ONTARIO ENERGY BOARD

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

For the period from
November 2016 – April 2017

March 2019

Ontario

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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 November 1, 2016 to April 30, 2017 (Winter 2016/17 Period). Certain portions of this report, notably Chapters 1 and 4, discuss noteworthy issues that are not necessarily linked to events in the Winter 2016/17 Period. Except where otherwise noted, developments occurring after April 30, 2017 are not reflected in this report.

This semi-annual monitoring report is broken down into four chapters:

- Chapter 1: General Assessment, Market Developments and the Status of Recent Recommendations
- Chapter 2: Market Outcomes
- Chapter 3: Analysis of Anomalous Market Outcomes
- Chapter 4: Matters to Report in the Ontario Electricity Marketplace

Chapter 1: General Assessment, Market Developments and Status of Recent Panel Recommendations

The Panel continues to view the current design of Ontario's electricity market as flawed in many respects, as outlined at length in previous reports. Many of the systemic issues that continue to hinder Ontario's electricity market and limit economic efficiency have been prevalent since the market was first launched in 2002. In many cases, these issues were expected to be temporary and reduced—or eliminated altogether—as the market matured and competition took hold.

Given the long-standing issues facing Ontario's electricity market, the Panel maintains its support for the Independent Electricity System Operator's (IESO) Market Renewal initiative, which has moved to the high-level design phase of the project. The Panel will continue to provide comments to the IESO through the individual design streams of Market Renewal.

In a separate initiative, the IESO has made changes in an effort to deal with the increased flexibility needs of the electricity system, as a growing fleet of variable generation has led to larger and more frequent price spikes. In 2016, the IESO launched a review of how it would meet these greater flexibility needs. In April 2018 it announced that it will increase its 30-minute

Operating Reserve (OR) requirement when it forecasts the need for greater flexibility. The Panel will monitor whether this solution proves effective.

The IESO has made some necessary changes to its Demand Response (DR) auctions. It has reduced the minimum number of hours that DR participants can be activated to one hour from four. It also introduced a price trigger, allowing the IESO to issue an activation notice to DR participants when pre-dispatch prices move higher than $200. Both of the changes are intended to increase the usage of Demand Response resources. Ratepayers will pay $161 million to resources procured under the first four Demand Response auctions. The Panel continues to question the value of this program for ratepayers, given that none of the hourly demand response resources have been activated to provide DR and reduce their consumption.

Chapter 2: Market Outcomes

Total system costs decreased for the first time in five years and, as a result, the price paid by consumers fell compared to the same time last year. The average effective price—which includes wholesale market prices, the Global Adjustment (GA) and uplift—for Class B consumers declined by $1.56/MWh, or 1.4%, when compared to the November 1, 2015 to April 30, 2016 period (Winter 2015/16 Period). For Class A consumers, the average price dropped by $1.93/MWh, or 2.9%. The main contributor to lower prices was a decline in GA costs, which were 7% lower than in the Winter 2015/16 Period, largely as a result of lower payments to nuclear generators due to outages. The decrease in payments to nuclear generators offset the increase in GA costs related to renewable generators, which were 11% higher than in the Winter 2015/16 Period.

Demand for electricity continued to decline, dropping 0.9 TWh, or 1.3%, compared to the Winter 2015/16 Period. April 2017 was the lowest month for demand since the Ontario electricity market first opened in 2002.

Wind resources are now likely the largest contributor to divergences between hour-ahead and real-time prices. While inaccurate demand forecasts are currently shown as the biggest contributor to the difference between pre-dispatch and real-time, a portion of this divergence is a result of embedded renewable generators—primarily wind, but also solar—whose production offsets demand on the IESO-controlled grid. A growing fleet of variable generation has contributed to the hour-ahead price falling within $10 per MWh of the real-time price just 69% of time in this reporting period, compared to 90% in the Winter 2015/16 Period.

Chapter 3: Analysis of Anomalous Market Outcomes

Instances of high prices in Ontario's wholesale electricity market are becoming less predictable and occurring more frequently during periods of low demand, such as off-peak hours and weekends.

The Winter 2016/17 Period saw Ontario's wholesale market post two of its three highest hourly prices since the market first opened in 2002. While wholesale prices, on average, have declined over the past decade, price spikes have become more common. The maximum market clearing price ($2,000/MWh) was hit more times in 2016 and 2017 than in all years since the market opened combined. Many of these price spikes now occur in times with moderate or low demand, rather than in the high market demand conditions where high prices are expected. While price spikes are more common, so too are negative or near zero prices. The average wholesale price in 2017 was $14.14/MWh—the lowest average Hourly Ontario Energy Price (HOEP) since the market opened. Negative prices are increasingly occurring during peak hours. The reason for increased price volatility is the combination of the retirement of coal generators, less usage of natural gas generators and an increase in variable generation, primarily wind and solar, being added to the system. As a result of these changes, Ontario's electricity market has become less flexible and less able to respond to sudden changes in demand or output from variable generators.

As well, the IESO relies on a real-time forecasting tool in an effort to mitigate the uncertainty of integrating variable generators into the wholesale market. But the IESO is often manually disabling this tool when its forecasts vary significantly from the actual output of variable generators. The IESO currently has no clear procedural steps for when it manually disables its forecasting tool—and in some cases, is forgetting to re-enable it. By disabling the real-time forecasting tool, the IESO artificially adds supply into the wholesale market, which suppresses wholesale prices and introduces greater volatility. It also allows for out-of-market payments to participants for output they could not have physically produced. By disabling the forecasting tool, the IESO paid generators $2 million between December 2016 and December 2017 for supply they could not deliver to the wholesale market, some of which has been recovered.

Recommendation 3-1:

A) The IESO should formalize the process by which it determines when to disable and re-enable the variable forecasting tool, and should communicate that process to market participants to increase transparency.

B) When a variable generator is on mandatory dispatch and the forecasting tool is disabled, the IESO should set the generator's unconstrained schedule at its forecasted output rather than its maximum offered capacity.

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

The Hydro-Québec Agreement

Hydro-Québec's interaction with Ontario's wholesale market has fundamentally changed as a result of a new province-mandated agreement it signed with IESO that came into force at the start of 2017. The objectives of the agreement include reducing green-house gas (GHG) emissions from Ontario's natural gas generators and providing savings to Ontario ratepayers and value to Québec. The Financial Accountability Office (FAO) completed its own analysis of the agreement, concluding it will provide $38 million in net savings over seven years and will not have a significant impact on GHG emissions in Ontario.

The Panel's analysis focuses on the impact that the agreement has had on Ontario's wholesale electricity market, highlighting that there are likely undesirable consequences for pricing efficiency and short-term reliability.

The agreement changes Hydro-Québec's participation in the market from one primarily based on "market forces" to one substantially based on the contract rate stipulated in the agreement, meaning a certain quantity of Hydro-Québec's offers no longer reflect their marginal cost (or opportunity cost) of generation. Hydro-Québec's contracted imports also now set the Market Clearing Price (MCP) more often, meaning there are more hours when the MCP induces too much or too little consumption than might otherwise be the case.

The agreement may also lead to short-term reliability issues in Ontario's wholesale market. To the degree that imports under the agreement replace Ontario gas-fired generators—which are scheduled in five-minute intervals and can respond quickly to fluctuations in demand and supply—this can impact the availability of flexible domestic supply. Imports are scheduled an hour ahead of real-time and are more limited in their ability to respond to sudden changes in the market.

On a separate but related matter, the Panel's Report on its investigation of the Hydro-Québec agreement was released on December 13, 2018. The focus of the investigation was on whether the agreement operates within the Market Rules, and the Panel's conclusion is that it does.

The Panel's Report on the Industrial Conservation Initiative

In December 2018, the Panel issued a Report on the impact of the Industrial Conservation Initiative (ICI)—a program that shifted nearly $5 billion in costs from larger volume consumers to households and small businesses from 2011 to 2017. The Panel's conclusion is that the ICI as presently structured is a complicated and non-transparent means of recovering costs, with limited efficiency benefits. In addition, the ICI arguably does not allocate costs fairly in the sense of assigning costs to those who cause them and/or benefit from them being incurred. The Report, prepared to contribute in a positive way to future discussions regarding the balancing of objectives and interests in respect of cost allocation, discusses how both the market efficiency and fairness of the ICI can be enhanced.

Chapter 1: General Assessment, Market Developments and Status of Recent Panel Recommendations

1 *General Assessment*

Once annually, the Panel is required to provide a general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness.

Since market opening in 2002, and particularly since the advent of the hybrid market in 2005, the Panel has assessed the state of the markets with regard to several design features and policy decisions that affect market participant behaviour and market outcomes. Several policy and design features have been frequently noted in past Panel reports, namely;

- Ontario’s two-schedule pricing and dispatch system. Under this system, the prices faced by wholesale market participants can diverge (sometimes significantly) from the incremental cost of supplying another megawatt hour of energy at a particular location.
- Investment decisions—and at times operating decisions—are not driven by market dynamics. Virtually all generation in Ontario is subject to long-term contracts with government agencies or rate regulation by the Ontario Energy Board. Additionally, incentives under the contracts and regulation can result in offer prices that deviate from the generators’ short-run marginal cost.
- The 3-times ramp rate multiplier. The use of the multiplier in the unconstrained sequence artificially depresses the market clearing price and distorts production and consumption decisions.
- Limitations with both the day-ahead and real-time commitment mechanisms for non-quick start generators result in higher system costs.

At market opening, some of the above-noted features and impacts were expected to be temporary, while others were never envisioned at all; all have persisted over a number of years. The Panel has a long history of reporting on the systemic issues associated with these features, including extended periods of deeply negative prices, inefficient trade on the interties and inappropriate wealth transfers.

Though the Panel has been critical of these features, it recognized them as ingrained parts of the current market design. In that context, the Panel’s past assessments of the competitiveness and efficiency of the IESO-administered markets have been made with regard to the inherent limitations created by those features. In other words, the Panel made its assessments “within the Ontario context”. On that limited basis, the Panel has said that the IESO-administered markets operated in a reasonably satisfactory manner.

Starting with the general assessment published in its May 2017 Monitoring Report, the Panel stepped out of the Ontario context, where it is as clear now as it was then that competitive market forces play a greatly diminished role relative to what was originally envisioned, as well as relative to markets in other North American jurisdictions. There remain significant opportunities to unlock competition and drive more efficient production, consumption and investment decisions.

The IESO acknowledges the deficiencies in the current system and recognizes the benefits that market reform could bring to the sector. To that end, the IESO is proceeding with its Market Renewal initiative, which has the potential to address many of the issues identified by the Panel over the years.

The Panel continues to support the IESO’s Market Renewal initiative through its comments on the individual design streams.

While important change is on the horizon, both the Panel and the IESO recognize the long timelines associated with implementing Market Renewal. Until the completion of the initiative, the Panel will continue to identify deficiencies in the current market design and Market Rules that impact the efficient and fair operation of the IESO-administered markets. In cases where the impacts are too costly to go unaddressed until the implementation of Market Renewal, or where Market Renewal will not address the issue, the Panel will continue to recommend expeditious changes, as it does in this report. The IESO is developing a market work plan that covers market changes that could occur in parallel with Market Renewal.

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

The IESO has proceeded, with the assistance of the Working Group, to the high-level design phase of the project. The goal of this phase is to consult with stakeholders on a high-level design for each of the following Market Renewal initiatives: [1]

- Single Schedule Market,
- Day-Ahead Market,
- Enhanced Real-Time Unit Commitment and
- Incremental Capacity Auction.

As of the date of writing, the IESO has published high-level design documents for three of these initiatives, with the fourth expected in the latter part of March 2019.[2]

System Flexibility

System flexibility is the ability of the electricity system to respond to short-notice or unexpected changes in intra-hour supply and demand. These intra-hour differences have grown larger and more frequent in recent years, primarily due to the inherent uncertainty associated with forecasting output from the increasing number of wind and solar generators on the system.

To assess whether the system possesses sufficient flexibility going forward, the IESO conducted an operability study. The *2016 Operability Assessment* found that the system required 1,000 MW of additional flexibility by 2018; a number that has since been revised down to 740 MW in light of the suspension of Large Renewable Procurement II and reduced Feed-in Tariff targets.[3]

In June of 2016, the IESO launched a stakeholder engagement to consider options for addressing this additional flexibility requirement. The engagement concluded in April 2018 with the IESO

[1] A fifth initiative - More Frequent Intertie Scheduling - was deferred in January 2018.
[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] 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.

implementing an interim flexibility solution. Specifically, the IESO will increase the 30-minute Operating Reserve (OR) requirement when its procedures indicate there will be insufficient flexibility on the system in future hours. By increasing the OR requirement ahead of real-time, the IESO will signal the upcoming need for additional flexibility while increasing the likelihood of committing additional non-quick start resources to provide that flexibility. The Panel will be closely monitoring the effectiveness of this short-term solution. The IESO has identified the need for a market mechanism to address the issue of system flexibility.

Demand Response Auction Changes[4]

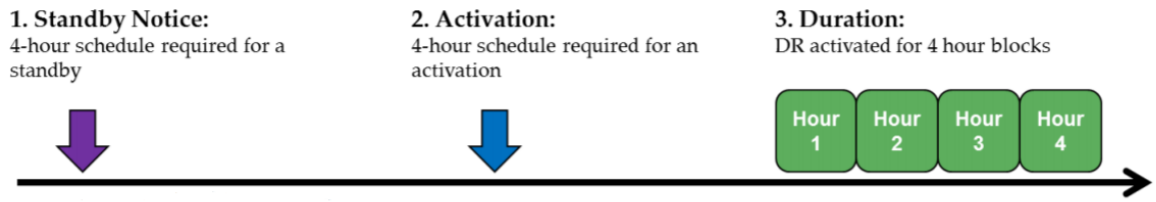
Each December, the IESO holds an auction to procure demand response (DR) capacity for the following year. DR resources selected through the auction receive an availability payment and can subsequently be called upon to provide energy to the grid if specific activation criteria are met.

In 2018, the IESO held its fourth annual DR auction. Participants who cleared the auction will be subject to the IESO's new activation criteria. Relative to earlier auctions, the IESO has reduced the number of hours required to trigger either a standby notice or a subsequent activation from four hours to one hour.[5]

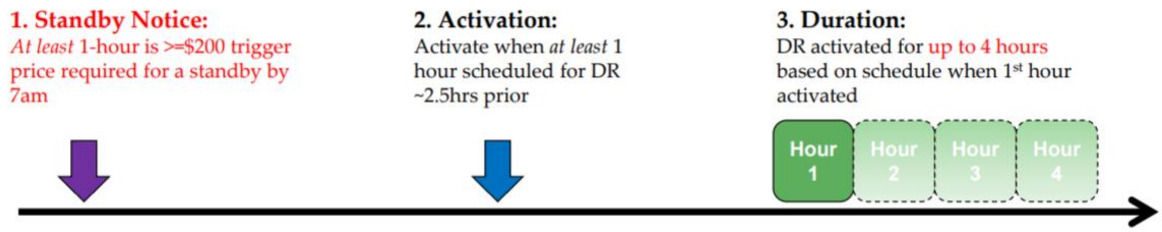
In addition, the IESO will now issue a standby notice to a DR participant when its pre-dispatch nodal price is greater than or equal to $200. DR participants have previously submitted very high bids, which has largely prevented them from receiving a standby notice and, ultimately, from being activated. The price trigger will be lowered to $100 in 2020.[6]

[4] The activation process and criteria changes discussed in this section only apply to hourly demand response resources, not dispatchable loads.
[5] A standby notice is a signal to the DR resource that they may be called upon to provide demand response. An activation requires the DR resource to actually reduce their consumption. A scheduled hour refers to an hour in which the nodal price has risen above the DR resource's bid price.
[6] The standby period is from HE 15 on the day before the dispatch day to HE 7 on the dispatch day.

Previous Trigger Criteria



New Trigger Criteria



Auctions held prior to December 2018 have shown that while the IESO has been able to procure DR capacity, hourly demand response resources have never been activated to reduce consumption in the real-time market. The criteria changes noted above will likely increase the number of standby notices that DR resources receive; however, it remains to be seen if there will be a significant increase in activations.

The IESO believes shortening the minimum dispatch duration and lowering the price-based trigger for standby will improve the value of DR resources in the short-term.[7] In a previous Panel report, the Panel recommended the IESO reassess the value provided by the capacity procured through its DR 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.

While the Panel is encouraged by the IESO's efforts to increase value through improved utilization of hourly DR resources, the IESO has yet to provide any value assessment of the DR auction itself. Resources procured through the first four annual demand response auctions will be paid upwards of $161 million in availability payments.

[7] See slide 4 of the IESO's May 3, 2018 presentation to the *Demand Response Working Group*, available at: http://www.ieso.ca/-/media/files/ieso/document-library/working-group/demand-response/drwg-20180503-improved-utlization-hdr.pdf?la=en.

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

Below are the recommendations made in the Panel's March 2018 Monitoring Report and the IESO's responses to them.[8]

Recommendation	IESO Response
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.*	The IESO is reviewing the performance of resources, including dispatchable loads, to dispatch instructions as well as application of the current rules governing uplift payments in certain circumstances. The IESO will incorporate the [Panel]'s recommendation with our own observations to develop a comprehensive approach to improve performance. The IESO is currently aiming to finalize the scope and approach for this project by the end of Q3 2018 and will provide an update to the [Panel] on next steps. The IESO will also connect with the [Panel] shortly in relation to its views on the application of the rules, owing to confidentiality obligations it must follow in respect of enforcement matters. As discussed with the Panel, the IESO intends to further discuss the Panel's recommendation to examine CMSC payments made to generators for operational constraints other than SEAL arising from conditions at a generator's facility to better understand their perspectives on this matter.
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.*	The IESO agrees with the Panel's observations that utilizing a $0/MWh replacement bid price could have reduced consumer uplift charges by over $2.1 million based on the report's lookback period from July 2011 to September 2016 for constrained-on export CMSC payments. However, the IESO believes that the Market Rule changes put in place in 2015 in response to previous Panel recommendations have addressed the issue of constrained-on export CMSC payments in the Northwest to the point where these payments are immaterial. Since the IESO implemented the 2015 Market Rule change, the amount of uplift charges related to this recommendation has decreased significantly to approximately $16,000 in 2016 and $4,000 in 2017. The IESO also notes that the existence of constrained-on export CMSC payments does not necessarily mean that any participant was engaged in "nodal price chasing", but only shows that traders were chasing perceived arbitrage opportunities, of which some could potentially be driven by "nodal price chasing" behaviour. Efficient intertie trade is critical to having an overall healthy and efficient electricity market. Specifically, intertie trade plays an important role in providing operational and planning flexibility that enhance the reliability and the cost-effectiveness of the Ontario

[8] See the May 29, 2018 letter from Peter Gregg, President and CEO of the IESO, to Rosemarie Leclair, Chair and CEO of the Ontario Energy Board, available at: https://www.oeb.ca/sites/default/files/ieso-letter-to-oeb-20180529.pdf

	electricity system. Interties allow energy providers from outside Ontario to compete with domestic suppliers to meet electricity needs at lowest cost and also provide opportunities to better utilize Ontario facilities. Given the importance of intertie trade, the IESO is concerned that a higher replacement bid price floor, as suggested by this recommendation, may deter traders from submitting export bids below $0/MWh on any intertie due to the risk of being constrained-on, which would impose unnecessary losses on traders and deter trading. This could result in both a reduction in the effectiveness of a valuable system tool during surplus conditions and possibly higher costs to ratepayers. The IESO believes the best course of action is not to make any changes related to this recommendation.
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.* **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.*	The IESO agrees with the Panel that Operating Reserve suppliers should not be paid if they do not provide the expected amount of energy during an Operating Reserve activation. However, the current formula for Operating Reserve claw back articulated in the Market Rules will often claw back Operating Reserve revenues even when the full amount of energy has been delivered within an Operating Reserve activation. Furthermore and as the [Panel] points out, depending on the threshold, the formula may not penalize Market Participants consistently for the same non-compliance. The IESO considers Operating Reserve to be a critical reliability service. As such, the IESO monitors the performance of Operating Reserve suppliers activated to provide energy. In general, Operating Reserve shortfalls have not impacted power system reliability. The IESO assesses compliance to Operating Reserve activations regularly and participants that are observed to fail to produce energy when activated are frequently disqualified from participation in the Operating Reserve market for days or weeks. The IESO has used the method described above (disqualifying participants from offering in the Operating Reserve market) to manage performance issues. This approach has allowed the IESO to maintain compliance to North American Electric Reliability Council (NERC) standards and Northeast Power Coordinating Council (NPCC) requirements related to power system balancing requirements for Ontario. For example, the BAL-002 standard requires the IESO to recover the Area Control Error (ACE), a measure to how we balance the system, using reserve within 15 minutes of a disturbance. The IESO has not had to report non-compliance to this standard. As discussed during our meeting with the Panel, the IESO is reviewing the effectiveness of the current Operating Reserve regime, including whether different mechanisms are needed to ensure that suppliers are delivering the expected reliability service and providing ratepayer value, and will provide an update to the Panel on its approach by Q4 2018.

4 *Panel Commentary on IESO Response*

In April 2018—following the publication of the Panel's March 2018 Monitoring Report—the Panel met with the IESO to discuss the Panel's recommendations and the IESO's approach to addressing them. The IESO's written response to those recommendations was sent in May 2018.

With respect to Recommendation 3-1 (unwarranted Congestion Management Settlement Credit payments), the IESO may initiate a rule amendment to claw back any unwarranted CMSC payments. The IESO will update the Panel in the first quarter of 2019.

With respect to Recommendations 4-2A and 4-2B (OR activation failures), the IESO agreed with the Panel that OR suppliers should not be paid if they fail to provide the expected amount of energy during an OR activation. The IESO noted that it expects to launch a stakeholder engagement in the first quarter of 2019 to consider potential changes that would improve reliability and provide greater value to ratepayers.

With respect to Recommendation 4-1 (replacement bid price), the Panel acknowledges that changes made by the IESO in response to previous Panel recommendations have decreased the magnitude of the problem. However, the opportunity to engage in nodal price chasing behaviour still exists—particularly in the Northwest where chronic congestion due to abundant hydroelectric generation, low demand and relatively limited transmission capacity routinely creates excess local supply conditions and negative nodal prices. The Panel will continue to monitor this issue.

Chapter 2: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between November 1, 2016 and April 30, 2017 (Winter 2016/17 Period), with comparisons to previous reporting periods as appropriate.

1 *Pricing*

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

Table 2-1: Average Effective Price by Consumer Class
Winter 2015/16, Summer 2016 & Winter 2016/17
($/MWh)

Description:

Table 2-1 summarizes the average effective price in dollars per megawatt hour by consumer class for the Winter 2016/17 Period, the period between May 1, 2016 and October 31, 2016 (Summer 2016 Period) and the period from November 1, 2015 to April 30, 2016 (Winter 2015/16 Period). The effective price is the sum of the HOEP,[9] 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".

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

Customer Class	Average Weighted HOEP	Average Global Adjustment	Average Uplift	Effective Price
Class A – Winter 2016/17	17.17	45.96	2.41	65.55
Class A – Summer 2016	16.45	49.73	2.68	68.86
Class A – Winter 2015/16	8.32	57.44	1.72	67.48
Class B – Winter 2016/17	20.14	90.01	2.66	112.81
Class B – Summer 2016	21.33	92.65	3.16	117.14
Class B – Winter 2015/16	10.31	102.14	1.91	114.37
All Consumers – Winter 2016/17				103.26
All Consumers – Summer 2016				107.55
All Consumers – Winter 2015/16				105.05

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 1 MW (or 500 kW for some sectors) that have opted into the Class (or not opted out of the Class, in the case of consumers whose average monthly peak demand is greater than 5 MW); and Class B, being all other consumers.[10]

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.[11]

[10] 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.

[11] 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, and the Panel’s December 2018 report entitled “The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches,” available at: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.

Prior to the Panel's March 2018 Monitoring Report, 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 the Summer 2016 Period, the Panel moved embedded Class A consumers from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table 2-1. This change allows for a clearer delineation between Class A and Class B consumers.[12]

Assumptions are called for with respect to the consumption patterns of embedded Class A consumers due to data limitations, which have been discussed at some length in previous Panel reports.[13] As such, the Panel assumes that embedded Class A consumers have a similar load profile to directly-connected Class A consumers.

The Panel has noted that assessing the impacts of certain market changes loses precision without access to additional data about embedded Class A consumption and embedded generation, and that assessing the province's overall demand for electricity also becomes increasingly difficult as a larger portion of that demand is no longer served by the province's high-voltage power system. Recent changes in the Class A eligibility threshold and the increase in the number of embedded Class A consumers only exacerbate the need for this data.

Commentary and Market Considerations:

The average effective price for both Class A and B decreased slightly when compared to the Summer 2016 and Winter 2015/16 monitoring periods. Comparing the Winter 2016/17 Period to the Winter 2015/16 Period, the Class A effective price decreased by $1.93/MWh and the Class B effective price decreased by $1.56/MWh. This is due to a decrease in the GA, largely attributable to a reduction in payments to nuclear generators due to outages.

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[12] Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and from "Class B & Embedded Class A" to just "Class B"), there is no direct comparison to be made between effective prices reported in this report and those from reports issued before the March 2018 Monitoring Report. All references to effective price in this report—including all tables and figures—reflect the Panel's updated methodology.

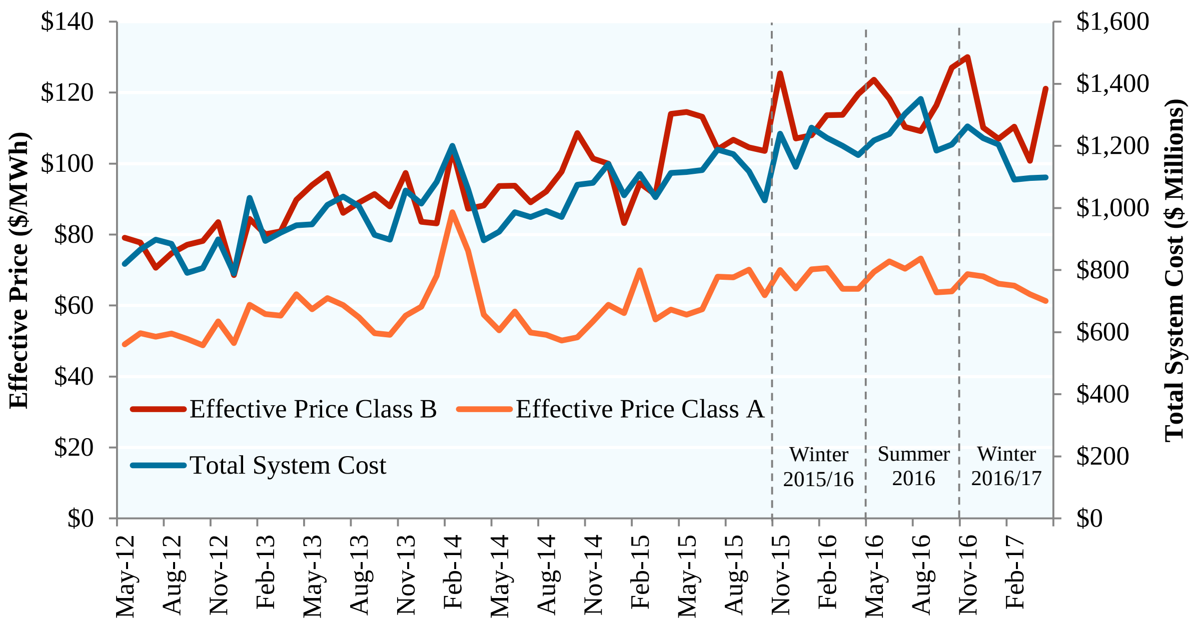
[13] The Panel's April 2015 Monitoring Report explained the need to obtain generation and consumption data at an hourly level of granularity, specifically for embedded generation, behind-the-meter generation and embedded Class A consumption. See pages 105-109 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf. See also the Panel's December 2018 report entitled "The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches," available at: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.

