	48,881	3,726
	Aug-16	Oct-16 to Sep-17	29,144	101,732	30,813	40,548	3,256

Relevance:

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. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

With the exception of the Québec interface, long-term export TR prices have increased significantly since the November 2015 auction, indicating that TR holders expected that export

[25] See the Panel's May 2017 Monitoring Report, pages 78-81, available at: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf. As noted in chapter 1, the IESO has indicated that it would review this matter and determine an appropriate avenue to address the issue.

congestion on the interties would not only persist but likely increase through to the summer of 2017. In the four auctions held from November 2015 to August 2016, the highest prices were for long-term export TRs on the Michigan interface ($113,934/MW); true to expectations, the export direction on the Michigan intertie experienced the most frequent and costly congestion of all the interties in the Summer 2016 Period.

Table 2-5: Average Short-Term (One-month) TR Auction Prices by Interface and Direction November 2015 – October 2016 ($/MW)

Description:

Table 2-5 lists the auction prices for one megawatt of short-term (one-month) TRs sold at each interface, in either direction, since November 2015.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-15	165	15	122	15	5
	Dec-15	117	0	201	0	28
	Jan-16	103	0	327	1	20
	Feb-16	121	0	143	0	28
	Mar-16	98	0	126	0	40
	Apr-16	113	14	130	0	82
	May-16	78	16	211	1	210
	Jun-16	87	12	79	11	21
	Jul-16	97	19	87	4	35
	Aug-16	67	1	113	15	112
	Sep-16	150	2	162	30	203
	Oct-16	126	15	124	8	351
Export	Nov-15	310	4,009	-	2,297	72
	Dec-15	457	4,494	-	1,208	220
	Jan-16	1,001	4,621	-	1,305	826
	Feb-16	1,510	6,145	-	1,655	355
	Mar-16	2,612	7,373	-	2,875	186
	Apr-16	2,320	6,586	-	1,523	10
	May-16	3,050	8,005	-	1,488	16
	Jun-16	3,626	8,656	4,233	4,380	50
	Jul-16	4,133	10,848	-	3,085	8
	Aug-16	2,020	5,394	2,334	2,664	3
	Sep-16	720	7,395	1,001	2,269	7
	Oct-16	2,002	11,108	-	2,305	8

Relevance:

As discussed in the Relevance section associated with Table 2-4, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

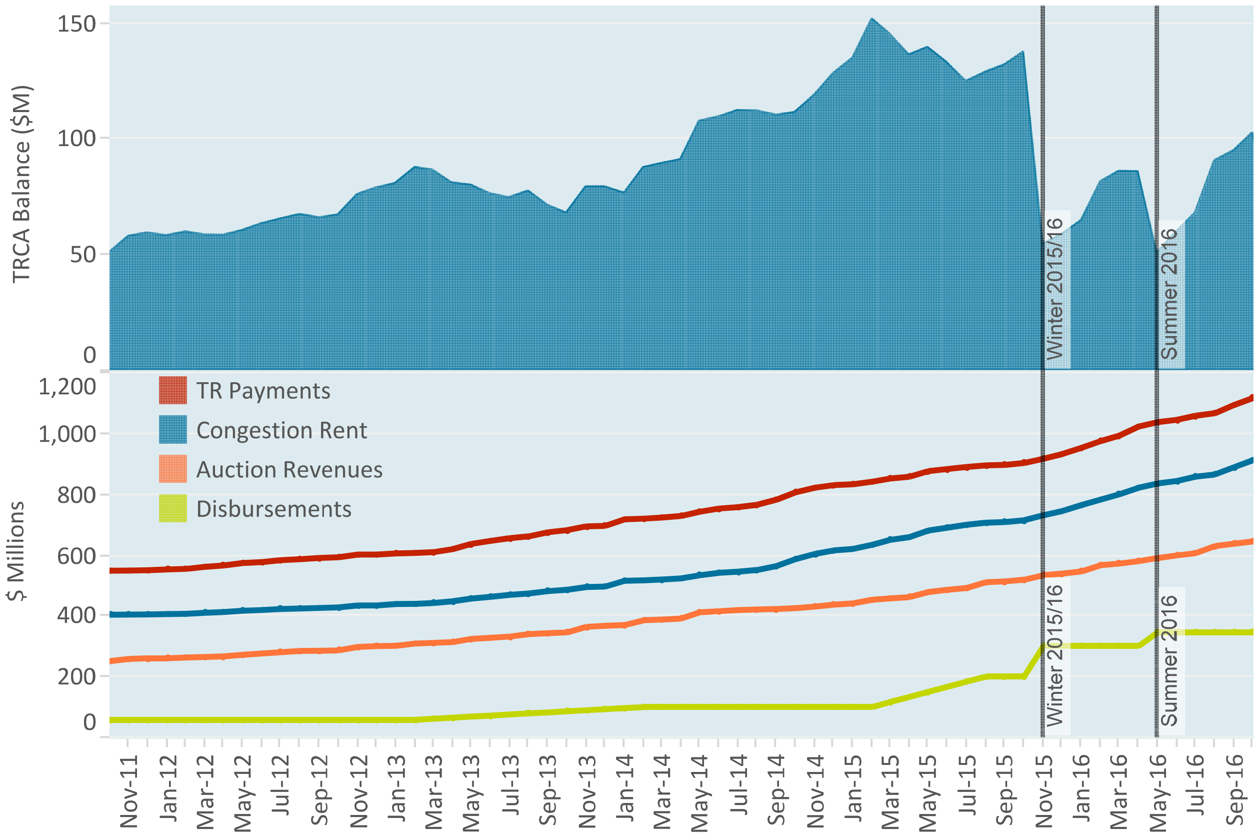
Commentary and Market Consideration:

Short-term auction prices in the Summer 2016 Period were reflective of the relative frequency of congestion experienced at each interface. Import TRs were consistently cheaper than export TRs due to the net export position in which Ontario routinely finds itself; Michigan had the most frequently congested interface (see Figure 2-16) and the highest TR auction prices throughout the Summer 2016 Period.

Figure 2-19: Transmission Rights Clearing Account
November 2011 – October 2016
($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts related to TRs. Figure 2-19 shows the estimated balance in this account at the end of each month for the previous five years, and well as a breakdown by its component transactions.



Relevance:

The TR Clearing Account balance is affected by five types of transactions:

<u>Credits</u>

- Congestion rent received from the market
- TR auction revenues
- Interest earned on the TR Clearing Account balance

<u>Debits</u>

- TR payouts to TR holders
- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. 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 & Market Considerations:

In the Summer 2016 Period, the balance in the TR Clearing Account increased by $18 million, from $85 million at the end of the Winter 2015/16 Period, to $103 million, $83 million above the Reserve Threshold. This change was composed of:

- $156 million in revenue:
    - $91 million in congestion rent collected
    - $65 million in auction revenues
    - $0.2 million in interest
- $138 million in disbursements:
    - $93 million in TR payments to rights holders
    - $45 million in disbursements to Ontario consumers[26]

Total congestion rent shortfall for the period was approximately $1.86 million, representing money that was paid to intertie traders. While the sum remains significant, it represents a significant improvement from the $13 million in congestion rent shortfall experienced during the Winter 2015/2016 Period.