The HOEP and the GA have an inverse relationship because the GA is primarily composed of payments to generators under contract to make up for shortfalls between market revenues and contracted or regulated rates. This can be seen when comparing the Winter 2016/17 and Winter 2015/16 Periods: the average load weighted HOEP for both consumer classes rose by about $10/MWh, while the GA fell by about $10/MWh.

Figure 2-1: Monthly Average Effective Electricity Price & System Costs
May 2012 – April 2017
($/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.



Relevance:

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

Commentary and Market Considerations:

In the Winter 2016/17 Period, total system costs fell modestly when compared to the previous two reporting periods. This is the first time in the past five years in which system costs fell when compared to the previous period of the same season. This reduction in system costs, coupled with a comparatively smaller reduction in demand, resulted in an effective price reduction for both consumer classes.

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

Description:

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

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 Winter 2016/17 Period, as it has been in past reporting periods.

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

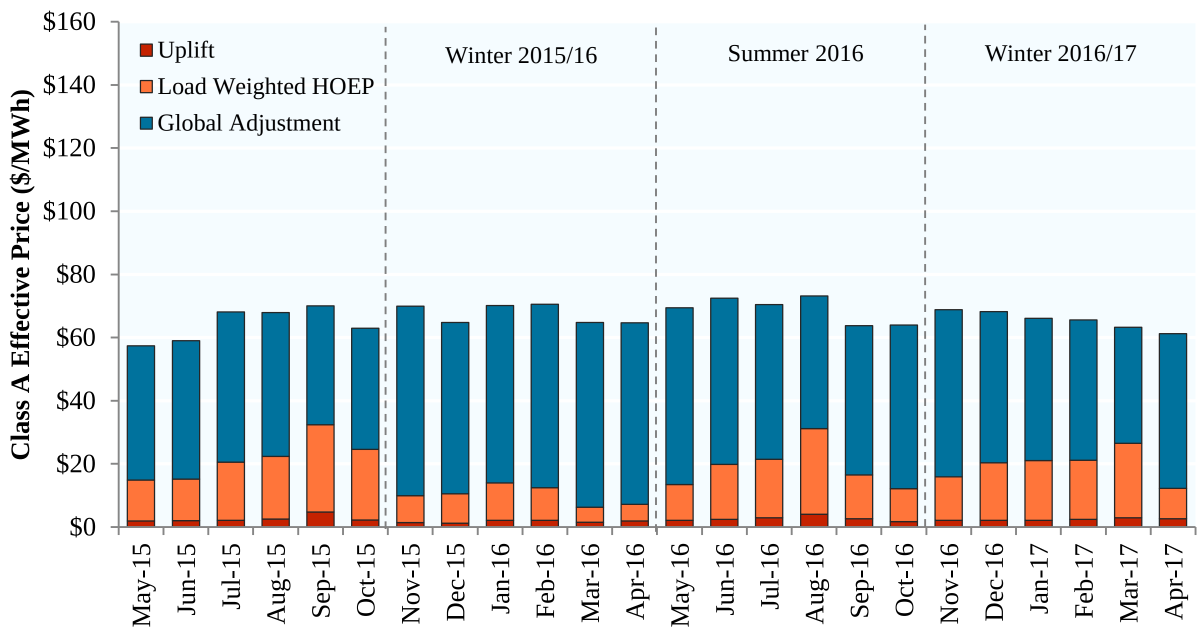
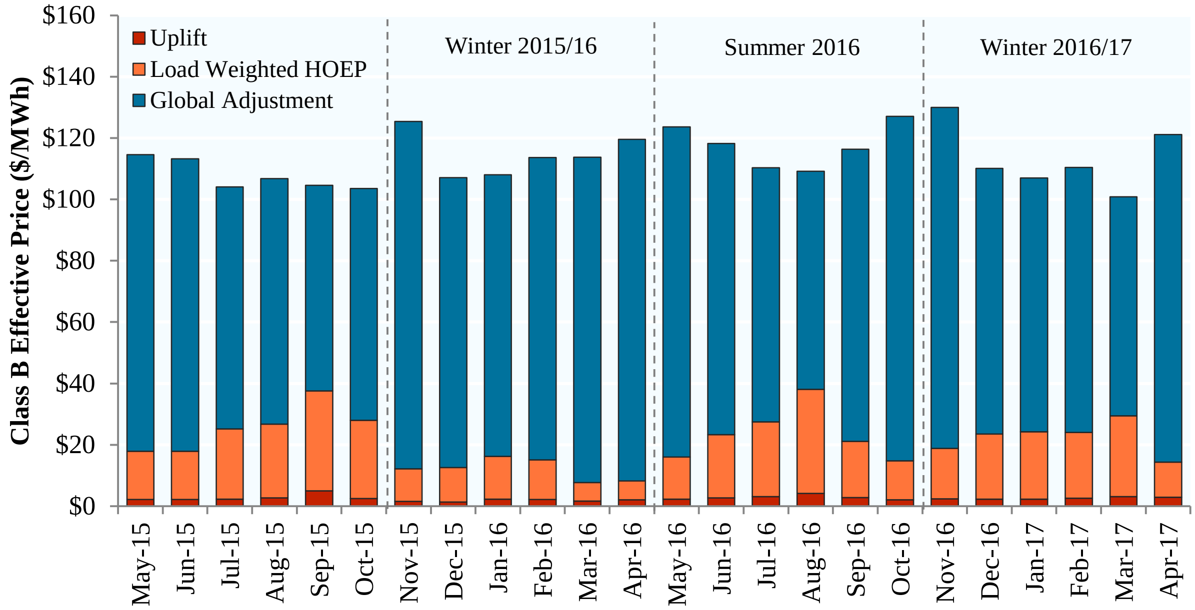


Figure 2-2B: Average Effective Price for Class B Consumers by Component
May 2015 – April 2017
($/MWh)



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.

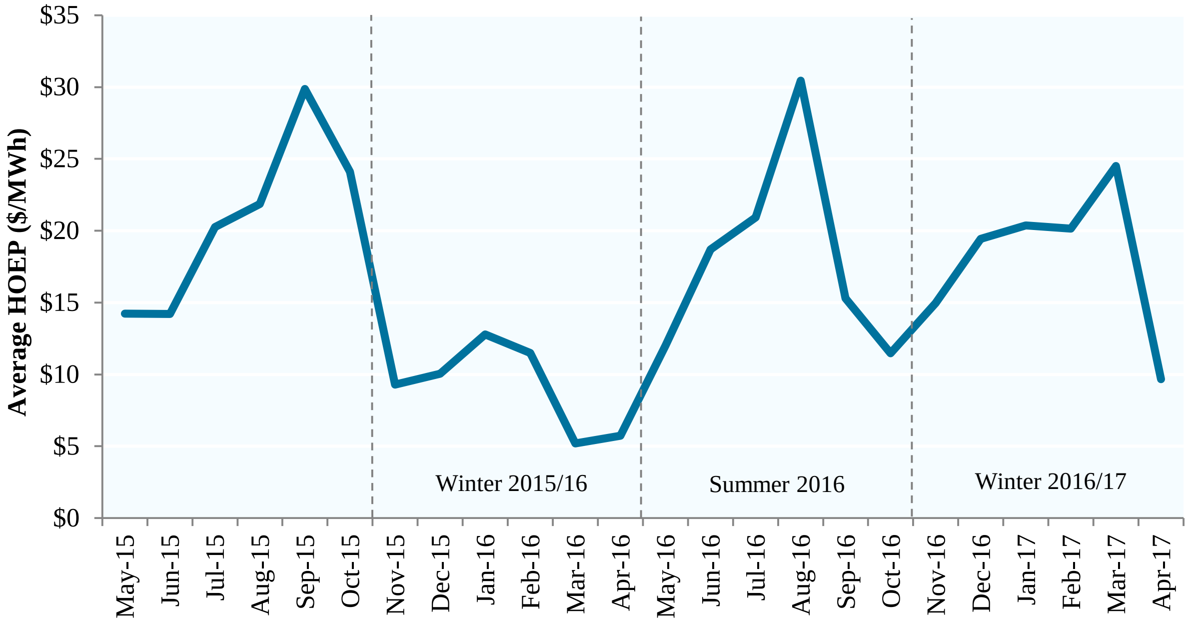
Commentary and Market Considerations:

The Class B effective price remained significantly higher than the Class A effective price, a division that began with the introduction of the change in the GA allocation methodology in 2011. On average, the effective price was $65.55/MWh for Class A and $112.81/MWh for Class B in the Winter 2016/17 Period. As previously noted, both represent small decreases relative to the Winter 2015/16 Period.

Figure 2-3: Monthly (Simple) Average HOEP
May 2015 – April 2017
($/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.

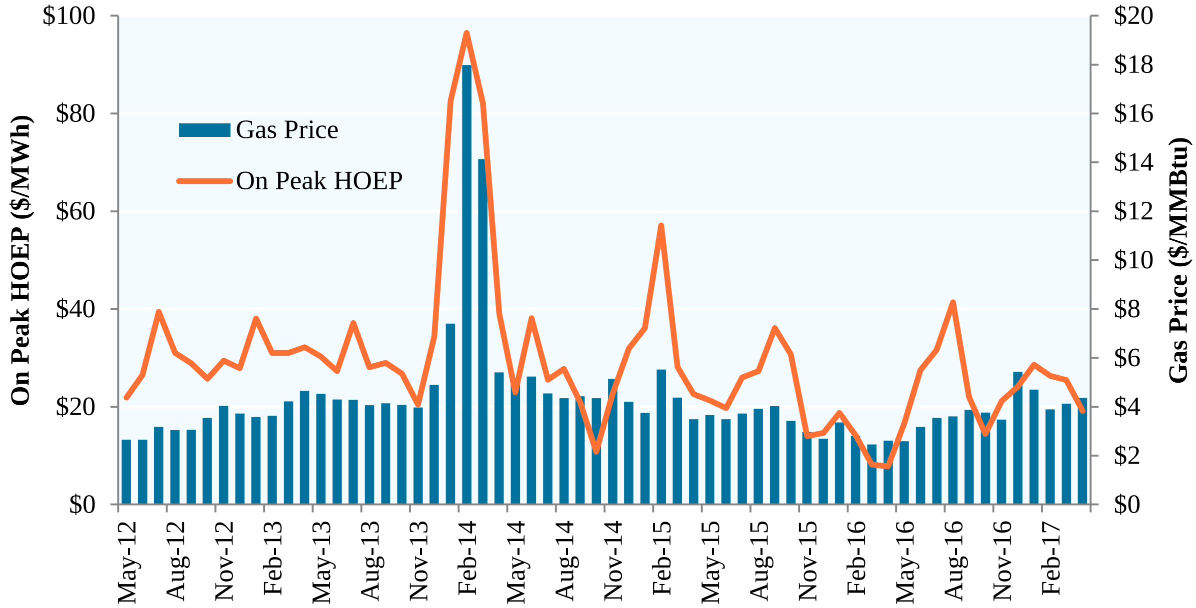
Commentary and Market Considerations:

Despite a 0.88 TWh reduction in demand between the Winter 2015/16 and Winter 2016/17 Periods, the average HOEP rose from $9.08/MWh to $18.21/MWh. In the Winter 2016/17 Period there was an increase in nuclear, hydro, wind and solar outages, which resulted in less supply being offered into the market at low or negative prices.

Figure 2-4: Natural Gas Price & On-Peak HOEP
May 2012 – April 2017
($/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[14] 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.

Commentary and Market Considerations:

Gas prices increased to an average of $4.33/MMBtu in the Winter 2016/17 Period, compared to $3.42/MMBtu in the Summer 2016 Period and $2.84/MMBtu in the Winter 2015/16 Period. In

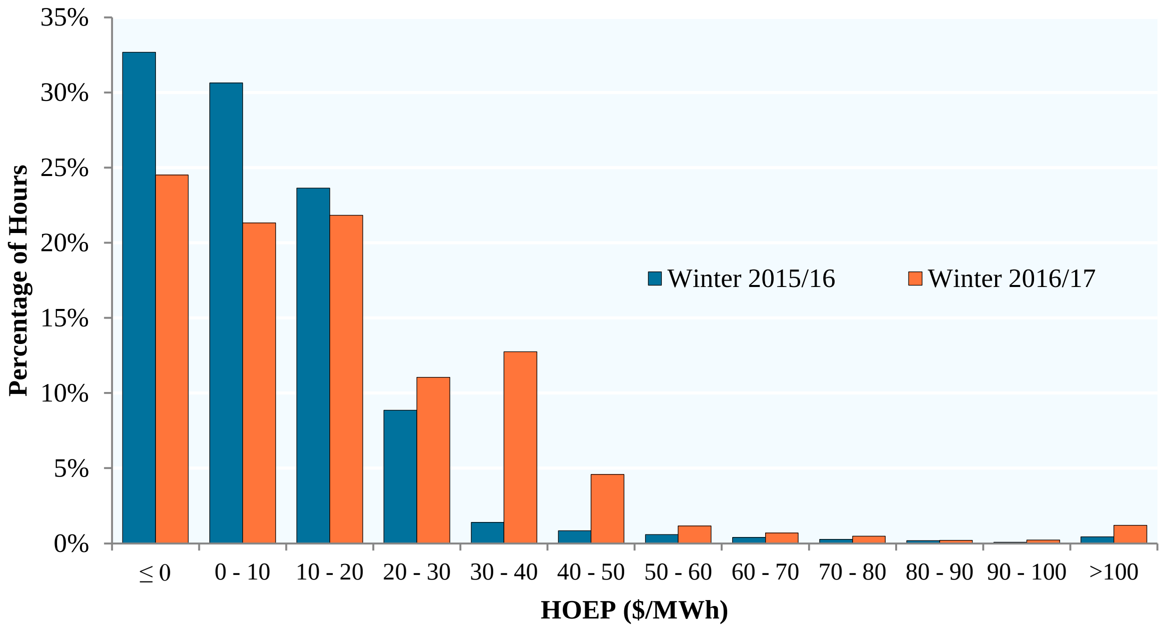
[14] On-peak hours are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays). Off-peak hours are all other hours.

the past, daily changes in gas prices have been positively correlated with movements in the on-peak HOEP, as natural gas generators were frequently the marginal resource during these hours. More recently, as new supply has been added to the grid, resources like wind have increasingly displaced natural gas as the on-peak marginal resource, weakening the correlation between the natural gas price and the on-peak HOEP to the point of being statistically insignificant.

Figure 2-5: Frequency Distribution of Hourly Ontario Energy Price
Winter 2015/16 & Winter 2016/17
(% of hours)

Description:

Figure 2-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Winter 2016/17 and Winter 2015/16 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.

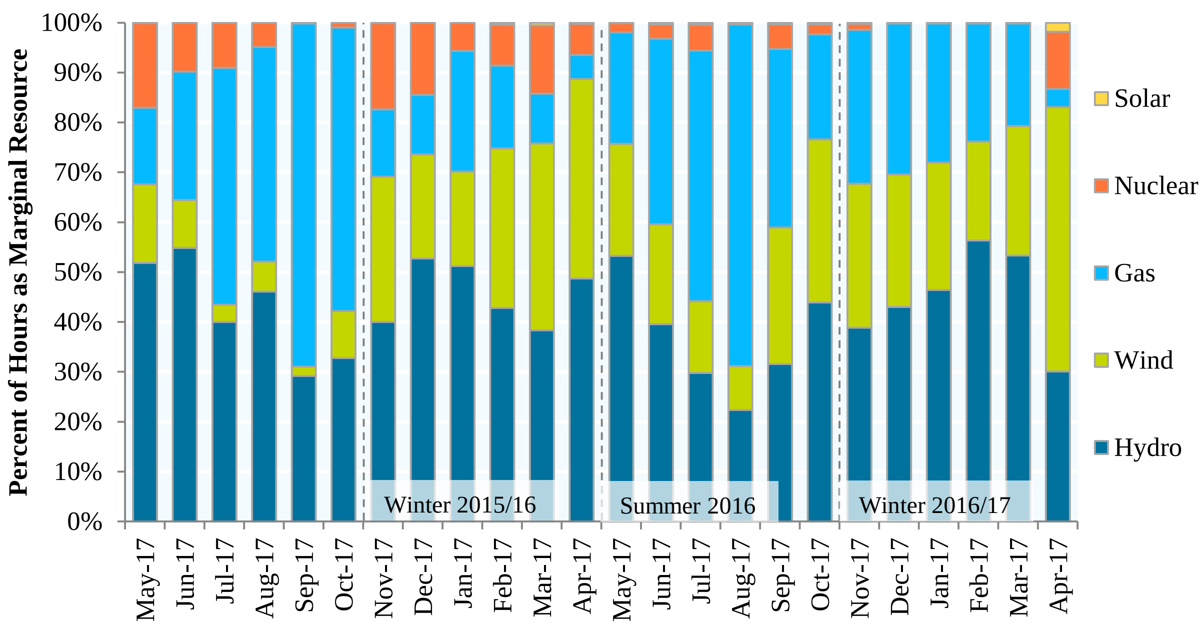
Commentary and Market Considerations:

The fraction of hours with a HOEP less than \$20/MWh decreased in the Winter 2016/17 Period, when compared to the Winter 2015/16 Period. The fraction of hours with higher HOEPs increased. In fact, the Winter 2016/17 Period included two of the four highest price hours since market opening in 2002.

Figure 2-6: Share of Resource Type Setting the Real-Time MCP
May 2015 – April 2017
(% of intervals)

Description:

Figure 2-6 presents the share of intervals in which each resource type set the real-time MCP in each month of 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:

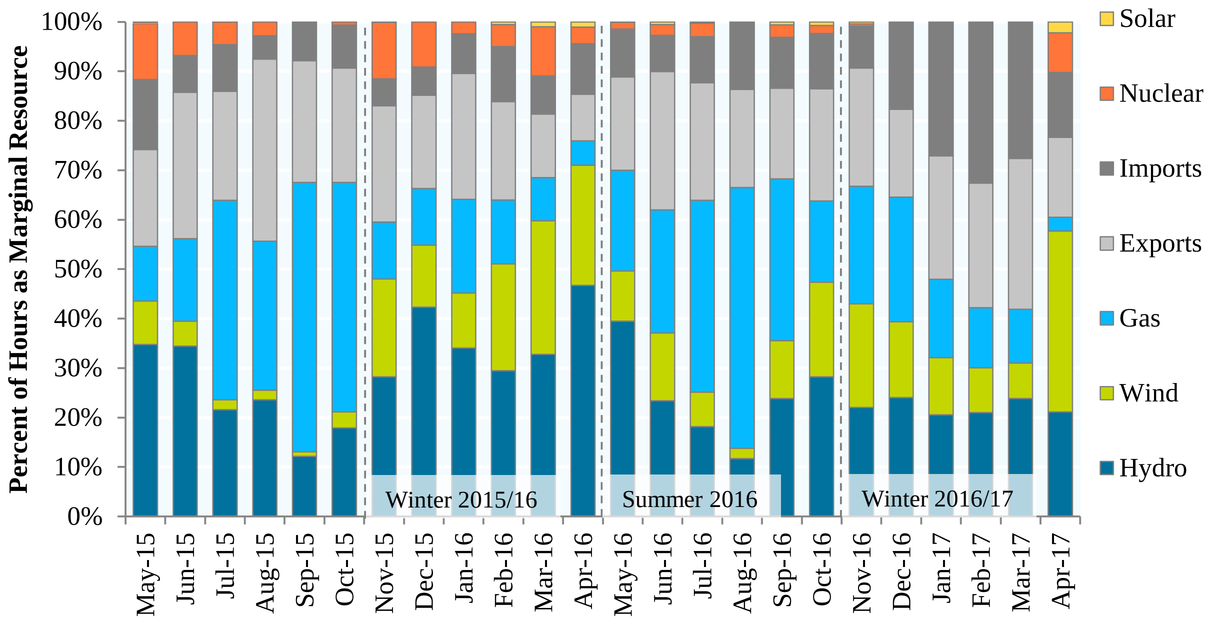
In the Winter 2016/17 Period a similar mix of resource types set the real-time MCP as in the Winter 2015/16 Period, with the number of hours when natural gas was the price-setting resource increasing and the number of hours when nuclear was the price-setting resource decreasing.

Increased nuclear outages in the Winter 2016/17 Period led to an increase in the market price and a decrease in nuclear generators as the price-setting resource.

Figure 2-7: Share of Resource Type Setting the One-Hour Ahead Pre-Dispatch MCP May 2015 – April 2017 (% of hours)

Description:

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



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.[15] 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.

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

Commentary and Market Considerations:

Imports set the PD-1 MCP 21% of the time in the Winter 2016/17 Period, compared to 8% of the time in the Winter 2015/16 Period. This included setting the PD-1 price more than 50% of the time in January, February and March 2017. This is largely due to a higher average HOEP and the energy sales agreement with Hydro-Québec which took effect January 1, 2017 (discussed further in Chapter 4).

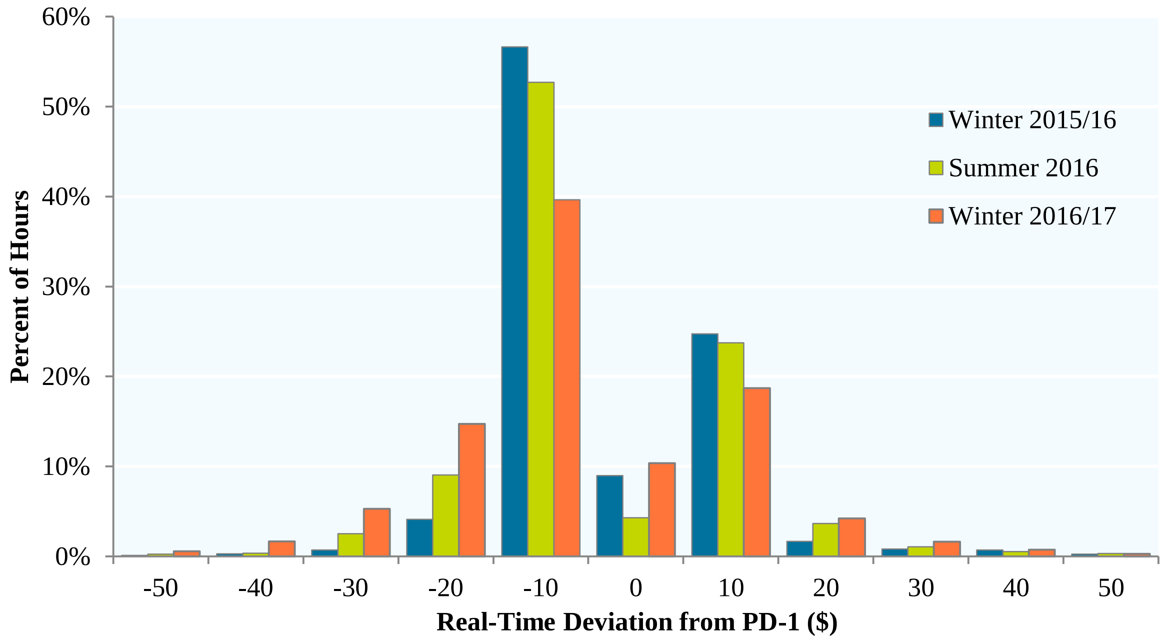
Figure 2-8: Difference between HOEP & PD-1 MCP
Winter 2015/16, Summer 2016 & Winter 2016/17
(% of hours)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Winter 2016/17, Summer 2016 and Winter 2015/16 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.

are treated as non-dispatchable in real-time and scheduled to flow for the entire hour regardless of the price, though their schedules may be curtailed within an hour to maintain reliability.



***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:

The PD-1 MCP was a less accurate predictor of real-time prices in the Winter 2016/17 Period compared to the previous periods. In the Winter 2016/17 Period, the PD-1 MCP was within $10/MWh of the HOEP 69% of the time, compared to 81% in the Summer 2016 Period and 90% in the Winter 2015/16 Period.

The absolute average deviation from the HOEP was $11.15/MWh in the Winter 2016/17 Period, compared to $5.19/MWh in the Winter 2015/16 Period. This is in part due to the increasing role of imports in setting the PD-1 MCP (21% in the Winter 2016/17 Period, up from 8% in the Winter 2015/16 Period). Since imports have their prices revised down to the bottom of the supply stack in real-time (to ensure they are scheduled), all else being equal, the real-time price is set by the closest offer below them in the supply stack, thus lowering the HOEP relative to the PD-1 MCP.

Table 2-2: Factors Contributing to Differences between PD-1 MCP & HOEP
Winter 2015/16, Summer 2016 & Winter 2016/17
(MW & % of Ontario demand)

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 also 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 relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

Factor	Winter 2016/17: Average Absolute Difference		Summer 2016: Average Absolute Difference		Winter 2015/16: Average Absolute Difference	
	MW	% of Ontario Demand	MW	% of Ontario Demand	MW	% of Ontario Demand
Ontario Average Demand	15,420		15,602		15,435	
Demand Forecast Deviation	195	1.26%	209	1.34%	219	1.42%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	18	0.12%	21	0.13%	17	0.11%
Wind Forecast Deviation	185	1.20%	185	1.19%	140	0.91%
Net Export Failures/Curtailments	88	0.57%	78	0.50%	90	0.58%

Relevance:

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

Commentary & Market Considerations:

Deviations from the one-hour ahead forecasts remained the largest sources of uncertainty between PD-1 and real-time. While the demand forecast has historically accounted for the most significant deviation between PD-1 and real-time, the Panel expects wind forecast deviations to be the largest contributor going forward as more wind capacity gets added to the system.[16]

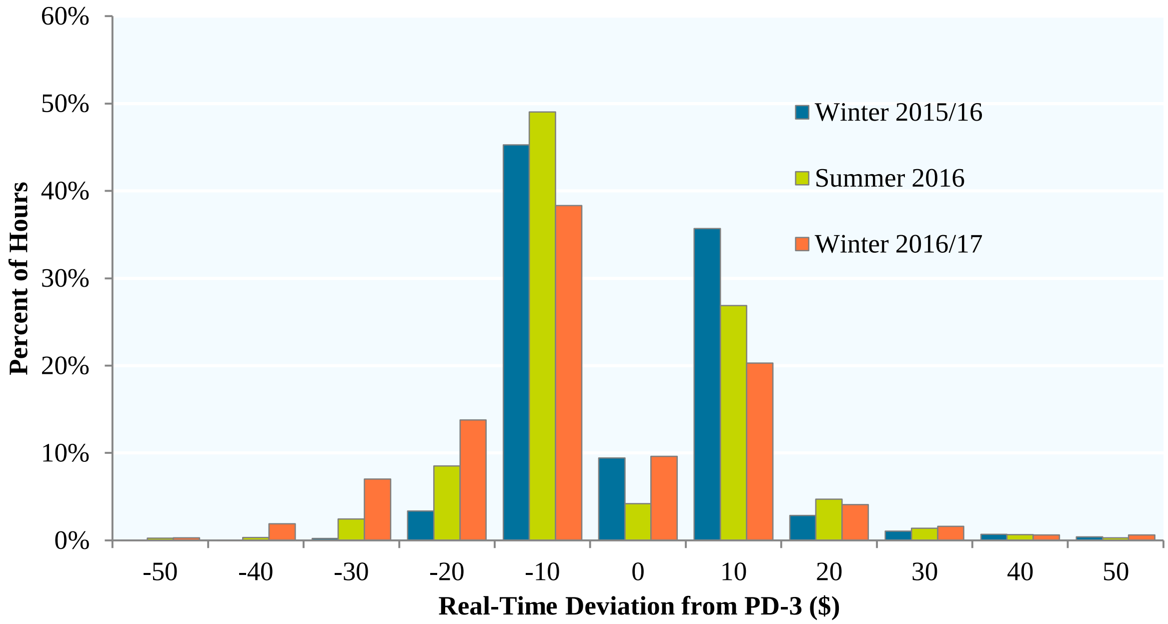
Figure 2-9: Difference between HOEP & PD-3 MCP
Winter 2015/16, Summer 2016 & Winter 2016/17
(% of hours)

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 Winter 2016/17, Summer 2016 and Winter 2015/16 Periods. The price differences are grouped in $10/MWh increments, save for the

[16] Wind forecast deviation may already be the largest contributor to PD-1 to real-time deviation. Forecast deviation associated with generation embedded within the distribution network is observed as an offset to demand on the IESO-controlled grid. Accordingly, forecast deviations associated with these resources (primarily wind and solar) appear as demand deviations in Table 2-2.

$0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



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 particularly relevant to non-quick start facilities and energy limited resources,[17] 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:

The PD-3 MCP was a less accurate indicator of the HOEP than in past reporting periods, similar to the trend observed in the deviation between PD-1 MCP and HOEP (as shown in Figure 2-8).

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

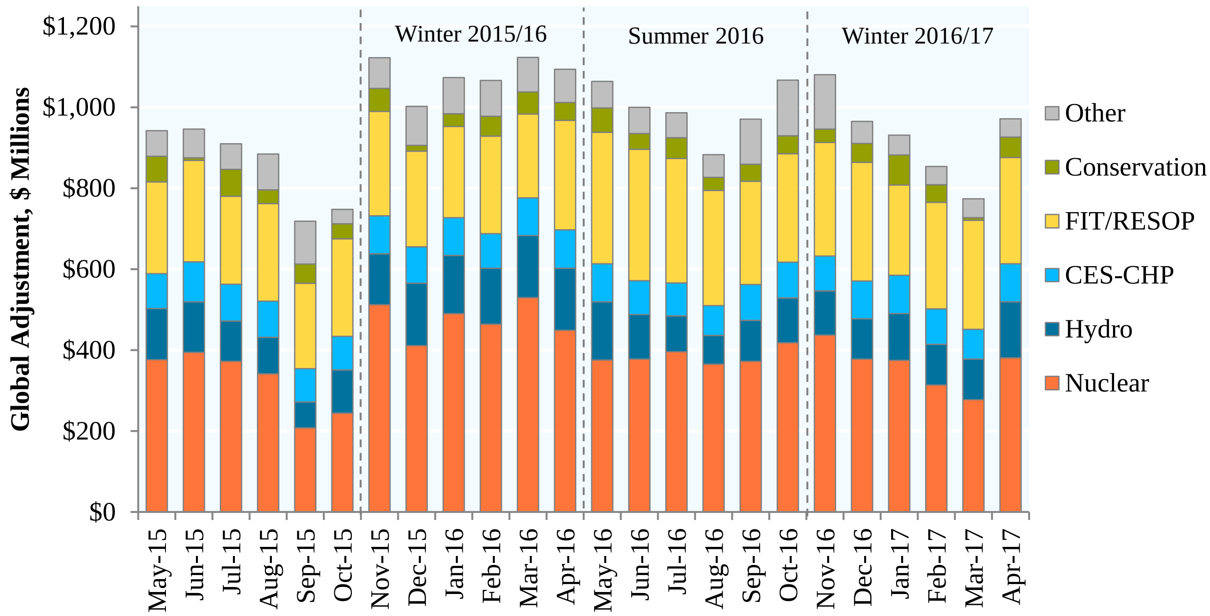
The PD-3 price was within $10/MWh of the HOEP 68% of the time in the Winter 2016/17 Period, 80% of the time in the Summer 2016 Period and 90% of the time in the Winter 2015/16 Period. In the Winter 2016/17 Period, the PD-3 MCP was over-forecast far more often than in past periods, in part due to a substantial increase in the number of hours for which imports set the PD-3 MCP in the Winter 2016/17 Period.

Figure 2-10: Monthly Global Adjustment by Component
May 2015 – April 2017
($)

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;
- Payments to regulated or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff, including microFIT (collectively "FIT"), and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including to holders of non-utility generator contracts and 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 or regulated rates, increased production, increased capacity or decreases in the HOEP.

Commentary and Market Considerations:

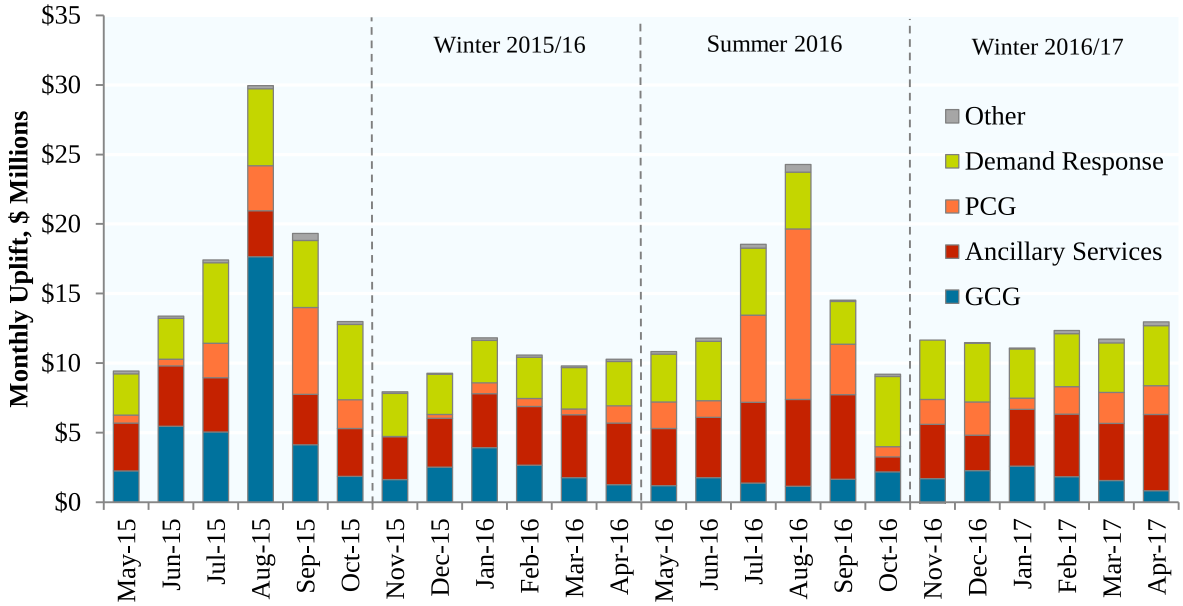
The GA decreased by 7% in the Winter 2016/17 Period when compared to the Winter 2015/16 Period. A higher hourly market price, as seen in the Winter 2016/17 Period when compared to the Winter 2015/16 Period, results in lower out-of-market payments required to meet generators' contracted or regulated rates. Payments to FIT/RESOP contract holders increased 11%, representing 29% of the total GA during the period, while payments to all other categories remained constant or fell. The largest decreases were in nuclear (down 24%, accounting for 39% of the total GA) and hydro (down 24%, accounting for 12% of the total GA).

Figure 2-11: Total Hourly Uplift Charge by Component on a Monthly Basis
May 2015 – April 2017
($)

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:

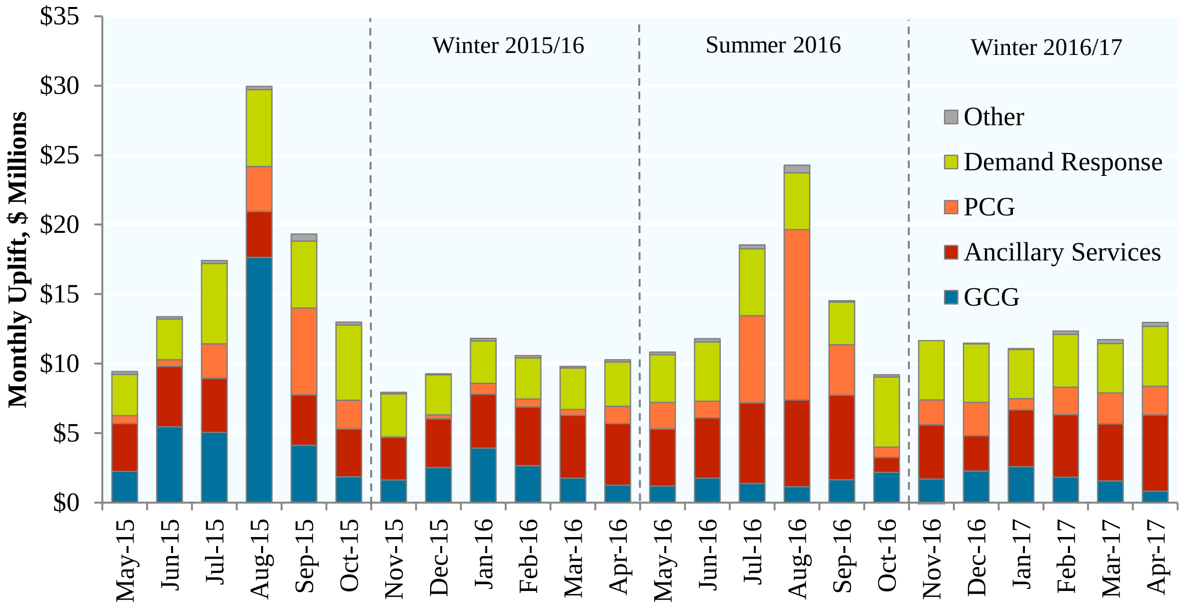
All components of Hourly Uplift increased in the Winter 2016/17 Period when compared to the Winter 2015/16 Period. IOG payments increased from $920,000 to $10.4 million, attributable to an increase in the frequency of PD-1 over-forecasting the HOEP and an increase in day-ahead import commitments. There was also a $13.7 million increase in CMSC payments and a $16.7 million increase in losses relative to the Winter 2015/16 Period. However, when comparing the Winter 2016/17 Period to the Summer 2016 Period, total Hourly Uplift decreased by $18.9 million.

Figure 2-12: Total Monthly Uplift Charge by Component
May 2015 – April 2017
($)

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:[18]

- 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.



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

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

applicable, in order to recover the costs associated with various market programs and design features.

The Panel has amended the manner in which it classifies Monthly Uplift charges to more closely align reported costs with the month in which they were incurred, rather than the month in which they were settled. As a result of this change, monthly totals reported in this report do not match with, and are not as directly comparable to, those previously reported by the Panel.

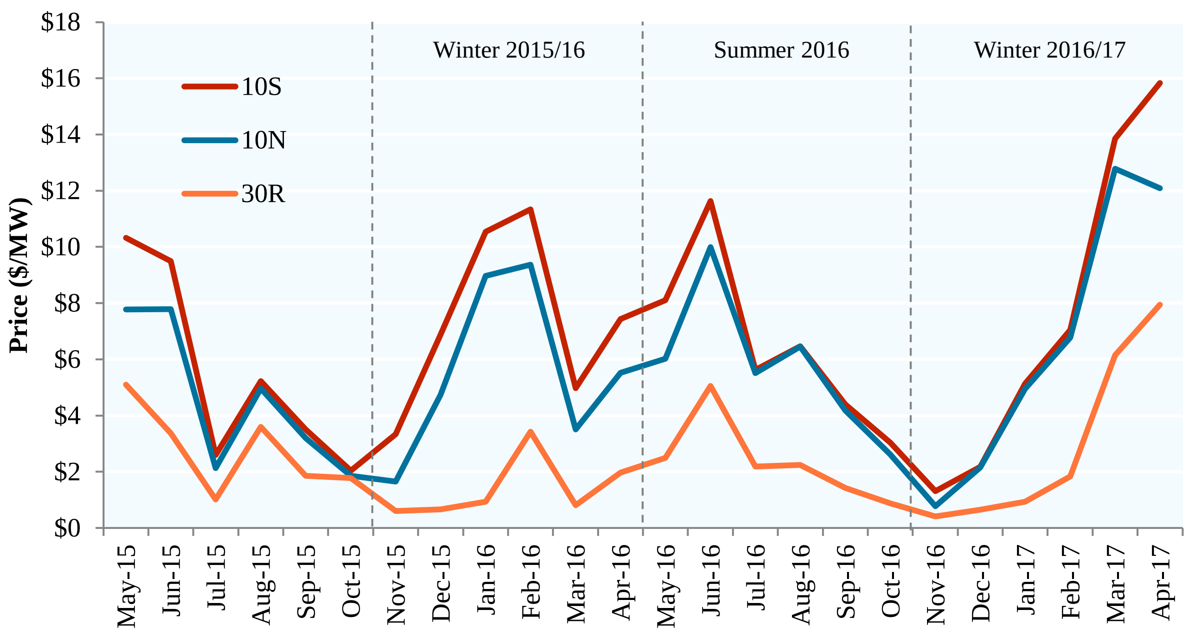
Commentary and Market Considerations:

Total Monthly Uplift for the Winter 2016/17 Period ($70.96 million) decreased relative to the Summer 2016 Period, but increased relative to the Winter 2015/16 Period ($59.67 million). This is due to an increase in payments under the PCG program of $7.90 million. While this represents an increase from winter to winter, PCG costs remained significantly lower than those in the Summer 2016 Period.

Figure 2-13: Average Monthly Operating Reserve Prices by Category May 2015 – April 2017 ($/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.

Unlike in the energy market, demand in the OR markets is non-discretionary and set by the 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. The OR requirement promotes the reliability of the IESO-controlled grid.

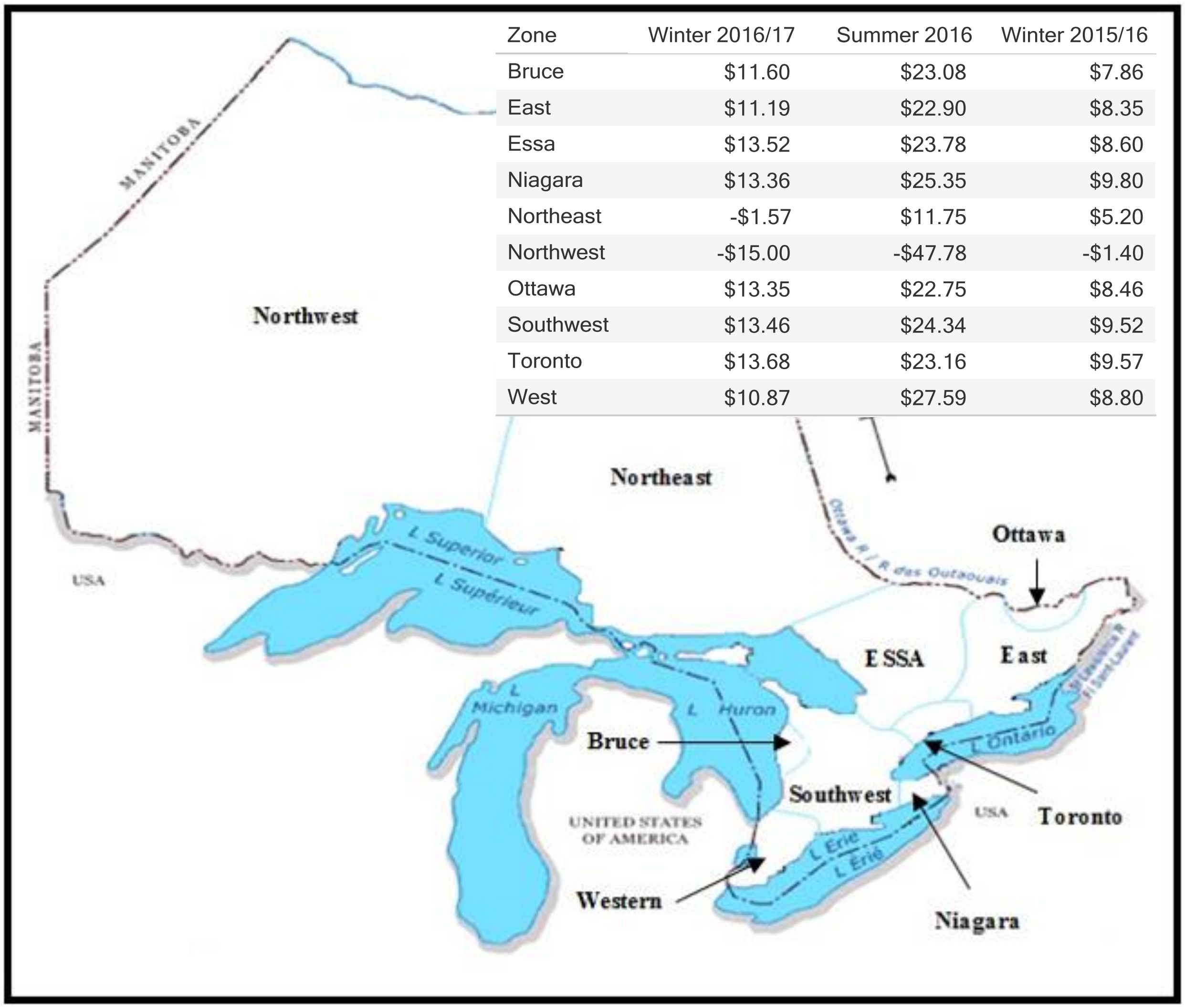
Commentary and Market Considerations:

OR prices increased modestly when compared to the Winter 2015/16 Period. Average OR prices were \$7.56/MW, \$6.59/MW and \$2.99/MW for 10S, 10N and 30R respectively, compared to \$7.42/MW, \$5.63/MW and \$1.40/MW in the Winter 2015/16 Period. Since the OR and energy markets are co-optimized, an increase in the HOEP, as was seen in the Winter 2016/17 Period, is typically coupled with an increase in OR prices.

Figure 2-14: Average Internal Nodal Prices by Zone
Winter 2015/16, Summer 2016 & Winter 2016/17
(\$/MWh)

Description:

Figure 2-14 illustrates the average nodal price of Ontario’s ten internal zones for the Winter 2016/17, Summer 2016 and Winter 2015/16 Periods. In principle, nodal prices represent the cost of supplying the next megawatt hour of energy at a given location.



Zone	Winter 2016/17	Summer 2016	Winter 2015/16
Bruce	$11.60	$23.08	$7.86
East	$11.19	$22.90	$8.35
Essa	$13.52	$23.78	$8.60
Niagara	$13.36	$25.35	$9.80
Northeast	-$1.57	$11.75	$5.20
Northwest	-$15.00	-$47.78	-$1.40
Ottawa	$13.35	$22.75	$8.46
Southwest	$13.46	$24.34	$9.52
Toronto	$13.68	$23.16	$9.57
West	$10.87	$27.59	$8.80

Relevance:

While the HOEP is the hourly 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 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.

In general, nodal prices outside the northern parts of the province are close in magnitude and 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:

Nodal prices in all zones, excluding the Northwest and Northeast zones, increased in the Winter 2016/17 Period when compared to the Winter 2015/16 Period. As discussed earlier, higher prices in the Winter 2016/17 are likely attributable to reduced baseload capacity due to increased nuclear and hydroelectric outages. The seasonal variation seen over the last number of periods is a result of the same factors which cause variations in the HOEP, primarily higher demand that brings more gas-fired resources online in the summer and greater wind output in the winter. Reduced export opportunities on the Minnesota and Manitoba interties due to a higher HOEP likely resulted in more surplus generation in the Northwest and Northeast zones, depressing the nodal prices in those zones in the Winter 2016/17 Period.

Figures 2-15 & 2-16: Congestion by Intertie

Description:

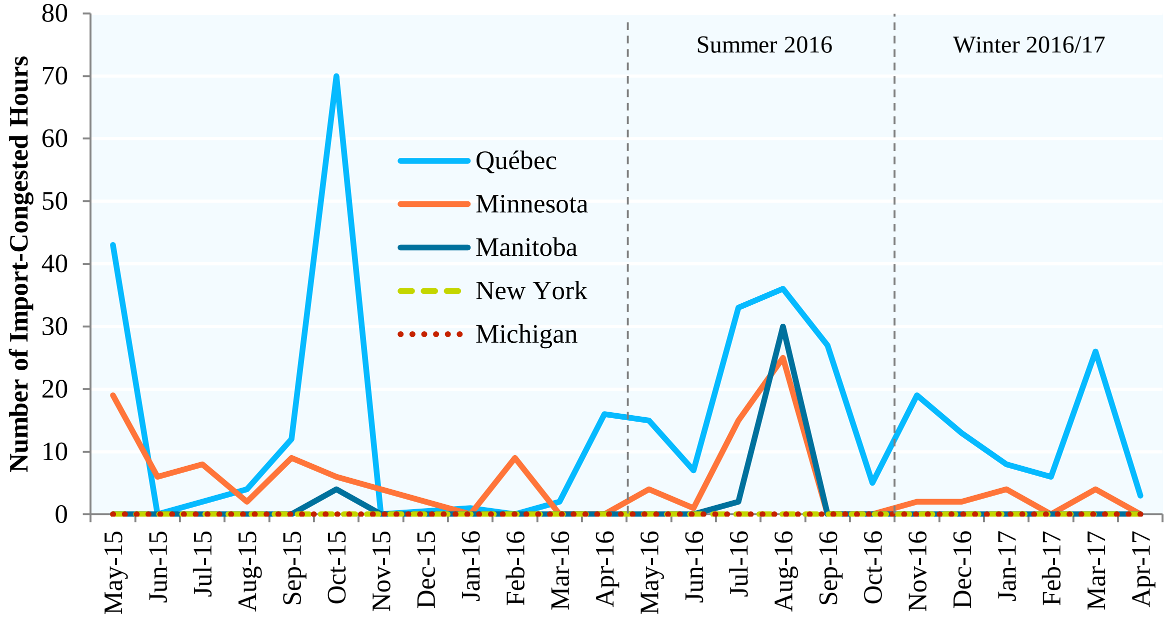
Figures 2-15 and 2-16 report the number of hours per month of import and export congestion, respectively, by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

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 intertie and 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.

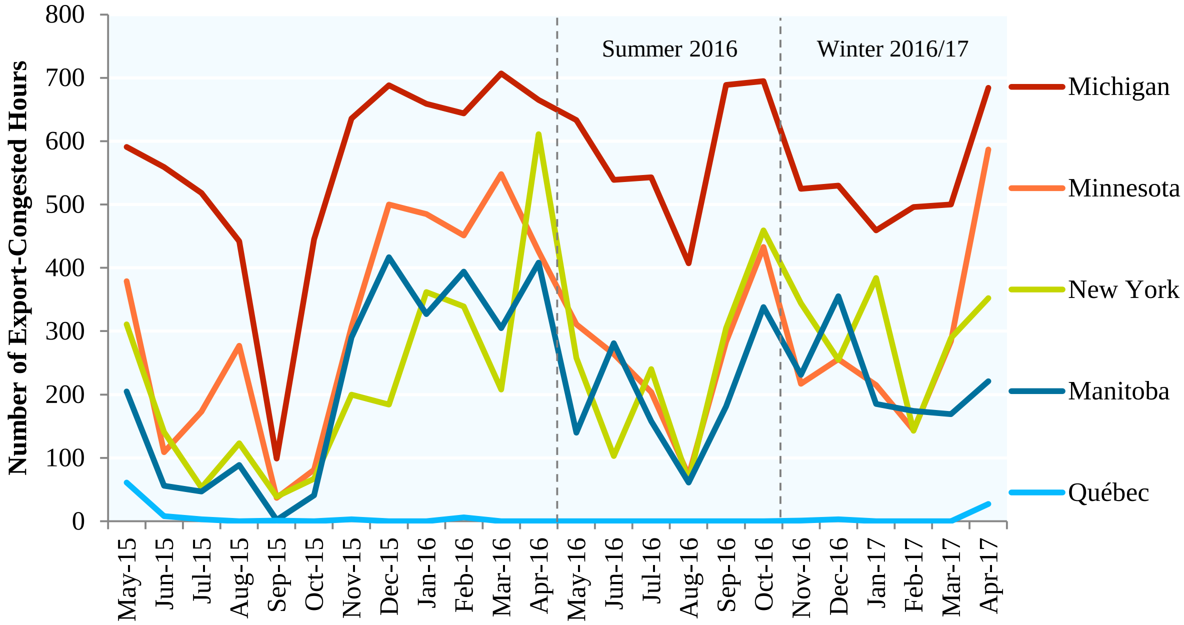
Figure 2-15: Import Congestion by Intertie
May 2015 – April 2017
(Number of hours in the unconstrained schedule)



Commentary and Market Consideration:

Only the Minnesota and Québec interties experienced import congestion during the Winter 2016/17 Period. When compared to the Winter 2015/16 Period, the number of congested hours on the Québec intertie increased, while the number of congested hours on the Minnesota intertie remained constant. Increased import congestion is expected during periods in which the HOEP is higher and imports are potentially more profitable, as was the case during the Winter 2016/17 Period.

Figure 2-16: Export Congestion by Intertie
May 2015 – April 2017
(Number of hours in the unconstrained schedule)



Commentary and Market Consideration:

Export congestion decreased during the Winter 2016/17 Period when compared to the Winter 2015/16 Period, as would be expected during a period with a higher average HOEP. The lower Ontario market prices in April 2017 resulted in an increase in congestion for that month. The Minnesota intertie saw its most congested month of the past two years in April 2017.

Table 2-3: Monthly Average Hourly Electricity Spot Prices
Ontario & Surrounding Jurisdictions
November 2016 – April 2017
($/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. Absent congestion at an intertie, 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 intertie with each jurisdiction. Québec is a frequent trading partner, but does not operate a wholesale market (and therefore does not publish prices) and thus is not included in Table 2-3. The prices listed for each jurisdiction reflect the marginal price of electricity; costs associated with capacity, such as Ontario's GA or NYISO, PJM or MISO's capacity market costs are not relevant to inter-jurisdictional trade as traders do not pay these costs.

Month	Ontario (HOEP)	Manitoba	Michigan (MISO)	Minnesota (MISO)	New York (NYISO)	PJM
Nov	14.96	37.71	47.87	40.19	28.28	31.69
Dec	19.43	33.59	41.80	35.71	36.13	41.22
Jan	20.36	33.13	37.73	34.36	33.23	39.84
Feb	20.14	25.87	32.64	27.79	27.43	31.96
Mar	24.51	29.11	40.06	31.50	33.62	39.61
Apr	9.66	29.05	37.08	31.00	31.60	35.26

Relevance:

One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low price 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 appeared profitable or efficient but becomes unprofitable or inefficient in real-time. 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 intertie in a 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 into or export from Ontario.