2 *Demand*

This section discusses Ontario energy demand for the Summer 2016 Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand by Class A and Class B Consumers November 2011 – October 2016 (TWh)

Description:

Figure 2-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The Figure represents total Ontario demand – not grid-connected demand – in that it includes demand satisfied by embedded generators.[27]

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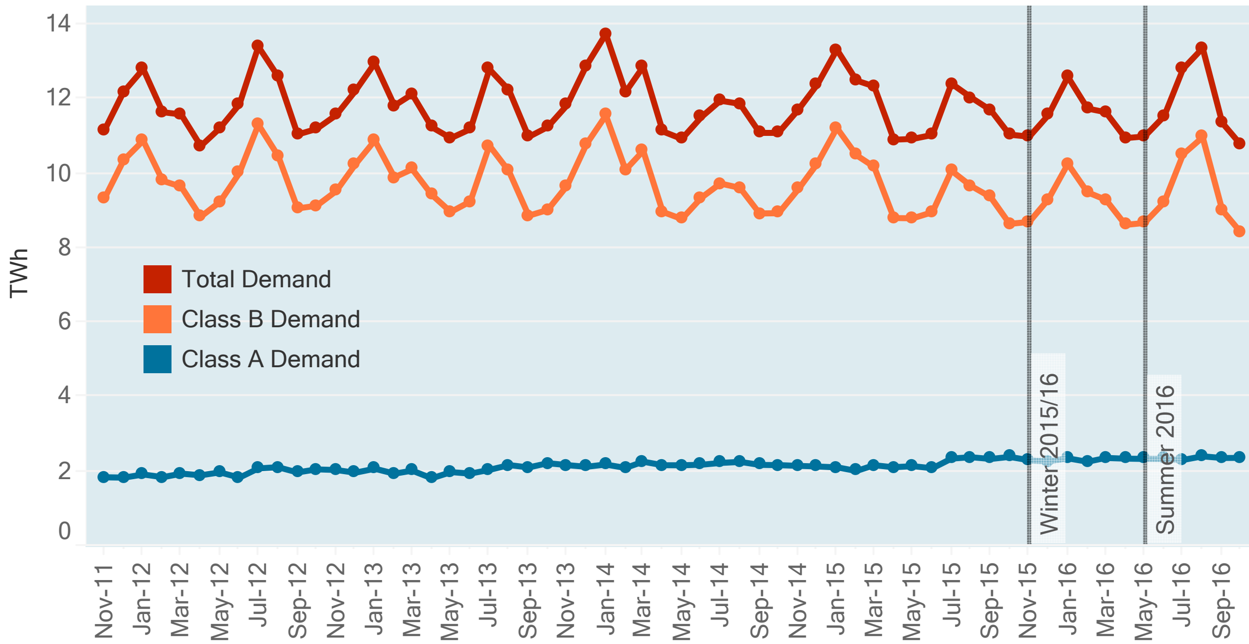
[26] On June 2, 2016, the IESO announced a lump sum disbursement from the TR Clearing Account of $45 million that was to occur during the June 2016 billing cycle: http://www.ieso.ca/sector-participants/ieso-news/2016/06/transmission-rights-clearing-account-disbursement

[27] Monthly embedded Class A consumption data may be understated as available data does not identify the quantity of behind-the-meter generation by consumer class. 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



Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns. The breakdown of consumers into Class A and Class B helps identify their respective monthly demand profiles.

Commentary and Market Consideration:

The peak monthly consumption during the Summer 2016 Period was 13.4 TWh, which was the highest monthly peak since the November 2013 – April 2014 winter period when Ontario was experiencing an abnormally cold winter. Total demand during the Summer 2016 Period was 70.7 TWh, a modest increase in demand from the Summer 2015 Period due to above normal temperatures.

Seasonal changes in Ontario demand are attributed almost entirely to Class B consumers, which include residential, small and medium commercial and small industrial loads. Demand from Class A consumers, a group primarily composed of industrial loads and large commercial consumers, exhibit little of the seasonality evident from Class B consumers.

3 *Supply*[28]

During the second and third quarters of 2016, 119 MW of nameplate generating capacity was added to the IESO-controlled grid. This new grid-connected capacity consisted of gas (0.8 MW), wind (99.3 MW) and hydro (18.9 MW) generation. At the end of the third quarter of 2016, grid connected generation capacity totalled 36,070 MW, consisting of nuclear (12,978 MW), gas-fired (9,934 MW), hydroelectric (8,451 MW), wind (3,923 MW), biofuel (495MW) and solar generation (280 MW).[29]

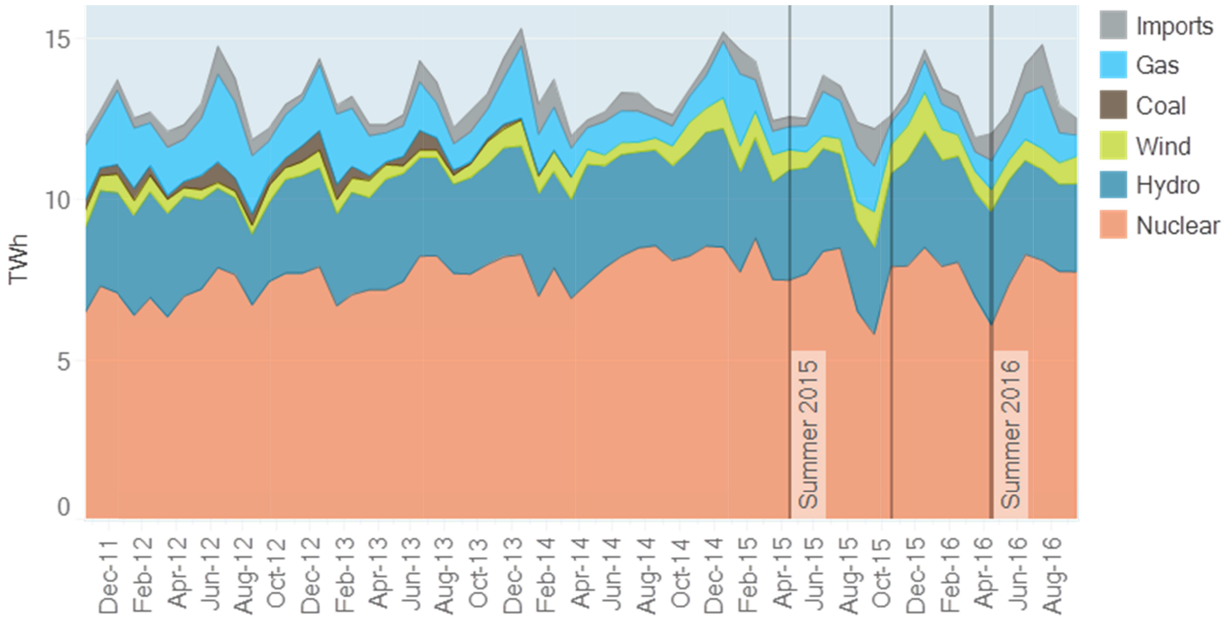
During the second and third quarters of 2016, 146 MW of nameplate IESO-contracted generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of solar (50 MW), wind (36 MW), gas-fired and combined heat and power (46 MW) and energy from waste (14 MW). At the end of the third quarter of 2016, IESO-contracted embedded capacity totalled 3,119 MW, consisting of solar (1,926 MW), wind (534 MW), hydroelectric (268 MW), gas-fired and combined heat and power (259 MW), biofuel (108 MW) and energy from waste (24 MW).[30]

Figure 2-21: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule November 2011 – October 2016 (TWh)

Description:

Figure 2-21 displays the share of real-time unconstrained production schedules from November 2011 to October 2016 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.

[28] A more detailed examination of medium-term supply capacity in Ontario is available from the IESO's regularly-published 18-month outlooks, available at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook
[29] Capacity totals were obtained from the IESO 18 month outlook reports which can be found at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook.
[30] Embedded capacity additions and totals were obtained from the quarterly Ontario Energy Reports, which can be found at: http://www.ontarioenergyreport.ca/index.php.



Relevance:

This figure displays the evolution of Ontario's changing mix of real-time energy supply. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations (for example, during the spring snowmelt or 'freshet' when hydroelectric plants have an abundant supply of fuel).