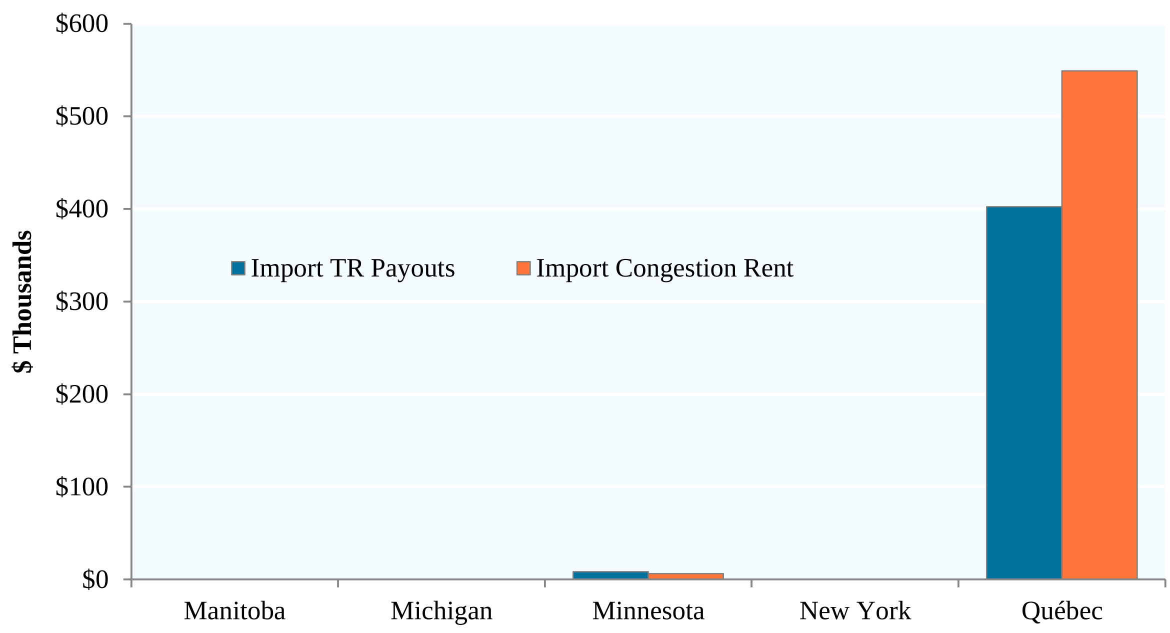
Commentary and Market Considerations:

For every month in the Winter 2016/17 Period, the average HOEP was lower than the market price in all neighbouring jurisdictions. This price difference is an incentive to export out of Ontario, which can be seen in Figures 2-15 and 2-16.

Figure 2-17: Import Congestion Rent & TR Payouts by Intertie
November 2016 – April 2017
($)

Description:

Figure 2-17 compares the total import congestion rent collected to total TR payouts by intertie for the Winter 2016/17 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 lower 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,[19] transaction failures and intertie de-ratings, there are congestion events in which a congestion rent 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

[19] 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”.

in the form of a reduction in transmission charges.[20] 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 Considerations:

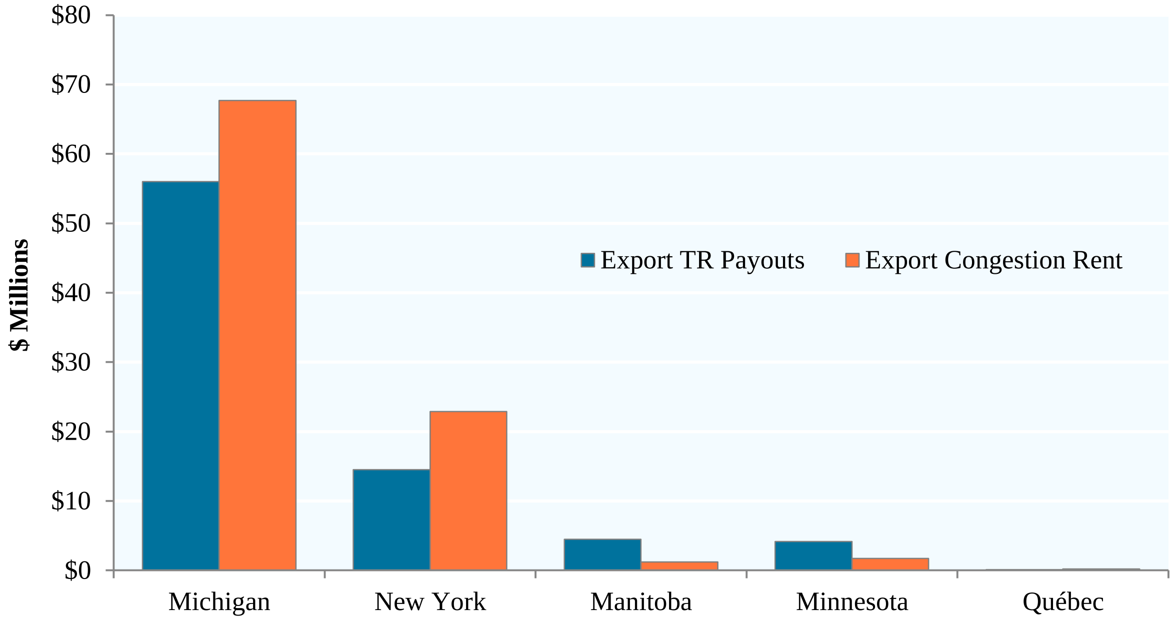
Total import TR payouts in the Winter 2016/17 Period were $410,000, with the vast majority of those payouts occurring over the Québec intertie. Given the absence of any import congestion on the New York, Michigan and Manitoba interties (Figure 2-15) and the regular net export position at all non-Québec interties, it is not surprising to see low import TR payouts relative to export TR payouts. The amount of congestion rent collected for the Québec intertie exceeded the TR payouts by a surplus of nearly $150,000, largely due to more megawatts of transmission being available throughout the period (averaging 1061 MW) than were sold as TRs (615 MW each month).

Figure 2-18: Export Congestion Rent & TR Payouts by Intertie
November 2016 – April 2017
_($)_

Description:

Figure 2-18 compares the total export congestion rent collected to total TR payouts by intertie for the Winter 2016/17 Period.

[20] 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:

Export congestion rent collected was $14.5 million in excess of TR payouts during the Winter 2016/17 Period. Michigan had the greatest absolute surplus of congestion rent, surpassing TR payouts by $11.7 million. New York had a congestion rent surplus of $8.4 million. For both interties, this was due to more megawatts of transmission being available throughout the period than were sold as TRs. On average, only 900 MW of export TRs were sold for the Michigan intertie each month compared to the average available export transmission capacity of 1206 MW. For the New York intertie, 600 MW of export TRs were sold each month compared to the average available export transmission capacity of 1157 MW.

Both Manitoba and Minnesota had significant congestion rent shortfalls in the Winter 2016/17 Period. On both interties TR payouts were more than double the collected congestion rent, resulting in a combined congestion rent shortfall of $5.7 million. This was largely due to a high number of congested hours in which fewer export megawatts flowed in the constrained schedule, based on which congestion rent is collected, than the unconstrained schedule. This is a result of the two-schedule dispatch system, which Market Renewal is looking to improve. This was compounded on the Manitoba intertie by a high number of failed transactions, from which congestion rent is not collected, and on the Minnesota intertie by more megawatts of TRs being sold than was available on the intertie: 130 MW of export TRs were sold each month, even though the period only had an average available export transmission capacity of 126 MW. For the Winter 2016/17 Period, the Minnesota intertie was the only intertie for which more TRs were sold than there was available capacity.

Table 2-4: Average Long-Term (12-Month) TR Auction Prices by Intertie & Direction May 2016 – April 2017 ($/MW)

Description:

Table 2-4 lists the average auction prices for one megawatt of long-term (12-month) TRs sold for each intertie, in either direction, since May 2016 (these TRs would have been valid during the Winter 2016/17 Period).

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	**May-16**	**Jul-16 to May-17**	1,437	350	1,564	252	1,259
	Aug-16	**Oct-16 to Aug-17**	2,208	164	3,006	384	2,662
	Nov-16	**Jan-17 to Dec-18**	2,117	175	1,840	383	3,989
	Feb-17	**Apr-17 to Mar-18**	1,421	78	1,603	128	1,463
Export	**May-16**	**Jul-16 to May-17**	31,341	113,934	42,647	48,881	3,726
	Aug-16	**Oct-16 to Aug-17**	29,144	101,732	30,813	40,548	3,256
	Nov-16	**Jan-17 to Dec-18**	35,203	113,394	40,466	43,017	4,425
	Feb-17	**Apr-17 to Mar-18**	28,353	108,664	34,175	47,840	3,013

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, revenues signal market participant expectations of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

TR prices remained fairly constant during the Winter 2016/17 Period. Export TR prices remained significantly higher than import TR prices, indicating intertie traders were expecting export congestion to continue to significantly surpass import congestion over the next 12 months.

Table 2-5: Average Short-Term (One-Month) TR Auction Prices by Intertie & Direction May 2016 – April 2017 ($/MWh)

Description:

Table 2-5 lists the auction prices for one megawatt of short-term (one-month) TRs sold at each intertie, in either direction, during the Winter 2016/17 and Summer 2016 Periods.

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	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
	Nov-16	115	14	140	22	233
	Dec-16	90	14	104	26	77
	Jan-17	68	3	157	37	135
	Feb-17	96	1	142	37	85
	Mar-17	62	4	35	5	37
	Apr-17	94	4	43	1	72
Export	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
	Nov-16	3,633	13,102	3,319	2,904	79
	Dec-16	3,846	10,601	3,802	4,096	120
	Jan-17	4,204	10,475	4,205	5,275	1,123
	Feb-17	3,945	7,855	3,864	3,645	370
	Mar-17	2,655	8,201	2,512	4,208	18
	Apr-17	3,750	12,960	4,471	5,401	19

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.

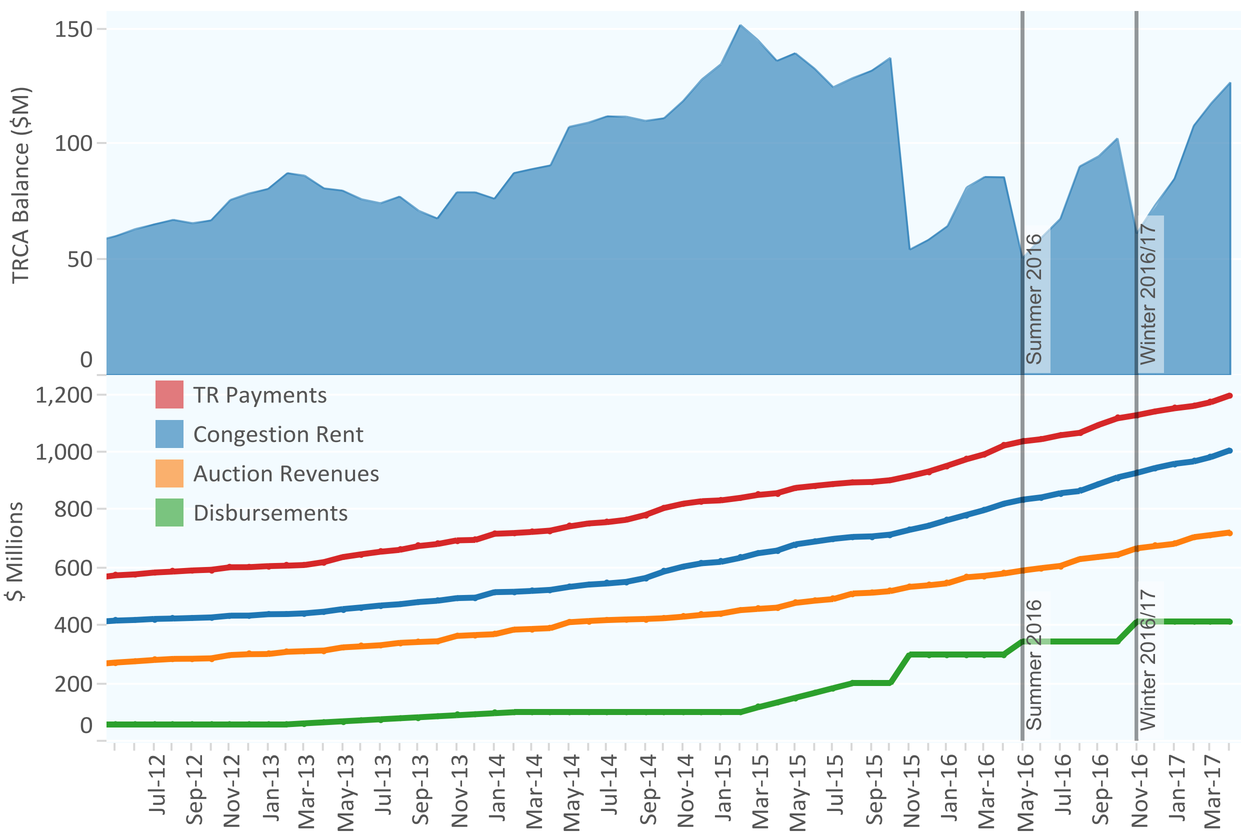
Commentary and Market Consideration:

Short-term export TR prices increased in the Winter 2016/17 Period, while import TR prices decreased. Higher import TR prices in the Summer 2016 Period can be attributed to higher import congestion associated with the high-demand summer months.

Figure 2-19: TR Clearing Account
May 2012 – April 2017
($)

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, as well as the cumulative effect of each type of transaction impacting the account.



Relevance:

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

Credits

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

Debits

- 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:

The balance of the TR Clearing Account increased to $126.7 million at the end of the Winter 2016/17 Period, up from $102.5 million at the end of the Summer 2016 Period. The April 2017 balance was $106.7 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:

- $172.5 million in revenue, specifically:
  - $94.3 million in congestion rent
  - $77.5 million in auction revenues
  - $0.7 million in interest
- $147.6 million in debits, specifically:
  - $79.6 million in TR payouts
  - $68.0 million in disbursements to Ontario consumers and exporters

Compared to the Summer 2016 Period, there was an increase in both revenues and disbursements in the Winter 2016/17 Period. This is attributable to an increase in TR auction revenues, as well as a large disbursement to consumers and exporters in April 2017.

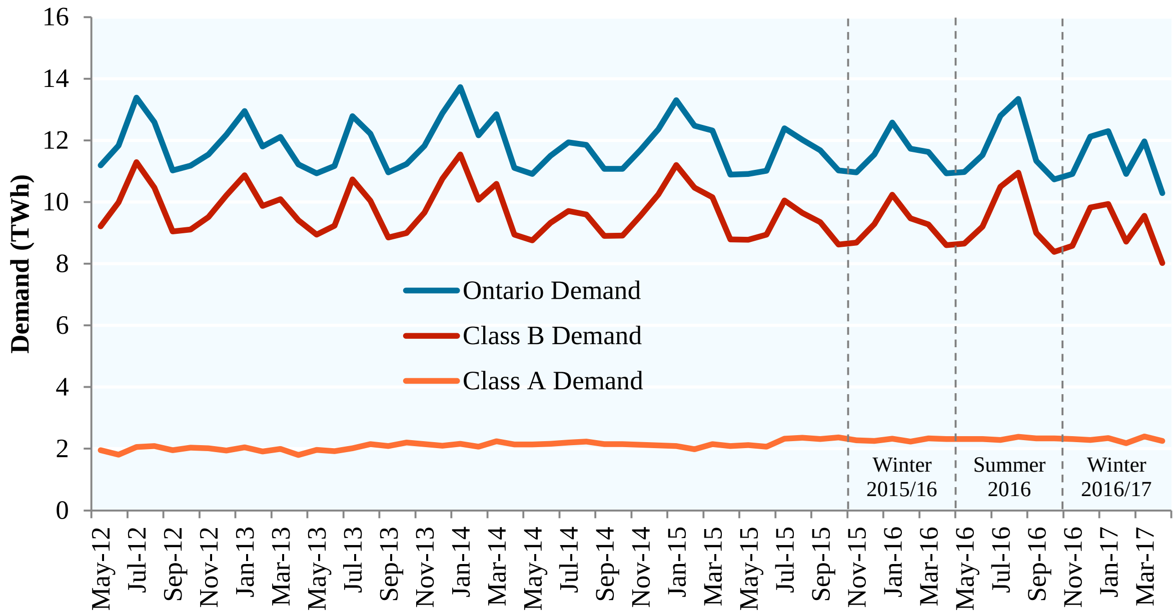
2 *Demand*

This section discusses Ontario energy demand for the Winter 2016/17 Period relative to previous years.

Figure 2-20: Monthly Ontario Energy Demand by Class A & Class B Consumers May 2012 – April 2017 (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.[21]



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

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 B identifies their respective monthly demand profiles.

Commentary and Market Consideration:

Demand for the Winter 2016/17 Period was 68.5 TWh, compared to 70.7 TWh in the Summer 2016 Period and 69.4 TWh in the Winter 2015/16 Period. April 2017 was the lowest demand month since market opening in 2002. The spring and fall seasons typically have lower demand due to reduced air conditioning and heating load. This trend can be seen in Ontario demand and Class B demand. Class A demand, which is primarily industrial processes, shows little variation from season to season.

3 *Supply*

During the fourth quarter of 2016 and the first quarter of 2017, 494 MW of nameplate generating capacity completed commissioning and was added to the IESO-controlled grid's total capacity. This consisted of 334 MW of new gas generation capacity, 100 MW of new solar capacity and 60 MW of new wind capacity. At the end of the first quarter of 2017, total grid-connected generation capacity was 36,564 MW, consisting of nuclear (12,978 MW), natural gas (10,277 MW), hydro (8,451 MW), wind (3,983 MW), biofuel (495 MW) and solar generation (380 MW).[22]

During the fourth quarter of 2016 and the first quarter of 2017, there was a 43 MW change in nameplate IESO-contracted generating capacity at the distribution level. This change in distribution-level capacity (or "embedded" capacity) consisted of a 34 MW increase in solar capacity, a 38 MW increase in wind capacity, a 30 MW reduction in hydro capacity and a 1 MW increase in biofuel capacity. At the end of the first quarter of 2017, IESO-contracted embedded capacity totalled 3,162 MW, consisting of solar (1,960 MW), wind (572 MW), hydroelectric

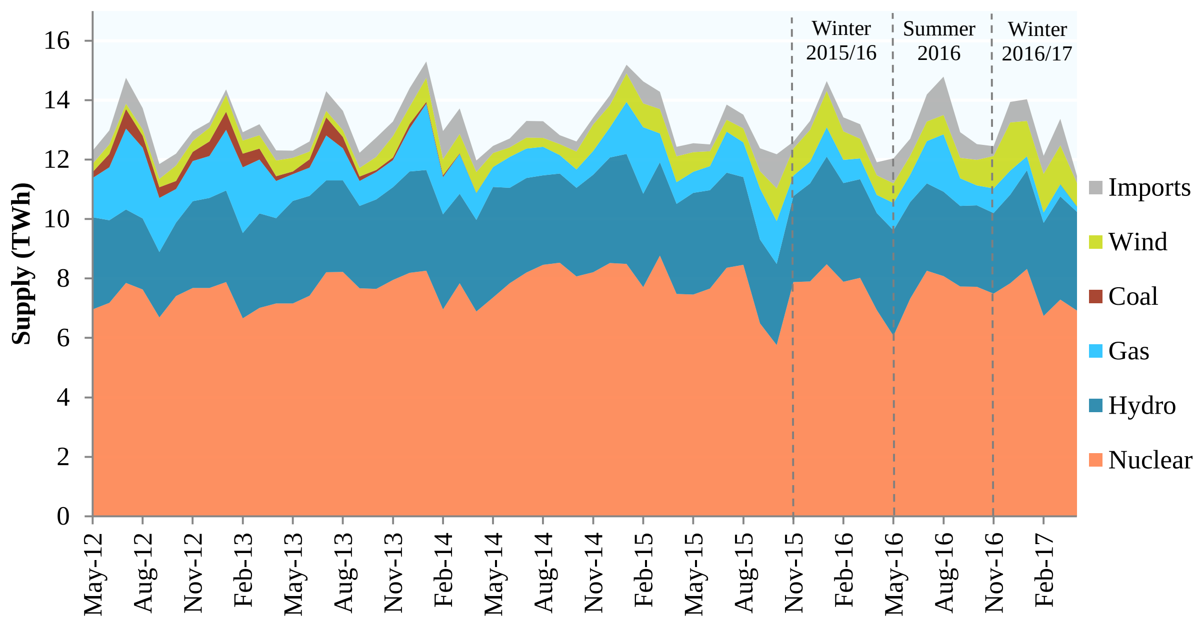
[22] Capacity totals were obtained from the IESO's *18-Month Outlook* reports, available at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook.

(238 MW), gas-fired and combined heat and power (259 MW), biofuel (109 MW) and energy from waste (24 MW).[23]

Figure 2-21: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule May 2012 – April 2017 (TWh)

Description:

Figure 2-21 displays the share of real-time unconstrained production schedules from May 2012 to April 2017 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.[24]



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

[23] Embedded capacity totals were obtained from the quarterly *Ontario Energy Report*, available at: http://www.ontarioenergyreport.ca/index.php.

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

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

Commentary and Market Considerations:

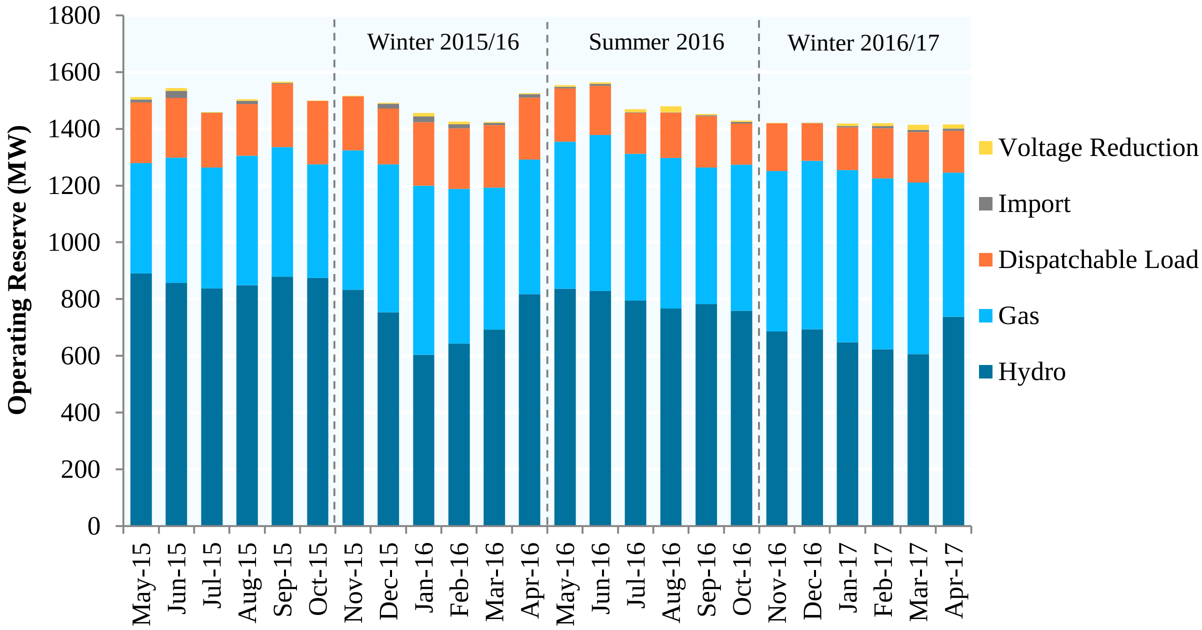
Comparing the Winter 2016/17 Period to the Winter 2015/16 Period, wind generation and imports increased, while nuclear and natural gas generation decreased. Wind output increased from 5.5 TWh to 7.3 TWh, which is to be expected given the increase in wind capacity during the year. Imports increased from 2.3 TWh to 3.5 TWh, natural gas output decreased from 4.5 TWh to 3.1 TWh and nuclear output decreased from 47.1 TWh to 44.6 TWh. Hydroelectric output showed a smaller decrease.

Figure 2-22: Average Hourly Operating Reserve Scheduled by Resource Type
May 2015 – April 2017
(MW)

Description:

Figure 2-22 displays the share of real-time unconstrained OR schedules from May 2015 to April 2017 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads and voltage reduction (taken as a control action by the IESO).[25] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

[25] 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 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.



Relevance:

This figure displays changes in the scheduling and supply of OR, as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as seasonal fuel variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors.[26]

Commentary and Market Considerations:

The average quantity of OR scheduled in the Winter 2016/17 Period was constant at approximately 1420 MW. This represents a small decrease from an average of 1473 MW in the Winter 2015/16 Period. A change in what the IESO predicts to be the grid's largest contingency at any point in time will result in a change in OR requirements.

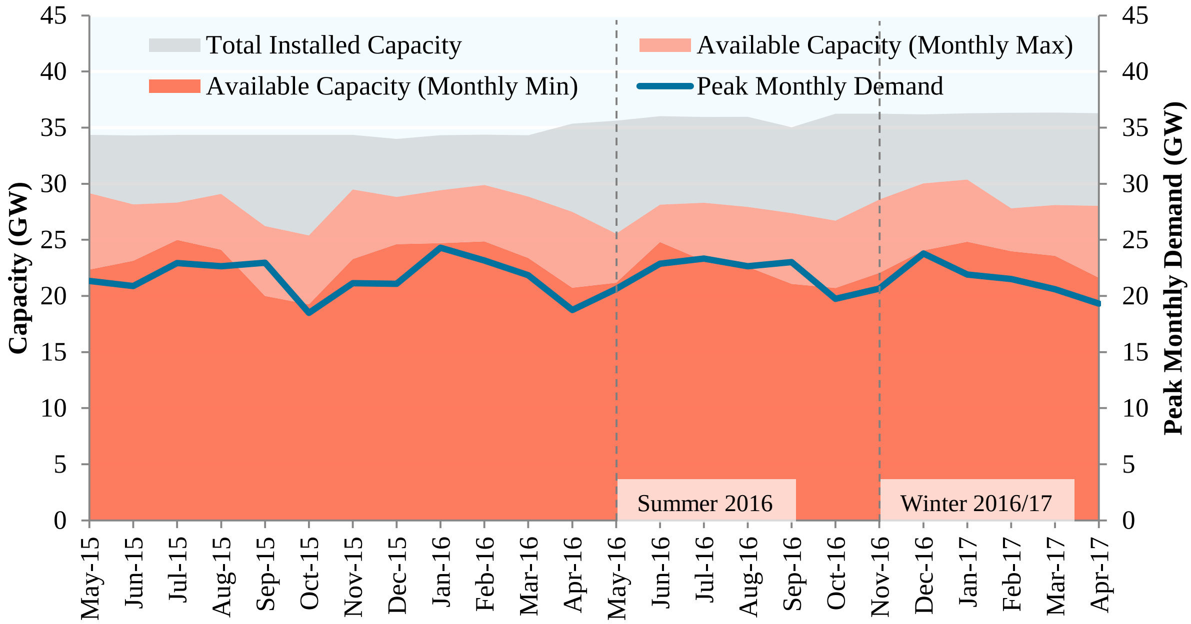
The OR resource mix changed little between the Winter 2015/16 and Winter 2016/17 Periods. The fraction of OR provided by dispatchable load fell from 14.3% to 11.2%, while the fraction provided by hydroelectric resources increased from 35.4% to 40.9%.

[26] The total energy available from the 10-minute OR market must be enough to cover the single largest contingency in 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 May 2015 – April 2017 (GW)

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 May 2015 to April 2017. The maximum and minimum megawatts on outage during a given month can be observed by comparing the total installed capacity to the monthly minimum and maximum available capacity, respectively. For reference, the figure also includes the monthly peak market demand, excluding demand served by imports.[27]



Relevance:

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

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

Commentary and Market Considerations:

The Winter 2016/17 Period on average had less unavailable capacity when compared to the Summer 2016 Period, but had more unavailable capacity when compared to the Winter 2015/16 Period. The increase in unavailable capacity between winters is due to an increase in nuclear and hydro outages and the addition of 250 MW of variable renewable generation, which is frequently unavailable due to weather conditions. The maximum unavailable capacities during the two winter periods were both approximately 14,650 MW.

4 *Imports, Exports and Net Exports*

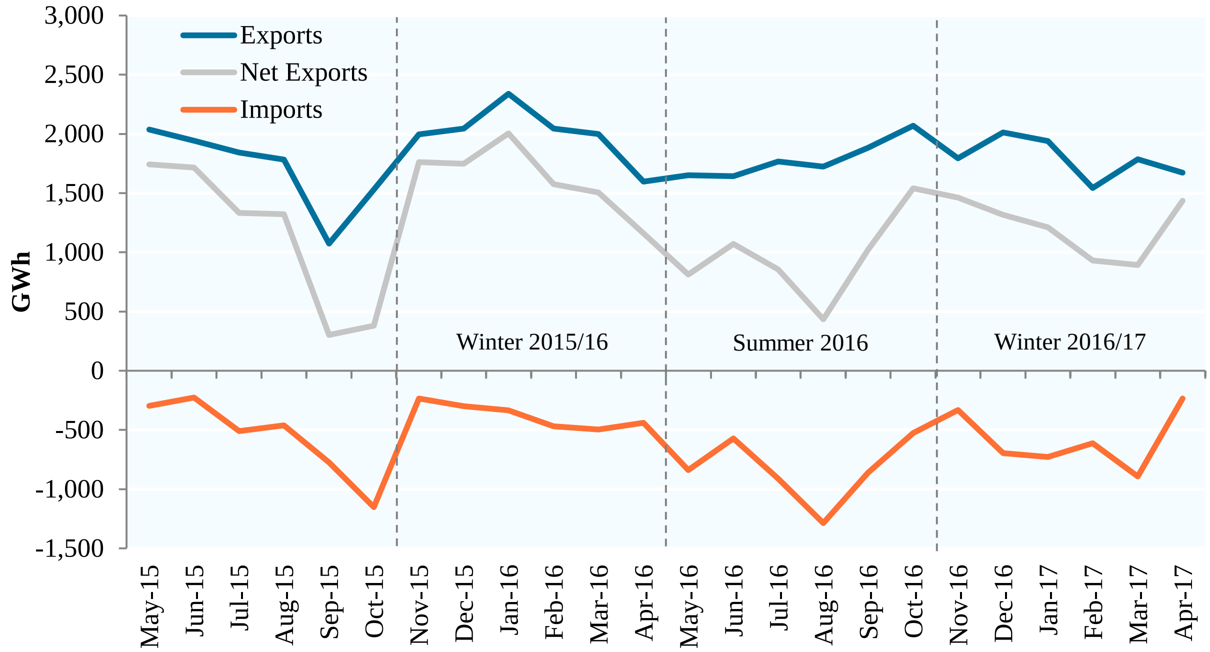
This section examines import and exports transactions in the unconstrained sequence, as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[28]

***Figure 2-24: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule)
May 2015 – April 2017
(TWh)***

Description:

Figure 2-24 plots total monthly imports, exports and net exports from May 2015 to April 2017. Exports are represented by positive values while imports are represented by negative values.

[28] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not impact 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 Winter 2016/17 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.

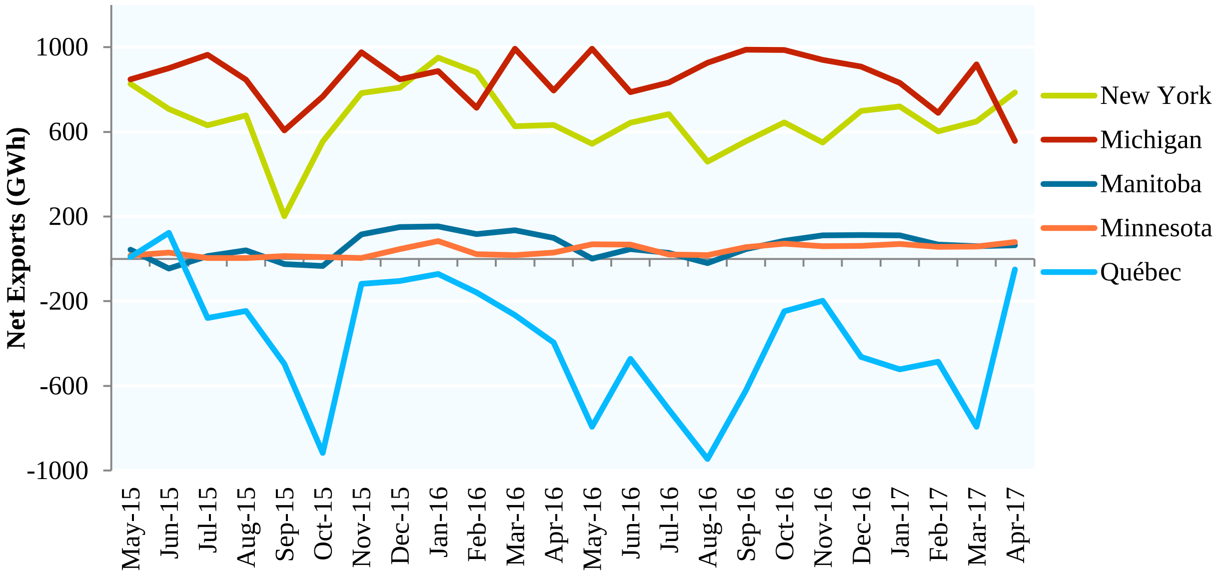
Commentary and Market Considerations:

Ontario remained a net exporter during the Winter 2016/17 Period with net exports of 5.74 TWh. Imports were 3.49 TWh compared to 2.27 TWh in the Winter 2015/16 Period, representing a 54% increase. Exports decreased from 12.02 TWh in the Winter 2015/16 Period to 10.75 TWh in the Winter 2016/17 Period. This is partially explained by the higher average HOEP of the Winter 2016/17 Period. As well, the energy sales agreement with Hydro-Québec that took effect January 1, 2017 impacted electricity trade between Ontario and Québec, as explored in greater detail in Chapter 4.

Figure 2-25: Net Exports by Intertie
May 2015 – April 2017
(GWh)

Description:

Figure 2-25 presents a breakdown of net exports from May 2015 to April 2017 to 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:

Net exports decreased relative to the Winter 2015/16 Period over every intertie other than Minnesota, which saw an increase in net exports of 182 GWh. Québec had the biggest change with an increase of net imports from 1,113 GWh to 2,511 GWh. Compared to the Winter 2015/16 Period, net exports on the New York, Michigan and Manitoba interties were all lower, as would be expected with a higher average HOEP in this period.

Table 2-6: Average Monthly Export Failures by Intertie & Cause
Summer 2016 & Winter 2016/17
(GWh & %)

Description:

Table 2-6 reports average monthly export curtailments and failures over the Winter 2016/17 Period and the Summer 2016 Period by intertie and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each intertie, excluding linked wheel transactions.[29]

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016
New York	326	278	0.9	1.0	6.2	5.7	0.3%	0.4%	1.9%	2.0%
Michigan	336	326	1.1	1.4	4.7	4.7	0.3%	0.4%	1.4%	1.4%
Manitoba	62	51	2.1	3.7	13.3	14.8	3.3%	7.2%	21.4%	29.1%
Minnesota	21	20	0.7	0.6	0.3	0.5	3.1%	2.7%	1.6%	2.6%
Québec	74	61	5.7	0.6	1.1	0.4	7.7%	1.1%	1.5%	0.7%

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.

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

Commentary and Market Considerations:

The Manitoba intertie continues to have an MP Failure rate significantly above that of all other interties. While the MP Failure rate at this intertie showed a modest decrease from the Summer 2016 Period, it remained an order of magnitude above that of all other interties.

The Québec intertie saw a significant increase in ISO-curtailed transactions in the Winter 2016/17 Period, caused by an increase in reliability-related curtailments in December, January and February.

Table 2-7: Average Monthly Import Failures by Intertie & Cause
Summer 2016 & Winter 2016/17
(GWh & %)

Description:

Table 2-7 reports average monthly import failures and curtailments over the Winter 2016/17 Period and the Summer 2016 Period by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Intertie	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016	Winter 2016/17	Summer 2016
New York	3	21	0.1	0.1	0.0	0.2	1.5%	0.4%	1.2%	1.1%
Michigan	2	6	0.1	0.1	0.2	1.6	2.6%	1.1%	11.2%	27.5%
Manitoba	32	28	4.0	5.6	0.2	0.4	12.4%	19.7%	0.7%	1.3%
Minnesota	9	2	0.2	0.1	0.7	0.2	2.2%	7.4%	8.3%	11.8%
Québec	179	196	1.4	2.5	0.1	0.2	0.8%	1.3%	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 MISO interties (Michigan, Manitoba and Minnesota) generally maintained a higher frequency of import failures compared to New York and Québec. However, all three MISO interties generally experienced decreases in failure rates compared to the previous period.

Chapter 3: Analysis of Anomalous Market Outcomes

1 *Introduction*

This chapter examines the market outcomes associated with anomalous prices and payments from November 1, 2016 – April 30, 2017 (Winter 2016/17 Period), making comparisons to the November 1, 2015 – April 30, 2016 period (Winter 2015/16 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, Operating Reserve (OR) payments and Intertie Offer Guarantee (IOG) payments. All of the above payments are recovered from Ontario 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 Winter 2016/17 Period, with comparisons to the Winter 2015/16 Period.

Table 3-1: Summary of Anomalous Events
Winter 2015/16 & Winter 2016/17
(Number of events)

Anomalous Event Threshold	Winter 2016/17	Winter 2015/16
HOEP > $200	20	5
HOEP ≤ $0	1,065	1,427
Energy CMSC > $1 million/day	0	0
Energy CMSC > $500,000/hour	0	0
OR Payments > $100,000/hour	24	5
IOG > $1 million/day	0	0
IOG > $500,000/hour	0	0

1.1 *Summary of High-Price Hours*

During the Winter 2016/17 Period, there were 20 hours when the HOEP was greater than $200/MWh and 24 hours when OR payments exceeded $100,000. These hours were largely the result of limited real-time supply capable of responding to some combination of the following unforeseen conditions:

- Demand under-forecast (demand higher than forecasted);
- Variable generation shortfall (actual output below forecast); and

- Unplanned generator outages.

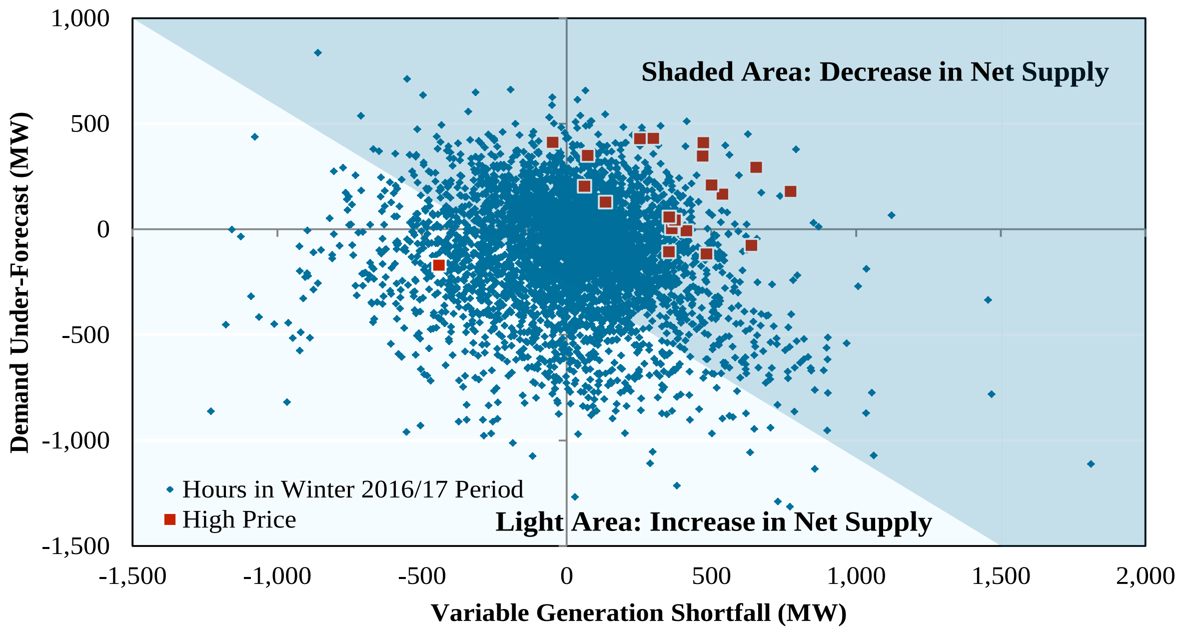
Other factors, such as inaccurate schedules for wind and solar resources resulting from the disabling of the forecasting tool (discussed below), also contributed to high prices in some hours.

Additionally, a significant number of hours in the Winter 2016/17 Period—including some of the high-price hours—likely had prices affected by an unintended consequence associated with the IESO's integration of Demand Response Auction resources into the unconstrained (price-setting) sequence. This issue caused demand from Demand Response Auction resources to be overstated, at times adding over 200 MW of fictitious demand to the unconstrained sequence. This additional "demand" would have led to increased prices in the affected hours. The Panel is researching this issue further, including the possibility that it affected pricing outcomes since the integration of the Demand Response Auction resources in May 2016. The Panel understands that the IESO has since addressed this unintended consequence.

While high prices are expected to be associated with high market demand conditions, most of the high-price hours in the Winter 2016/17 Period occurred during periods of relatively low or moderate market demand, ranging from 16,400 to 20,900 MW. In these hours, ample supply conditions in pre-dispatch resulted in relatively low prices; consequently, few gas-fired facilities were committed in the lead-up to real-time. With few gas-fired facilities online to provide flexibility and OR, the system had limited ability to respond to unforeseen conditions that arose in real-time. This necessitated the use of increasingly expensive sources of supply, resulting in high HOEPs and high OR payments.

As illustrated in Figure 3-1, the majority of the 20 high-price hours, marked in red, had a decrease in net supply in real-time. That is, the sum of demand under-forecast and variable generation shortfall was positive in those hours, creating tighter supply conditions in real-time relative to pre-dispatch.

Figure 3-1: HOEP by Net Supply Conditions November 2016 – April 2017 (MW)



As indicated by the leftmost red point, there was one high-price hour that took place during an hour with a net increase in supply: this was Hour Ending (HE) 17 on December 11, 2016. This hour was similar to the other high-price hours in that an unexpected event, in this case an 831 MW nuclear outage, necessitated the dispatching of higher-priced supply in the absence of gas-fired generation online. Real-time demand increased modestly during the latter intervals of the hour, but enough to require the IESO to schedule resources that set the Market Clearing Price (MCP) at $1,500/MWh and $1,999/MWh during intervals 9 and 10, respectively. The result of these high-price intervals was a HOEP of $368/MWh.

The two hours with the highest prices in the Winter 2016/17 Period exemplify the general conditions that contributed to the high prices described throughout this section. On March 11, 2017, the HOEP for HE 20 was $1,823/MWh and on April 12, 2017, the HOEP for HE 8 was $1,711/MWh. These were the second and third highest HOEPs since the market opened in May 2002. The following sections describe these two hours in greater detail.

Market Circumstances during HE 20 on March 11, 2017

During HE 20 on March 11, 2017, the HOEP was $1,823/MWh, the second highest since market opening. The high price occurred during an hour in which average market demand was relatively modest at 20,885 MW.[30] While demand was modest, there were unexpected conditions that made real-time supply much tighter than in PD-1 and ultimately triggered the high prices. The unexpected conditions included more than 400 MW of variable generation shortfall, 100 MW of unforecasted demand and a number of forced outages at hydroelectric facilities resulting in the loss of 118 MW of capacity following PD-1. In all, there was a net supply decrease of more than 600 MW in real-time relative to PD-1.

When the net supply decreased, there was insufficient available capacity to replace it, largely because most of the online gas generators and available hydroelectric facilities had already been scheduled to provide close to their full offered capacity in some combination of energy and OR in the final pre-dispatch run. The supply scarcity resulted in an OR shortfall because there was insufficient supply to meet both energy demand and OR requirements. The result of this shortfall was an MCP of $1,999/MWh or $2,000/MWh during the first 10 of the 12 intervals during the hour.

The quantity of available capacity was also impacted by offer revisions on the Québec intertie. In a number of the HE 20 pre-dispatch hours, one trader (Trader A) had large quantities of imports scheduled. However, two hours before real-time, just before the closing of the window in which market participants can change their offers and bids, Trader A modified its import offers so that more than 500 MW of imports scheduled in the previous pre-dispatch were no longer available. This loss of supply caused the pre-dispatch price to increase from $39/MWh in one pre-dispatch run to $57/MWh in the next. The continued modest pre-dispatch price implies that the IESO's dispatch algorithm was predicting the market would still have adequate supply, despite the change in the import offers.

The last minute nature of Trader A's revisions prevented other market participants from adjusting their offers in response to the increased pre-dispatch price. The inability to change

[30] For comparison, the peak hourly average market demand was 23,925 MW during the Winter 2016/17 Period.

offers is particularly relevant for gas-fired generators, who regularly remove their offers when observing low pre-dispatch prices. Had Trader A withdrawn its offers earlier, pre-dispatch prices would have been higher earlier, and as a result fewer gas-fired generators may have chosen to withdraw their offers. With more gas-fired facilities offered into the market due to fewer withdrawals and higher pre-dispatch prices, the commitment of a gas-fired generator is more likely. Additionally, importers may choose to submit offers only when they observe profitable pre-dispatch spreads between jurisdictions. In HE 20 on March 11, 2017, additional gas-fired generation online and/or additional import offers would have increased available capacity and helped mitigate the eventual price spike.

Market Circumstances during HE 8 on April 12, 2017

During HE 8 on April 12, 2017, the HOEP was $1,711/MWh. This hour had the third highest HOEP since market opening despite relatively low market demand of 17,301 MW. This was largely due to low pre-dispatch prices (around $6/MWh for the last few pre-dispatch runs) that indicated amply supply conditions, which had the effect of limiting available supply by not committing any non-quick start gas-fired generators.

When real-time arrived, Ontario demand was approximately 350 MW above the PD-1 forecast and wind supply was more than 450 MW below forecast, creating a decrease in net supply of more than 800 MW. The net supply decrease was greater than the available capacity online, resulting in the IESO being unable to acquire adequate OR during intervals 3-7 and 9-10. The OR shortfall resulted in the MCP clearing around $1,999/MWh for most of the hour, and a HOEP of $1,711/MWh.

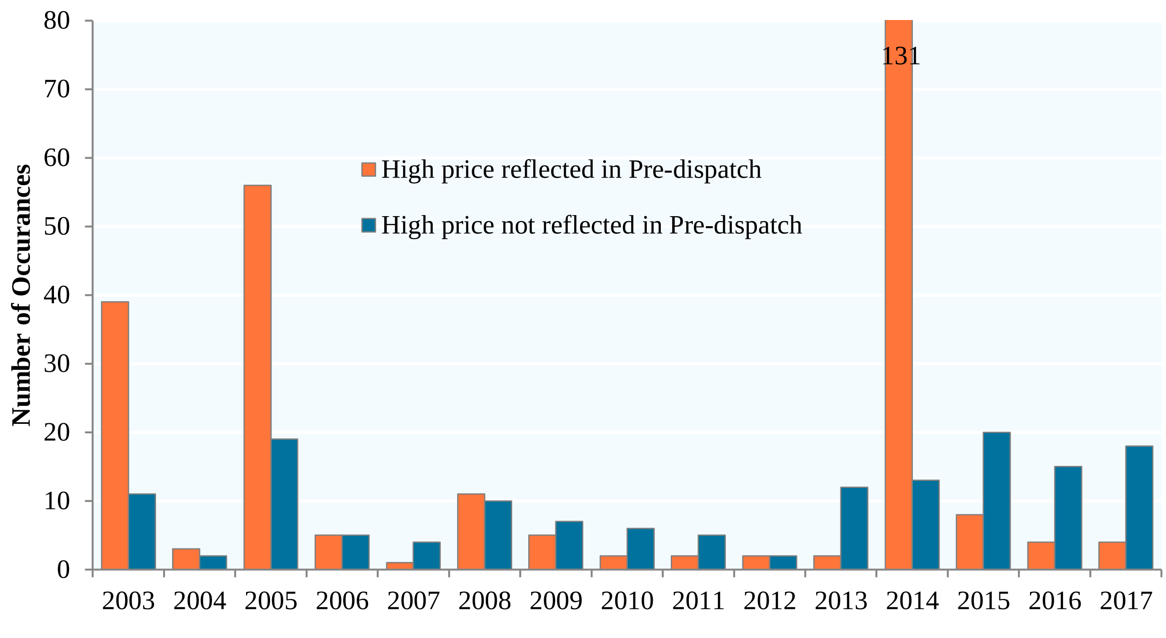
The Panel's analysis also suggests that this hour was affected by the unintended consequence associated with the IESO's integration of Demand Response Auction resources into the unconstrained sequence referred to above. This caused demand from Demand Response Auction resources to be overstated, adding fictitious demand to the unconstrained sequence and contributing to higher prices. As noted earlier, the Panel is researching this issue further.

1.2 *Unpredicted High-Price Hours are on the Rise*

As discussed above, the Winter 2016/17 Period saw two of the three highest HOEPs since market opening in 2002. Prices spikes precipitated by variable generation and demand forecast errors can be particularly extreme, and they are occurring on an increasingly regular basis. In fact, there have been more intervals priced at the maximum market clearing price in 2016 and the first half of 2017 than over the rest of the history of the market combined.

Increasingly, instances of high real-time prices are not foreseen or reflected in pre-dispatch prices. Figure 3-2 displays the number of hours in each year in which the HOEP was more than $200/MWh, segmented by whether or not the one-hour ahead pre-dispatch price was within $150/MWh of the real-time price.

Figure 3-2: Frequency of High Price Hours (HOEP greater than $200/MWh) 2002 – 2017 (Number of hours)



Notably, the nature of high price hours has changed. As can be seen in the years following market opening, high prices were typically reflected in pre-dispatch prices. More recently, with the exception of the polar vortex in 2014, a significant majority of high prices were preceded by much lower pre-dispatch prices. This increase in the frequency of unpredicted high market prices has been driven by decreased availability of flexible supply in real-time, itself largely driven by the retirement of coal-fired resources and the decreased utilisation of gas-fired resources—as well as by forecast uncertainty associated with increased variable generation.

Flexibility describes the ability of the market to respond to rapid changes in supply or demand, particularly those that occur within a dispatch hour. When discussing generation, this can be measured by the time it takes to start a generator, the ability of the generator to alter its output from interval-to-interval and the frequency with which it can make these changes. A lack of flexibility on the system can result in high or volatile market prices, reflecting the need to use more expensive, faster ramping resources or, in the case of significant forecast error, reflecting a scarcity of available supply resulting in OR shortfalls. Recently, record high prices have occurred when there was a limited availability of flexible supply.

The following section analyzes the long-term trends in the Ontario market which have led to more frequent instances of unpredicted high prices. Specifically, the increased forecast error associated with higher penetration of variable renewable energy (primarily wind and solar) and the decreasing real-time availability of flexible resources are discussed.

Increased Forecast Error Associated with Variable Generation

Since market opening in 2002, the supply mix has undergone significant changes. In 2003, the Government of Ontario committed to phasing out coal-fired electricity generation. The gradual elimination of coal-fired generating capacity culminated in 2014, when the Thunder Bay Generating Station closed. To replace these coal-fired generators, significant gas-fired generation (5,500 MW) and refurbished nuclear (1,500 MW) capacity was introduced. Additionally, the Renewable Energy Supply and Feed-in-Tariff contract programs have added more than 4,000 MW of grid-connected wind and solar generators.[31]

As the quantity of wind and solar generation in the market has increased over the past decade, it is increasingly displacing output from flexible hydroelectric and gas-fired generators, which offer into the market at higher prices. Wind and solar resources bring distinct challenges not

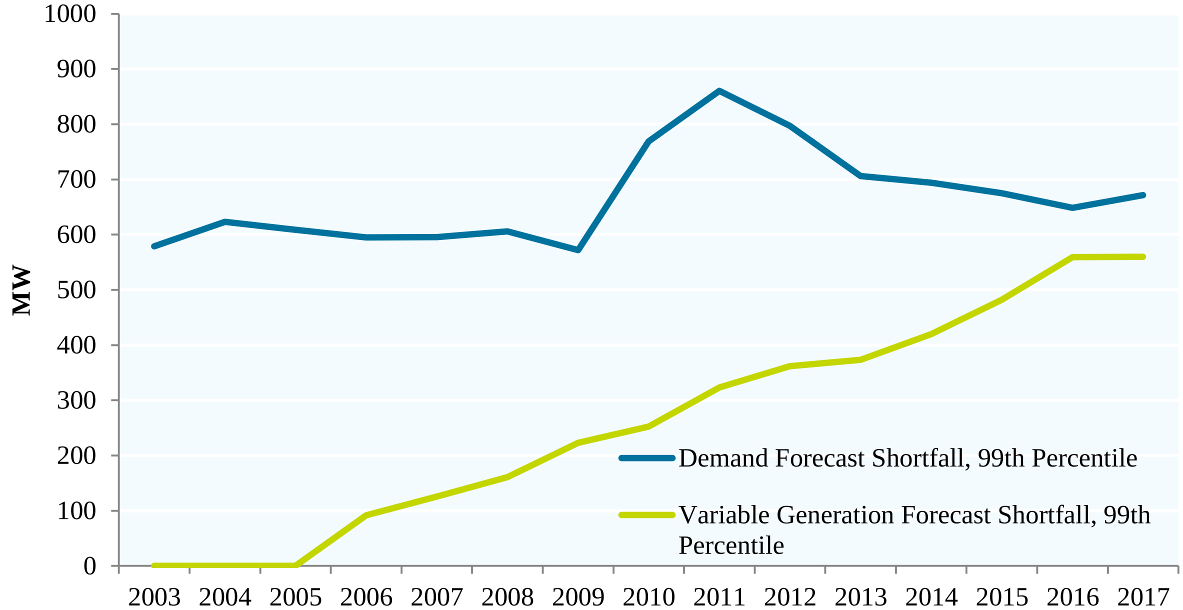
[31] Grid-connected resources participate in IESO-administered markets and receive dispatch instructions from the IESO. In addition to the 4,000 MW of grid-connected wind and solar, Ontario has also gained 2,500 MW of distribution-connected wind and solar, which are non-dispatchable and serve to offset demand on the grid.

posed by fossil fuel-fired generation, primarily because they are variable (sometimes there is no wind and little sunshine) and unpredictable (it is difficult to predict how windy and sunny it will be).

This adds to other major sources of forecast error that have existed since market opening, as discussed in Table 2-2 in Chapter 2. These include demand forecast uncertainty, self-scheduling resources' deviation from their submitted schedules, import and export transaction failures or curtailments and short-notice outages. Figure 3-3 displays the 99th percentile of hourly demand and renewable resource forecast shortfall in each year since market opening.[32] The 99th percentile was used to approximate the most significant forecast shortfall, while excluding hours when there were tool issues that interfered with the use of the forecast.

[32] In this context, demand under-forecast is measured as the difference between the PD-1 forecasted demand and actual demand, treating HE 6-9 as ramp hours year-round, and HE 17 and 18 as ramp hours in November, December and January (in February 2017 the IESO switched to dynamic demand forecasting in which ramp hours change daily; due to data limitations the Panel has not captured this change in Figure 3-3). During ramp hours, the forecasted hourly peak demand is used as the pre-dispatch quantity, in place of the hourly average. For renewable resources, forecast shortfall is measured as the difference between the PD-1 forecast and the real-time unconstrained quantity of wind and solar resources, excluding commissioning resources and all hours in which resources were partially or fully uneconomic.

Figure 3-3: Hourly Forecast Error by Year
2002 – 2017
(MW)



Forecast error associated with grid-connected variable generators has increased as capacity has been added. In the worst hours, variable generation forecast error can be well in excess of 500 MW. Even here, the impact of variable generation forecast error is understated, as forecast error associated with distribution-connected variable generators is captured as demand forecast error (from an IESO grid perspective, generation from distribution-connected resources appears as a reduction in demand from that distributor). The Post-2011 improvements in the quality of demand forecasts are in part due to the implementation of centralized wind forecasting in 2013.