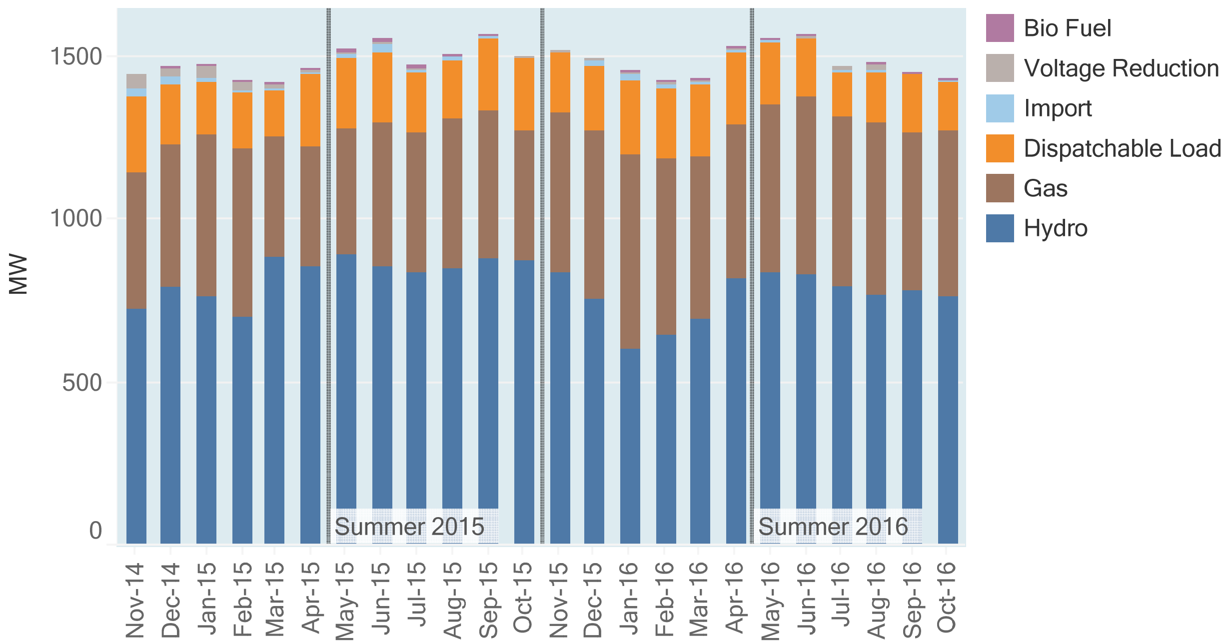
Commentary and Market Considerations:

Comparing the Summer 2016 and Summer 2015 Periods, the composition of resources scheduled to meet demand in the unconstrained schedule was largely unchanged, save for a modest increase in the quantity of imports scheduled.

***Figure 2-22: Average Hourly Operating Reserve Scheduled by Resource Type
November 2014- October 2016
(MW)***

Description:

Figure 2-22 displays the share of real-time unconstrained OR schedules from November 2014 to October 2016 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads, and voltage reduction (taken as a control action by the IESO).[31] Changes in the total average hourly operating reserve scheduled reflect changes in the OR requirement over time.



Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors.[32]

Commentary and Market Considerations:

The amount of OR scheduled in the Summer 2016 Period remained stable relative to the Summer 2015 Period. The composition of resources scheduled for OR changed slightly: the amount of OR supplied by gas-fired resources increased by 7% while the amount supplied by hydroelectric and dispatchable load resources combined fell by 6%. Imports, biofuel and voltage reduction continued to play a minor role, together contributing less than 1% of the total OR scheduled.

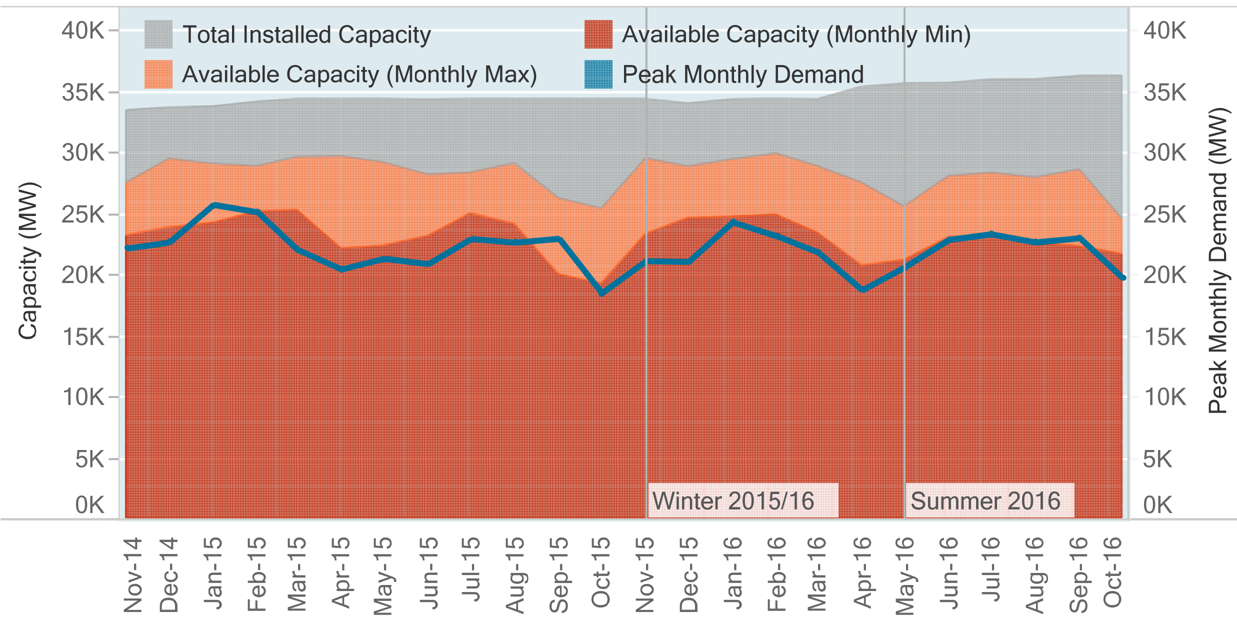
[31] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only scheduled in real-time, 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.

[32] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency on Ontario's electricity grid, with at least 25% of that energy available as 10-minute spinning reserve. The total energy available from the 30-minute OR market must be enough to cover half the second largest contingency on Ontario's grid.

Figure 2-23: Unavailable Generation Relative to Installed Capacity
November 2014 – October 2016
(MW)[33]

Description:

Figure 2-23 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from November 2014 to October 2016. For reference, the figure also includes the monthly peak market demand, excluding imports. [34]



Relevance:

The availability of generating capacity and the size of the supply cushion are key factors in determining market prices.

[33] Until the May 2017 Monitoring Report, this figure reported planned and forced outages and derates relative to capacity. The Panel revised the methodology by which it reports on unavailable generation capacity to also include unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid, in addition to planned and forced outages and derates. In addition, the manner of reporting unavailable generation capacity has changed; it is no longer reported as a percentage of capacity. As such, the data reported in this figure will not align with similar data published in previous Panel reports.

[34] Unavailable generation capacity data was obtained from adequacy reports published daily by the IESO. The maximum and minimum hours of the month were used. Daily, weekly and monthly market summaries published by the IESO can be found om the IESO website, available at: http://www.ieso.ca/power-data/market-summaries-archive

Commentary and Market Considerations:

An increase in planned outages for nuclear and gas generation facilities were the main reason for outages reaching 40% of installed capacity by the end of the Summer 2016 Period. Three nuclear reactors underwent planned maintenance and the refurbishment of Darlington Unit 2 began in mid-October.