Decrease in the Real-Time Availability of Flexible Resources

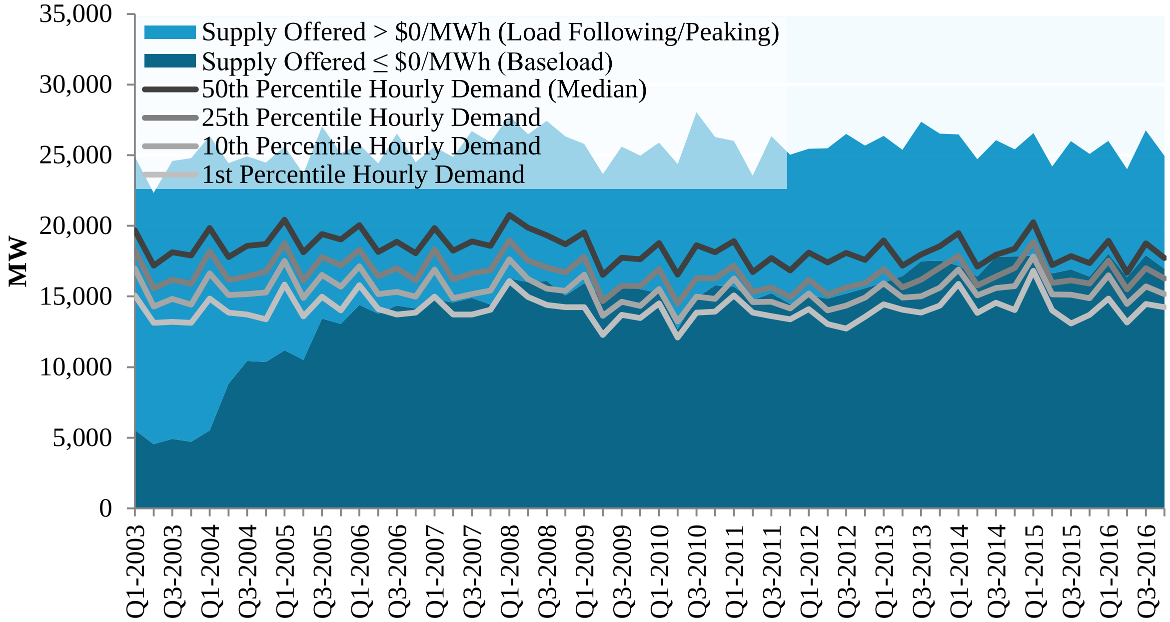
To ensure supply and demand remain balanced, the IESO dispatches generation to increase or decrease production in response to the forecast errors discussed above. Certain generators are considered “baseload”, meaning they operate constantly and at a steady output. This includes a significant percentage of Ontario’s 8,480 MW of hydroelectric generation capacity, which either has no storage capacity or minimum output requirements due to environmental regulations, as well as most of its nuclear fleet. Along with variable renewable generators whose output is unpredictable but that can be dispatched down to manage surplus generation (such as wind generators), baseload resources typically submit negatively-priced offers to ensure dispatch.

Ontario also has significant load-following generation capacity, including its non-baseload hydroelectric generation capacity and most of its 10,277 MW of gas-fired generation capacity. Unlike baseload and variable generators, these resources have the ability to increase or decrease production in response to changes in supply and demand conditions. It is these load-following resources that provide the system with potential flexibility when they are online and available to respond to dispatch.

Despite the ample installed capacity of potentially flexible resources, there has been a significant increase in the number of high-price hours resulting from a lack of system flexibility. Many of the potentially flexible resources face limitations that may preclude them from providing flexibility, including the long lead time required when starting a gas-fired generator and the environmental and safety constraints faced by hydroelectric generators.

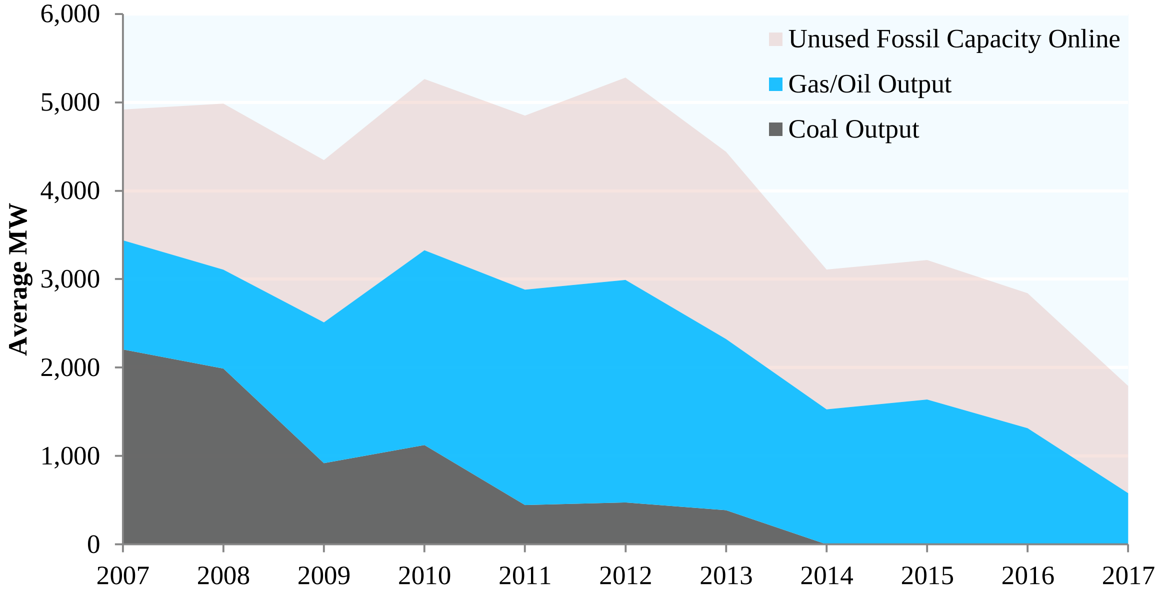
Over the past decade, Ontario's stock of baseload generators has increased. Concurrently, domestic demand on the IESO-controlled grid has decreased as a result of increases in energy efficiency, conservation and distribution-connected generation, as well as reduced industrial consumption. This trend can be seen in Figure 3-4 below, which groups baseload and variable generators together on the basis of their negative-priced offers.

Figure 3-4: Available Capacity by Offer Price & Demand
2003 – 2017
(MW)



Lower demand and more baseload generation resulted in a higher fraction of demand being met by baseload generators with a limited ability to alter their output. This increase reduced the amount scheduled of flexible resources, primarily gas-fired generators, leaving the market less able to respond to unforeseen changes in supply and demand due to forecasting errors. Figure 3-5 displays the production and available capacity of flexible fossil-fired generators by year (i.e. fossil-fired generators that are online to respond to forecast error).

Figure 3-5: Average Output & Online Capacity of Gas-, Coal- & Oil-Fired Generators 2006 – 2017 (MW)



More baseload supply offered at negative prices and lower demand for electricity have resulted in lower prices and thus fewer fossil-fired generators being online and able to provide flexibility. As discussed further in Chapter 4, the introduction of contracted imports from Québec has the potential to affect system flexibility.

While Ontario has significant hydroelectric generation capacity, much of this capacity is frequently not offered into the market in a manner conducive to providing flexibility. In 2016, 54% of hydroelectric generation was baseload, offering into the market at -$5/MWh or less. In addition to this significant capacity of baseload hydro, the Panel has observed a trend of increasing numbers of hydroelectric “lockouts”, instances when generators notify the IESO control room that their output cannot be changed. The Market Rules allow generators to request a fixed output in order to manage conditions relating to safety, equipment damage or applicable laws at their facility. Similar to supply offered at negative prices or non-quick start facilities that are offline, locked out hydro facilities are unable to alter their output in response to price signals.

Conclusion

As discussed above, significant variable generation and demand forecast error—coupled with limited flexible resource availability—contributed to the high prices on March 11 and April 12, 2017, as well as likely to other high-price hours during the Winter 2016/17 Period. Lower demand and more baseload supply, which contribute to low pre-dispatch prices, have resulted in fewer flexible generators being online, meaning that more expensive resources were needed to respond to unpredicted changes in variable generation output or demand. These structural changes to the supply mix in IESO-administered markets have resulted in unpredicted price spikes becoming more common. A greater number of high-price events are now attributable to structural factors in the market, as opposed to transitory events such as unexpected outages. While technological advances in forecasting and energy storage are probable, the trend of unpredicted high price events is likely to continue as additional variable generators enter the market.

As discussed in more detail in Chapter 1, the IESO has made changes to its OR requirements in an attempt to get more flexible generation online. By increasing OR requirements during hours where additional flexibility could be needed, such as hours with high forecasted output from variable generators, prices would, ideally, increase sufficiently to result in additional gas-fired generators being committed to provide the needed flexibility.

1.3 Summary of Non-Positive Price Hours

This section analyzes the drivers of non-positive prices in IESO-administered markets during the Winter 2016/17 Period, as well as the longer term trend towards more non-positive price hours.

Non-Positive HOEPs in the Winter 2016/17 Period

Non-positive HOEPs (zero or negative) are typically the result of abundant low-marginal cost generating capacity offering at non-positive prices, at times in combination with relatively low demand. Of the 4,344 hours during the Winter 2016/17 Period, there were 1,065 hours (25%) when the HOEP was non-positive. This represents a decrease compared to the Winter 2015/16 Period, when there were 1,427 non-positive HOEPs (33%). An increase in outages at baseload generators during the Winter 2016/17 Period contributed to less available baseload capacity and fewer non-positive price hours. Baseload generators typically offer supply at non-positive prices;

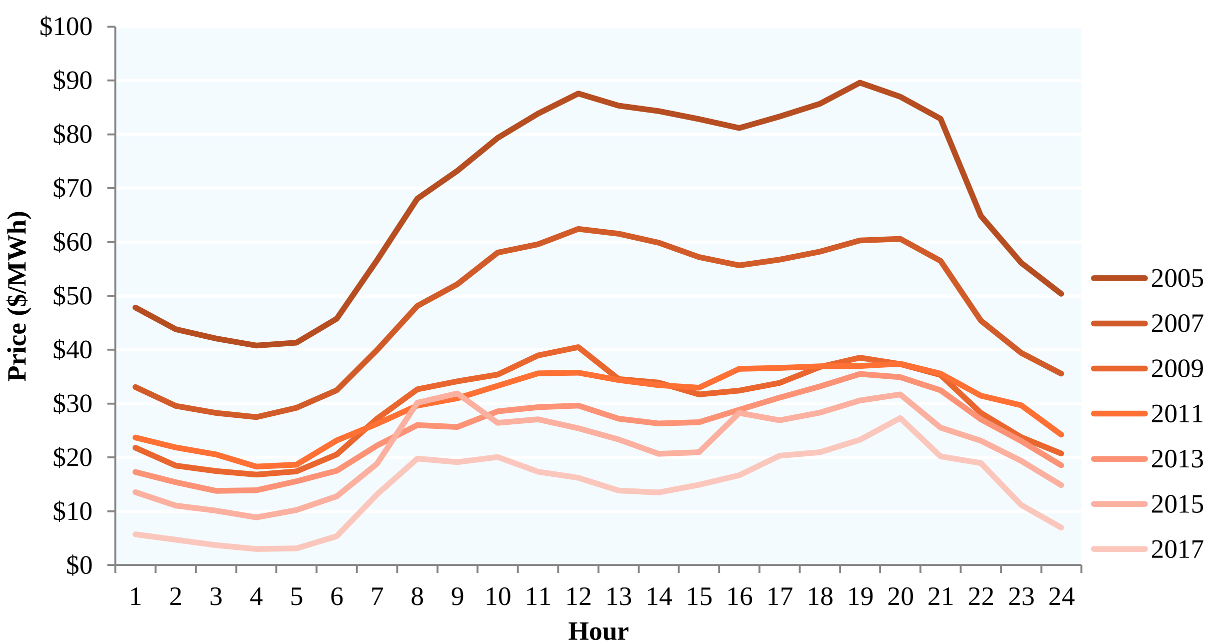
on average, 534 fewer megawatts were offered at $0/MWh or below when comparing the Winter 2016/17 Period to the Winter 2015/16 Period. This reduction in negatively-priced supply was in large part the result of an extended outage at the Darlington nuclear station, as it was removed from service in October 2016 for refurbishment.

Trend in Non-Positive HOEPs over the Years

Average market prices have been gradually decreasing in the Ontario electricity market since their peak in 2005, reaching an all-time low monthly average of $2.56/MWh in May 2017. Low market prices are becoming commonplace, as shown in Figure 2-5 earlier. This section provides an overview of the trends that have contributed to lower prices, specifically discussing changes in the generation fleet and the impact of contracting and regulation on generators' participation in the IESO-administered markets.

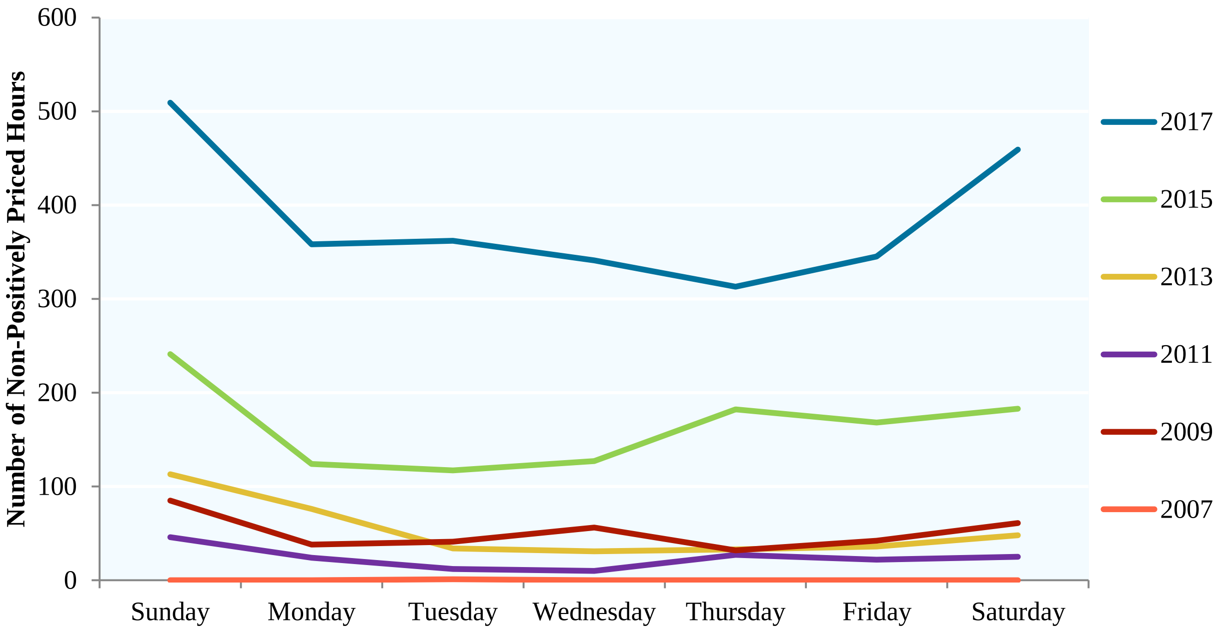
Reductions in the market price over time can be seen in a comparison of the daily profile of prices by year in Figure 3-6.

Figure 3-6: Average HOEP by Year & Time of Day
2005 – 2017
($/MWh)



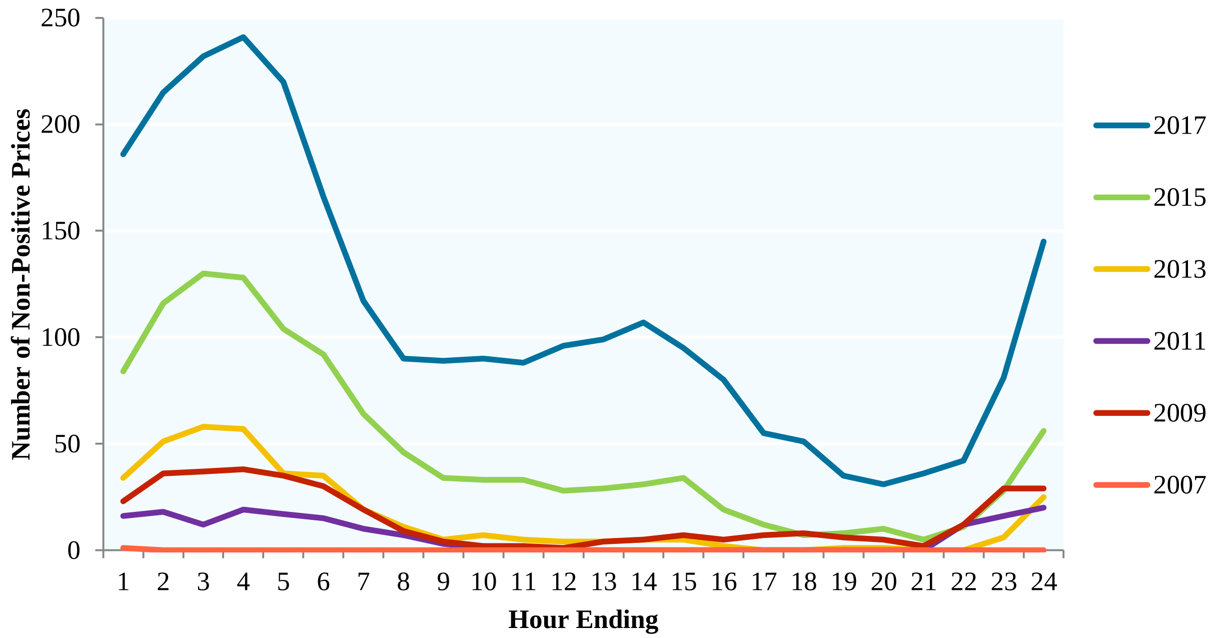
The 2017 calendar year as a whole had the lowest average HOEP since market opening at $14.14/MWh. Historically, Ontario has typically experienced low prices during periods of low demand overnight and on weekends, but increasingly low prices are also occurring at other times. Non-positive price hours have occurred when market demand was as high as 21,844 MW.[33] In 2017, 23% of non-positive price hours occurred during on-peak hours;[34] 64% of non-positive price hours now occur on weekdays, mostly overnight. Figures 3-7A and 3-7B display the number of non-positive price hours by day of the week and time of day.

Figure 3-7A: Non-Positive Price Hours by Day of Week
2007 – 2017
(Number of hours)



[33] This non-positive price hour occurred in 2016; the market demand of 21,844 MW during the hour exceeded market demand in over 93% of all hours that year.
[34] The IESO's on-peak hours are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays).

Figure 3-7B: Non-Positive Price Hours by Time of Day
2007 – 2017
(Number of hours)



While non-positive prices used to occur almost exclusively during Surplus Baseload Generation conditions overnight, they are now occurring during all hours of the day as Ontario's supply from baseload generators has increased and demand has fallen. Non-positive prices almost never occurred during daytime hours before 2014.

Why Generators Submit Negative-Priced Offers

The Market Rules limit generators' offers to between $2,000/MWh and -$2,000/MWh, with negative-priced offers representing a generator's willingness to pay consumers for the opportunity to generate electricity. The Market Rules further limit the offers of some generators by way of resource-specific offer price floors. Generators may submit negative-priced offers to avoid costly reductions in output and shutdowns, to attract contracted or regulated revenues or to attract additional uplift payments, each of which is discussed below.

First, generators may submit negative-priced offers to avoid incurring costs associated with shutting down or reducing output. Baseload generators, specifically nuclear and some hydroelectric, have costs associated with reducing their output beyond a certain threshold. Under such circumstances, a generator may use negative offer prices to represent its willingness to pay to continue producing electricity and avoid incurring shutdown costs. Shutdown costs may include the incremental operational costs associated with the shutdown and subsequent start-up process, as well as any lost profit opportunities associated with remaining offline for a period before the unit can be safely restarted. For example, in some instances a nuclear generator may need to remain offline for three days after shutting down. Similarly, environmental regulations related to river flows may require certain hydroelectric generators to operate at minimum output levels; reducing output below these would induce costs associated with being non-compliant with these regulations.

Second, generators may submit negative-priced offers to ensure dispatch in order to receive contracted or regulated revenues. The contracts and rate regulation governing Ontario's hydroelectric and non-hydroelectric renewable generators provide payments based on generator output. For example, generators with FIT contracts are subject to a guaranteed flat rate per megawatt hour produced and, beyond a certain number of hours, for any production curtailed.[35] Rate regulation governing Ontario Power Generation's hydroelectric assets incents some responsiveness to market price signals by way of the Hydroelectric Incentive Mechanism,[36] however the rate structure may still incent production when spillage may otherwise be economic, particularly during long periods of moderate prices (as is frequently the case). While the Panel is unable to assess what the offer strategy for all individual generators would be absent production-based contract payments, resources may be less likely to submit negative-priced offers and to continue to produce during prolonged periods of low or negative prices.

Finally, generators may submit negative-priced offers in an attempt to get Congestion Management Settlement Credit (CMSC) payments. If a geographic area has a surplus of economic generation relative to the transmission capacity available to move that energy to demand centres, the IESO will pay market participants to not produce. These payments

[35] FIT contracts contain a cap on the number of hours a resource can be curtailed without receiving its contracted rate of payment for its forgone production. Prior to this cap being reached, resources with FIT contracts have an incentive to ensure dispatch (avoid curtailment) by offering into the market as low as allowed by the price floors in the Market Rules.

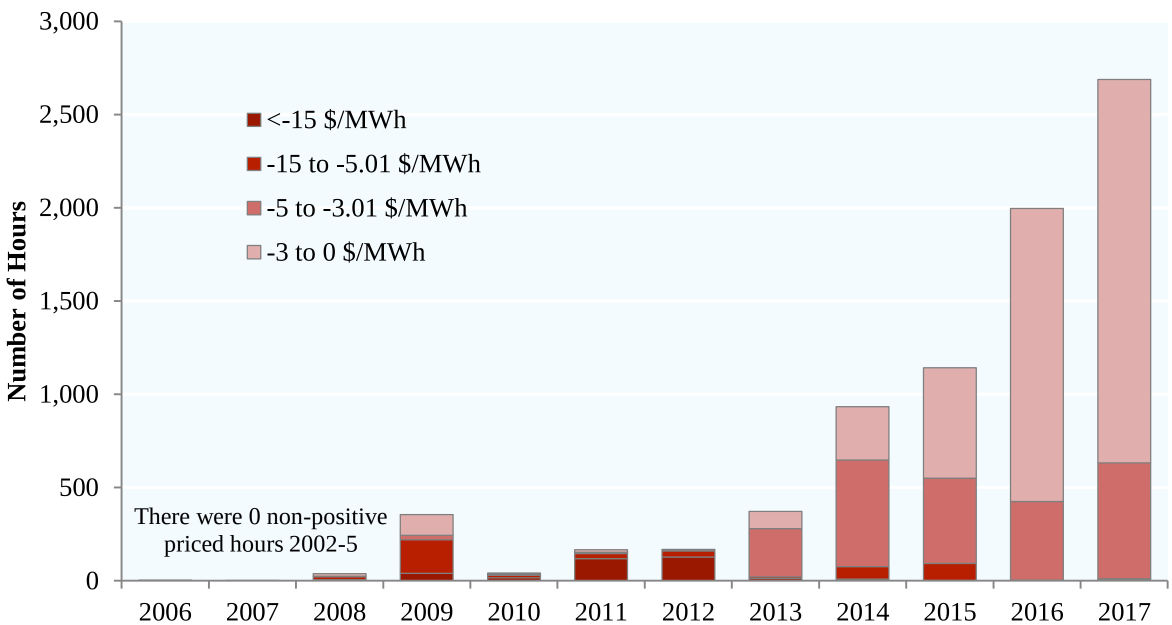
[36] Prescribed hydroelectric assets receive a flat rate per megawatt hour of production, plus the MCP times the difference between their current and monthly average production. For periods of sustained low or moderate prices, the first term (the flat regulated rate) will dominate the second. For more information on how regulated payments to hydroelectric generators affect production decisions, see pages 211-214 of the Panel's July 2009 Monitoring Report, available at: https://www.oeb.ca/oeb/_Documents/MSP/msp_report_200907.pdf.

notionally correspond to the market participant's forgone profit, measured as the difference between the market price and their offer price. If a market participant expects to be constrained off, the incentive is to submit offers as low as possible while still being constrained off.[37] This incentive to offer below cost can contribute to increases in the quantity of supply offered at negative prices.

Magnitude of Negative Prices

When demand can be met exclusively by generators with non-positive priced offers, non-positive prices will occur. As Ontario's supply of baseload generation has increased and demand has fallen (as further discussed in section 3.1.1.3), non-positive price hours have become more frequent. This trend is shown in Figure 3-8, which categorizes low HOEPs based on the most recent price floors for nuclear and variable renewable generation, which are discussed later, to give a sense of how frequently each resource type is curtailed.

Figure 3-8: Non-Positive HOEPs by Year
2006 – 2017
(Number of hours)



[37] This behaviour, called "nodal price chasing", is discussed in detail in pages 119-160 of the Panel's April 2015 Monitoring Report, available at: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf.

While the frequency of non-positive price hours has increased, these prices have become less negative because of changes to the Market Rules (explained below). As wind generators began to enter the market following the enactment of the *Green Energy and Green Economy Act, 2009*, the frequency of negative prices began to increase. At first, this was due to wind and solar resources not being dispatchable and instead being scheduled automatically, which decreased the amount of dispatchable generation required, allowing cheaper resources to set the MCP. This caused nuclear resources to become marginal more often in the ensuing years, and nuclear generators tend to offer heavily negative prices due to their contracts or rate regulation (which guarantee a flat rate for every megawatt hour they produce). Receiving the same payment regardless of the market price incents price taking behaviour, where these resources offer at the lowest possible price to ensure they are dispatched to produce.

Up until 2013, it was not uncommon to have -$125/MWh prices. To counteract the impact of contract incentives, the IESO introduced offer price floors for a number of resource types. Starting in 2013, when wind and solar resources became dispatchable, offers from wind resources were subject to price floors of -$10/MWh for 90% of their capacity and -$15/MWh for the remaining 10% of capacity, while all offers from solar resources were subject to a price floor of -$10/MWh. The price floors had the effect of moving wind up the supply stack, significantly reducing the need to curtail inflexible nuclear or baseload hydro and effectively eliminating prices below -$15/MWh. In 2016, the price floors for wind and solar were adjusted to -$3/MWh for all of solar and 90% of wind capacity and -$15/MWh for the remaining 10% of wind capacity. As a result of the new price floors, non-positive prices became less negative in 2016 and 2017, with the majority falling between $0/MWh and -$3/MWh, the price at which wind or solar are curtailed, and a minority between -$3/MWh and -$5/MWh, the price at which "flexible nuclear" capacity is usually offered and thus the price at which it is dispatched to a reduced level of output.

Changing Resource Mix Creates Non-Positive Prices

The introduction of lower marginal cost generators and a decrease in the level of market demand have contributed to more frequent non-positive HOEPs. A significant number of wind and solar resources, which offer into the market at negative prices, have entered the market in the past decade. Through refurbishments, Ontario's capacity of inflexible nuclear generation offering into the market at negative prices has grown. Lower market demand has increased the frequency with which non-positive priced resources can satisfy demand during a given hour, as shown in Figure 3-4.