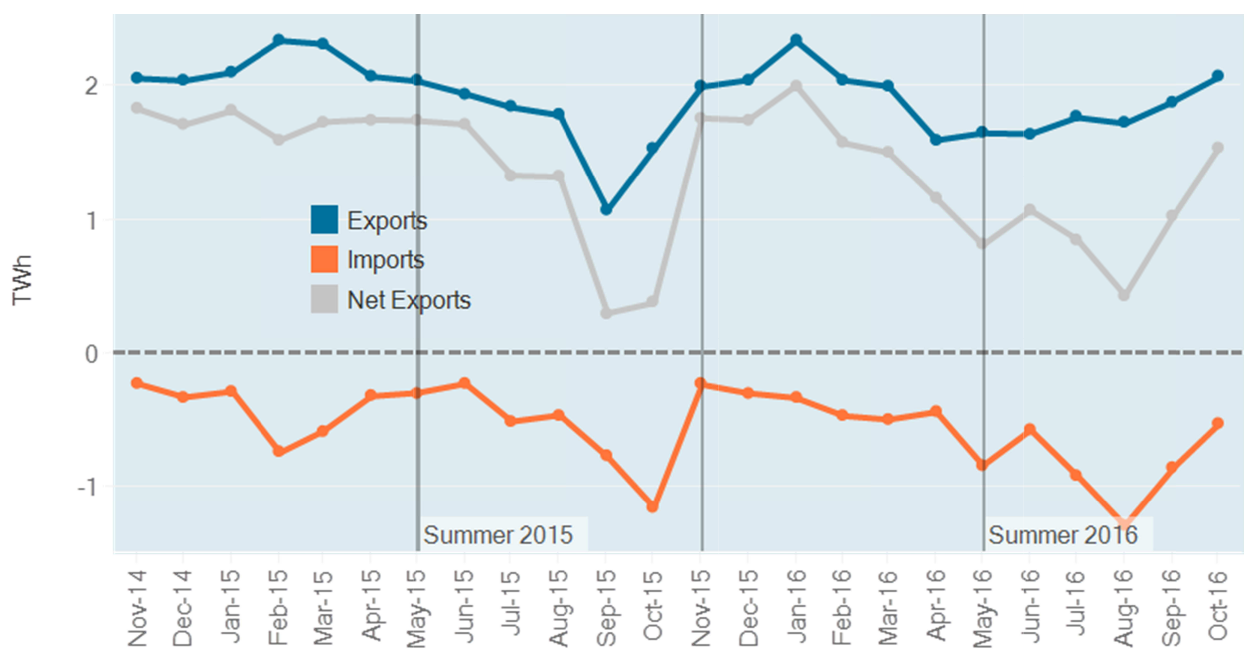
4 *Imports, Exports and Net Exports*

The data used in this section is based on the unconstrained sequence as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[35]

Figure 2-24: Total Monthly Imports, Exports & Net Exports
November 2014 – October 2016
(TWh)

Description:

Figure 2-24 plots total monthly imports, exports and net exports from November 2014 to October 2016. Exports are represented by positive values while imports are represented by negative values.



[35] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or the Ontario uniform price.

Relevance:

Imports and exports play an important role in determining supply and demand conditions in the province, and thus affect the market price. Tracking net export transactions over time provides insight into supply and demand conditions in Ontario relative to neighbouring jurisdictions. Periods of sustained net exports, such as the Summer 2016 Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

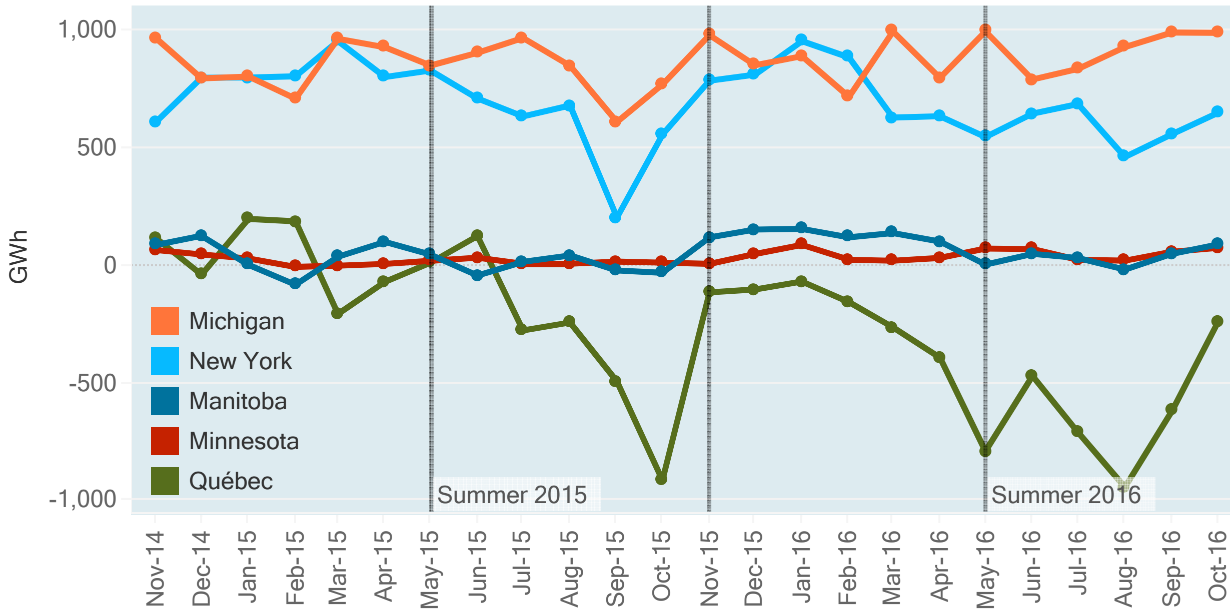
Commentary and Market Considerations:

Ontario was a net exporter in each month of the Summer 2016 Period, totalling 5.7 TWh, down from 6.7 TWh in the Summer 2015 Period. High Ontario demand in August 2016 resulted in total imports reaching the highest monthly import total over the last two years. As was the case in the Summer 2015 Period, Québec was the primary source of imports (see Figure 2-25).

Figure 2-25: Net Exports by Interface Group
November 2014 – October 2016
(GWh)

Description:

Figure 2-25 presents a breakdown of net exports from November 2014 to October 2016 for each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. Net exports are represented by positive values while net imports are represented by negative values.



Relevance:

This figure shows how Ontario's energy trading with each external jurisdiction evolves over time.

Commentary and Market Considerations:

During the Summer 2016 Period, both the Québec and Michigan interfaces had monthly totals representing two year highs. Québec was a net importer delivering a high of 946 GWh in August, and Michigan was a net exporter reaching a high of 993 GWh in May (and nearly achieving that high again in August and September).

Compared to the Summer 2015 Period, net exports at the Michigan, Minnesota, Manitoba and New York interfaces were all higher, together increasing by 786 GWh, while net imports from Québec more than doubled to 1,862 GWh. All told, net exports decreased by just over 1 TWh.

Table 2-6: Average Monthly Export Failures by Interface Group and Cause
Winter 2015/16 & Summer 2016 Periods
(GWh and %)

Description:

Table 2-6 reports average monthly export curtailments and failures over the Summer 2016 and Winter 2015/16 Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[36]

Interface Group	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 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16
New York	277.8	386.3	1.0	1.8	5.7	8.3	0.4	0.5	2.0	2.1
Michigan	326.3	348.1	1.4	1.5	4.7	3.2	0.4	0.4	1.4	0.9
Manitoba	50.6	79.9	3.7	2.6	14.8	16.3	7.2	3.2	29.1	20.4
Minnesota	20.4	6.0	0.6	0.2	0.5	0.2	2.7	2.7	2.6	3.7
Québec	60.6	93.2	0.6	4.2	0.4	1.3	1.1	4.5	0.7	1.4

Relevance:

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, 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. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to Surplus Baseload Generation conditions. The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

Commentary and Market Considerations:

The Manitoba interface continues to experience an MP failure percentage that far exceeds the failure rate experienced at other interties: 29.1% in the Summer 2016 Period versus 20.4% in the Winter 2015/16 Period and 31.1% in the Summer 2015 Period.