While the scheduled quantity of resources with low or negative offer prices in real-time (imports, nuclear, wind, solar, and baseload hydro) has only increased slightly over the past decade, these resources have become the price-setting units in the market much more frequently. In 2003 and 2004, coal- and gas-fired resources set the price in 77% of intervals, while nuclear never set the price and wind and solar were not dispatchable, meaning they *could not* set the price. In 2016 and 2017, coal was gone from the market and gas set the price in only 30% of intervals, while wind, solar and nuclear set the price 39% of the intervals.

Impact of Long-Term Contracting and Regulation

In most commodity markets, including other competitive electricity markets, an environment in which prices are zero or negative upwards of 30% of the time would likely be unsustainable. In the short- and medium-run, firms would reduce production and temporarily shut down to avoid losing money. If reduced production still resulted in some firms being unprofitable, these firms would exit the market. Despite an increasing number of non-positive price hours in recent years, generation capacity in Ontario has grown.

In the IESO-administered markets, all generation receives some form of out-of-market payment to ensure revenue sufficiency (these payments are largely recovered through the GA). For private generators, this consists of long-term contracts (mostly between 20 and 40 years in length) with the IESO or the Ontario Electricity Financial Corporation. For assets owned by Ontario Power Generation, rates are regulated by the Ontario Energy Board. The effect of these out-of-market payments is two-fold.

In the short-run, some of these contracts and this regulation have the effect of lowering the market price by incenting production that would otherwise be uneconomic. The short-run incentives provided by the contracts are discussed above, under the heading *Why Generators Submit Negative-Priced Offers.*

In the long-run, contracting and rate regulation ensure that generators recover their fixed costs regardless of the energy market revenues they receive. This incents firms to remain in the market when they might otherwise exit.

The introduction of an incremental capacity auction (as part of the IESO's Market Renewal initiative) will provide a market-based opportunity for generators to recover their fixed costs. That said, resources currently under contract or rate regulation will not participate in the auction.[38] As a result, the auction will not fully address the inefficiencies associated with having a surplus of baseload generation, at least until long-term contracts expire and regulation changes.

1.4 *Summary of Uplift Payments*

As noted in Table 3-1, there were no days or hours during the Winter 2016/17 Period that exceeded the Panel's IOG and CMSC thresholds. However, IOG payments in the period as a whole increased significantly from the Winter 2015/16 Period (discussed in greater detail below). There were 24 hours in which OR payments exceeded $100,000, the Panel's threshold for defining an anomalous hour.

Energy and OR markets are co-optimized to produce the lowest combined-cost outcome; as a result energy and OR prices are closely correlated. All of the 24 hours of anomalous OR payments in the Winter 2016/17 Period coincided with a HOEP of more than $80/MWh and similarly high OR prices. As a result of the co-optimization of energy and OR markets, OR payments tend to exceed $100,000 when energy and, correspondingly, OR prices reach around $80.

2 *Analysis of Other Anomalous Events*

Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. Since its report covering the period May to October 2016, 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

[38] For more information on design decisions regarding the Incremental Capacity Auction, see the IESO's *Market Renewal – Incremental Capacity Auction* webpage, available at: http://www.ieso.ca/en/sector-participants/market-renewal/market-renewal-incremental-capacity-auction.

relative to the Market Objective[39] and the Market Rules, the novelty and frequency of an event, as well as the relevance of the outcome to current IESO initiatives and stakeholder engagements.

In the sections that follow, the Panel reports on two anomalous trends during the Winter 2016/17 Period: the recent increase in IOG payments and the market impacts of disabling the variable generator forecasting tool.

2.1 *Recent Increase in IOG Payments*

Background

The IESO's IOG program insulates importers from the risk associated with price fluctuations between the time imports are scheduled and the time they are settled. Intertie transactions are scheduled in either the Day-Ahead Commitment Process (DACP) or the final run of pre-dispatch (PD-1) one hour prior to real-time; however, they are settled on the real-time energy market clearing price (MCP). When fluctuations occur between day-ahead or pre-dispatch prices and the real-time MCP, this can result in an unexpected loss or gain on import and export transactions. The IOG provides importers with a guarantee that they will, at a minimum, recover their as-offered costs on import transactions. This mechanism was included in the Market Rules at market opening in 2002, at a time when Ontario had a much smaller supply cushion and was seeking to increase imports.

In the Winter 2016/17 Period, IOG payments totalled $10.42 million, a significant increase relative to the $0.92 million paid in the Winter 2015/16 Period and the $3.01 million paid in the Winter 2014/15 Period. Earlier winter periods have had higher IOG payments than the Winter 2016/17 Period. When comparing this winter period to the last, 90% of the increased IOG payments went to one market participant for transactions on the Ontario-Québec interties.

Analysis

There were no hours in the Winter 2016/17 Period that met the Panel's criteria for anomalous IOG payments (more than $500,000 in an hour or $1 million in a day); rather, there were many hours with $5,000-$70,000 in IOG payments. No single hour accounted for a significant portion

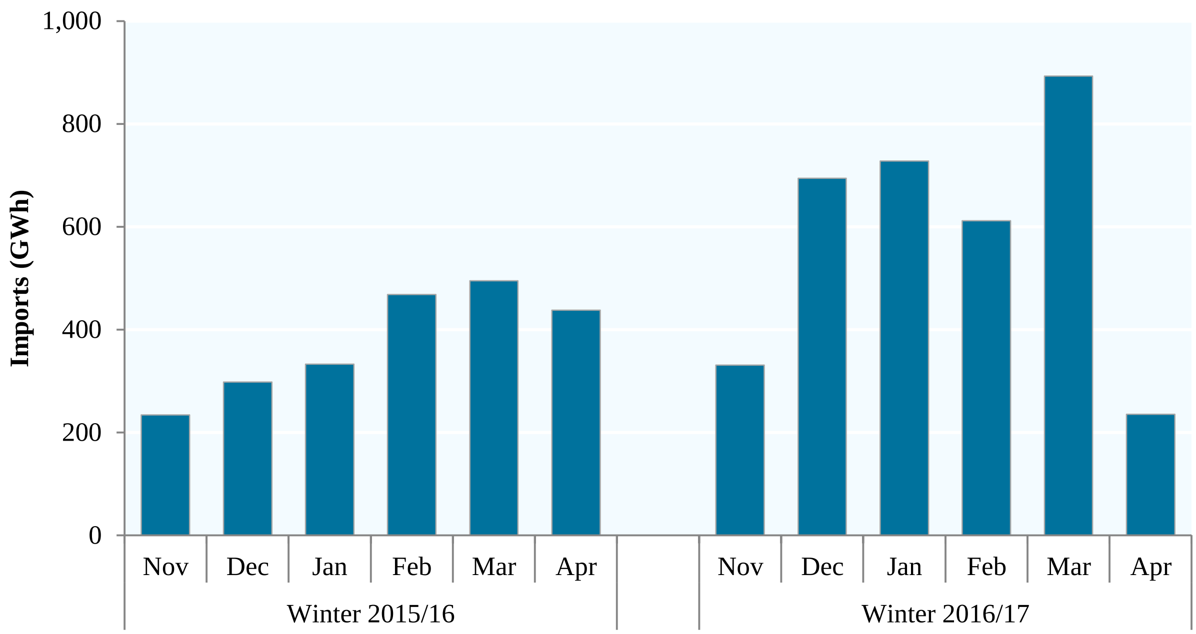
[39] The Market Objective of the IESO-administered markets is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

of total IOG payments made over the period. The significant increase in smaller, but more frequent, IOG payments can be largely explained by three factors: an increase in imports, an increase in imports scheduled in the DACP and an increase in the variation between PD-1 and real-time prices.

Increased Imports

The volume of imports and total IOG payments are closely correlated. The Winter 2016/17 Period had significantly higher import volumes when compared to the Winter 2015/16 Period, as shown in Figure 3-9.

Figure 3-9: Imports in the Unconstrained Schedule
Winter 2015/16 & Winter 2016/17
(GWh)

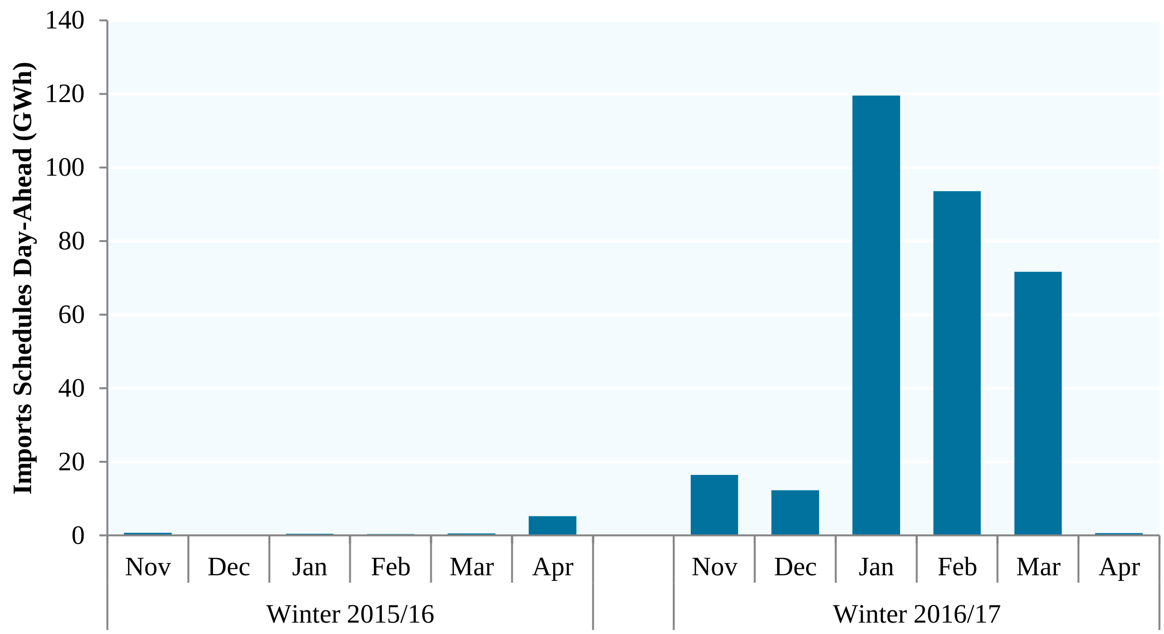


Imports in the Winter 2016/17 Period totalled 3.49 TWh, compared to 2.27 TWh in the Winter 2015/16 Period, representing a 54% increase. This increase in imports is largely attributable to higher average Ontario market prices in the Winter 2016/17 Period ($18.21/MWh) compared to the Winter 2015/16 Period ($9.08/MWh).

Increased Import Commitment in the Day-Ahead Commitment Process

When an import transaction is committed in the DACP, it is guaranteed to recover its as-offered costs as represented in its day-ahead offers. Imports are committed in the DACP according to day-ahead nodal prices in the constrained sequence; day-ahead there is no unconstrained sequence and thus no market clearing price, as there is in pre-dispatch and real-time. When real-time prices clear below day-ahead nodal prices, IOG payments are more likely; when more imports are committed day-ahead, the greater the sum of those IOG payments. Figure 3-10 compares day-ahead import commitments between the Winter 2015/16 and Winter 2016/17 Periods.

***Figure 3-10: Day-Ahead Import Schedules
Winter 2015/16 & Winter 2016/17
(GWh)***



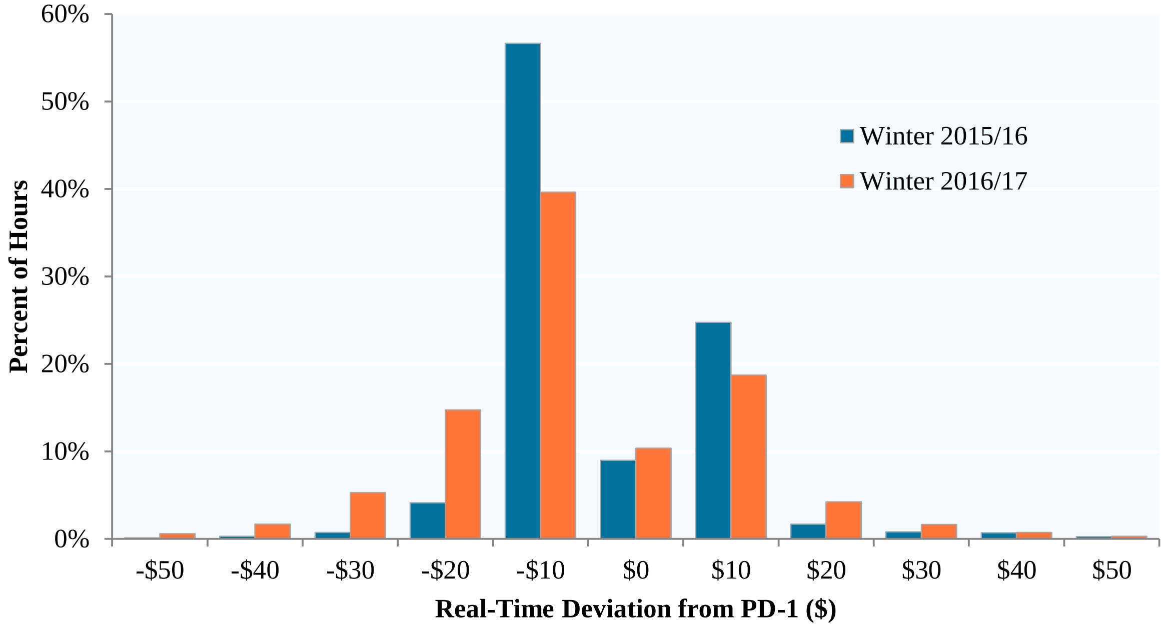
The Winter 2016/17 Period had a significant increase in the volume of DACP imports scheduled. The vast majority of the increase was attributable to Hydro-Québec, which has an agreement with the IESO that provides for electricity trade between the provinces over a seven-year period from 2017 to 2023. The increase in the volume of day-ahead scheduled imports is a result of the way in which those contracts require Hydro-Québec to offer into the IESO-administered markets: previously, these offers would typically have been offered after day-ahead or not at all. The Panel's analysis of the market impact of the agreement is set out in Chapter 4 of this report.

Imports committed in the DACP were, on average, more expensive than those committed in pre-dispatch. The average cost at which imports were committed day-ahead was $40/MWh, while the average pre-dispatch price at which imports were committed was $26/MWh. This resulted in imports that were committed day-ahead receiving, on average, twice as much in IOG payments per megawatt hour as imports scheduled in pre-dispatch. Overall, DACP imports accounted for 15% of total IOG payments in the Winter 2016/17 Period.

Deviation between PD-1 and Real-Time prices

Whenever the real-time MCP is less than the offer price at which an import was scheduled during PD-1, importers receive an IOG payment for the difference. For example, if the PD-1 price is $35/MWh, the real-time MCP is $20/MWh and an import was economic in pre-dispatch with an offer of $25/MWh, the importer would receive $5/MWh for having to sell $25/MWh power at the $20/MWh real-time MCP. Accordingly, significant price fluctuations from PD-1 to real-time can result in large IOG payments. Figure 3-11 compares the difference between the PD-1 and real-time prices for the Winter 2015/16 and Winter 2016/17 Periods (this information is also contained in Figure 2-8).

Figure 3-11: Real-Time MCP Deviation from PD-1 MCP
Winter 2015/16 & Winter 2016/17
(% of hours)



Real-time prices deviated more significantly from PD-1 prices in the Winter 2016/17 Period relative to the Winter 2015/16 Period. In the Winter 2016/17 Period, the total number of hours in which the price decreased from PD-1 to real-time remained relatively constant, however, the price decreases were often larger (as evidenced by the increase in hours with decreases in excess of $20/MWh). Larger price decreases contributed to greater IOG payments. This increase in deviation between PD-1 and real-time prices is in part due to an increase in the instances of imports setting the pre-dispatch MCP, as well as an increase in capacity forecasting variances.

When an import is economic in PD-1, its offer is subsequently moved to -$2,000/MWh in real-time to ensure it remains economic for the full hour in which it is scheduled. If this import was the price-setting offer in pre-dispatch, the real-time MCP will now be set by the offer below the import in the supply curve, resulting in a real-time MCP lower than the PD-1 price (absent other changes to supply and demand). Imports were the price-setting offer in PD-1 for 21% of hours in the Winter 2016/17 Period, compared to 8% in the Winter 2015/16 Period. This increase in instances of imports being the marginal unit in pre-dispatch contributed to increased PD-1 to real-time price deviation and the associated IOG payments.

Additionally, capacity of variable renewable energy was higher in the Winter 2016/17 Period than ever before. Differences between the PD-1 forecast of variable resources' output and their actual output in real-time contributes to price fluctuation between PD-1 and RT, which can result in IOG payments.

2.2 *Market Impacts of Disabling the Variable Generator Forecasting Tool*

In recent years, significant wind and solar generating capacity has been added to the transmission and distribution grids. While these resources provide clean and renewable energy, they rely on variable and unpredictable sources of fuel (and are thus referred to as "variable generators"). To mitigate the uncertainty associated with these resources, the IESO integrated centralized variable generator forecasting into its system operations. While centralized forecasting is considered industry best practice, unpredictable weather systems inevitably lead to forecast error. When forecast error does materialize, balancing system-wide supply and demand can be a challenge.

When facing significant variable generator forecast error in real-time, the IESO may temporarily disable the real-time forecasting tool (which continues to produce a forecast, but which is no longer relied upon as a scheduling input) instead relying on current actual variable generation output as an indicator of near-term future output. When the real-time forecasting tool is disabled, a design flaw often causes fictitious supply to be added to the unconstrained supply stack. This fictitious supply results in suppression of the MCP and price volatility. The impacts associated with disabling the variable generator forecasting tool are not transparent to market participants, as the IESO does not communicate when the forecasting tool is disabled or the effect it can have on price. Disabling the forecasting tool has also resulted in over $2 million in inflated CMSC payments to variable generators since mid-2016.

The sections that follow provide an overview of the purpose, process and outcomes of disabling the variable generator forecasting tool. Given the ongoing and material impact on both the MCP and CMSC payments, the Panel recommends that the IESO change the way it represents variable generator output in the unconstrained schedule when the forecasting tool is disabled, such that fictitious supply is not added to the supply stack. The IESO has indicated that it is revisiting the tools, processes and controls associated with disabling the variable generator forecasting tool.

How Variable Generators are Dispatched

A variable generator receives one of two possible instructions to deliver electricity to the grid, a release notification or a mandatory dispatch. When a variable generator is economic, it receives a release notification and is expected to generate as much electricity as the ambient weather conditions will permit. When a mandatory dispatch is received, the variable generator must alter its output to the megawatt quantity indicated by the mandatory dispatch instruction. Mandatory dispatches typically decrease a variable generator's constrained schedule either for economic or security reasons, such as a transmission constraint.

How the Unconstrained Schedule is Determined for Variable Generators

When a variable generator is operating under a release notification, its unconstrained schedule is set to its actual output during that interval. When a variable generator is following a mandatory dispatch instruction, its schedule will be set to its forecasted output for that interval. The exception is when the variable generator forecasting tool has been disabled, in which case its unconstrained schedule is set at the resource's maximum offered capacity (note that the forecasting tool still produces a forecast during this time, but it is not relied upon). Table 3-2 displays how the unconstrained schedule is determined for variable generators when they are either in release mode or receiving mandatory dispatches, and when the forecasting tool is either enabled or disabled.

Table 3-2: How Unconstrained Schedules are Determined for Variable Generators

Forecasting Tool	Mode	Unconstrained MW
Enabled	**Release**	Actual Output
	Mandatory Dispatch	Forecast
Disabled	**Release**	Actual Output
	Mandatory Dispatch	Max Capacity

For example, assume a wind generator is offering 100 MW of capacity to the market, the resource is in release mode and the variable forecasting tool is enabled. The resource's forecasted output is 25 MW; however, actual wind conditions have limited its current output to 23 MW, resulting in a forecast error of 2 MW. Under such circumstances the resource's unconstrained schedule is set to its actual output (23 MW). Say that the resource then receives a mandatory dispatch; its unconstrained schedule would be set to its forecasted output (25 MW).

Assume the same conditions, although now the variable generator forecasting tool has been disabled. Under release mode the wind generator's unconstrained schedule is again set at its actual output (23 MW). When the resource subsequently receives a mandatory dispatch, its unconstrained schedule is set to its maximum offered capacity (100 MW). In effect, disabling the variable generator forecasting tool while the resource is on mandatory dispatch increases its unconstrained schedule from its forecasted output (25 MW) to its maximum offered capacity (100 MW), adding fictitious supply (75 MW) to the unconstrained supply stack.

Forecasting Tool Enabled	
Mode	**Unconstrained MW**
Release	23 (actual output)
Mandatory Dispatch	25 (from forecast)

Forecast Disabled →

Forecasting Tool Disabled	
Mode	**Unconstrained MW**
Release	23 (actual output)
Mandatory Dispatch	100 (max capacity)

IESO Rationale for Disabling the Variable Generator Forecasting Tool

Due to its dependency on weather conditions, variable generator output can be difficult to predict. With the forecasting tool enabled, the constrained schedules for variable generators in release mode are set by their forecasted output. This can cause operability issues when the variable generator fleet's output deviates from its forecasted output, resulting in more or less electricity supplied to the grid than anticipated. Small forecast errors are manageable; however, large errors could cause unintentional outflow or inflow across interties with surrounding jurisdictions.[40] To correct this unintentional flow, the IESO control room makes use of balancing services to restore supply and demand equilibrium.[41] In conjunction with balancing services, the IESO may disable the variable generator forecasting tool, as this switches the determination of the constrained schedule from a resource's forecasted output, to its actual output, thus limiting the forecast error. When the forecast error is large, disabling the variable generator forecasting tool can greatly improve the accuracy of constrained schedules, allowing the IESO to more effectively balance supply and demand.

[40] This unintentional flow is called Area Control Error (ACE).
[41] One such balancing service is called regulation service. This balancing service responds within seconds to a grid imbalance by rapidly injecting or withdrawing up to 100 MW from the grid. However, if the grid imbalance exceeds the regulation service's capability then additional balancing services are called upon to restore grid balance, such as OR.

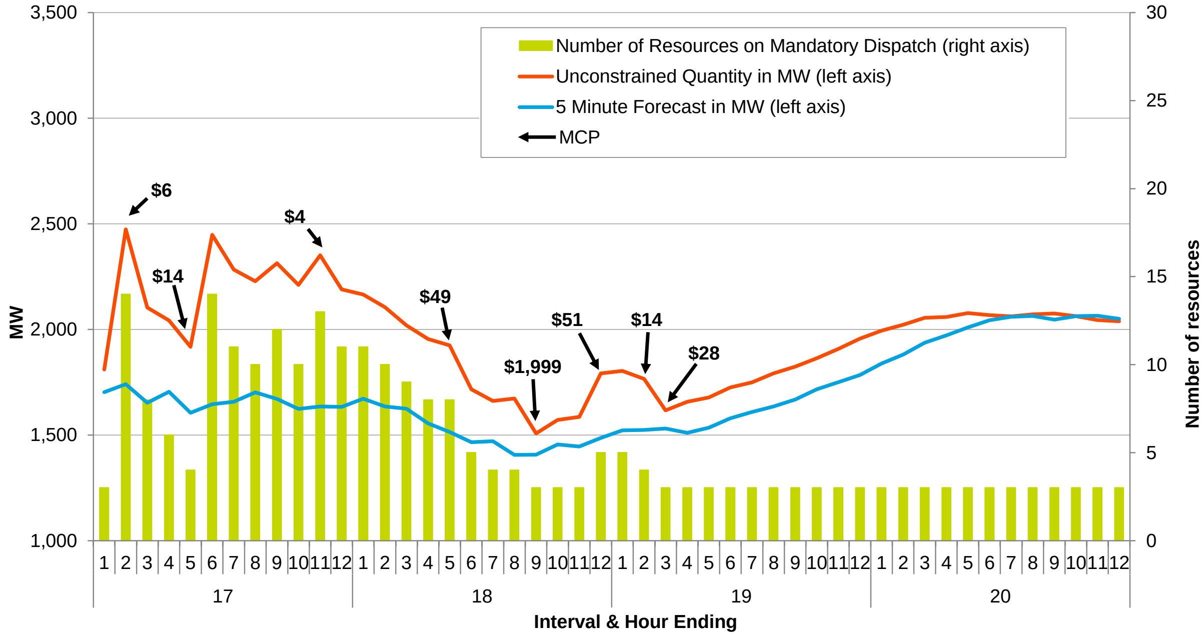
Effects of Disabling the Variable Generation Forecasting Tool on the Unconstrained Sequence

While disabling the variable generator forecasting tool helps alleviate operating concerns in the real-time constrained sequence, it has undesirable impacts on the MCP in the unconstrained sequence.

When a variable generator receives a mandatory dispatch, the status of the unconstrained schedule is determined by whether or not the forecasting tool is disabled. As noted earlier, when the forecasting tool is on, the unconstrained sequence is set at the forecasted value. When the forecasting tool is off, the unconstrained schedule is set at the maximum offer quantity of the resource, typically equivalent to its maximum installed capacity. Variable generators rarely, if ever, operate at anything near their maximum installed capacity. Accordingly, using their maximum offer quantity to set their unconstrained schedules grossly overstates the supply available from these resources. This fictitious supply has the effect of supressing the MCP.

Furthermore, as variable resources switch between release mode and a mandatory dispatch, their schedules switch between forecasted output and maximum offer quantity. The resultant addition and subtraction of fictitious supply can create significant price volatility. Figure 3-12 displays a series of hours on September 26, 2016, in which the variable generator forecasting tool was disabled, contributing to price volatility.

Figure 3-12: Price Impact of Fictitious Supply from Variable Generators September 26, 2016 (MW & Number of resources)



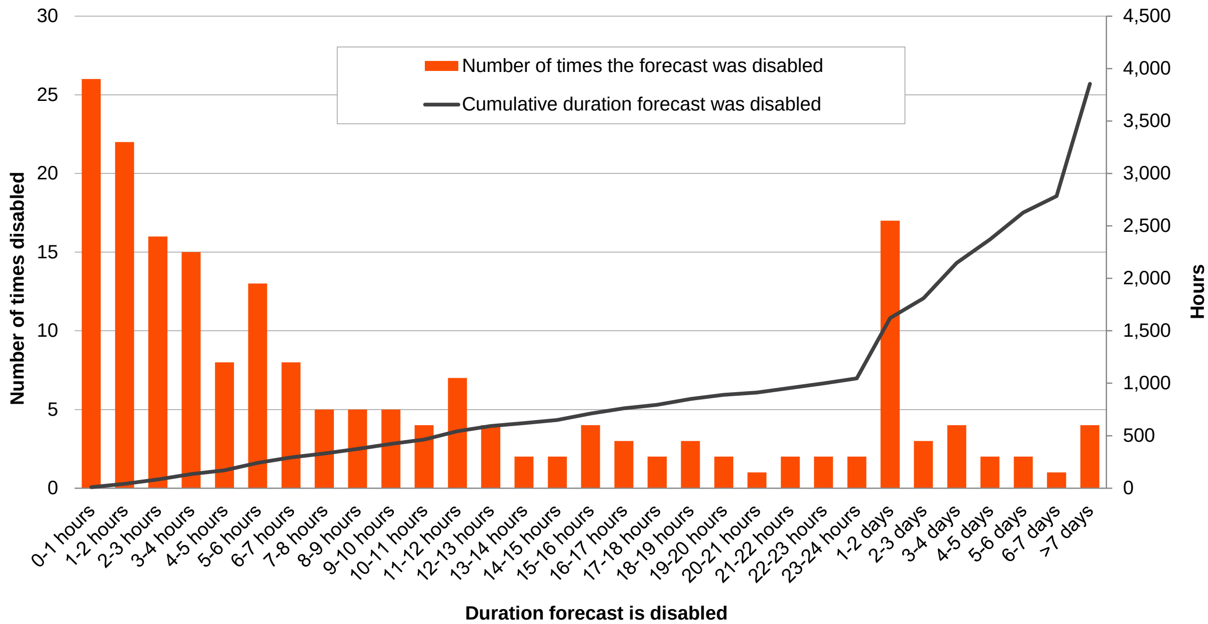
As variable generators alternate between release mode and mandatory dispatches (yellow bars), fictitious supply gets added and removed from the unconstrained supply stack (approximated by the difference between the blue and orange lines), causing price suppression and volatility. Each time the number of economic resources under mandatory dispatch rose, fictitious supply increased, resulting in a deflated price. Likewise, when fictitious supply decreased, prices rose. These impacts can be significant; for instance, in interval 11 of HE 17, there were twelve variable generators scheduled for approximately 700 MW of fictitious supply, resulting in an MCP of $4/MWh. Eleven intervals later, nine of those variable generators had been switched to release mode, resulting in approximately 600 MW of fictitious supply being removed from the supply stack and causing the MCP to spike to $1999/MWh.