[36] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

Table 2-7: Average Monthly Import Failures by Interface Group and Cause Winter 2015/16 & Summer 2016 Periods (GWh and %)

Description:

Table 2-7 reports average monthly import failures and curtailments over the Summer 2016 and Winter 2015/16 Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Interface Group	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 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16	Summer 2016	Winter 2015/16
New York	20.9	1.4	0.1	0.0	0.2	0.1	0.4	0.6	1.1	3.8
Michigan	5.9	1.2	0.1	0.2	1.6	0.4	1.1	16.6	27.5	34.7
Manitoba	28.4	34.8	5.6	5.9	0.4	0.3	19.7	16.9	1.3	0.8
Minnesota	2.0	8.2	0.1	0.9	0.2	0.7	7.4	11.5	11.8	8.8
Québec	196.5	85.7	2.5	2.6	0.2	0.1	1.3	3.1	0.1	0.1

Relevance:

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 and Market Considerations:

The average monthly import quantity from Québec has increased to 197 GWh, significantly higher than the 86 GWh and 136 GWh experienced during the Winter 2015/16 and Summer 2015 Periods, respectively. Despite the increase, curtailment quantities and rates on the Québec interface were lower than in the previous two reporting periods.

Michigan continues to experience a high MP Failure rate on relatively low volumes, at 27.5% in the Summer 206 Period.

Chapter 3: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments from May 1, 2016 to October 31, 2016 (Summer 2016 Period), making comparisons to the May 1, 2015 to October 31, 2015 period (Summer 2015 Period) as appropriate.

Traditionally, the Panel's analysis of anomalous events has focussed on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of high uplift such as Congestion Management Settlement Credit (CMSC) payments and Intertie Offer Guarantee (IOG) payments. More recently, the Panel has also reported on payments made under the Real-Time Generation Cost Guarantee (RT-GCG) program and the Day-Ahead Commitment Program (DACP) where they are of particular interest. Payments made under the DACP are referred to as Day-Ahead Production Cost Guarantee (DA-PCG) 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 3-1 displays the number of events that exceeded the Panel's thresholds during the Summer 2016 Period, with comparisons to the Summer 2015 Period.

Table 3-1: Summary of Anomalous Events
May 2016 – October 2016 & May 2015 – October 2015
(Number of Events)

Anomalous Event Threshold	Number of Events May 1, 2016 to October 31, 2016	Number of Events May 1, 2015 to October 31, 2015
HOEP > $200	13	9
HOEP ≤ $0	735	452
Energy CMSC > $1 million/day	7	0
Energy CMSC > $500,000/hour	1	0
OR Payments > $100,000/hour	20	15
IOG > $1 million/day	0	0
IOG > $500,000/hour	0	0

1.1 *Summary of High-Price Hours*

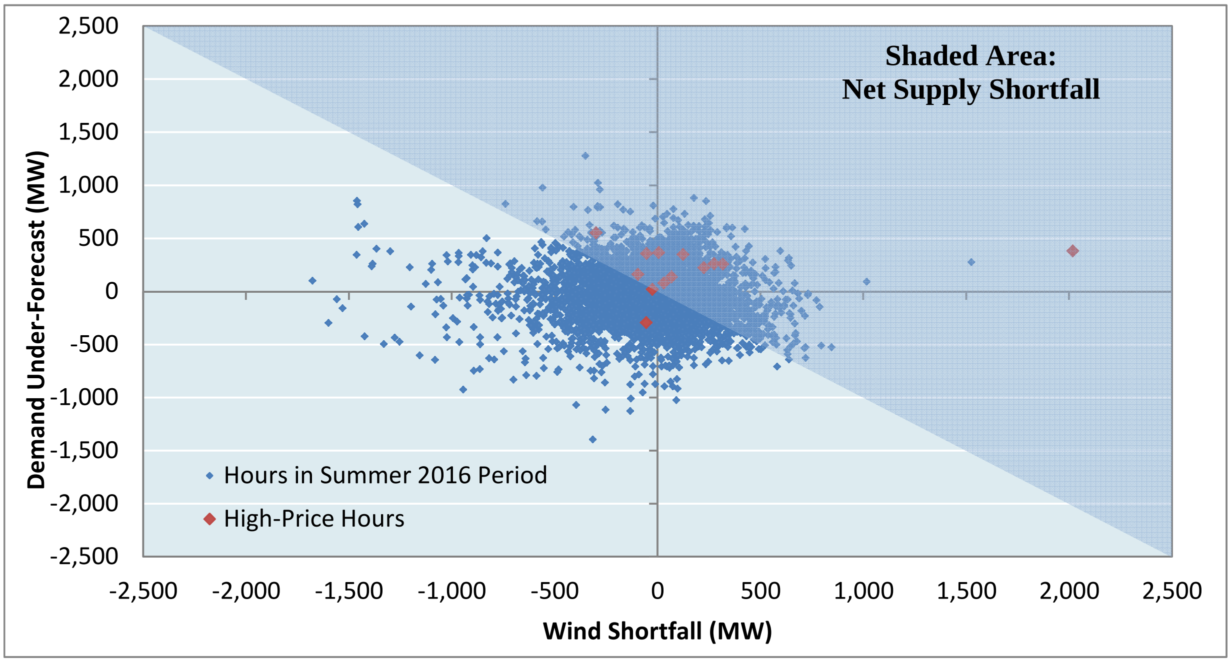
During the Summer 2016 Period, there were 13 hours when the HOEP was greater than $200/MWh; in 10 of these 13 hours, there were also operating reserve (OR) payments in excess of $100,000. Having analyzed these hours, the Panel has concluded they were largely the result of the following:

- Relatively high market demand;
- Variable generation shortfall (actual output below the forecast); and
- Demand forecast errors.

In these hours, ample supply conditions in pre-dispatch resulted in relatively low prices and few gas-fired facilities being committed to generate. With few gas-fired facilities online to provide relatively inexpensive ramping capability and OR, the system had limited ability to respond to the shortfall of variable generation and the increase in demand that occurred from pre-dispatch (PD-1) to real-time, resulting in high HOEPs and high OR payments. These circumstances contributed to the two highest-priced hours in the Summer 2016 Period: on June 9, 2016, the HOEP for Hour Ending (HE) 20 and HE 21 was $1,619.60/MWh and $1,327.89/MWh respectively.

As illustrated in Figure 3-1, almost all 13 high-price hours, marked in red, occurred during net supply shortfall conditions (defined as hours in which the sum of demand under-forecast and variable generation shortfall are positive, creating tighter supply conditions in real-time relative to PD-1).

Figure 3-1: HOEP by Net Supply Conditions
May 2016 – October 2016
(MW)



In one of the hours during which there was a net supply shortfall (HE 19 on October 23, 2016), a manual error made by the IESO in the operation of the pre-dispatch wind forecasting tool overstated the variable generation shortfall by more than 1,540 MW. While this error had the initial effect of driving the HOEP to an artificially high level, the IESO corrected the forecast and administratively lowered the HOEP for the hour to $257/MWh after the fact.

There were also two high-price hours that did not take place in net supply shortfall conditions. The first was HE 17 on September 6, 2016. In this hour, conditions from PD-1 to real-time remained fairly consistent, with a modest net supply excess of 6 MW. Nevertheless, high Ontario demand above 22,000 MW and a thin supply cushion necessitated the dispatch of more expensive hydroelectric generation for half the hour, which resulted in an HOEP of $201.31/MWh.

The second was HE 18 on September 26, 2016. In contrast to the other high-price hours, during this hour there was initially a relatively large net supply excess of 350 MW in real-time relative to PD-1. While such excess supply conditions typically correspond to a lower HOEP than the PD-1 Market Clearing Price (MCP), in this instance the HOEP was ultimately much higher at

$332.39/MWh. The increase in price from PD-1 to real-time was the result of a loss of generation that materialized from interval 8 to interval 9 of HE 18, when the energy MCP and OR MCP increased from below $100/MWh to $1999.99/MWh. The loss of supply was in part the result of a hydroelectric facility that was de-rated by 173 MW in interval 9. Additionally, an issue with the IESO's wind forecasting tool resulted in wind output appearing artificially high in the unconstrained schedule during HE 18, resulting in artificially supressed prices for the first eight intervals. In interval 9 of that hour, the quantity of artificial supply decreased to more accurately reflect actual wind output, putting upward pressure on price. Compensating for this loss of supply in five minutes required scheduling higher-priced gas-fired resources from the energy and OR market, resulting in the high-price hour.

1.2 *Summary of Low-Price Hours*

There were 735 hours when the HOEP was non-positive (zero or negative) during the Summer 2016 Period, an increase relative to the Summer 2015 Period when there were 452 such hours. A non-positive HOEP may arise as a result of low Ontario demand, failed export transactions or abundant supply offered at negative prices, among other causes. A contributor to the increase in non-positive price hours during the Summer 2016 Period was the addition of more wind and solar capacity, which offers energy at non-positive prices. Between the Summer 2015 Period and the Summer 2016 Period, 829 MW of new grid-connected wind and solar capacity was added.

1.3 *Summary of Anomalous Uplift Payments*

In the Summer 2015 Period, there were no days or hours in which the Panel's CMSC and IOG thresholds were exceeded. The same is true of IOG payments in the Summer 2016 period. However, there were eight anomalous CMSC events in the Summer 2016 Period.

There was one hour during the Summer 2016 Period with more than $500,000 in CMSC payments: in HE 1 on July 23, 2016, there was $518,557 in CMSC payments, most of which was the result of ramp-down CMSC paid to a generator.[37]

[37] In section 2.2 of Chapter 3 of the Panel's May 2017 Monitoring Report, the Panel estimated that CMSC payments caused by ramp down would have been reduced by $1.9 million from June 25, 2015 to December 7, 2016 (including the hour noted here) if the market rule change had taken effect on June 24, 2015 when the change was approved. However, implementation of the market rule change was delayed to December 8, 2016 due to the relative complexity of the required IT solution.

Table 3-2 presents the seven instances of CMSC payments that exceeded the Panel's daily CMSC threshold of $1,000,000.

Table 3-2: CMSC Payments Exceeding the Panel's Daily CMSC Threshold May 2016 – October 2016 ($)

Date	CMSC Payments
2016/07/23	$2,164,848
2016/07/24	$1,778,072
2016/08/04	$1,648,947
2016/08/10	$1,580,464
2016/08/11	$1,462,285
2016/09/07	$1,142,533
2016/08/13	$1,087,558

The high CMSC payments on July 23, 2016 and July 24, 2016 were partially the result of a single dispatchable load (Load A) receiving significant constrained-off CMSC payments. On July 23, Load A received $942,168 in constrained-off CMSC payments (43.5% of the daily total CMSC); on July 24, the same load received another $1,082,089 in constrained-off CMSC payments (60.9% of the daily total CMSC). The IESO had informed Load A in HE 20 of July 21 that the circuits in its vicinity would be on outage for several days, but despite being aware that its energy consumption would be limited by grid conditions Load A bid at $1,999/MWh, thereby maximizing its constrained-off CMSC payments for the duration of the outage.

On August 4, 2016, CMSC payments amounted to $1,648,947. During this day, hourly Ontario demand was relatively high from HE 8 to HE 23, with a peak demand of 22,521 MW in HE 18. As a result, a gas-fired facility with high-priced energy offers (above $200/MWh) was constrained on in order to relieve a zone with thermal line limit concerns, resulting in over $430,000 in CMSC payments throughout the day. The remainder of the CMSC payments were paid to various domestic resources and intertie traders that received less than $100,000 each.

The remaining four high CMSC days all experienced high Ontario demand well above 20,000 MW, which led to transmission constraints resulting in CMSC payments to multiple market participants for various measures such as constraining on domestic generation and curtailing exports in real-time. In another instance, as discussed in Section 2.1, an equipment concern at a dispatchable load resulted in significant constrained-off CMSC payments.

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 May 2017 Monitoring Report, 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 and the Market Rules;[38] the novelty and frequency of an unexpected event; and the relevance of the outcome to current IESO initiatives and stakeholder engagements. The Panel's approach is informed by the historic thresholds, as summarized in the preceding sections, but has been expanded to include other relevant events as appropriate.

In the section that follows, the Panel reports on an anomalous event during the Summer 2016 Period relating to a dispatchable load operating under constraints arising at its facility.

2.1 *Dispatchable Loads Operating under Operational Constraints*

Relevance

The Market Rules permit generators to request alternate dispatch instructions in situations where following the IESO's initial instructions would endanger the safety of any person, damage equipment or violate any applicable law (referred to as SEAL-related constraints). In such situations, generators are required to notify the IESO of their inability to follow dispatch instructions and to request that their dispatch be constrained to reflect their revised level of output.

While it is appropriate for generators to request that their dispatch be constrained to respect SEAL-related conditions at their facilities, it is inappropriate for them to receive CMSC payments as a result given that the constraint is necessitated by conditions at the facility rather than by conditions on the IESO-controlled grid. In December 2011, the IESO implemented a market rule amendment to allow the recovery of CMSC payments made to generators when they are unable to follow their initial dispatch instructions by reason of a SEAL-related constraint.

[38] Section 2 of Chapter 1 of the Market Rules states that the 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.

While provisions exist to recover CMSC payments made under SEAL-related constraints for generators, the same is not true for such payments when made to dispatchable loads. The Panel sees no reason why this outcome would be appropriate, as the root cause of the payments is the same in both cases. In the following section the Panel highlights one example of a dispatchable load receiving CMSC payments associated with a constraint necessitated by conditions at the facility, similar to a SEAL-related constraint.

Analysis

In HE 19 on August 10, 2016, a dispatchable load informed the IESO that it could not follow its expected dispatch due to issues at its facility. The IESO placed a manual constraint of 0 MW from HE 20 to HE 22 to reflect expected consumption by the load. This resulted in over $360,000 in constrained-off CMSC payments, as the load's original bids at $1,999/MWh were still in effect.

The conditions at the dispatchable load that necessitated the operational constraint in this case may not fall into the SEAL categories specified in the Market Rules that currently apply to generators. Nonetheless, it is a clear example of a dispatchable load receiving CMSC payments due to an operational constraint specific to its facility, and in this regard it is similar to a SEAL-related constraint. In the Panel's view, it is inappropriate that dispatchable loads are compensated for SEAL-related and other operational constraints arising from conditions at their facilities. The IESO should also examine whether the scope of the current provisions that allow it to recover CMSC payments from generators in relation to SEAL-related constraints should be expanded to cover any other operational constraints arising from conditions at the generator's facility.

Recommendation 3-1:

The Independent Electricity System Operator should implement rules that allow it to recover Congestion Management Settlement Credit payments made to dispatchable loads when those payments are the result of an operational constraint arising from conditions at the dispatchable load's facility. The IESO should also examine whether the scope of the current provisions that allow it to recover CMSC payments from generators in relation to SEAL-related constraints should be expanded to cover any other operational constraints arising from conditions at the generator's facility.

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

1 *Introduction*

In this chapter, the Panel discusses potential market design deficiencies or concerns related to market participant conduct or activities of the IESO that are not necessarily linked to events during the May 1, 2016 – October 31, 2016 reporting period.

2 *New Matters*

2.1 *Constrained-on CMSC for Exporters*

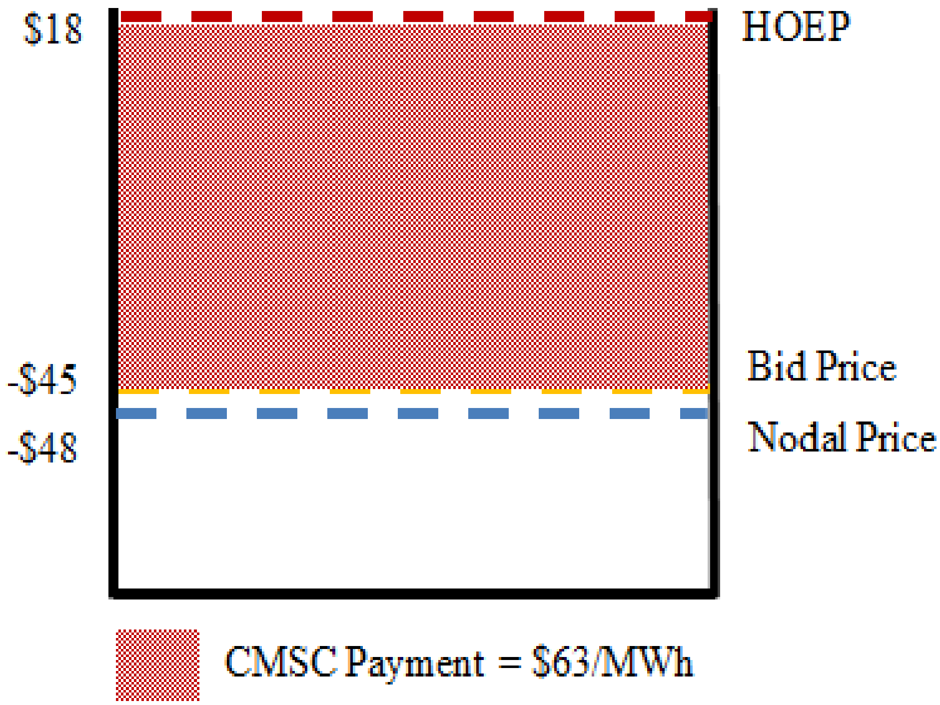
In its January 2010 Monitoring Report, the Panel identified that exporters may use strategic bids to obtain significant Congestion Management Settlement Credit (CMSC) payments during periods of excess local supply. Periods of excess local supply are particularly prevalent in the Northwest, a chronically congested region due to abundant hydroelectric generation, low demand and relatively limited transmission capacity linking it to other load centres in Ontario. Such transmission constraints cause a divergence between the Hourly Ontario Energy Price (HOEP) and local nodal prices; this is evident in the Summer 2016 Period when the average hourly nodal price in the Northwest was -$48/MWh, while the average HOEP was $18/MWh. Notionally, a -$48/MWh price implies that all suppliers scheduled at that price were willing to pay $48/MWh or more to supply energy.[39] Of course, a -$48/MWh average price over a six month period is not reflective of the underlying economics of supply in the region. In other words, suppliers to the Northwest did not actually have to pay this amount to deliver energy; instead, they were paid the HOEP, or roughly $18/MWh on average. The disconnect between the average nodal price and the HOEP is just one consequence of Ontario's two-schedule system.

When scheduling exports, the IESO's dispatch tool treats the -$48/MWh average nodal price as though it reflects underlying economics. As illustrated in Figure 4-1, this provides exporters with an opportunity to receive constrained-on CMSC payments on the basis of the spread between their bid price and the HOEP. To be constrained on, the exporter's bid price must be higher than the nodal price but lower than the HOEP. Since the bid is economic in the constrained sequence (which had an average nodal price of -$48/MWh) but uneconomic in the unconstrained sequence

[39] This also implies that all exporters scheduled at that price were willing to be paid that price or more to take power from the Northwest and deliver it to neighbouring jurisdictions.

(which had an average HOEP of $18/MWh), the export is constrained-on. The greater the spread between the exporter's bid price and the HOEP, the higher the constrained-on CMSC payment.

Figure 4-1: Illustration of Constrained-on CMSC Calculation



The opportunity to receive significant CMSC payments gives exporters the incentive to engage in a behaviour that the Panel has previously described as "nodal price chasing", which involves submitting bids as close to the nodal price as possible without going below in order to maximize CMSC payments. To eliminate this incentive and limit the resulting uplift charges, the Panel previously recommended that the IESO use a replacement bid price of $0/MWh when calculating the CMSC payable for negatively-bid exports.[40]

In response to the Panel's recommendation, the IESO agreed that, for CMSC calculation purposes, a replacement bid price was warranted. However, the IESO was concerned that setting the replacement bid price too high might discourage otherwise efficient trades at negative prices,

[40] For more information, refer to Chapter 3, pg. 97-104 of the Panel January 2010 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf

and it therefore set the replacement bid price at -$125/MWh. The IESO's rationale for a negative non-zero replacement bid price was to minimize the potential loss of efficient export transactions that may occur between jurisdictions with negative prices.

An efficient transaction moves power from a lower-price to a higher-price jurisdiction; accordingly, an efficient export transaction from Ontario involves buying power from Ontario at a lower price and selling that power to another jurisdiction at a higher price. The same applies for negatively priced transactions; for example, an export would be considered efficient if the Midcontinent Independent System Operator (MISO) price in Minnesota was -$110/MWh and the Ontario nodal price at the intertie was -$120/MWh. Under such circumstances an exporter would be paid $120/MWh to buy power in Ontario, but pay $110/MWh to sell it in Minnesota, for a profit of $10/MWh. The IESO worried that if it set the replacement bid price too high, such as a price of -$100/MWh, then this otherwise efficient transaction would not be pursued because it was no longer profitable.

To assess the efficiency implications of a replacement bid price on electricity trading between neighbouring jurisdictions and the Northwest region of Ontario, the IESO considered differences between nodal prices in the Northwest and the locational marginal price in Minnesota.[41] The IESO decided that a replacement bid price should limit the opportunity for efficient transactions in no more than 1% of the hours when the MISO price in Minnesota was negative and greater than the nodal price in the Northwest of Ontario. The IESO calculated that this criterion corresponded to a replacement bid price of -$125/MWh.[42]

The Panel believes that this efficiency argument was ill-founded because it did not account for the fact that the nodal prices in the Northwest are artificially low and do not reflect the actual cost of supplying power in the region, thus undermining the premise that a -$125/MWh replacement price supports efficient transactions.

[41] The IESO's assessment – and the Panel's assessment that follows – is limited to exports on the Minnesota intertie. The assessments are limited to Minnesota because the Northwest is the only zone in Ontario that regularly experiences negative nodal prices.

[42] The methodology consisted of identifying the 1st percentile in the subset of hours when the MISO external price was negative and greater than the Ontario nodal price, which resulted in a price of -$120/MWh. After considering transactional costs in Ontario (including relevant hourly and monthly uplifts as well as an export tariff fee) and transactional costs in MISO (including the revenue sufficiency guarantee), the IESO modified the applicable price to be -$125/MWh.

Further analysis into MISO's Minnesota prices indicates that by changing the replacement bid price to $0/MWh, the loss of any supposedly efficient export transactions would be insignificant. It should be emphasized that the transactions would be truly "efficient" only if the negative nodal price in Ontario during the hours in question accurately reflects the underlying cost of supply, which at least on average is clearly not the case.

Table 4-1 displays a price frequency profile for all hours from July 2011 to September 2016. It describes:

1. Applicable price range for MISO's real-time locational marginal prices (LMP) at the Minnesota intertie. For example, the first range denotes the set of hours when the MISO real-time LMP was greater than -$2,000/MWh but less than or equal to -$125/MWh.
2. Number of hours when the MISO real-time LMP is in the specified price range, all of which total 46,032 hours during the Panel's study period.
3. Number of hours when the MISO real-time LMP exceeded the Ontario nodal price; this represents the number of hours where potentially efficient transactions could have occurred in each price range.
4. Number of hours when the MISO real-time LMP exceeded the Ontario nodal price and where exports actually flowed; this represents the number of hours where efficient transactions actually occurred in each price range.

Table 4-1: Frequency Profile of Locational Marginal Prices at Minnesota Intertie July 2011 – September 2016 (Number of Hours)

MISO Real-Time Locational Marginal Price Range ($/MWh)	Number of Hours	Number of Hours when the MISO Price Exceeded the Ontario Nodal Price	Number of Hours when the MISO Price Exceeded the Ontario Nodal Price and Exports Flowed
-2000 to -125	16	2	1
-124.9 to 0	568	110	28
0.1 to 100	44,891	38,975	12,865
100.1 to 200	442	437	156
200.1 to 1000	114	115	42
1000.1 to 2000	1	1	1
Total	46,032	39,640	13,093

It is noteworthy that only 112 hours (approximately 0.25% of all hours, as shown in the top two rows of the middle column of Table 4-1) even had the potential to support an efficient transaction when the MISO real-time LMP was less than or equal to $0/MWh. During those few hours when an efficient transaction was theoretically possible, an efficient export transaction only occurred in 29 of those hours (approximately 0.065% of all hours, as shown in the top two rows of the right-hand column of Table 4-1). This suggests that increasing the replacement bid price for negatively-bid exports to $0/MWh would have virtually no impact on efficiency. However, implementing a $0/MWh replacement bid price would have reduced consumer uplift charges by over $2.1 million from July 2011 to September 2016.

In reassessing the appropriate replacement bid price, the IESO may wish to consider the transaction costs associated with exporting, such as uplift, the export tariff and charges associated with importing into other jurisdictions. These costs effectively add to the replacement bid price floor, so to avoid setting a replacement bid price that is effectively above $0/MWh, the IESO may wish to consider setting a slightly negative replacement bid price.

Recommendation 4-1:

The Independent Electricity System Operator should set the replacement bid price to $0/MWh, or slightly negative, when it calculates constrained-on Congestion Management Settlement Credit payments for exports bid at negative prices.

2.2 *Claw Back for Failure to Provide Operating Reserve when Activated*

Operating reserve (OR) is standby capacity intended to respond to, and recover from, a contingency on the grid. Such a contingency could take the form of a sudden, unexpected increase in demand, a forced outage to generation or transmission equipment, or significant dispatch deviations by generators or dispatchable loads, among other possibilities. OR requirements must adhere to reliability standards established by the North American Electric Reliability Council and the Northeast Power Coordinating Council.[43] This usually amounts to an OR requirement of approximately 1,500 MW in any given hour. Resources scheduled to provide standby capacity in the 10-minute OR market must provide the entirety of that energy within 10 minutes of receiving an OR activation, and must be able to provide the activated energy for at least one hour; likewise for 30 minute OR.[44]

[43] The quantity of OR scheduled in a given hour must equal the largest possible single contingency plus half of the second largest possible contingency.
[44] Refer to the Market Rules, Chapter 5 Appendices, Section 1.2

To encourage compliance with OR activations, the Market Rules make provision for a claw back of OR payments from market participants that fail to meet their OR activations.[45] The claw back is a partial or full recovery of OR payments[46] received during the 30 days prior to the failed OR activation.[47] The claw back is assessed for each metering interval during the OR activation in which the market participant failed to deliver the required energy. The portion of payments clawed back is equal to the portion of the total scheduled energy that the market participant did not provide upon activation –this value is referred to as the energy shortfall fraction. For example, if a market participant provides the entirety of its scheduled energy, none of its OR payments would be clawed back; if it fails to provide 20% of its scheduled energy, then the claw back would be 20% of its OR payments. As this assessment is to be carried out for each metering interval during the OR activation, the total claw back could exceed the OR payments initially earned in the 30 days prior to the failed OR activation.[48] The claw back process involves a manual settlement adjustment by the IESO. The Market Rules require the IESO Board of Directors to set a materiality threshold, being the energy shortfall fraction below which no OR payments would be clawed back.

Despite the rule for this claw back being in place since market opening, it has never been applied. Prior to June 2016, the IESO Board of Directors had not set the materiality threshold to establish when claw backs should occur. In June 2016, the IESO set the materiality threshold to a value of infinity,[49] meaning that even if a market participant were to completely ignore an OR activation, the IESO would not claw back any OR payments under this rule.

[45] Refer to the Market Rules, Chapter 9, Section 3.8

[46] OR payments consist of OR market settlement credits and OR CMSC. OR market settlement credits are payments for a market participant's standby schedule. If a market participant has an OR standby schedule of 100 MW in the 10-minute OR market, it is paid the 10-minute OR market clearing price for those 100 MW, regardless of whether the OR was activated. OR CMSC is analogous to energy market CMSC in that a resource can be constrained on or constrained off relative to its unconstrained OR schedule, receiving OR CMSC to return it to the operating profit implied by its unconstrained OR schedule.

[47] The Market Design Committee deemed that a "billing period" would be an appropriate time horizon over which to evaluate any claw back for a market participant's non-compliance. Such a claw back necessarily had to be large in order to incentivize a market participant to follow its OR activation at all times. In practical terms, a "billing period" would amount to a settlement month lasting 30 days or 720 hours.

[48] For example, suppose a market participant completely ignored its OR activation during two metering intervals. If the market participant earned $10,000 in OR payments in the 30 days prior to this failed OR activation, the OR claw back would amount to $20,000.

[49] Refer to the equations published for charge types 251, 253, and 255 in the *IESO Charge Types and Equations* manual: http://www.ieso.ca/sector-participants/market-operations/-/media/490945b625004c60b45982771a644356.ashx

From January 2012 to October 2016, market participants in the 10-minute OR markets received 3,800 individual OR activations, yet failed to fully respond to their OR activations in over 1,700 of those instances. Had the materiality threshold for a permissible energy shortfall fraction been set to 0, the Panel estimates that there would have been over $6 million in OR claw backs. The Panel believes that an inoperative claw back provision is inappropriate, particularly where market participants are able to retain significant payments for services they did not provide. Moreover, an infinity materiality threshold can reduce the incentive to provide OR when called upon. The Panel is therefore recommending that the materiality threshold value be revised such that operating reserve payments are clawed back when a market participant fails to fully respond to its operating reserve activation. In the Panel's view, a materiality threshold higher than 0 would appear to be warranted only if the claw back is a manual process, to accommodate situations where the level of effort involved in administering the claw back would be disproportionate to the benefit.

Recommendation 4-2A:

The Independent Electricity System Operator's Board of Directors should revise the materiality threshold value such that operating reserve payments are clawed back when a market participant fails to fully respond to its operating reserve activation.

Calculating the Claw Back

The Panel has also identified what it believes to be a flaw in the formula for establishing the claw back amount.

In the Panel's view, since the claw back is intended to address the failure to respond fully to an OR activation, the amount of the claw back should be calculated based on the energy shortfall relative to the OR activation quantity, not the total scheduled quantity (which includes energy that was scheduled prior to the activation). The existing formula utilises the latter methodology,[50] making the claw back highly dependent on the facility's operating state prior to activation, not the extent to which it responded to the OR activation.

[50] Refer to the Market Rules, Chapter 9 Section 3.8.2.1

For example, suppose there are two generators, Generator A and Generator B, both of which are activated to provide 10 MW of OR. Assume Generator A was initially providing 0 MW and its activation required it to increase to 10 MW, while Generator B was producing 100 MW of energy before it was activated to increase to 110 MW. When the generators receive their respective OR activations, both ignore the activation entirely. Under the claw back formula as currently written, and absent the materiality threshold of infinity, the claw back for Generator A would be calculated at 100% (MW Shortfall / Total Energy Schedule, 10 MW / 10 MW = 100%) of any applicable OR payments, while the claw back for Generator B would only be 9.09% (10 MW / 110 MW = 9.09%). Both generators equally failed to respond to their OR activation; however, Generator B would be treated more favourably by reason of already generating energy when the OR activation occurred. Intuitively this is neither equitable nor commensurate with the purpose that the claw back is intended to serve. Where a facility fails to provide OR when activated, it would be more appropriate to calculate its claw back as a function of the energy delivered in response to the OR activation, as opposed to the total energy delivered. The Panel believes that the IESO should calculate the claw back on this basis.

Recommendation 4-2B:

When a market participant fails to fully respond to an operating reserve activation, the Independent Electricity System Operator should calculate the claw back based on the ratio of the energy not provided in response to the activation relative to the energy required by the activation.