Determining when the Variable Generator Forecasting Tool should be Turned On or Off

The IESO indicated that there are no specific criteria in place to determine when the variable generator forecasting tool should be disabled and re-enabled. The IESO noted that it monitors the accuracy of the disabled forecasting tool and aims to re-enable it when it converges with actual variable generator output; however, a review of the frequency and duration of disablements reveals little consistency in its application.

The IESO began switching off the variable generator forecasting tool in earnest mid-2016. Figure 3-13 displays the frequency with which the forecasting tool was disabled for a given length of time.

Figure 3-13: Frequency & Duration of Disabled Forecasting Tool
June 2016 – December 2017
(Number of resources & Hours)



The IESO disabled the variable forecasting tool frequently and left it off for significant lengths of time in a number of instances. In reviewing logs from the IESO's control room, it appears that, on occasion, the IESO forgot to re-enable the forecasting tool once the operability concerns subsided. In the 19 month period between June 2016 and December 2017, the IESO disabled the variable generator forecasting tool 201 times for a cumulative total down time of 160.5 days, or 28 percent of the period. The forecasting tool was disabled for one day or longer on 33 occasions, including four instances in which it was disabled for longer than a week. In addition to the concerning price suppression and volatility impacts, market participants were not alerted to the fact that the variable generator forecasting tool was being disabled, nor to the impact it was having on price.

Impacts on CMSC

Disabling the variable generator forecasting tool causes inflated CMSC payments to variable generators that receive mandatory dispatches. Like other dispatchable resources, variable generators receive CMSC payments when their unconstrained schedule exceeds their constrained schedule. Notionally, the spread between the schedules represents the additional megawatts the variable generator could have delivered to the grid, if not constrained by mandatory dispatch. The addition of fictitious supply in the unconstrained sequence increases this spread, causing CMSC to be paid to variable generators for energy that they could not have produced, regardless of whether they were on mandatory dispatch or not. From June 2016 through December 2017, nearly $2 million in CMSC was paid to variable generators as a result of this fictitious supply. A portion of these CMSC payments has been recovered through adjustments to payments received under the variable generators' supply contracts with the IESO.

Recommendation 3-1:

A) The IESO should formalize the process by which it determines when to disable and re-enable the variable forecasting tool, and should communicate that process to market participants to increase transparency.

B) When a variable generator is on mandatory dispatch and the forecasting tool is disabled, the IESO should set the generator's unconstrained schedule at its forecasted output rather than its maximum offered capacity.

Adopting the above recommendations will increase transparency while reducing price suppression and volatility in the unconstrained sequence. Additionally, adopting these changes would have no impact on the IESO's ability to resolve the operational concerns associated with forecast error in the constrained sequence.

Chapter 4: Matters to Report in the Ontario Electricity Marketplace

1 *Introduction*

In this chapter, the Panel provides a brief update on the status of its investigations, examines the market impact of the electricity trade agreement between the IESO and Hydro-Québec and notes the publication of the Panel's special report on the Industrial Conservation Initiative in December 2018.

2 *Panel Investigations*

The Panel may conduct an investigation into activities related to the IESO-administered markets and the conduct of market participants.

The Panel's Report on an Investigation into the Electricity Trade Agreement between the Ontario IESO and Hydro-Québec was published in December, 2018.[42] The focus of the investigation was on whether the agreement operates within the Market Rules, and the Panel's conclusion is that it does. In the Report, the Panel also noted that it was monitoring how the agreement with Hydro-Québec may be affecting efficiency or effective competition in the IESO-administered markets. The results of that monitoring effort are reported in the section that follows.

3 *New Matters*

3.1 *The Market Impact of the Hydro-Québec Agreement*

In November 2016, the IESO and Hydro-Québec[43] entered into a series of agreements (collectively, the Agreement) that provide for electricity trade between the provinces over a seven-year period from 2017 to 2023. The Agreement has its origins in a Memorandum of Understanding between the two provinces, and a subsequent Ministerial directive to the IESO. The objectives of the Agreement include reducing green-house gas (GHG) emissions by displacing some Ontario natural gas-fired generation, providing savings to Ontario ratepayers and value to Québec, and complementing other electricity wholesale market and policy initiatives in Ontario and Québec.

[42] The Report is available at https://www.oeb.ca/sites/default/files/msp-report-ieso-hydro-quebec-201809.pdf.
[43] The counterparty to the agreement is HQ Energy Marketing Inc., a wholly owned subsidiary of Hydro-Québec that is also a registered market participant (intertie trader) in the IESO-administered markets. For convenience, this report refers simply to Hydro-Québec.

In April 2018, the Financial Accountability Office of Ontario (FAO) released a report that provides a financial assessment of the effect of the Agreement on Ontario ratepayers and reviews the impact of the Agreement on Ontario-based natural gas generation and GHG emissions.[44] It concluded that the Agreement would result in an estimated net total of $38 million in savings to ratepayers (compared to the $70 million estimated by the province), and that the Agreement will not have a significant impact on natural gas generation or GHG emissions in Ontario.

Some policies implemented through Ontario's electricity sector seek to achieve objectives beyond those of the electricity market, including the environmental objective underlying the Agreement. What follows is an examination of how the Agreement has impacted the IESO-administered markets. Because of the confidentiality of the Agreement, the analysis predominantly focuses on the impact based on the Agreement structure. The Agreement fundamentally changes the way Hydro-Québec interacts with the IESO-administered markets; where previously Hydro-Québec's participation would have been determined by "market forces", for a certain quantity of their imports it is now prescribed by the terms of the Agreement.[45] The likely results of this change are undesirable consequences for pricing efficiency and short-term reliability in the IESO-administered markets.

3.1.1 Background on the Agreement

The History of the Agreement

The ability to trade electricity between Ontario and Québec yields potential benefits to both Québec and Ontario electricity consumers. The two provinces have extensively engaged in uncontracted spot market electricity trade prior to the introduction of the Agreement in 2017.

In May 2015, Ontario and Québec finalized the *Seasonal Capacity Sharing Agreement*, under which Ontario would provide Québec with 500 MW of available capacity in winter and Québec would provide Ontario with 500 MW of available capacity in the summer. This agreement was structured to increase available supply during the provinces' respective peak demand periods—

[44] The Financial Accountability Office's report on the Electricity Trade Agreement is available at http://www.fao-on.org/en/Blog/Publications/Electricity-Trade-0418.

[45] "Market forces" include the market incentives that would have driven Hydro-Québec's participation in the IESO-administered markets, such as its marginal cost in relation to wholesale market prices in Ontario. This is further described in the section below titled "How Hydro-Québec Engaged in the IESO-Administered Markets before the Agreement".

winter in Québec, driven by electric heating load, and summer in Ontario, driven by air conditioning load. This agreement had no impact on electricity trade between the provinces.

In October 2015, the Governments of Ontario and Québec concluded a Memorandum of Understanding with a primary objective for Ontario of mitigating GHG emissions from natural gas-fired generators otherwise expected to increase during periods of nuclear refurbishment.[46]

In October 2016, the two provinces signed an agreement reaffirming their intention to cooperate in the fields of clean electricity trade, the reduction of greenhouse gases, and network reliability and accessibility.[47]

Also in October 2016, a Ministerial directive was issued to the IESO calling on it to negotiate a medium-term electricity trade agreement with Hydro-Québec based on the following principles, requirements and considerations:

- Provides savings to Ontario ratepayers and provides value to Québec
- Achieves greenhouse gas (GHG) emissions reductions by ensuring that Québec electricity imports are structured for delivery such that they displace some Ontario natural gas-fired electricity generation
- Considers other electricity wholesale market and policy initiatives in Ontario and Québec, including Ontario's proposed cap-and-trade program.[48]

The Components of the Agreement

The Agreement is made up of three components:

- an "energy sales" component whereby Québec sells 2 TWh of electricity per year to Ontario at a set contract price
- a "capacity purchase" component whereby Ontario would sell Québec 500 MW of capacity in winter in return for monthly capacity payments as set out in the Agreement

[46] See the October 2015 *Memorandum of Understanding Between the Government of Ontario and the Government of Québec Regarding Continued Energy Collaboration and Potential Opportunities for Ontario-Québec Electricity Trade Agreement*, available at: https://news.ontario.ca/opo/en/2015/10/memorandum-of-understanding-between-the-government-of-ontario-and-the-government-of-quebec-regarding.html.
[47] See the October 2016 *Agreement Concerning Electricity Between the Government of Ontario and the Gouvernement du Québec*, available at: https://news.ontario.ca/opo/en/2016/10/agreement-between-the-government-of-ontario-and-the-gouvernement-du-quebec-concerning-electricity.html.
[48] The Ministerial directive is available at http://www.ieso.ca/-/media/files/ieso/document-library/ministerial-directives/2016/directive-ontario-quebec-20161021.pdf?la=en.

- an "energy cycling" component whereby Québec would essentially store electricity for Ontario under a mechanism whereby Ontario can deliver up to a certain amount of electricity to Québec when there is surplus baseload generation in Ontario, and then recall (import) a portion of it (estimated by the FAO at 300 GWh per year) during hours of higher demand to displace production from GHG emitting resources. This is separate from purchases contemplated in the energy sales component.

For a portion of Hydro-Québec's imports, the Agreement is structured in such a way as to supplant market incentives that previously would have driven all of their trading in Ontario. In addition to the contracted import offers, Hydro-Québec can also offer additional non-contracted imports at any price and quantity. In other words, the Agreement does not operate to affect any other Hydro-Québec offer outside of the contractual commitments. In 2017 imports under the contract represented roughly one-third of total Hydro-Québec imports and roughly half of imports net of linked wheels.[49]

How Hydro-Québec Engaged in the IESO-Administered Markets before the Agreement

As with all other entities registered as intertie traders in the IESO-administered markets, Hydro-Québec submits offers to import energy into Ontario and bids to export energy from it. Ontario shares eight interties with Québec for a total transfer capacity of more than 2,600 MW. Since market opening in Ontario, the most significant increase in import and export volumes with Québec occurred in 2009 when the Outaouais high-voltage direct current line was completed, adding 1,250 MW of Ontario-Québec transfer capacity. As discussed below, total imports from Hydro-Québec decreased in 2017 relative to 2016, as was the case for imports generally.

Prior to January 2017, one would expect Hydro-Québec's engagement in the IESO-administered markets would have been driven by market forces, such as its marginal cost and/or opportunity cost in relation to wholesale market prices in Ontario. Revenue streams from the IESO-administered markets would have served as the incentive driving Hydro-Québec's import and export behaviour. In hours when Ontario electricity prices were high, Hydro-Québec was incented to offer more imports, and vice versa.

[49] A linked wheel is a transaction in which a market participant schedules a simultaneous import and export through Ontario, thus "wheeling" energy through the province to its final destination.

How Hydro-Québec Interacts with the Market under the Agreement

The Agreement aims to achieve GHG emissions reductions primarily by replacing Ontario gas-fired generation with non-emitting hydroelectric-backed imports from Québec. To do this, the Agreement requires that Hydro-Québec submit import offers to the Ontario market using offer prices and quantities specified in the Agreement. Those offer prices are determined using a formula that aims to undercut natural gas-fired generation by considering the costs that natural gas-fired generators are likely to incorporate into their offers, including heat rates, natural gas prices and a carbon index. To illustrate how this, among other possible influences, has altered Hydro-Québec's participation in the market, Hydro-Québec's average offer price was roughly 33% lower in 2017 than it was in 2016. The offer prices fell within a much narrower range: 90% of offers in 2017 were within a range of +/-$25/MWh, while the range for 90% of offers in 2016 was twenty times larger. Hydro-Québec receives a fixed contract price for 2 TWh of contracted exports to Ontario, annually; to date, that contract price has on average exceeded the prevailing market price in Ontario.

3.1.2 Market Impact of the Agreement

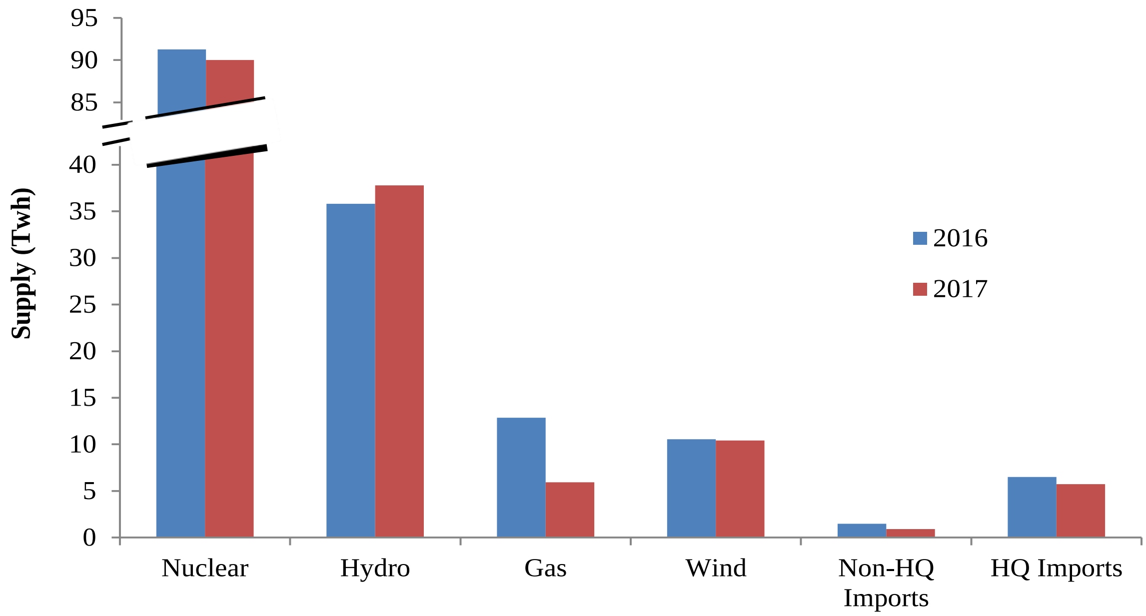
Below are the Panel's observations on the likely impacts to the market since the Agreement took effect on January 1, 2017, including on gas-fired generator schedules, pricing efficiency, price fidelity and short-term reliability. As cost savings for ratepayers and the impact on GHG emissions were the subject of the relatively recent report of the FAO, the Panel has not analysed the Agreement from those perspectives.

Impact on Natural Gas Generators—Are They Running Less?

Gas generators produce the vast majority of GHG emissions in the Ontario electricity sector. Gauging the Agreement's impact on gas generation in Ontario is not as straightforward as comparing the change in gas generator schedules pre- and post-Agreement. There have been several other influences that make it difficult to isolate the estimated impact of the Agreement. The most significant complicating factor is the introduction of the cap-and-trade program, which came into effect at the same time as the Agreement in 2017 and remained in place through to the summer of 2018. Like the Agreement, the cap-and-trade program also targeted gas generation reductions. While it is not possible to ascribe the change in gas generator schedules to a single factor, there are some indicators that can provide insight.

Figure 4-1 shows the year-over-year change in energy scheduled by various resource types—including gas—pre- and post-Agreement.

Figure 4-1: Energy Scheduled by Fuel Type (Constrained Sequence)
2016 – 2017
(TWh)



Gas units have been scheduled significantly less in 2017 than was the case in 2016. Real-time scheduled gas generation was down considerably in every month in 2017 relative to 2016. For the year as a whole, gas generator schedules were down 54%. A closer look at the breakdown of changes in scheduled generator types shows that—in the context of overall lower market demand—gas has experienced the greatest reduction in scheduled output.

Also of note, import volumes have shrunk both overall and in the majority of months in 2017 relative to 2016, including those from Hydro-Québec. That said, Hydro-Québec import volumes have fallen relatively less than imports from other participants, meaning that Hydro-Québec made up an even larger majority of total imports to the province (a year-over-year increase of 6 percentage points in the share of total imports). Another important trend was the increase in hydroelectric generation, predominantly driven by the abundant water conditions in Ontario in 2017. In combination, the reduction in Hydro-Québec's import volumes, the decrease in overall market demand and the increase in the generation scheduled from hydroelectric facilities provide some indication that Hydro-Québec imports may not have been the primary driver of natural gas-fired generation reductions in 2017.

Impact on Market Pricing—An Inefficient Price Setting the MCP

The introduction of the Agreement has likely had some undesirable impacts on efficiency and price fidelity. As noted earlier, under the Agreement, Hydro-Québec offers a certain quantity of supply at a price stipulated in the Agreement. That price is based on the estimated marginal cost of Ontario gas generators, not on the marginal cost (or opportunity cost) of the imports themselves. These imports are offered at prices that are not reflective of the resource's marginal cost and/or opportunity cost and are therefore inefficient in that they re-order the supply stack away from least costly to most costly, with more costly resources being scheduled ahead of less costly resources. In the case of Hydro-Québec's imports under the Agreement, their offer prices now fall in a different place in the supply stack relative to where they would have if their offer behaviour were driven by prevailing market conditions. In situations where Hydro-Québec's import offers would have been higher if not for the Agreement, imports offered at the contract price may be scheduled ahead of less costly resources.

In terms of ensuring the least costly resources are scheduled to meet demand, the Agreement impacts efficiency when Hydro-Québec's non-marginal cost based offers change which resources get scheduled relative to what would have been scheduled had Hydro-Québec been offering at its marginal cost and/or opportunity cost. For example, efficiency is impacted when a Hydro-Québec import offer priced below its marginal cost is scheduled over a resource with lower costs. Offer prices that diverge from marginal cost are most likely to alter schedules for resources around the margin—those that are on the cusp of being scheduled or not. Accordingly, the frequency with which Hydro-Québec's contracted import offer prices set the market clearing price (MCP) in pre-dispatch can be used as an indicator of the impact its non-marginal cost based offers are having on efficient dispatch.

Since the Agreement took effect in January 2017, Hydro-Québec imports have more frequently set the PD-1 MCP. In 2017, Hydro-Québec set the pre-dispatch MCP three and half times more often than was the case in 2016. This represented a significant portion of hours for the year, suggesting that its non-marginal cost based offer prices are more likely to have altered the schedules of other resources.

In addition to impacting the market's ability to schedule the least costly resources to meet demand, hours in which Hydro-Québec contracted imports set the MCP are hours in which consumers are paying a price that does not represent marginal cost. As Hydro-Québec's contracted imports set the MCP more often, there are more hours when the MCP now induces too much consumption (if the MCP is below marginal system cost), or too little consumption (if it is above marginal system cost).

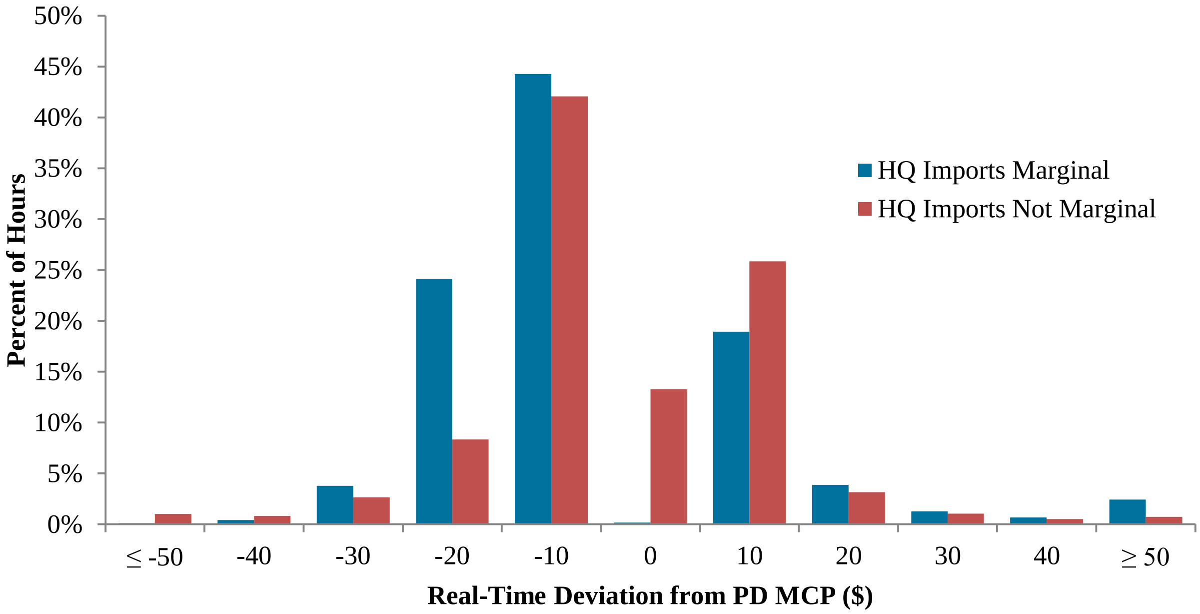
Impact on Price Fidelity

While import offers can set the pre-dispatch price, they cannot set the real-time price (which is set by the highest priced domestic resource scheduled to meet demand). Imports scheduled in pre-dispatch are considered price-takers in real-time, administratively scheduled into the market with an offer at the minimum MCP (-$2,000/MWh) to ensure uninterrupted flow. As a result of this scheduling discrepancy, and with Hydro-Québec import offers now setting the pre-dispatch price more often, price fidelity between pre-dispatch and real-time has worsened.

The need for accurate pre-dispatch prices as an indicator of the real-time price of electricity has been an area of concern for the Panel since market opening. Clear, consistent and credible price signals enhance effective competition by providing participants with better information with which to make market decisions. For example, hydroelectric resources with storage capability rely on pre-dispatch price signals to plan the efficient use of their water. Dispatchable loads rely on pre-dispatch price signals to plan the operation of their primary businesses. Importers and exporters may include risk premiums in their offers and bids if the pre-dispatch prices that determine their schedules differ significantly from the real-time prices they are settled on.

Figure 4-2 displays the deviation between the pre-dispatch MCP and the real-time MCP for two subsets of hours: those where a Hydro-Québec import set the pre-dispatch MCP and those where a different resource set the MCP (including other imports).

Figure 4-2: Deviation between Real-Time & Pre-Dispatch MCP
2017
(% of hours)



When Hydro-Québec imports set the pre-dispatch price, the variation between the pre-dispatch and real-time prices was larger than when they were not the pre-dispatch price setter. For all hours where Hydro-Québec was not the pre-dispatch price setter in 2017, the average pre-dispatch to real-time deviation was -$0.33/MWh and the average absolute deviation was $7.73/MWh. That compares to an average deviation of -$2.37/MWh and an average absolute deviation of $10.59/MWh for hours when Hydro-Québec was the pre-dispatch price setter. The impact on price fidelity is roughly the same regardless of whether it was a Hydro-Québec import or another import setting pre-dispatch prices as far as the dollar value of the deviations goes. However, the Agreement has resulted in imports from Hydro-Québec setting the pre-dispatch price more frequently than before, and as such can be expected to contribute to the more frequent recurrence of price fidelity issues.

Impact on Reliability

Generally speaking, there are reliability benefits to having access to electricity imports on Ontario's various interconnections. Integrated electricity jurisdictions provide the opportunity to employ energy infrastructure from a larger network, expanding the options available to reliably meet system needs. From a reliability perspective then, there can be value in having a contractual flow of energy from Québec when this energy may otherwise go elsewhere. While this helps ensure supply adequacy during periods of high demand or significant generator outages, these contracted imports, which are less flexible than other resources, can have negative impacts on short-term system operability.

In 2016, the IESO identified that additional flexibility was "required in the near-term to address reliability needs";[50] in December 2017, the IESO stated that adding system flexibility "continues to be a priority."[51] Given that flexible supply is largely provided by gas-fired and hydroelectric generators, the Agreement with Hydro-Québec—to the extent that it displaces flexible resources with less flexible imports—has the potential to exacerbate the need for flexibility in Ontario's real-time energy market.

Imported energy lacks many of the characteristics of flexible domestic supply. Domestic generation is scheduled at five-minute intervals, allowing gas-fired and hydroelectric generators to respond to intra-hour changes in supply and demand. Additionally, these generators are capable of supplying 10-minute Operating Reserve (OR). Imports are scheduled on an hourly basis, cannot respond to five-minute dispatch instructions and are more restricted in the OR they can provide.

To the degree imports under the Agreement replace gas-fired generators, this can impact the availability of flexible domestic supply. In 2016, there was an hourly average of 1,660 MW of spare gas-fired capacity online to provide flexibility.[52] In 2017, there was an average of 1,400 MW of spare gas-fired capacity available. This modest decrease in spare capacity available in the energy market is consistent with both the decreased commitment of gas-fired generators to provide energy and the increased scheduling of gas-fired generators to provide OR. OR schedules for gas-fired generators increased 10% from 2016 to 2017. While the Agreement may

[50] The IESO's 2016 *Operability Assessment* is available at http://www.ieso.ca/-/media/files/ieso/document-library/engage/esf/esf-20161208-2016-ieso-operability-assessment-summary.pdf?la=en.
[51] The IESO's December 2017 *18-Month Outlook* is available at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2017dec.pdf?la=en.
[52] This "available capacity" is measured as spare capacity of committed gas-fired resources, plus the available capacity of the York Energy Centre and Kirkland Lake single cycle (quick-starting) gas turbines.

not have been the primary driver of natural gas-fired generation reductions in 2017, it is not structured to address concerns around the availability of flexible supply or OR in Ontario.

Conclusion

The Agreement fundamentally changes the way Hydro-Québec interacts with the IESO-administered markets; where previously Hydro-Québec's participation would have been determined by "market forces", for a certain quantity of their imports it is now prescribed by the terms of the Agreement. In the Panel's view, the likely result is undesirable consequences for pricing efficiency and short-term reliability in the IESO-administered markets. And while Ontario gas-fired generation schedules have been considerably reduced, thereby lowering GHG emissions from the electricity sector, the degree to which that is a result of the Agreement or the cap-and-trade program, among other influences, is indeterminate.

3.2 *The Panel's Report on the Industrial Conservation Initiative*

In December, 2018, the Panel issued a Report on The Industrial Conservation Initiative: Evaluating its Impact and Potential Alternative Approaches.[53] The Panel's conclusion is that, as presently structured, the Industrial Conservation Initiative (ICI), which changed the way in which Global Adjustment costs are allocated to different classes of consumers, is a complicated and non-transparent means of recovering costs, with limited efficiency benefits. In addition, the ICI arguably does not allocate costs fairly in the sense of assigning costs to those who cause them and/or benefit from them being incurred. The ICI shifted nearly $5 billion in costs from larger volume consumers to households and small businesses from 2011 to 2017.

The Report, prepared to contribute in a positive way to future discussions regarding the balancing of objectives and interests in respect of cost allocation, discusses how both the market efficiency and fairness of the ICI can be enhanced.

[53] The report is available at https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf.