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

Ontario

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2014 – April 2015

May 2016

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Investigation Report

In August 2015, the Market Surveillance Panel (the Panel) published its report on an investigation into the conduct of Abitibi-Consolidated Company of Canada and its affiliate Bowater Canadian Forest Products Inc. (Resolute FP Canada Inc. had become the successor in interest to Abitibi and Bowater when the Panel's report was published), which concluded that the market participants engaged in gaming while their facilities were operating as dispatchable loads, and in so doing received $20.4 million in unwarranted Congestion Management Settlement Credit (CMSC) payments during the eight month period from January to August in 2010.

The cost of these CMSC payments was included in uplift and ultimately paid by consumers. In its report, the Panel recommended that the Independent Electricity System Operator (IESO) review ongoing CMSC payments to dispatchable loads. The Panel also encouraged the IESO to take whatever action may be open to it to recover the amounts paid to Abitibi and Bowater as a result of their gaming behaviour, which to date has not happened.

Review of Generation Cost Guarantee Program

Since market opening, the IESO has maintained various guarantee programs to support the reliable operation of the IESO-administered markets. These guarantee programs include the Real-Time Generation Cost Guarantee (GCG), the Day-Ahead Production Cost Guarantee, and the Intertie Offer Guarantee (IOG) programs.

The IESO launched a stakeholder engagement on the subject of the GCG program on October 1, 2015. The scope of the stakeholder engagement is limited to clarifying the costs eligible to be submitted for recovery under the program. The Panel is participating in that stakeholder engagement, and pressed for an examination of the need for the program in its current form given the high cost of the program. The Panel's analysis indicates that, in 2014, commitments under the GCG program were needed to meet domestic demand and operating reserve needs in real-time in less than 1% of the hours in which a commitment actually occurred. These needs were therefore met at a cost of $61 million in 2014, and over $420 million since 2006, a cost that has ultimately been borne by consumers. The Panel has also recommended that the IESO reconsider the criteria by which it determines whether a cost is recoverable under the GCG program to better align with the reliability objectives of the program. The IESO has not to date established that the costs that it has proposed as recoverable are consistent with the principle that costs should only be guaranteed recovery to the extent necessary to ensure that the ultimate reliability objective is achieved, and no more.

Market Outcomes

The Panel's review and analysis of market outcomes covers the period from November 1, 2014 to April 30, 2015 (Current Reporting Period), and compares those outcomes to outcomes in the May 1, 2014 to October 31, 2014 period (Previous Reporting Period), the November 1, 2013 to April 30, 2014 period (Winter 2014 Period) or earlier winter periods (as applicable).

Demand and Supply Conditions

During the Current Reporting Period, 978 MW of nameplate generating capacity was added to the IESO-controlled grid, consisting of wind, hydroelectric, biofuel and solar generation. 230 MW of nameplate capacity was also added at the distribution level, consisting of wind, solar and small-scale hydroelectric and biofuel.

Monthly Ontario energy consumption in the Current Reporting Period peaked at 11.3 TWh in January 2015, compared to 12.3 TWh per month in the Winter 2014 Period.

Ontario was a net energy exporter on a monthly basis during most of the Current Reporting Period. Net exports totalled 10.4 TWh during the Current Reporting Period, an increase of 18% compared to the Previous Reporting Period.

Market Prices and Effective Prices

The Panel reports what it calls the "effective price" for Ontario consumers, which comprises the Hourly Ontario Energy Price (HOEP), the Global Adjustment (GA), and uplift charges. In the Current Reporting Period, the average effective price was $56.68/MWh for Class A consumers that are directly connected to the IESO-controlled grid (Direct Class A) and $95.93 for all other consumers (Class B consumers and Class A consumers that are connected at the distribution level (Embedded Class A)). Relative to the Previous Reporting Period, the average effective price in the Current Reporting Period increased for Direct Class A and for Class B & Embedded Class A consumers. The increase in the effective price for all classes reflects an increase in the average HOEP (while the average GA decreased, both the average HOEP and the average effective price increased). The increase in the weighted HOEP had a greater effect on the average effective price for Class A consumers than for Class B consumers as increases in the HOEP for Class B consumers are offset by a corresponding decline in the GA.

High HOEPs

In the Current Reporting Period there were 28 hours in which the HOEP exceeded $200/MWh (High HOEPs). This Period also had the highest HOEP since market opening, reaching $1402/MWh in hour ending 8 on February 20, 2015. The High HOEPs were primarily caused by under-forecasts of demand and short-notice losses of supply (curtailing of imports and under-generation of wind facilities relative to their forecast production).

Low HOEPs

The Current Reporting Period had a total of 324 hours when the HOEP was negative (Low HOEPs), representing approximately 7% of the total hours. This was a significant increase in Low HOEPs compared to previous winter (November to April) reporting periods. This increase was due to unseasonably mild temperatures during November and December, coupled with year-over-year increases in energy production from nuclear facilities during March and April.

Uplift Payments

There were three instances when the Panel's screening threshold for CMSC payments was met in the Current Reporting Period. All three occurred in February and consisted of days where over $1,000,000 in CMSC payments were made.

Two out of the three instances were associated with a large difference between the HOEP and nodal prices, resulting in export transactions being constrained off and substantial CMSC payments made to intertie traders. Effective September 18, 2015, these constrained-off intertie CMSC payments have been eliminated by the IESO. The third instance was associated with

CMSC payments made to domestic resources: gas-fired facilities were constrained on to allow them to continue to generate a minimum output during their minimum run time, an operating requirement for these facilities, and hydroelectric resources were constrained off to accommodate the minimum output from the gas-fired facilities.

There were 32 instances when operating reserve (OR) payments exceeded the Panel's screening threshold of $100,000 per hour.

Total OR payments, which equal the product of the price of OR and the quantity of OR scheduled, averaged $299,828 for the 32 anomalous OR hours in the Current Reporting Period. The average HOEP during these hours was $372/MWh. The average prices for OR during these hours were $313/MW, $306/MW, and $294/MW for 10-minute spinning, 10-minute non-spinning and 30-minute OR, respectively. During relative shortage conditions, prices for energy and OR tend to converge due to the co-optimization of markets; of the 32 hours with anomalous OR payments, 26 coincided with a high energy market price (HOEP).

The 32 hours in the Current Reporting Period is the greatest number of anomalous OR payment hours during any winter reporting period since market opening. The high OR payments are the result of high OR prices, which themselves have resulted in part from declining offers from hydroelectric resources, a trend beginning in the November 2009 to April 2010 winter reporting period.

Overall Assessment

The focus of the Panel's overall assessment of the state of the IESO-administered markets has been on the fairness and efficiency of the markets when considered in the context of the current design. Given this scope, the Panel has concluded that the IESO-administered markets operated in a reasonably satisfactory manner for the year ended April 2015. Having said that, the Panel has made recommendations in prior reports aimed at improving efficiency and eliminating inappropriate payments, and continues to view certain payments as contributing to inefficient outcomes in the market.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period from November 1, 2014 to April 30, 2015 (Current Reporting Period), with comparisons to the period between May 1, 2014 and October 31, 2014 (Previous Reporting Period), as well as other periods where relevant. A reference to a Winter Period is a reference to the period running from November 1 in one year to April 30 in the next.

1 Pricing

This section summarizes pricing in the IESO-administered markets, including the Hourly Ontario Energy Price (HOEP), the effective price (HOEP, the Global Adjustment (GA) and uplift charges), operating reserve (OR) prices, and transmission rights auction prices.

Table 1-1: Average Effective Price by Consumer Class May 2014 – October 2014 & November 2014 – April 2015 ($/MWh)

Description:

Table 1-1 summarizes the average effective price[1] by consumer class for the Current Reporting Period and the Previous Reporting Period. The average effective price is the sum of the average HOEP, the average GA and average uplift charges. Results are reported for three consumer groups: Class A consumers that are directly connected to the IESO-controlled grid (Direct Class A); Class A consumers that are connected at the distribution level (Embedded Class A) and Class B consumers;[2] and "All Consumers", which is provided for reference purposes and represents what the effective price would have been for all consumers but for the change in the methodology for allocating the GA that took effect in January 2011. Information pertaining to Embedded Class A consumers is aggregated with information pertaining to Class B consumers because information regarding hourly consumption by Embedded Class A consumers is not readily available. Accordingly, average effective price information presented for Class A consumers relates only to Direct Class A consumers.[3]

[1] The average effective price does not include delivery, regulatory, or debt retirement charges.
[2] Aggregating Class B consumers with Embedded Class A consumers has the effect of under-representing the average effective price paid by Class B consumers, as the lower prices paid by the Embedded Class A consumers reduces the average.
[3] For more information on this topic see the Panel's April 2015 Monitoring Report, pages 105-109, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

Customer Class	Average HOEP[4] ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Average Effective Price ($/MWh)
Direct Class A – Current*	25.96	28.17	2.54	56.68
Direct Class A – Previous	17.89	28.26	2.40	48.55
Class B & Embedded Class A – Current	28.19	65.11	2.62	95.93
Class B & Embedded Class A – Previous	19.79	71.33	2.39	93.50
All Consumers – Current	27.95	60.97	2.61	91.53
All Consumers – Previous	19.55	65.96	2.39	87.90

*Current means the Current Reporting Period and Previous means the Previous Reporting Period.

Relevance:

In Ontario, the effective price a consumer pays for electricity depends on its consumer class. Consumers are divided into two groups for purposes of the allocation of the GA: Class A—consumers with an average peak demand of at least 5 MW[5] (these consumers, typically factories or other large industrial consumers, can be directly connected to the IESO-controlled grid or connected at the distribution level); and Class B—all other consumers (including, for example, all small commercial and residential consumers).[6] Since January 2011, the GA payable by a Class A consumer is determined based on its peak demand factor, which is the ratio of the consumer's electricity consumption during the five highest peak hours in a year relative to total consumption by all consumers in each of those hours. The GA payable by a Class B consumer is, and has always been, based on the consumer's consumption during the period.[7]

Many Class B consumers—those that use less than 250,000 kWh of electricity per year and some others—are eligible for the Regulated Price Plan (RPP) prices set by the Ontario Energy Board (OEB). They pay those prices unless they choose to enter into a contract with an electricity retailer (in which case they pay the contract price) or they opt out of the RPP. The commodity price payable by Class B consumers that are not eligible for the RPP or that opt out of the RPP depends on their meter. If they have an interval meter, they pay the HOEP. If they do not have an

[4] The average HOEP, as reported here, consists of the total charges for energy divided by the respective consumption for each consumer class.
[5] Effective July 1, 2015, Class A was expanded to include certain consumers with a peak demand greater than 3 MW but less than or equal to 5 MW. As the Current Reporting Period ends April 30, 2015, this report refers to the composition of Class A before the scope of that class was expanded.
[6] 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.
[7] For more information on the GA allocation methodology and its effect on each consumer class, see the Panel's June 2013 Monitoring Report, pages 69-92, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

interval meter, they pay a weighted average HOEP based on the net system load profile in their distributor's service area. For consumers that are not on the RPP, the GA appears as a separate line item on their electricity bill. Since RPP prices include a forecast of the GA, the GA is not a separate line item on RPP consumer bills.

The GA primarily recovers the cost of payments to contracted and regulated generating resources when market revenues are insufficient to cover their contracted or regulated rates.[8] The HOEP and the GA are inversely proportional, as the recovery of contract and regulated payments through the GA to generators generally increases if market revenues decrease. When market prices rise, the amount of the contract or regulated payments to be recovered through GA declines.

Commentary and Market Considerations:

The average effective price increased for both Class A and Class B & Embedded Class A consumers relative to the Previous Reporting Period, and reached an all-time high of $111.84/MWh for Class B & Embedded Class A consumers in April 2015. This increase reflects an increase in the average HOEP (while the average GA decreased, both the average HOEP and the average effective price increased). The increase in the average HOEP had a greater effect on the average effective price for Class A consumers than was the case for Class B consumers, as increases in the HOEP for Class B consumers are offset by corresponding declines in the GA to a greater extent than is the case for Class A consumers.

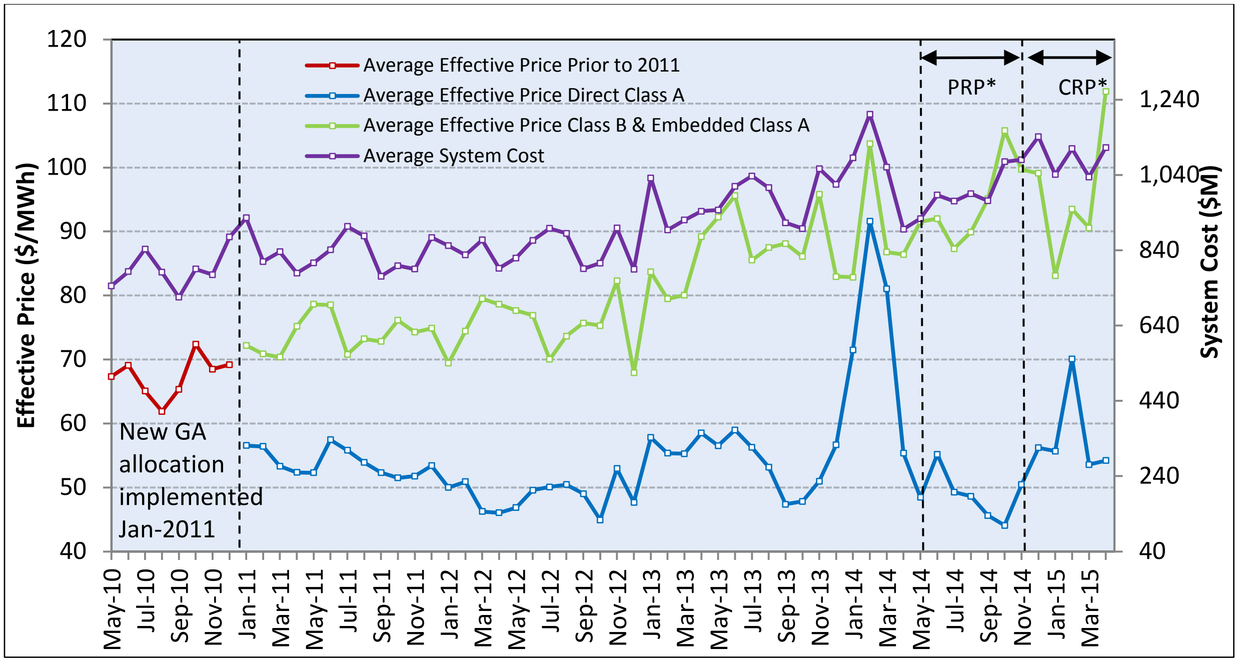
The Commentary section associated with Figures 1-2a and 1-2b below provides greater detail on how the GA allocation affected each consumer class in the Current Reporting Period. The Commentary section associated with Figure 1-10 discusses the reasons contributing to the decrease in the GA.

[8] The costs associated with compensating loads under the IESO's three demand response programs and with administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/Pages/Ontario%27s-Power-System/Electricity-Pricing-in-Ontario/Global-Adjustment.aspx

Figure 1-1: Monthly Average Effective Price and System Cost May 2010 – April 2015 ($/MWh & $)

Description:

Figure 1-1 plots the monthly average effective price for Direct Class A and Class B & Embedded Class A consumers, as well as the monthly average system cost[9] (System Cost), for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This Figure highlights the changes in the effective price paid by each consumer class over the past five years, as well as the changes in System Cost.

Commentary and Market Considerations:

The peak monthly System Cost during the Current Reporting Period did not exceed the previous monthly peak, set in February 2014. However, in March 2015 average effective prices for Class B consumers exceeded previous highs set in October 2014. Over the Current Reporting Period, the System Cost continued to steadily increase as it has in recent years.

[9] The System Cost is the sum of the HOEP, the GA, and the uplift charges paid by Ontario consumers for a given month. It does not account for any amounts paid by exporters.

Figures 1-2A & 1-2B: Average Effective Price by Consumer Class and by Component

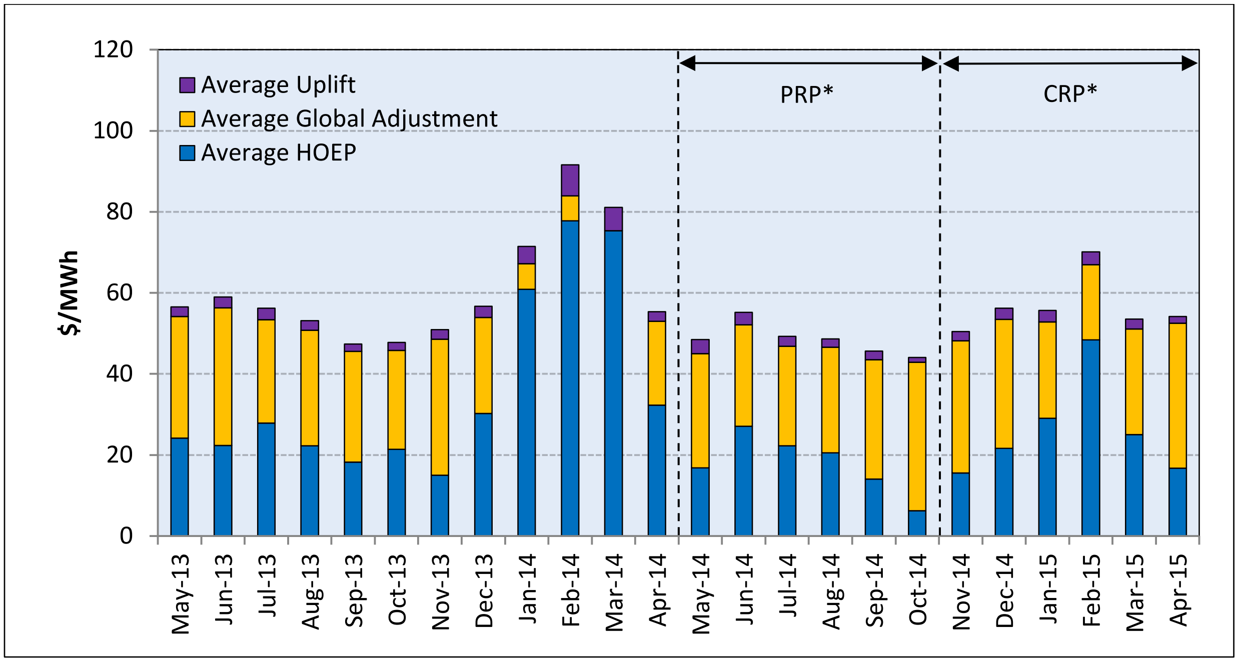
Description:

Figures 1-2A and 1-2B divide the monthly average effective price into its three components (average HOEP, average GA, and average uplift charges) for Direct Class A and Class B & Embedded Class A consumers for the previous two years.

As noted previously, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A consumers respond to that methodology are responsible for the significant difference in the average effective price paid by each consumer group. As the GA is charged to Class A consumers based on their share of peak load during the five hours with the highest total demand in a 12-month base period,[10] Class A consumers can substantially reduce their GA by reducing their consumption during these hours. 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 that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

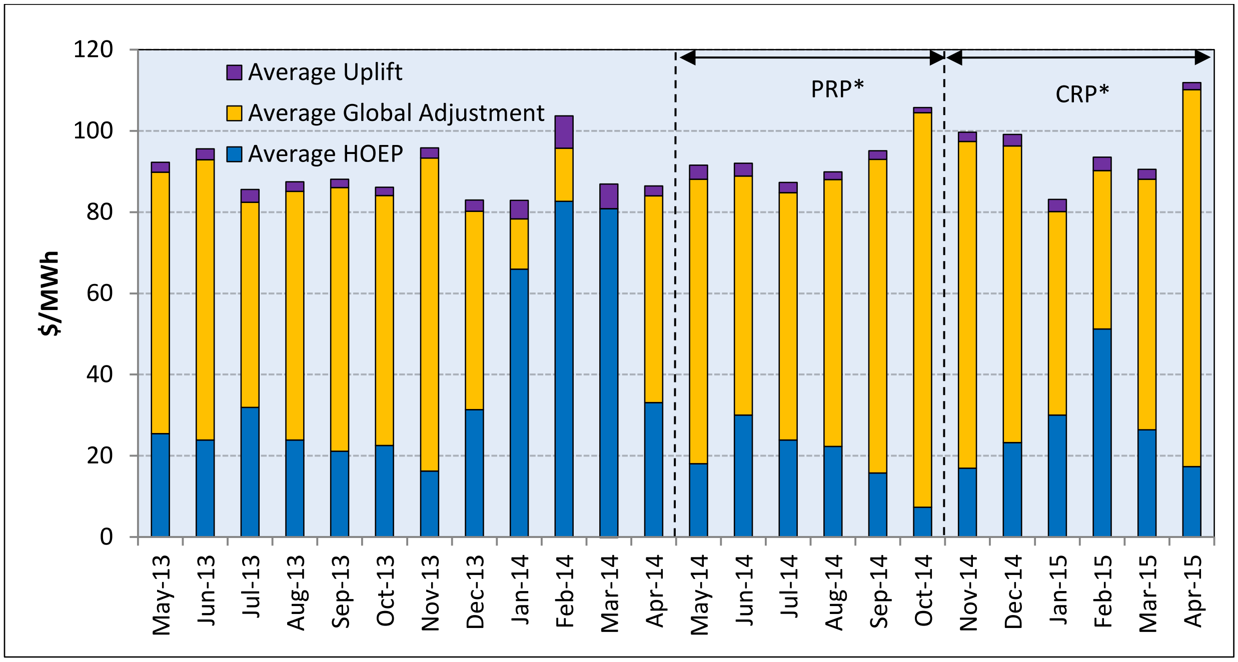
[10] Each base period runs from May 1 in one year to April 30 in the following year. The GA allocation for the Current Reporting Period is based on the base period from May 2013 to April 2014.

Figure 1-2A: Average Effective Price for Direct Class A Consumers by Component May 2013 – April 2015 ($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Figure 1-2B: Average Effective Price for
Class B & Embedded Class A Consumers by Component
May 2013 – April 2015
($/MWh)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

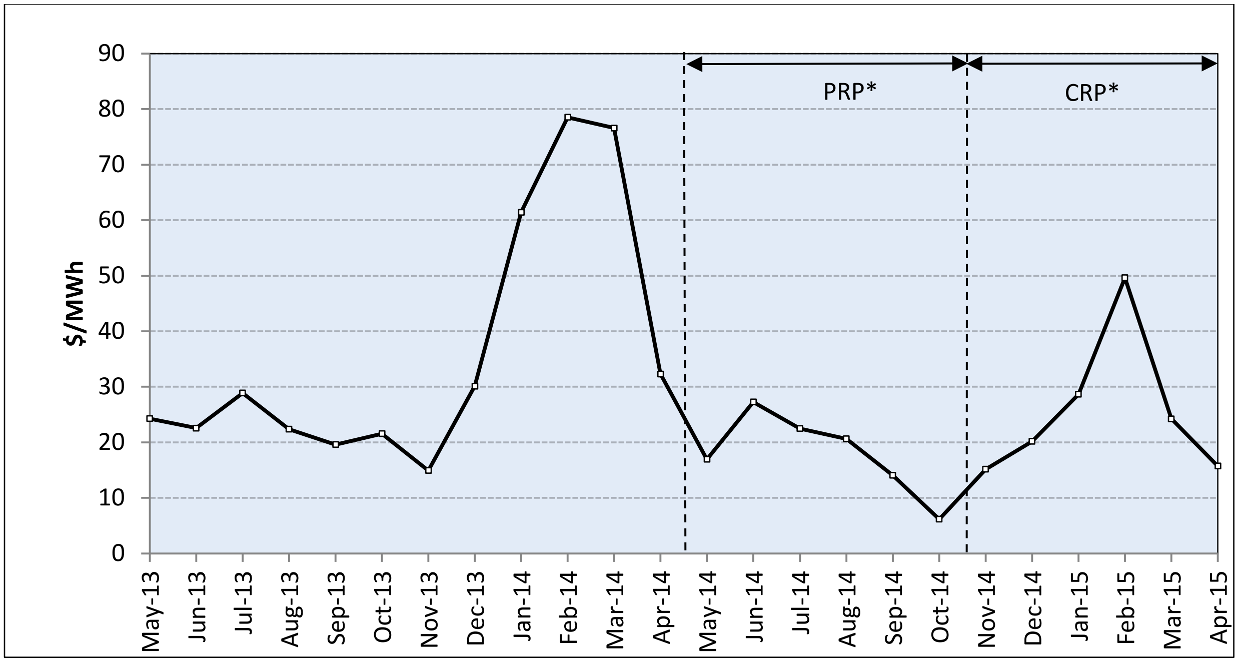
Commentary and Market Considerations:

The average HOEP in the Current Reporting Period reached a peak in February 2015 of $48.27/MWh for Direct Class A consumers and a peak of $51.21/MWh for Class B & Embedded Class A consumers; lower than the peak values during the Winter 2014 Period. This is consistent with lower gas prices in the Current Reporting Period compared to the Winter 2014 Period.

Figure 1-3: Monthly (Simple) Average HOEP
May 2013 – April 2015
($/MWh)

Description:

Figure 1-3 displays the simple monthly average HOEP for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

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) within the hour that are set every five minutes by balancing supply and demand. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's RPP.

Commentary and Market Considerations:

In the Current Reporting Period, the monthly average HOEP was highest in February 2015 at \$49.65/MWh. Higher prices during harsh winter weather conditions are common as energy demand increases and supply to satisfy the higher demand comes from progressively more expensive generating facilities. Temperature levels were the lowest they have been in the past five years during February 2015, when there were 856.8 heating degree days compared to 737.1 such days in the Winter 2014 Period.[11] Because weather and energy demand are positively related, and the same is true for energy demand and price, the extreme weather conditions experienced in the Current Reporting Period caused a spike in the average HOEP during February.

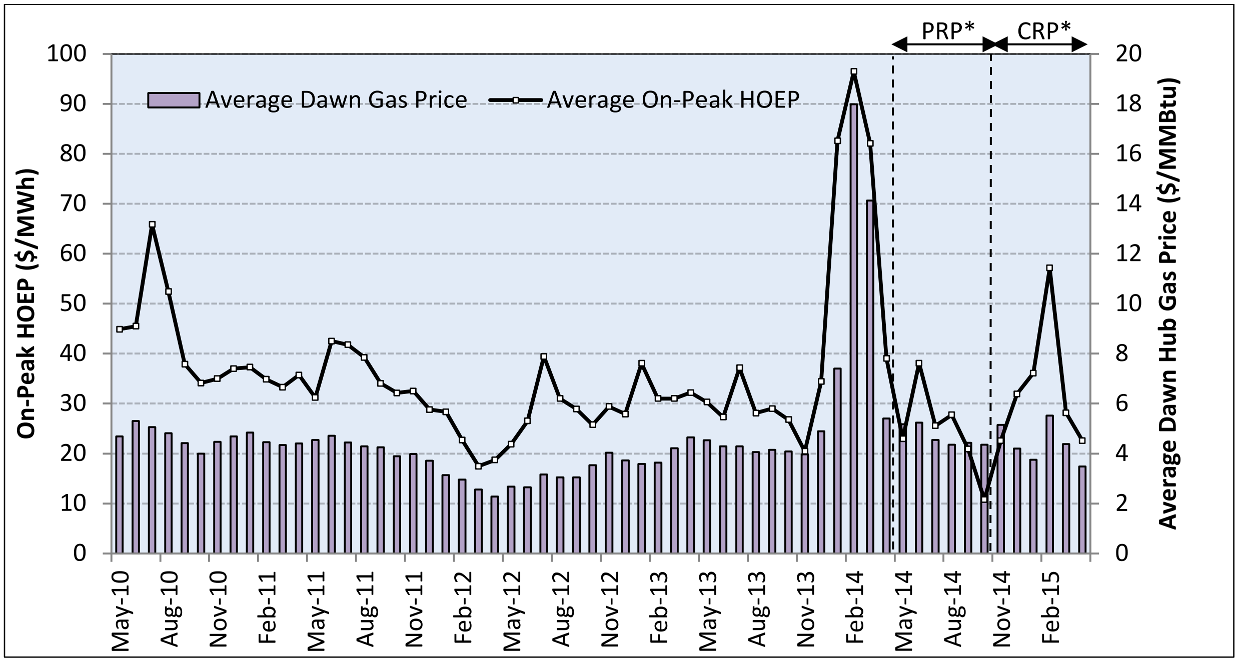
[11] Weather data can be found at http://climate.weather.gc.ca/, The Panel selected Pearson International Airport as the reference location.

While cold winter weather drove electricity prices up, the price impact of the weather was mitigated because natural gas prices, which were high and volatile during the Winter 2014 Period, were lower and more stable during the Current Reporting Period.

Figure 1-4: Average Monthly Dawn Hub Day-Ahead Natural Gas Price and Average Monthly On-Peak HOEP May 2010 – April 2015 ($/MWh & $/MMBtu)

Description:

Figure 1-4 plots the monthly average Dawn Hub day-ahead natural gas price and the average monthly HOEP during on-peak hours, for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

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:

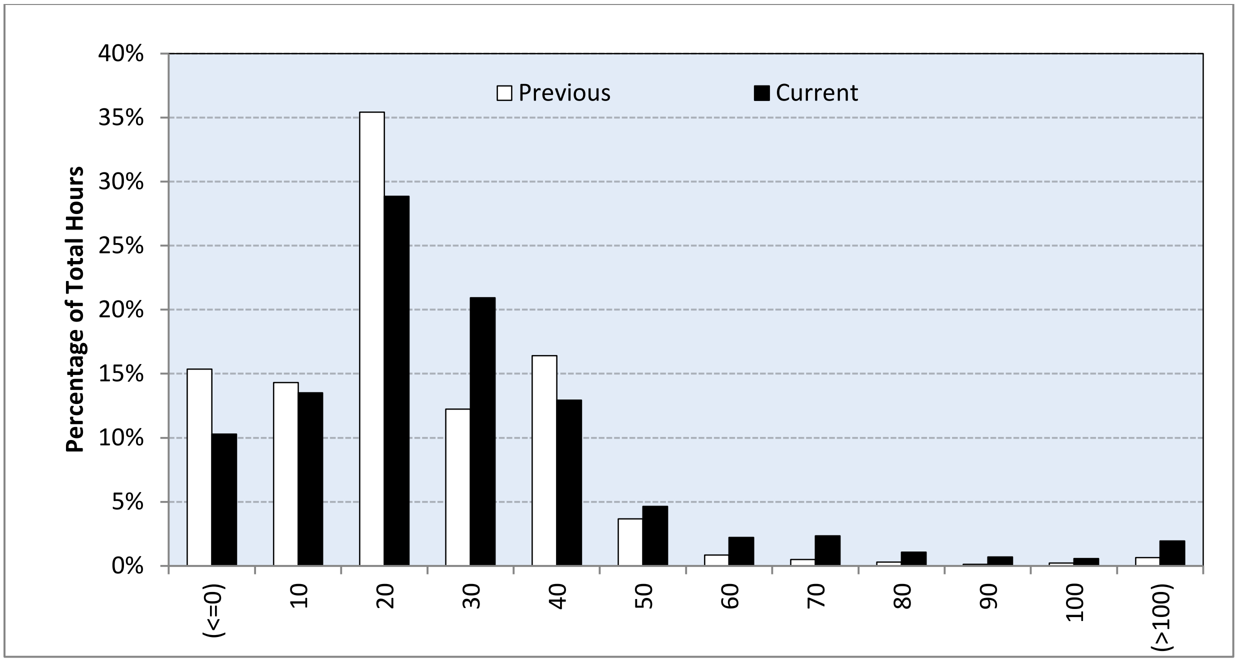
Movements in the on-peak HOEP are, in general, strongly correlated with movements in the day-ahead gas price as gas-fired facilities are often used to meet peak demand. The correlation coefficient between the day-ahead gas price and the on-peak HOEP was 0.73 for the 4 years preceding the Current Reporting Period and 0.56 for the Current Reporting Period, showing that the on-peak HOEP did not move with the day-ahead gas price during the Current Reporting Period as closely as it had in recent years. , However, as shown in Figure 1-6 it is evident that gas-fired facilities contributed more to setting the real-time MCP in the Current Reporting Period than in the Previous Reporting Period (the correlation coefficient between on-peak HOEP and the day-ahead gas price in the Previous Reporting Period was of 0.29[12]).

Figure 1-5: Frequency Distribution of HOEP
May 2014 – October 2014 & November 2014 – April 2015
(% of hours, $/MWh)

Description:

Figure 1-5 compares the frequency distribution of the HOEP as a percentage of total hours for the Current Reporting Period and the Previous Reporting Period. The HOEP is grouped in $10/MWh increments (for example, the $30/MWh group includes all HOEPs between $20/MWh and $30/MWh), save for all negative HOEPs which are grouped together with all $0/MWh values in the category <=$0/MWh.

[12] The methodology which was used to calculate the correlation coefficients has been modified for the Current Reporting Period. As a result, the coefficient reported for the Previous Reporting Period (0.29) is not the same as what was reported in the Panel's October 2015 Monitoring Report.



*Current means the Current Reporting Period and Previous means the Previous Reporting Period.

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 extremely high or low prices.

Commentary and Market Considerations:

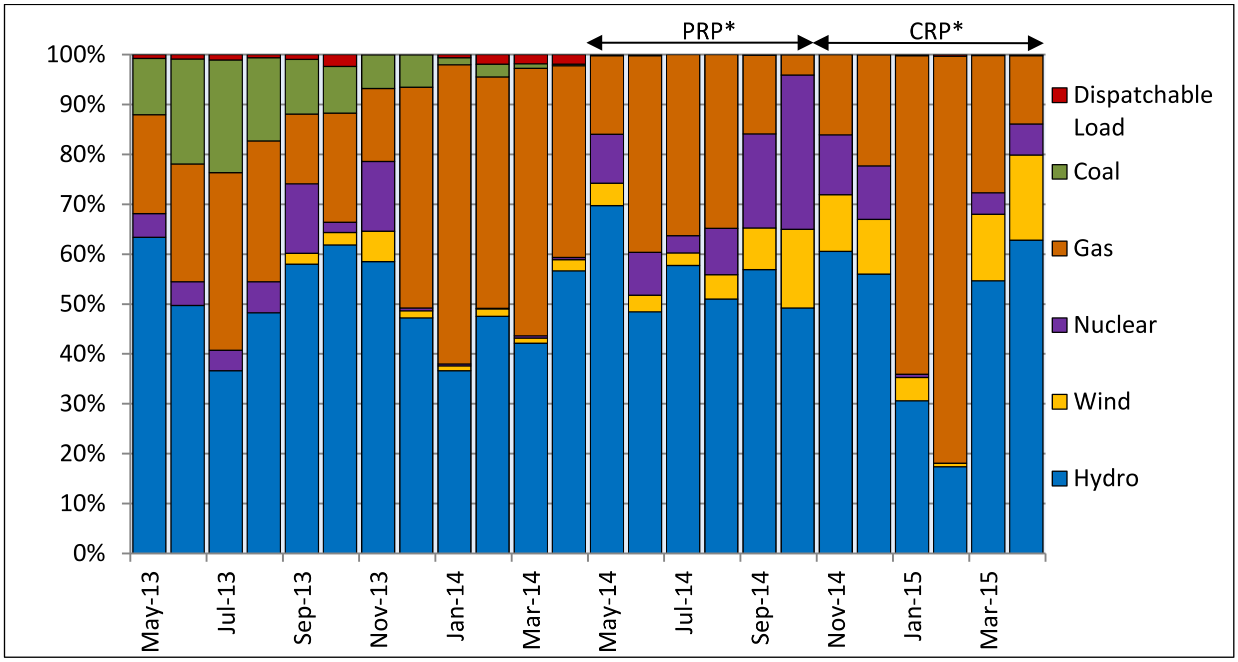
The distribution of the HOEP was broader in the Current Reporting Period as compared to the Previous Reporting Period. During the Previous Reporting Period, the HOEP tended to cluster in the most frequently occurring price range, reflecting less variability than during the Current Reporting Period.

Negative (including $0/MWh) HOEPs were observed in 5% fewer of the total hours during the Current Reporting Period compared to the Previous Reporting Period. In contrast, the frequency of hours where the HOEP was above $40/MWh increased in the Current Reporting Period. This is predominantly due to higher energy demand in the Current Reporting Period than was the case in the Previous Reporting Period. Higher levels of demand generally result in the scheduling of higher-priced resources.

Figure 1-6: Share of Resource Type Setting the Real-time Market Clearing Price May 2013 – April 2015 (% of intervals)

Description:

Figure 1-6 presents the monthly share of intervals in which each resource type set the real-time MCP, for the previous two years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

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:

The relative frequency of each resource type setting the real-time MCP is influenced by Ontario's changing supply mix as well as seasonal factors and changing fuel costs.

Ontario's electricity generation supply mix continued to evolve during the Current Reporting Period. Changes in the availability of different types of generation facilities have affected the frequency with which they each set the real-time MCP. The addition of 442 MW of installed wind capacity during the Current Reporting Period lead to an increase in the frequency with which wind resources set the real-time MCP.

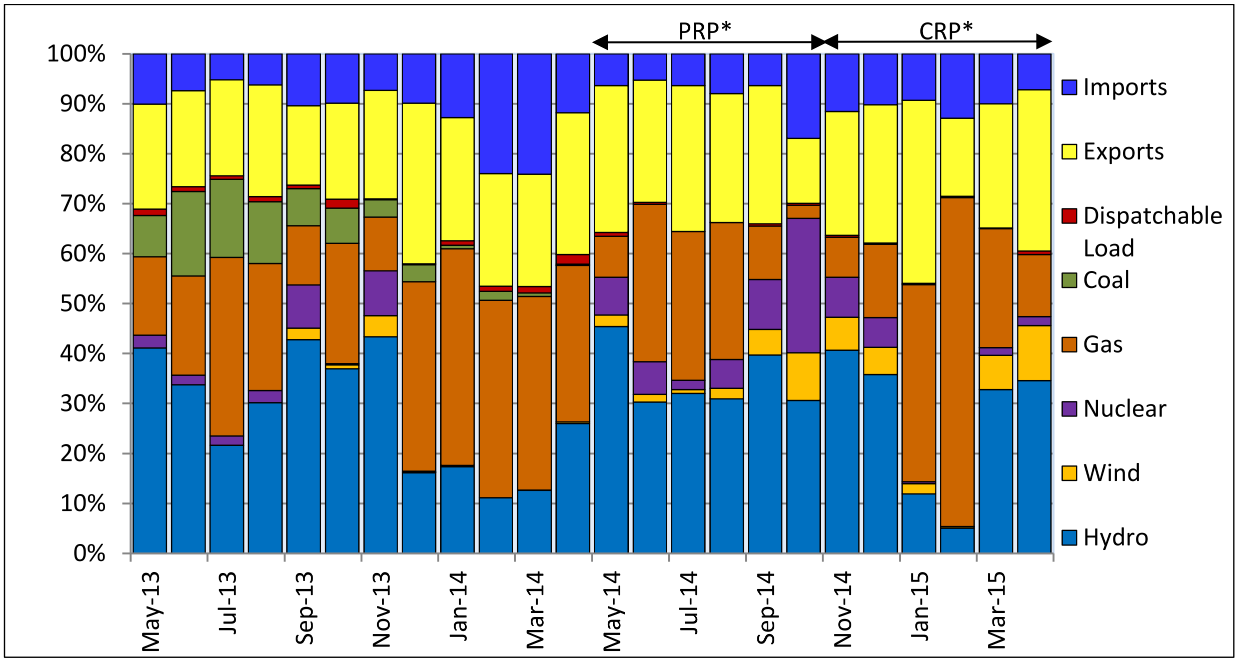
During the Current Reporting Period, the number of intervals in which nuclear or hydroelectric facilities set the real-time MCP decreased, and the number of intervals when wind or gas-fired facilities set the real-time MCP increased relative to the Previous Reporting Period.

There was an overall decrease in the proportion of time when the real-time MCP was set by a facility offering at a negative price. While there was an increase in the frequency with which wind resources set the real-time MCP, this was more than offset by the decrease in the frequency with which nuclear resources did so. This is consistent with the observed reduction in the percentage of hours during which the HOEP was negative (shown in Figure 1-5).

Figure 1-7: Share of Resource Type Setting the One-Hour Ahead Pre-dispatch Market Clearing Price
May 2013 – April 2015
(% of hours)

Description:

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



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

When compared with Figure 1-6 (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.[13] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

During the Current Reporting Period, intertie transactions (the aggregate of imports and exports) set the PD-1 MCP approximately 37.1% of the time, compared to 33.2% in the Previous Reporting Period. Hydroelectric and gas-fired facilities set the PD-1 MCP approximately 26.9% of the time over the Current Reporting Period.

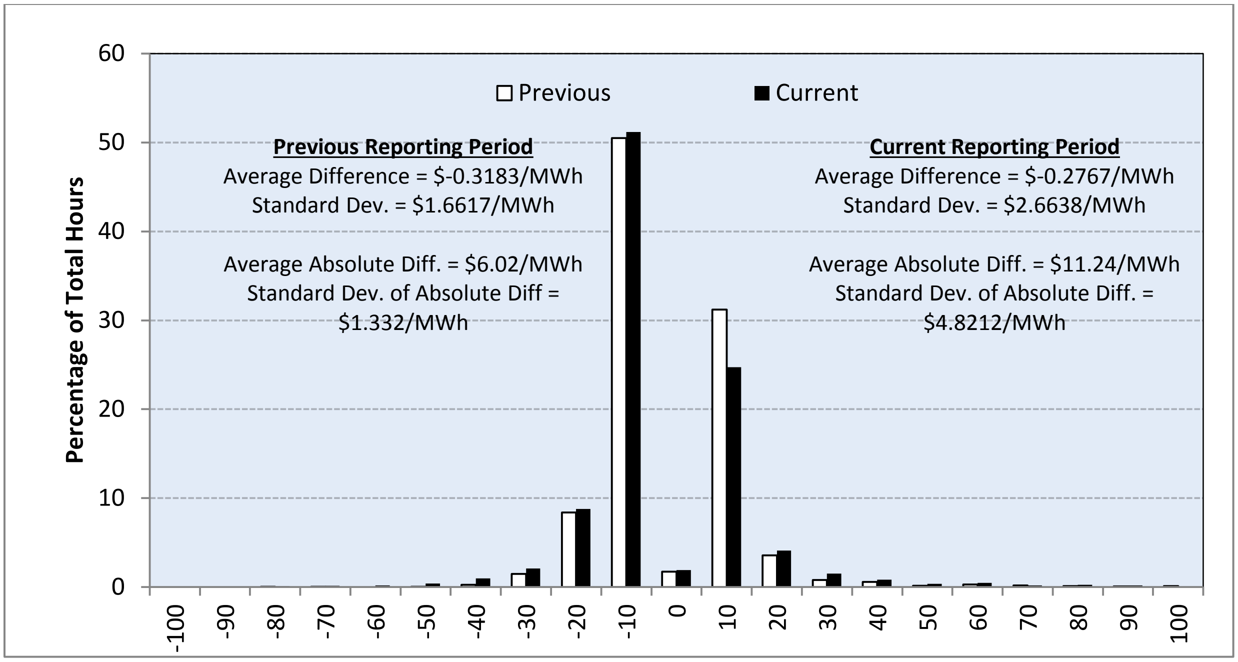
Figure 1-8: Difference Between the HOEP and the One-Hour Ahead Pre-dispatch Price May 2014 – October 2014 & November 2014 – April 2015 (% of hours)

Description:

Figure 1-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Current and Previous Reporting 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 $100/MWh is negligible and so is not included in Figure 1-8, and the same is true of Figure 1-9 in relation to the absolute difference between the three-hour ahead 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.

[13] Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour and their prices are adjusted in real-time to -$2,000 and $2,000/MWh, respectively. This means that they are scheduled to flow for the entire hour regardless of the price, though their schedule may change within an hour to maintain reliability. As a result, they are treated like non-dispatchable resources in real-time.



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 (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. 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 distribution of the difference between the PD-1 MCP and the HOEP was wider in the Current Reporting Period compared to the Previous Reporting Period. The average absolute price difference was further from zero in the Current Reporting Period, signifying more price volatility between the PD-1 MCP and the HOEP.

Relative to the Previous Reporting Period, there were more instances where the difference between the HOEP and the PD-1 MCP exceeded ± $10/MWh in the Current Reporting Period.

Demand during the Current Reporting Period was higher than in the Previous Reporting Period, resulting in the market clearing at a steeper point along the supply curve, exacerbating the impact of the various factors that contribute to differences between PD-1 MCP and the HOEP (see Table 1-2).

Table 1-2: Factors Contributing to Differences Between One-Hour Ahead Pre-dispatch Prices and Real-time Prices May 2014 – October 2014 & November 2014 – April 2015 (MW per hour & % 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.

Metrics for all but one of these factors are presented in Table 1-2 as the average absolute difference between PD-1 and real-time. The effect of generator outages is not shown in this table as they tend to be infrequent, although short-notice outages can have significant price effects.

Factor	Current		Previous	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	16,461		15,118	
Pre-dispatch to Real-time Demand Forecast Deviation[14]	213	1.29	213	1.41
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	55	0.33	51	0.33
Wind Deviation	126	0.77	97	0.64
Net Export Failures/Curtailments	101	0.61	76	0.50

Relevance:

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

Commentary & Market Considerations:

The Current Reporting Period saw an increase in the deviation between the PD-1 MCP and the HOEP due to both wind forecast deviations and net export failures/curtailments. Net export curtailments reached a maximum monthly average value of 155.1 MW during February 2015. Similarly, wind deviation also reached a maximum monthly average during February 2015, with a value of 145.3 MW.

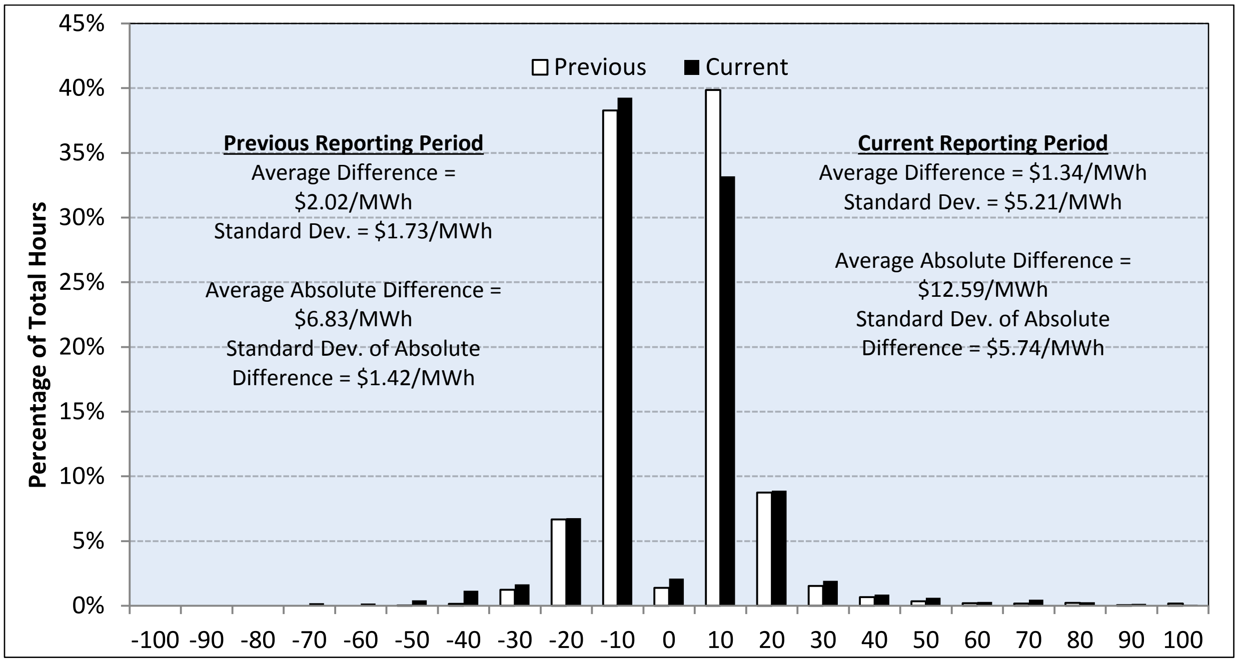
While demand forecast deviation and intermittent resource forecast deviation remained relatively constant, wind forecast deviation was significantly higher (by almost 30%) during the Current Reporting Period than the Previous Reporting Period. This increase in wind forecast volatility corresponds with the addition of new wind capacity on the IESO-controlled grid.

[14] This variable shows the average number of MW difference between PD-1 demand forecasts and real-time demand.

Figure 1-9: Difference Between the HOEP and the Three-Hour Ahead Pre-dispatch Price May 2014 – October 2014 & November 2014 – April 2015 (% of hours)

Description:

Figure 1-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP for the Current and Previous Reporting Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the 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 with the approval of the IESO.

Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[15] 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 results observed from Figure 1-9 above are consistent with those observed from Figure 1-8. In both cases, there was a decrease in the occasions when the pre-dispatch price was marginally lower than the HOEP.

At the same time, both the PD-1 MCP and the PD-3 MCP experienced greater deviation from the HOEP in the Current Reporting Period relative to the Previous Reporting Period. This is primarily due to increased price volatility resulting from increased wind forecast deviation and net export curtailments as shown in Table 1-2 above.

According to Figure 1-8, prices tended to decrease between PD-1 and real-time. This is not surprising, and can be explained by a number of contributing factors such as:

(i) The inclusion of Control Action Operating Reserve (CAOR) in the operating reserve market in real-time. CAOR is a supply of operating reserve in the form of out-of-market control action taken by the IESO which is only available in real-time. Given that the energy and operating reserve markets are jointly optimized, the inclusion of CAOR in the real-time operating reserve market puts downward pressure on both operating reserve and energy prices in real-time (see Chapter 2 for more details).

(ii) For certain ramping hours, the demand forecast used in determining pre-dispatch prices is based on the highest interval demand forecast for that hour (compared to the average interval demand used for other hours). As a result, during those ramping hours real-time demand will likely only reach the forecast in 1 out of 11 intervals. As there is therefore less real-time demand than forecast in these ramping hours, downward pressure on prices from pre-dispatch to real-time occurs.

[15] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

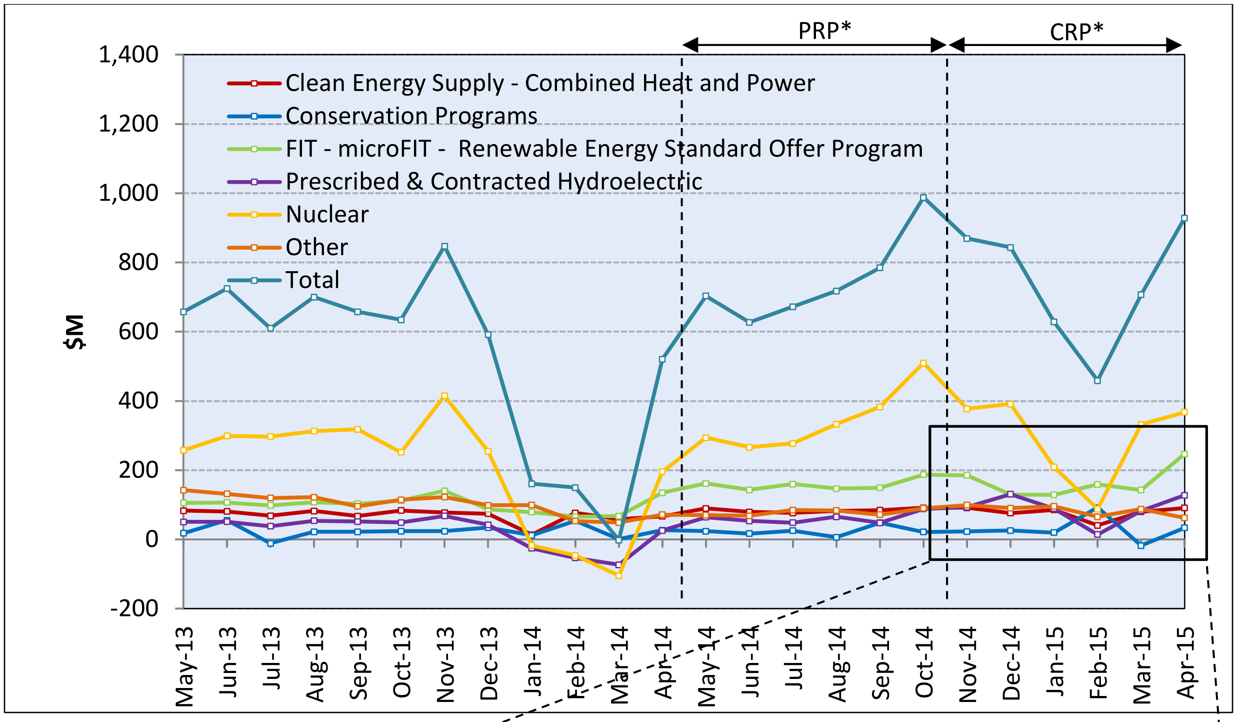
The above factors bias price downward from PD-1 to real-time. While these factors also put downward pressure on prices from PD-3 to real-time, the impact on PD-3 to real-time price differentials is dampened by other changes to supply and demand, including changes in market participant bids and offers.

Figure 1-10: Monthly Global Adjustment by Component
May 2013 – April 2015
($)

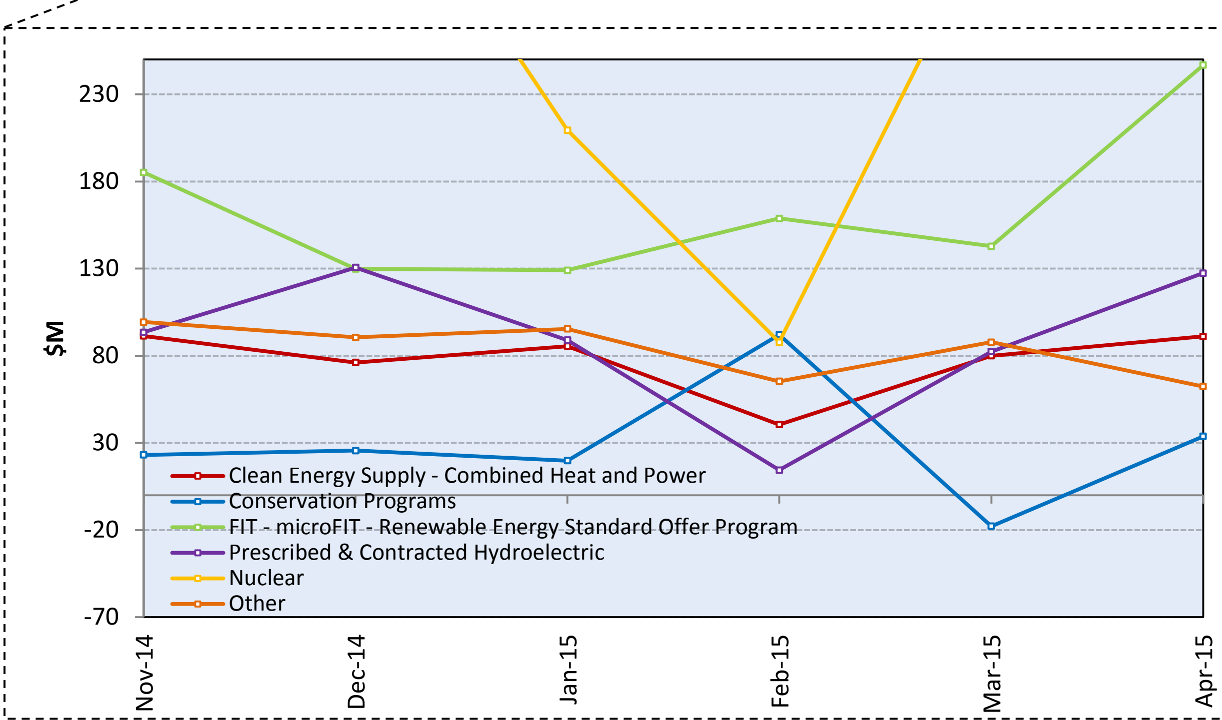
Description:

Figure 1-10 plots the revenue 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's) nuclear assets);
- Payments to holders of Clean Energy Supply contracts and Combined Heat and Power contracts;
- Payments to prescribed or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff (FIT), microFIT and the Renewable Energy Standard Offer Program);
- Payments related to the IESO's conservation programs; and
- Payments to others (including under the IESO's demand response programs, to holders of non-utility generator contracts, and under the contract with OPG's Lennox Generating Station).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.



Relevance:

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

Commentary and Market Considerations:

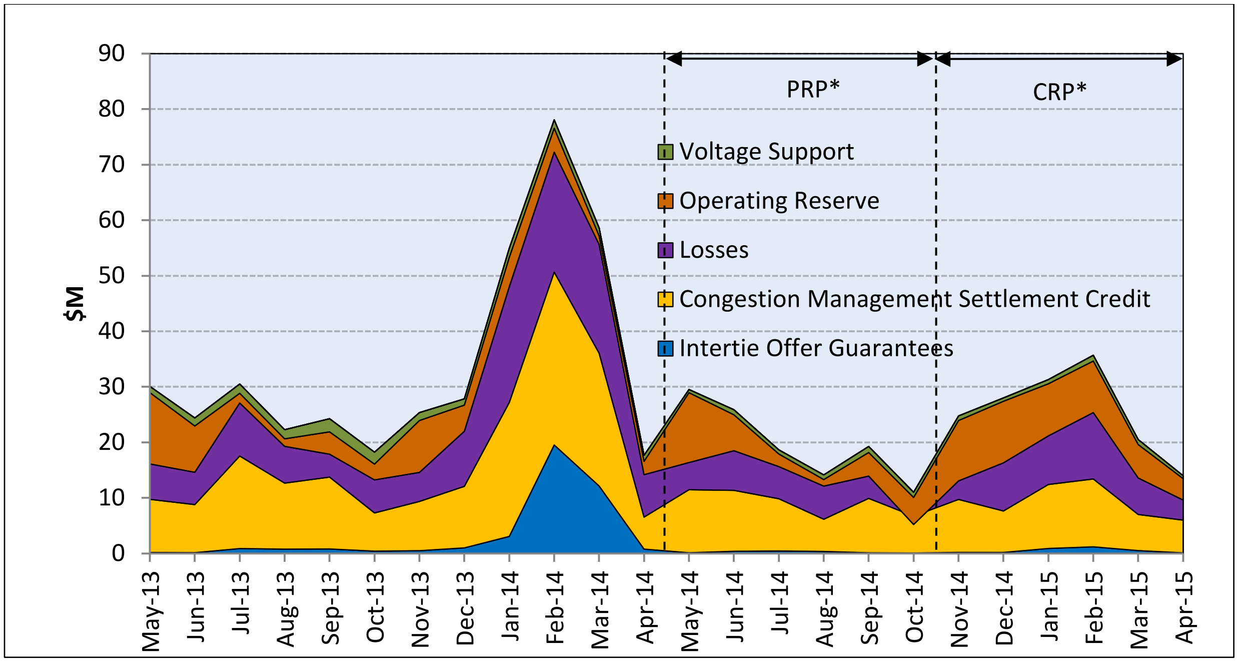
The GA totalled $4.44 billion during the Current Reporting Period, compared to $4.49 billion in the Previous Reporting Period. As previously stated, the GA and the HOEP are generally inversely related. As a result, high HOEP levels from January 2015 to March 2015 resulted in lower GA amounts for all GA components except conservation programs. Unlike the other contributors to the GA, the cost of conservation programs is positively related to demand (which is in turn positively related to the HOEP).

The GA reached a low of $459 million in February 2015, the same month in which the HOEP peaked.

Figure 1-11: Total Hourly Uplift
By Component and Month
May 2013 – April 2015
($)

Description:

Figure 1-11 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, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, OR payments, voltage support payments, and losses.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

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 the Hourly Uplift are generally linked to the HOEP, either directly or indirectly. How each component of the Hourly Uplift responds to changes in the HOEP can be seen by comparing Figure 1-11 with Figure 1-3. For instance, total losses are a function of the HOEP[16] and loss factors.

The OR component of Hourly Uplift was higher ($50.5M) in the Current Reporting Period than in any other reporting period in the past 2 years. OR payments are calculated as the product of OR prices and the total scheduled quantity of OR. High OR payments can be primarily attributed

[16] Losses can be significant when electricity is transmitted over long distances. As losses are the amounts of electricity lost during transmission, the monetary value of that energy is directly proportional to the HOEP. For instance, if the HOEP was $100/MWh and 5 MWh of energy was lost during transmission, the value of the losses is $500. However, if the HOEP was $20/MWh, then the value of the same volume of losses is only $100. As a result, losses can actually be a negative value when the HOEP is negative. For example, in October 2014 aggregate monthly losses were negative due to the significant number of negative HOEPs.

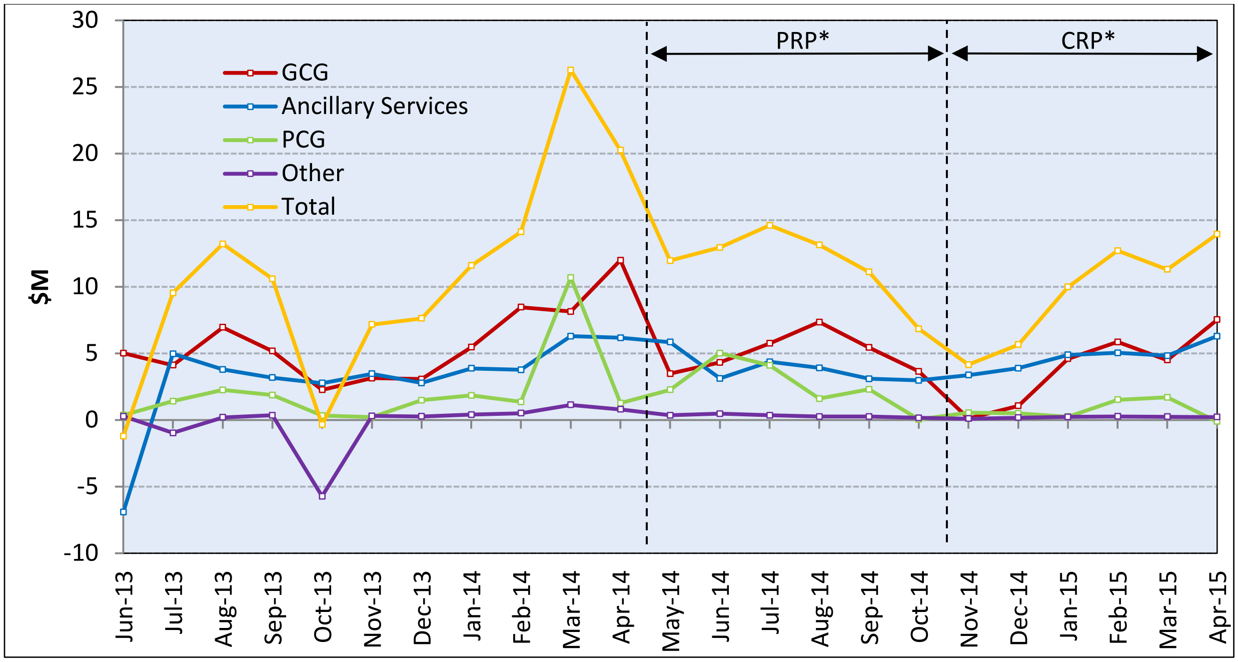
to persistently high OR prices during the Current Reporting Period (see Figure 1-13). The increase in OR prices is discussed further in Chapter 2.

Figure 1-12: Total Monthly Uplift by Component and Month May 2013 – April 2015 ($)

Description:

Figure 1-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:[17]

- Payments for ancillary services (i.e., regulation service, black start capability, monthly voltage support);
- Guarantee payments to generators —payments under the Day-Ahead Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee (GCG) programs; and
- Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

[17] The Monthly Uplifts in this figure are all uplifts that are charged other than on an hourly basis.

Relevance:

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

Commentary and Market Considerations:

Changes in Monthly Uplift over the Current Reporting Period were primarily driven by changes in GCG, PCG and ancillary service payments. The GCG and PCG programs are IESO reliability programs through which certain eligible generators are guaranteed recovery of their eligible fuel and operations and maintenance costs.

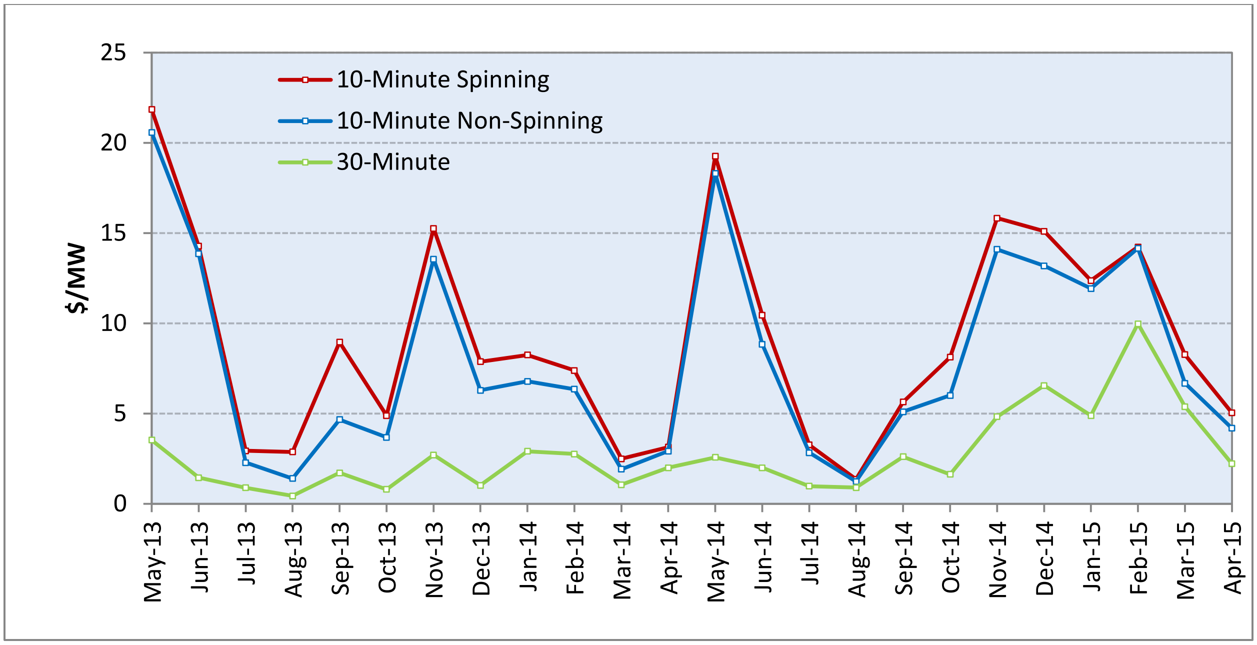
Total Monthly Uplift equalled $60.1 million during the Current Reporting Period, compared to $63.6 million in the Previous Reporting Period. This decrease is primarily due to a net decrease in GCG and PCG payments in the Current Reporting Period compared to the Previous Reporting Period.

Total Monthly Uplift was also significantly lower during the Current Reporting Period than it was during the Winter 2014 Period. This difference is largely driven by the fact that gas prices (and the fuel cost of gas-fired facilities) were much lower during the Current Reporting Period than the Winter 2014 Period.

Figure 1-13: Average Monthly Operating Reserve Prices by Category May 2013 – April 2015 ($/MW)

Description:

Figure 1-13 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).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

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

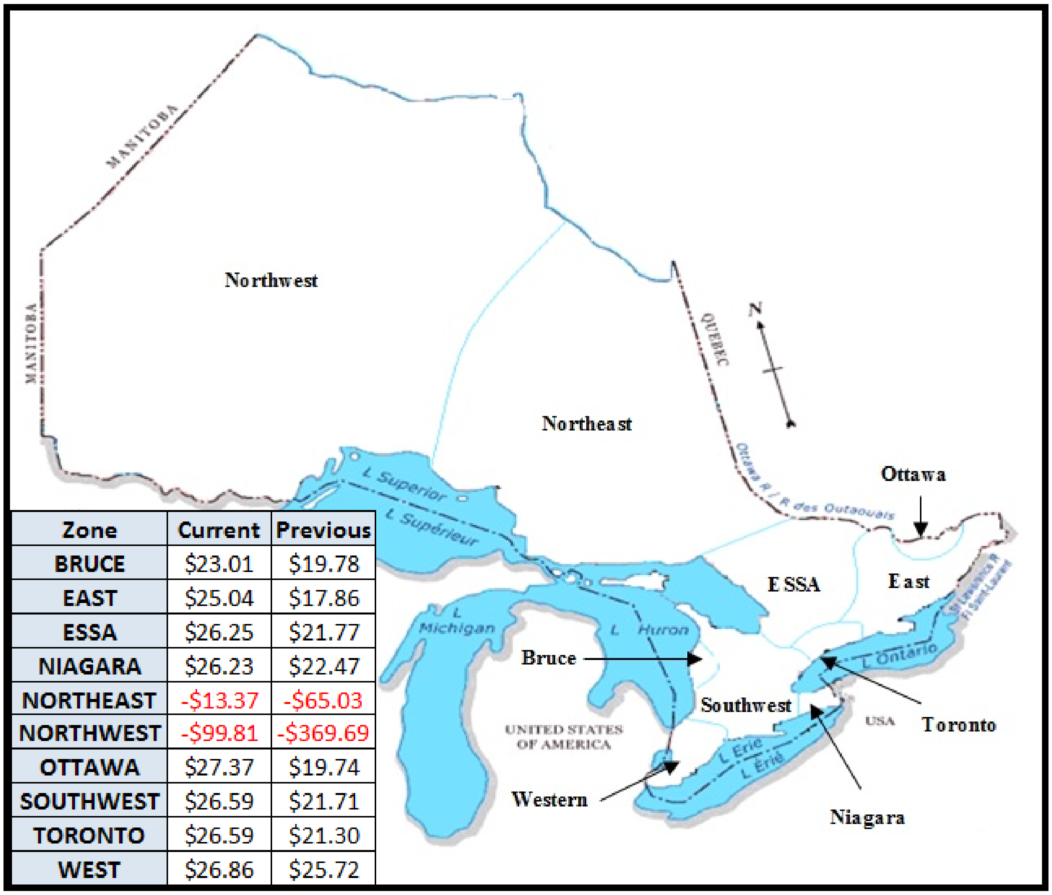
Commentary and Market Considerations:

Sustained high OR prices were observed from November 2014 to February 2015. For a detailed analysis of the high OR prices during the Current Reporting Period see Chapter 2.

Figure 1-14: Average Internal Nodal Prices by Zone
May 2014 – October 2014 & November 2014 – April 2015
($/MWh)

Description:

Figure 1-14 illustrates the average nodal price of Ontario's ten internal zones for the Current and Previous Reporting Periods. In principle, nodal prices represent the cost of supplying the next megawatt of power at a given location.



Zone	Current	Previous
BRUCE	$23.01	$19.78
EAST	$25.04	$17.86
ESSA	$26.25	$21.77
NIAGARA	$26.23	$22.47
NORTHEAST	-$13.37	-$65.03
NORTHWEST	-$99.81	-$369.69
OTTAWA	$27.37	$19.74
SOUTHWEST	$26.59	$21.71
TORONTO	$26.59	$21.30
WEST	$26.86	$25.72

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the cost of satisfying demand for electricity may differ across the province due to limits on the transmission system and the cost of generation in different regions. Nodal prices approximate the marginal value 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, the supply conditions are relatively tight; in zones in which average nodal prices are low, the supply conditions are relatively more abundant.

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

Contributing to negative prices in the northern zones are hydroelectric facilities operating under must-run conditions. Must-run conditions necessitate that units generate at certain levels of output for safety, environmental, or regulatory reasons. Under such conditions, market participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Commentary and Market Considerations:

Relative to the Previous Reporting Period, average nodal prices in all zones in the Current Reporting Period increased in tandem with the increase in the average HOEP. Conversely, average nodal prices were lower in all zones in the Current Reporting Period than they were during the Winter 2014 Period.

Figures 1-15 & 1-16: Congestion by Interface Group

Description:

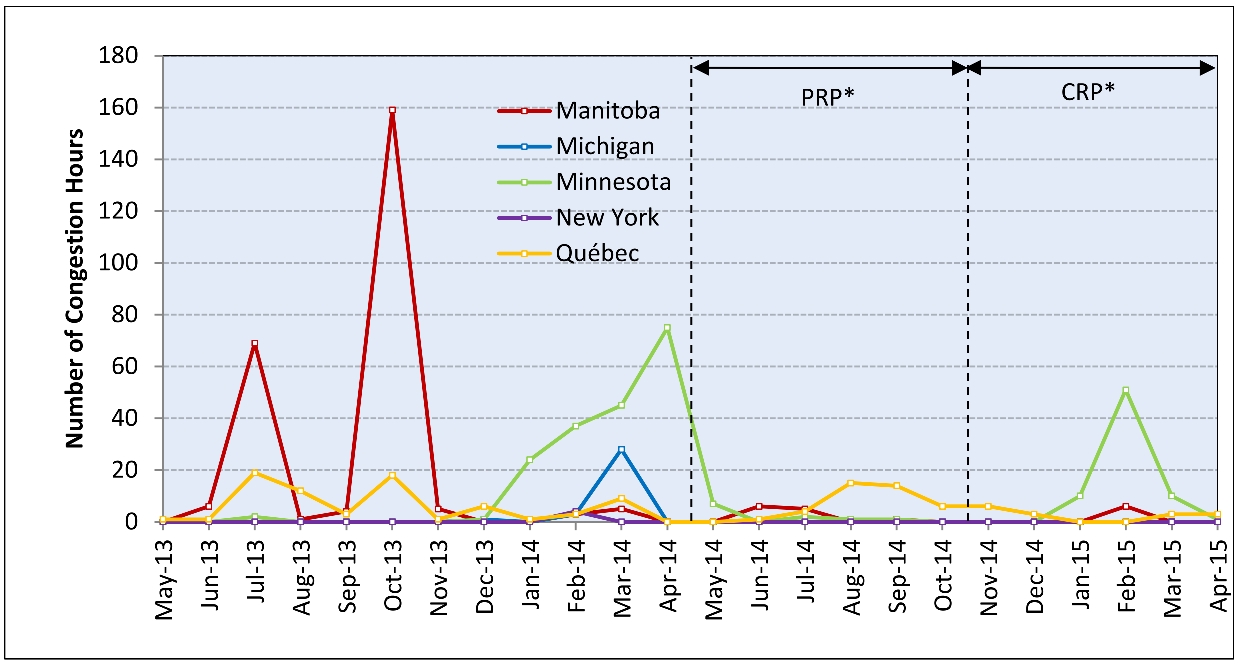
Figures 1-15 and 1-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. The supply of intertie transfer capability is dictated by the available capacity at each interface, and also by line outages and de-ratings. When an intertie has a greater amount of economic net import offers (or economic net export bids) than its one-hour ahead pre-dispatch 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 energy transactions than the intertie transmission lines can withstand. 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 1-17.

Figure 1-15: Import Congestion by Interface Group
May 2013 – April 2015
(number of hours in the unconstrained schedule)

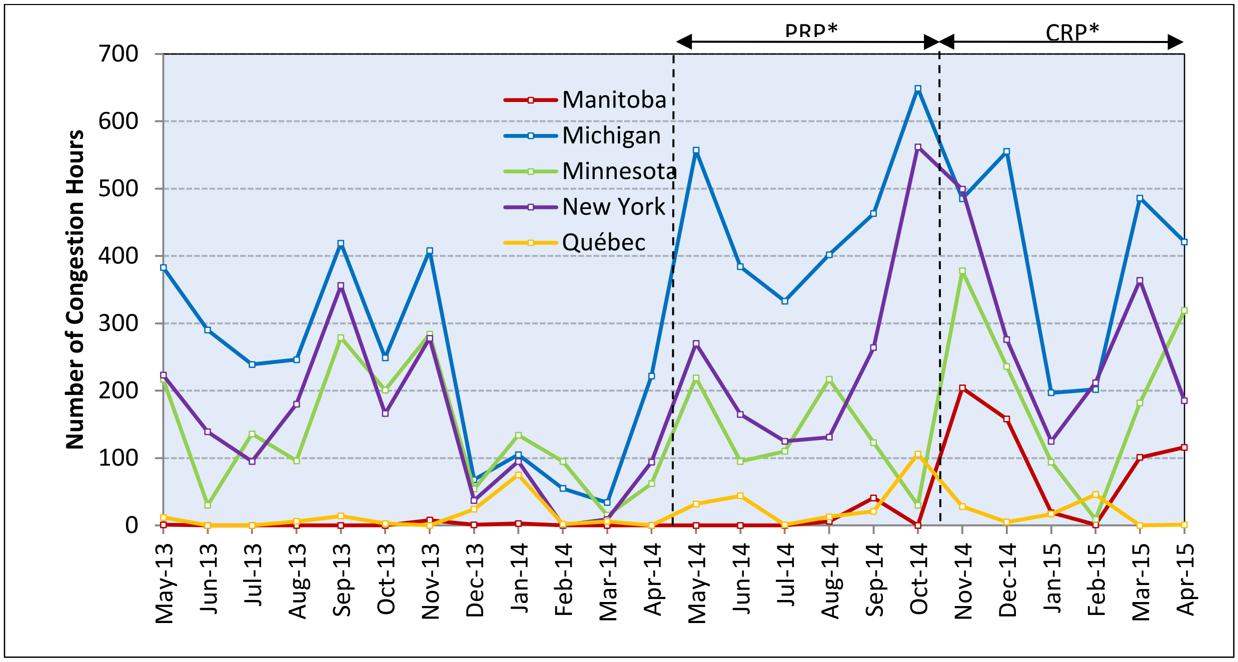


*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

Import congestion was infrequent during the Current Reporting Period for the New York, Québec, and Michigan interties. The most significant instance of congestion occurred during the month of February 2015 at the Minnesota intertie with 51 hours of import congestion; the capacity of the intertie was not lower than normal during this month.

Figure 1-16: Export Congestion by Interface Group
May 2013 – April 2015
(number of hours in the unconstrained schedule)



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Commentary and Market Consideration:

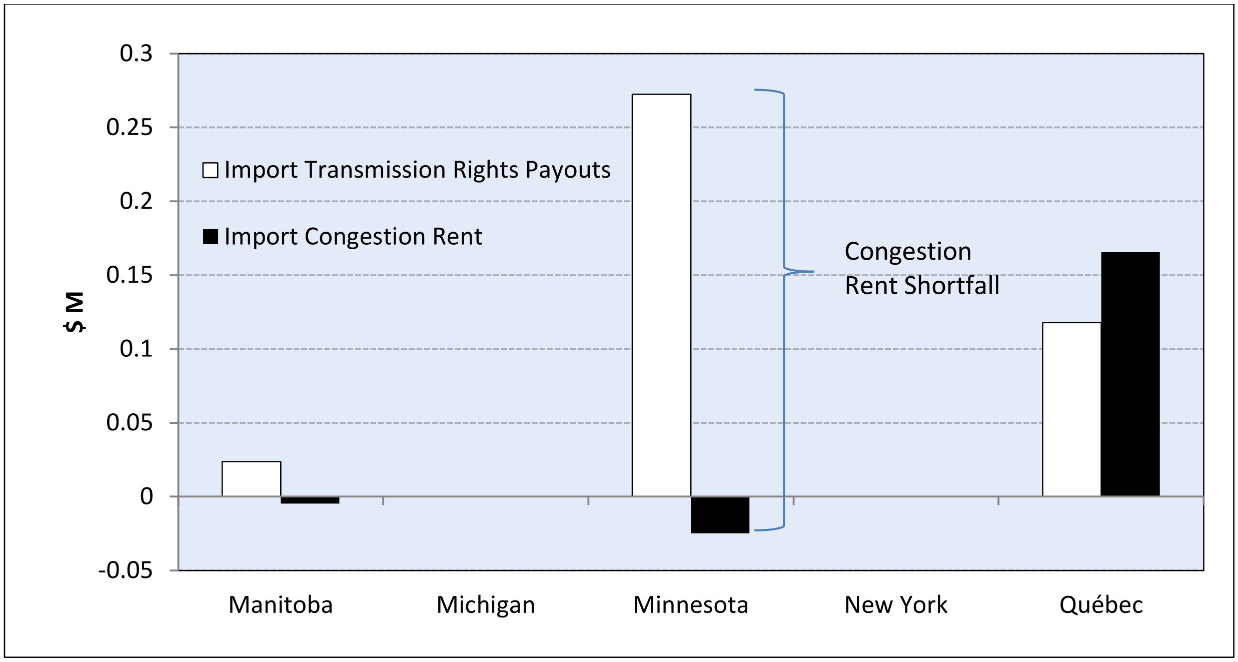
Export congestion on the New York and Michigan interties decreased significantly from November 2014 to April 2015, reaching a monthly low in January 2015 of 125 hours on the New York intertie and 197 hours on the Michigan intertie. High export congestion levels typically reflect a large demand for exports from Ontario to higher-priced neighbouring jurisdictions.[18] The reduction in export congestion on the Minnesota intertie in February is consistent with the higher rate of import congestion during that month, as in shown in Figure 1-15.

Figure 1-17: Import Congestion Rent &
Transmission Rights Payouts by Interface Group
November 2014 – April 2015
($)

Description:

Figure 1-17 compares the total collection of import congestion rent to total payouts under transmission rights (TRs) by interface group for the Current Reporting Period.

[18] As exports only pay a small amount of the uplift that domestic consumers pay, demand for exports in neighbouring jurisdictions is based primarily on the HOEP rather than the effective price.



Relevance:

As discussed in the relevance section associated with Figures 1-15 and 1-16, 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 Ontario price and the PD-1 intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TR Clearing Account). This account is discussed in greater detail in the Relevance section associated with Figure 1-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of 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 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 Ontario price 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 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. The IESO has recently made changes to its TR auction process to address recurring congestion rent shortfalls, which is discussed further in the Relevance section associated with Figure 1-19.

Note that interties with a high frequency of import congestion hours (see Figure 1-15) 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.

[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".

[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 the Panel's January 2013 Monitoring Report, pages 146-160, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

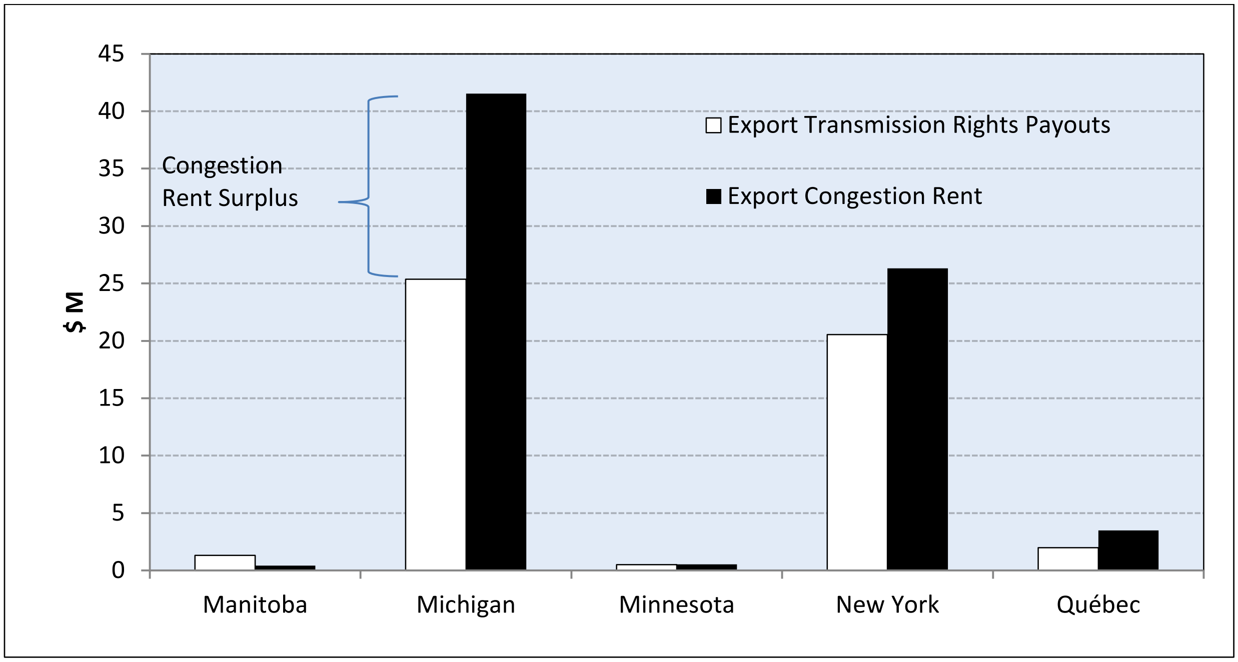
Commentary and Market Consideration:

During the Current Reporting Period, no intertie experienced a significant congestion rent shortfall (Minnesota experienced the largest shortfall, at approximately $0.3 million).[21] The Minnesota and Manitoba interties both experienced modest "negative" congestion rent collected, which can happen if congestion occurs in one direction in the pre-dispatch unconstrained schedule but not in the real-time constrained schedule.

Figure 1-18: Export Congestion Rent & Transmission Rights Payouts by Interface Group November 2014 – April 2015 ($)

Description:

Figure 1-18 compares the total collection of export congestion rent to total TR payouts by interface group for the Current Reporting Period.



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 1-17 which describes the relationship between

[21] Figure 1-17 in the Panel's October 2015 Monitoring Report reported a congestion rent shortfall of $3.45 million in relation to TR payouts for imports on the Québec intertie. However, the congestion rent was adjusted in accordance with an IESO settlement process, leaving only $14,400 of congestion rent shortfall as opposed to $3.45 million as previously reported.

congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR Clearing Account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

During the Current Reporting Period there was a considerable amount of export congestion at the New York and Michigan interties as reflected in Figure 1-16, and consistent with Ontario's status as a net exporter of energy. Congestion rent exceeded the TR payouts for the New York and Michigan interties by $5.8 million and $16.1 million, respectively, and to a lesser extent also for the Québec intertie.

Table 1-3: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction May 2014 – April 2015 ($/MW)

Description:

Table 1-3 lists the average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since May 2014 (these TRs would have been valid during the Current Reporting Period).

			Average Auction Price ($/MW)				
Direction	**Auction Date**	**Period TRs are Valid**	**Manitoba**	**Michigan**	**Minnesota**	**New York**	**Québec**
Import	**May-14**	**Jul-14 to Jun-15**	-	1,396	5,506	1,214	828
	Aug-14*	**Oct-14 to Sep-15**	-	-	-	-	-
	Nov-14	**Jan-15 to Dec-15**	3,788	-	-	2,480	-
	Feb-15	**Apr-15 to Mar-16**	2,847	1,172	4,525	767	1,367
Export	**May-14**	**Jul-14 to Jun-15**	-	38,836	-	32,216	9,211
	Aug-14*	**Oct-14 to Sep-15**	-	-	-	-	-
	Nov-14	**Jan-15 to Dec-15**	5,695	-	33,518	61,225	-
	Feb-15	**Apr-15 to Mar-16**	7,293	43,370	28,558	36,741	4,176

*There was no long-term TR auction in August 2014.

Relevance:

If an auction is efficient, the price paid for one megawatt of TRs should reflect the expected payout from owning that TR for the period. This is equivalent to the expected sum of all ICPs in the direction of the TR over the period for which the TR is valid. The greater the expected frequency and/or magnitude of congestion on the intertie, the more valuable the TR. Assuming an efficient auction, auction revenues signal the market’s expectation of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

Auction prices for long-term TRs are generally higher for export TRs than import TRs for all interties, as the province of Ontario regularly exports more energy than it imports. The highest average auction price recorded for long-term export TRs in the Current Reporting Period was $61,225/MW for the New York intertie for the January 2015 to December 2015 period. The highest average auction price recorded for long-term import TRs was $5,506/MW for the Minnesota intertie for the July 2014 to June 2015 period. Relative to the Previous Reporting Period, these results imply that the purchasers of TRs expected a decrease in import congestion and an increase in export congestion.

Table 1-4: Short-Term (One-month) Transmission Right
Auction Prices by Interface and Direction
May 2014 – April 2015
($/MW)

Description:

Table 1-4 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during the Previous and Current Reporting Periods.

		Average Auction Price ($/MW)				
Direction	**Period TRs are Valid**	**Manitoba**	**Michigan**	**Minnesota**	**New York**	**Québec**
Import	May-14	511	91	328	38	175
	Jun-14	506	126	379	12	152
	Jul-14	469	90	491	30	175
	Aug-14	482	48	338	11	173
	Sep-14	-	55	231	49	38
	Oct-14	380	49	-	65	40
	Nov-14	506	134	251	129	118
	Dec-14	380	119	351	136	131
	Jan-15	328	136	317	160	19
	Feb-15	306	45	268	171	32
	Mar-15	259	99	376	79	152
	Apr-15	310	55	418	90	135
Export	May-14	50	3,799	-	2,520	446
	Jun-14	32	4,787	-	2,239	1,079
	Jul-14	49	2,526	-	1,019	506
	Aug-14	58	2,913	-	1,295	368
	Sep-14	-	4,486	-	3,119	149
	Oct-14	318	7,020	-	4,129	288
	Nov-14	329	7,626	-	5,022	2,000
	Dec-14	701	6,245	1,674	6,049	3,169
	Jan-15	692	6,176	2,001	2,500	2,070
	Feb-15	410	3,678	1,868	2,500	300
	Mar-15	511	4,221	2,074	2,689	158
	Apr-15	810	4,494	1,735	2,262	179

Relevance:

As discussed in the relevance section associated with Table 1-3, auction revenues signal market participant expectations of intertie congestion conditions for the forward period.

Commentary and Market Consideration:

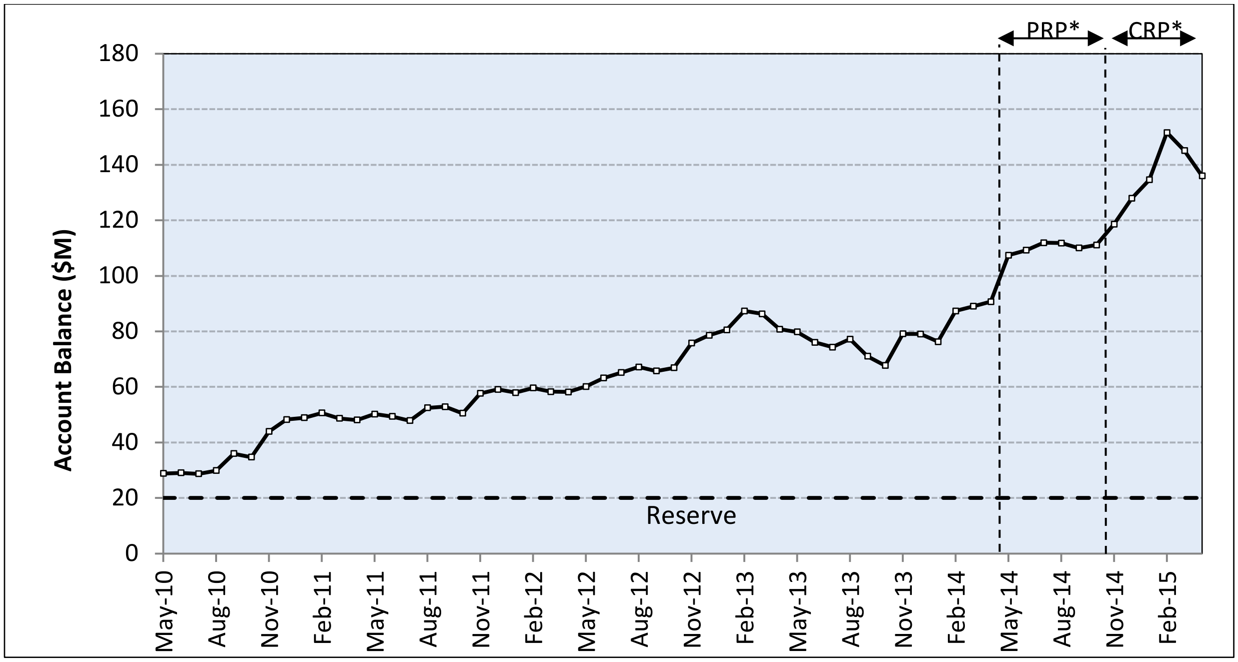
The auction prices for short-term TRs were relatively higher for the Current Reporting Period than the Previous Reporting Period for all interties. The decrease in export congestion in January on the Michigan intertie was not accompanied by a decrease in the TR auction price; this decrease in congestion therefore appears not to have been predicted by the market. By contrast, the decrease in export congestion in February on both the New York and Michigan interties was accompanied by a decrease in the TR auction price. The increased import congestion on the

Minnesota intertie in February was not accompanied by a spike in the TR auction price; this increase in congestion was apparently not predicted by the market.

Figure 1-19: Transmission Rights Clearing Account Balance May 2010 – April 2015 ($)

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 1-19 shows the estimated balance in this account at the end of each month for the previous five years.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

<u>Credits</u>

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

<u>Debits</u>

- TR payouts to TR holders

- Disbursements to Ontario market participants

Tracking TR Clearing Account transactions over a period of time provides an indication of the health of the TR market and the policies that govern it. The account has a reserve threshold of $20 million set by the IESO Board of Directors; funds in excess of this threshold can be disbursed to wholesale loads and exporters at the discretion of the IESO Board of Directors.

Commentary & Market Considerations:

Over the Current Reporting Period, the balance in the TR Clearing Account increased by $24.9 million (from $111.1 million to $136.0 million). This change was composed of:

- $109.6 million in revenue
    - $72.4M in congestion rent collected
    - $36.6M in auction revenues
    - $0.6M in interest
- $84.7 million in disbursements
    - $51.3M in TR payouts to TR holders
    - $33.4M in disbursement to wholesale loads and exporters

There are number of noteworthy observations to make relating to the TR Clearing Account during the Current Reporting Period. In September 2013, the IESO Board of Directors approved a revision to the process by which the number of TRs auctioned is determined.[22] The new process is intended to more closely balance the congestion rents collected with TR payouts, consistent with past Panel recommendations.[23] In October 2014, the IESO implemented an interim maintenance process until the IT tools for the new process are in place. The interim process resulted in a surplus of congestion rent collected relative to TR payouts in the amount of $21.1 million. This is in stark contrast to the recurring congestion rent shortfalls experienced prior to the implementation of the IESO's interim maintenance process. The Panel does not expect to see congestion rent surpluses on a recurring basis in the future once the permanent process is in place.

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[22] For more information on the IESO Board's decision and the interim maintenance process, see the pages 3 – 5 of the IESO's "Market Manual 4: Market Operations, Part 4.4: Transmission Rights Auction", available at: http://www.ieso.ca/Documents/marketOps/mo_TransmissionRights.pdf.

[23] For the Panel's recommendations on this topic see the Panel's January 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2011-Apr2012_20130114.pdf

In addition to the $21.1 million congestion rent surplus, auction revenues and interest added $37.2 million to the TR Clearing Account during the Current Reporting Period. Overall, the TR Clearing Account was approximately $116.0 million above the reserve threshold by the end of the Current Reporting Period. However, in March 2015 the IESO Board of Directors approved the disbursement of $100 million from the TR Clearing Account, to be disbursed in six monthly installments of approximately $16 million, beginning March 2015.[24] The impact of the first of these disbursements can be seen in the month over month TR Clearing Account balance shown in Figure 1-19.

2 Demand

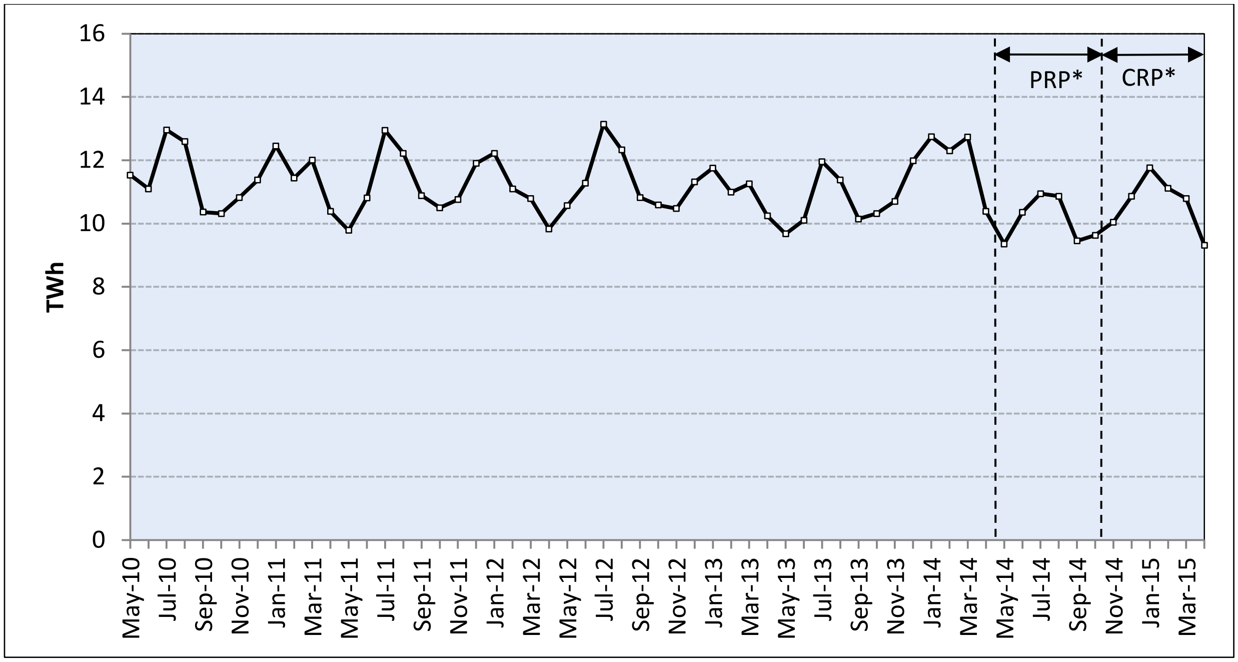
This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

Figure 1-20: Monthly Ontario Energy Demand
May 2010 - April 2015
(TWh)

Description:

Figure 1-20 presents energy consumption by all Ontario consumers in each month in the past 5 years. The figure represents Ontario demand, which includes demand satisfied by behind-the-meter (embedded) generators.

[24] For more information, see the IESO news release on disbursements from the TR Clearing Account, available at: http://www.ieso.ca/Pages/News/NewsItem.aspx?newsID=7013



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Ontario monthly consumption information shows seasonal variations in consumption and year-to-year changes in consumption patterns.

Commentary and Market Consideration:

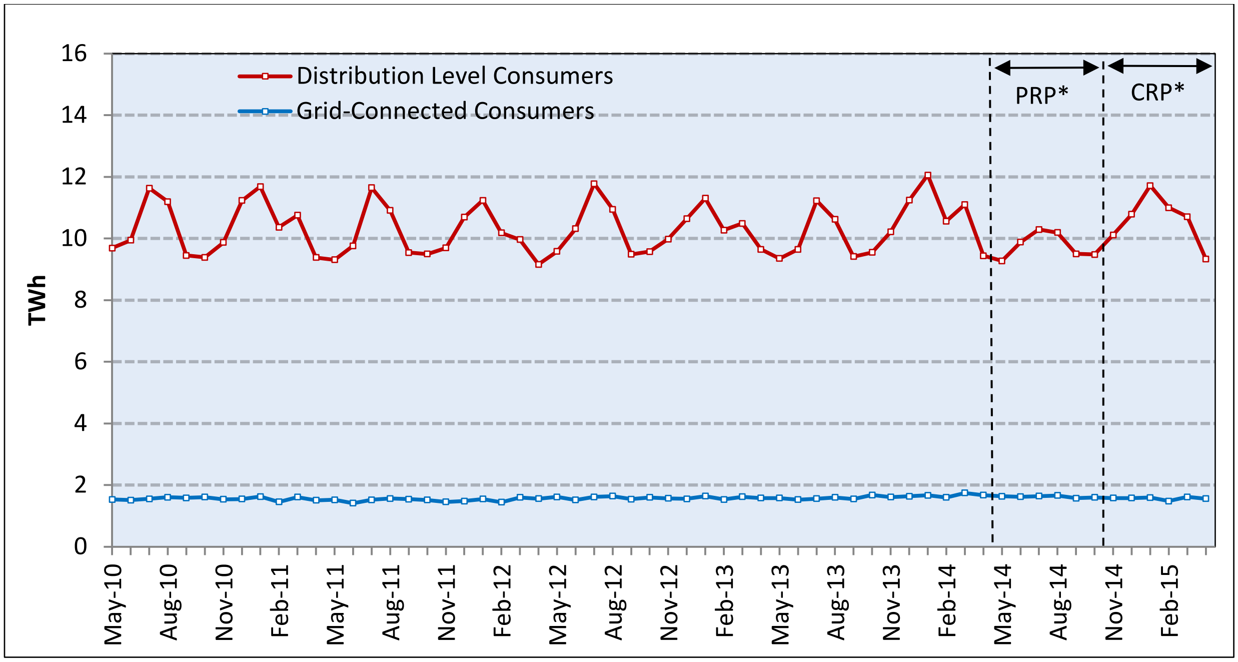
In the last three years, the winter and summer months have become relatively cooler in Ontario; this has resulted in winter peaking energy patterns for 2013 and 2014 rather than summer peaking as was previously the case.

Ontario energy demand in the Current Reporting Period includes the 2014-2015 winter months when demand peaked at approximately 11.3 TWh in January 2015. In comparison, energy demand peaked at approximately 12.3 TWh in the Winter 2014 Period. This difference is primarily due to the difference in weather. While the Current Reporting Period had more instances of extreme low temperatures than the Winter 2014 Period, the total number of heating degree days in the Winter 2014 Period exceeded those in the Current Reporting Period by approximately 160 degree days (in other words, it was consistently colder during the Winter 2014 Period than during the Current Reporting Period).

Figure 1-21: Monthly Total Energy Withdrawals - Distributors and Wholesale Loads May 2010 – April 2015 (TWh)

Description:

Figure 1-21 charts the demand of two categories of consumers: market participants that are directly connected to the IESO-controlled grid other than distributors (Grid-Connected Consumers), and consumers connected to distribution systems (Distribution Level Consumers).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

The breakdown of consumers into these two categories helps identify their respective monthly demand profiles.

Commentary and Market Consideration:

Seasonal change in Ontario demand is attributable almost entirely to Distribution Level Consumers. These include residential, small and medium commercial consumers, and some industrial loads. Low demand on the part of these consumers is particularly evident in the spring (April and May) and fall (September and October) – these “shoulder periods” exhibit lower demand primarily due to more moderate temperatures.

Demand from Grid-Connected Consumers, a group that primarily comprises industrial loads and large commercial consumers, does not appear to vary seasonally, and moreover has remained relatively unchanged over the past five years. The maximum and minimum monthly energy consumption values for Grid-Connected Consumers during the Current Reporting Period are 1.61 TWh and 1.48 TWh, respectively (an 8% difference). These values are 11.7 and 9.3 TWh for Distribution Level Consumers (a 20% difference).

3 Supply

During the Current Reporting Period, 978 MW of nameplate generating capacity was added to the IESO-controlled grid. This new grid-connected capacity consisted of wind (442 MW), hydroelectric (343 MW), biofuel (153 MW) and solar (40 MW).[25]

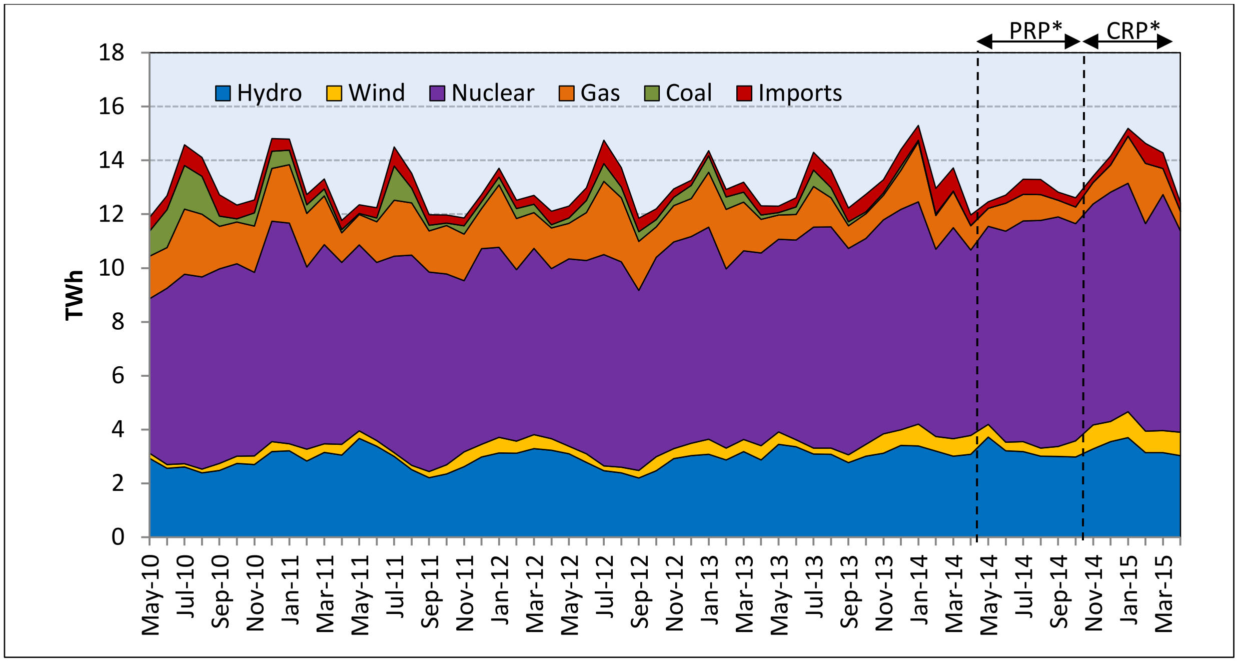
During the Current Reporting Period, 230 MW of nameplate generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of wind (15 MW), solar (213 MW) and small-scale hydroelectric and biofuel (2 MW).

Figure 1-22: Resources Scheduled in the Real-time Market (Unconstrained) Schedule May 2010 – April 2015 (TWh)

Description:

Figure 1-22 illustrates the cumulative share of energy in the real-time unconstrained schedule from May 2010 to April 2015 by resource or transaction type: wind, coal, gas, 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.

[25] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in March 2016 and available at: http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2016mar.pdf



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

Commentary and Market Considerations:

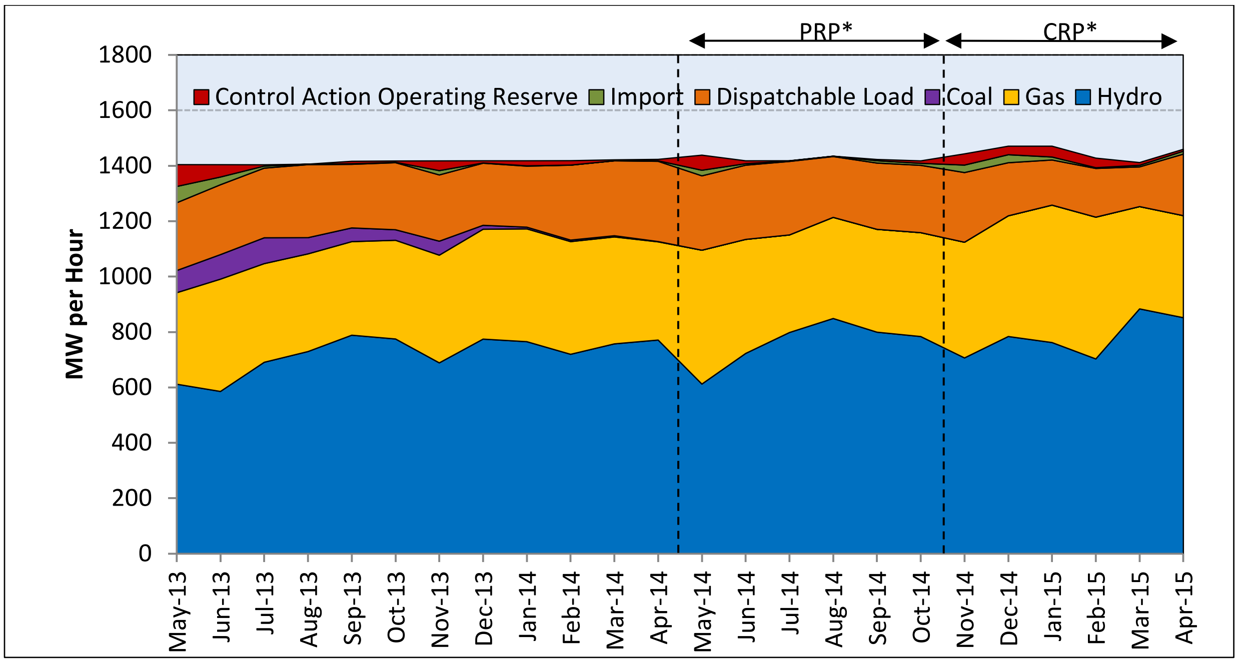
The total energy scheduled in the Current Reporting Period was 84.4 TWh, approximately 7 TWh more than the Previous Reporting Period. This marked the third consecutive year in which winter energy consumption exceeded that of the previous summer. Nuclear units continued to be the predominant resources scheduled, comprising on average 58.4% of all scheduled supply. Hydroelectric facilities were the second most scheduled resources at 23.5%, followed by gas, wind and imports—each at less than 10%.

There was an increase in the scheduling of gas-fired facilities in the Current Reporting Period compared to the Previous Reporting Period, from 6.3% to 8.7%. Similarly, the percentage of scheduled wind energy increased from 3.1% to 6.0%. The increases in scheduled wind energy are due to the combination of seasonal increases in wind supply and the 442 MW of incremental grid-connected wind capacity added during the Current Reporting Period.

Figure 1- 23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type May 2013 – April 2015 (MW per hour)

Description:

Figure 1-23 plots the average hourly amount of OR in the unconstrained schedule from May 2010 to April 2015 by resource or transaction type: hydroelectric, gas, coal, imports, dispatchable loads and Control Action Operating Reserve (CAOR).[26] Changes in the total average hourly operating reserve scheduled reflect changes in the OR quantity requirements.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors such as changes in energy policy or seasonal variations, while changes to the OR requirement may result from changes in grid configuration and outages, among other factors.[27]

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

[27] 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.

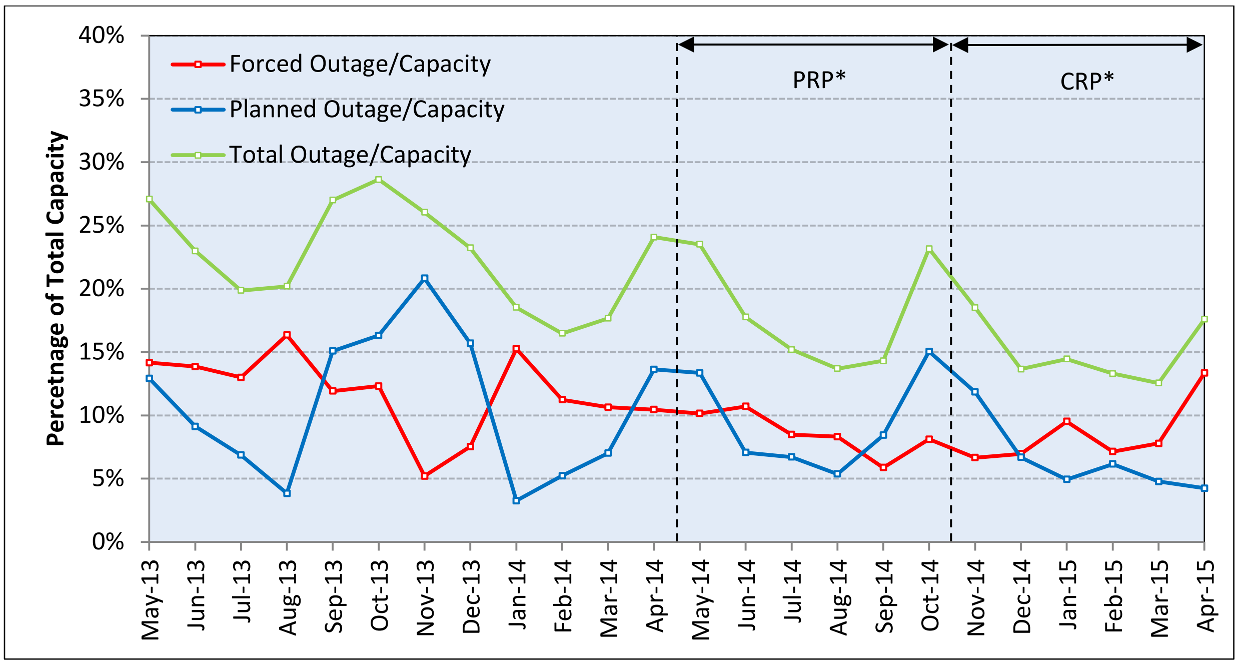
Commentary and Market Considerations:

In the Current Reporting Period, hydroelectric resources accounted for 54% of the total MW scheduled in the OR market, gas-fired facilities for 30%, and dispatchable loads for 13.1%. In comparison, these values were 53.4%, 27.5%, and 17.5%, respectively, for the Previous Reporting Period. There was an increase in the total OR requirement of approximately 2% in the Current Reporting Period, due to changes in the grid configuration resulting from an upgrade at the Lower Mattagami facility.

Figure 1-24: Planned & Forced Outages Relative to Capacity
May 2013 – April 2015
(% of total capacity)

Description:

Figure 1-24 plots planned and forced (i.e. unforeseen) outages as a percentage of total capacity from May 2013 to April 2015.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

Statistics regarding planned and forced outages provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices. Forced outage rates also indicate how the generation fleet responds to external factors, such as extreme weather conditions.

Commentary and Market Considerations:

The Current Reporting Period saw the lowest outage rates of the past three years. Planned outages typically follow a seasonal pattern, with higher outage rates during the spring and fall months and lower outage rates during the summer and winter months. The average amount of capacity on outage in the Current Reporting Period was approximately 5,110 MW or 15% of installed capacity. In comparison, the average amount of capacity on outage in the Previous Reporting Period was approximately 5,970 MW or 18% of installed capacity.

Planned outages were at extremely low levels in April 2015, a time of the year when they have historically been high in relative terms (the 'shoulder period' between the winter and the summer). Although forced outages increased markedly from March to April 2015, total outages remained at seasonal norms due to the low level of planned outages during the same months.

4 Imports, Exports and Net Exports

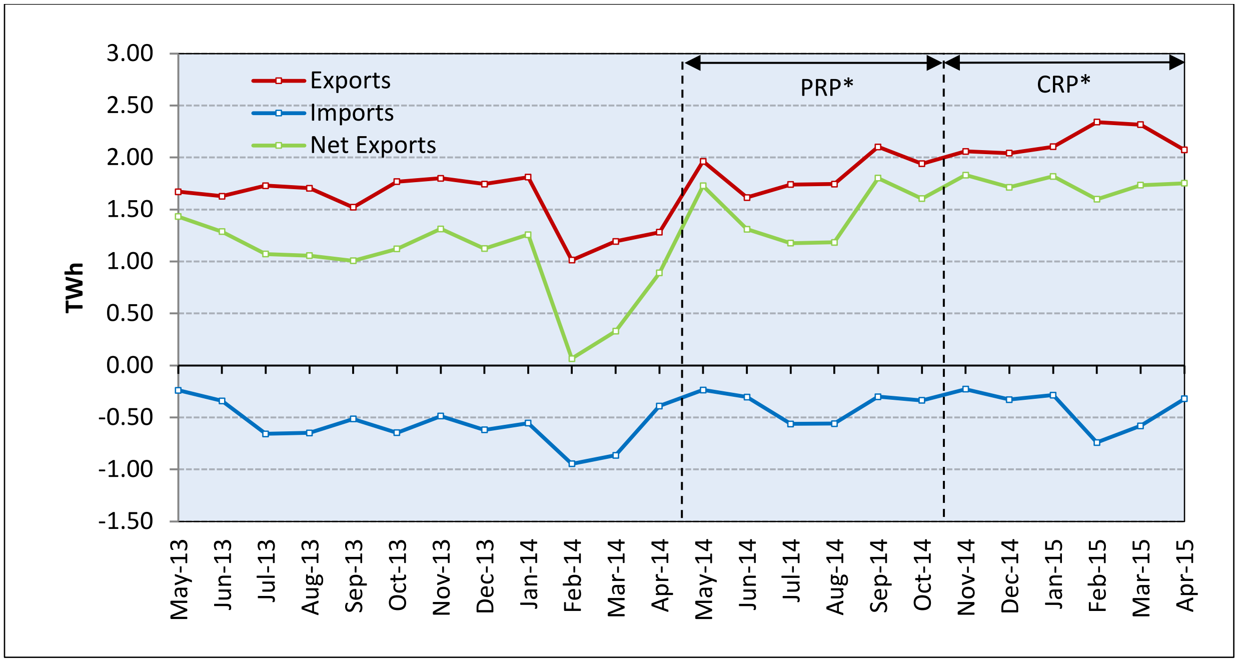
The data used in this section is based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.[28]

Figure 1-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) May 2013 – April 2015 (TWh)

Description:

Figure 1-25 plots total monthly energy imports, exports and net exports from May 2013 to April 2015. 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 provide information on intertie congestion prices or the Ontario uniform price (either in pre-dispatch or in real-time).



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

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 Current Reporting Period, indicate times of relative energy surplus in Ontario, while sustained periods of net imports, such as during the mid-2000s, indicate periods of relative scarcity.

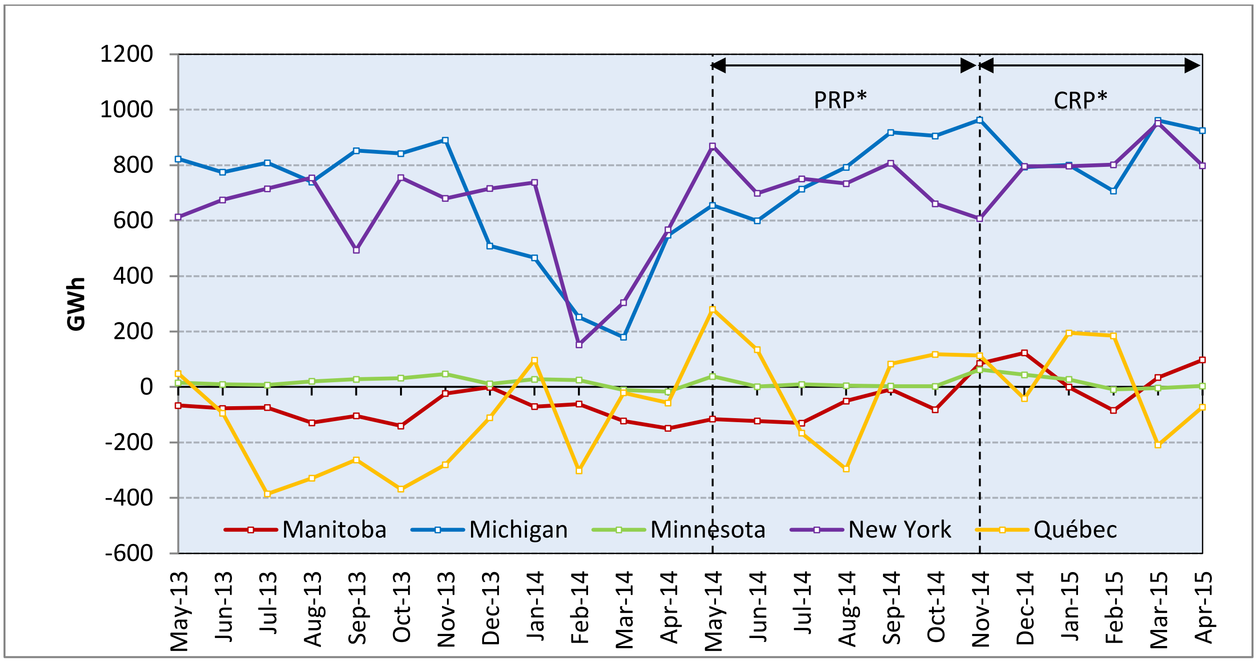
Commentary and Market Considerations:

Ontario was a net energy exporter on a monthly basis from May 2013 to April 2015. Net energy exports totaled 10.4 TWh during the Current Reporting Period, an increase (of 18%) from the Previous Reporting Period. Net exports peaked in the Current Reporting Period at 1.83 TWh during the month of November, which is the largest amount of monthly net exports in the last three years.

Figure 1-26: Net Exports by Interface Group (Unconstrained Schedule)
May 2013 – April 2015
(GWh)

Description:

Figure 1-26 presents a breakdown of net energy exports from May 2013 to April 2015 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.



*PRP: Previous Reporting Period. CRP: Current Reporting Period.

Relevance:

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

Commentary and Market Considerations:

Across the Michigan and the New York interties, Ontario has been a consistent net exporter in recent years. Ontario has fluctuated between small scale energy imports and exports at both the Manitoba and Minnesota interties. Although net export flows on the Québec intertie were comparable to those on the Manitoba and Minnesota interties, those ties are much smaller than the Québec intertie. The small net flows on the Québec intertie reflect a significant amount of offsetting imports and exports, while the flows on the Manitoba and Minnesota interties also reflect some offsetting transactions but much smaller capacity.

Ontario's trade with Québec has alternated between net imports and net exports. Historically, Ontario has been a net importer from Québec during the summer months and a net exporter during the winter months. This reflected the fact that Québec is a winter peaking jurisdiction and, until recently, Ontario was a summer peaking jurisdiction. However, in 2014 and 2015 peak demand in Ontario occurred during the winter. This developing trend will continue to be monitored by the Panel as it may have consequences for future planning decisions, especially in light of the capacity trading agreement that was signed in 2015 between the IESO and Hydro Québec Energy Marketing.[29] The agreement was made to support reliability by taking advantage of the two provinces' complementary seasonal peaks of electricity resources and needs.

Table 1-5: Average Monthly Export Failures by Interface Group and Cause (Constrained Schedule) May 2014 – October 2014 & November 2014 – April 2015 (GWh and %)

Description:

Table 1-5 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[30]

Interface Group	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	387.6	348.4	1.0	1.4	5.1	6.1	0.3	0.4	1.3	1.8
Michigan	410.8	324.3	3.7	1.7	4.9	4.1	0.9	0.5	1.2	1.3
Manitoba	40.8	14.2	3.3	1.9	4.8	4.0	8.2	13.1	11.7	28.3
Minnesota	9.1	9.6	0.4	1.3	0.3	0.1	4.4	13.6	2.8	1.3
Québec	187.2	149.0	13.3	3.1	1.9	1.9	7.1	2.1	1.0	1.3

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

[29] For a description of the arrangement, see:http://www.ieso.ca/Documents/corp/Summary-Capacity-Sharing-Agreement-Ontario-Quebec.pdf.
[30] A linked wheel transaction is one in which an import and an export are scheduled in the same hour, thus wheeling energy through Ontario.

fails due to a failure on the part of a market participant (such as an inability to obtain transmission service).

MP failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule 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 (SBG) conditions.[31] The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

Commentary and Market Considerations:

The Current Reporting Period saw Manitoba experience the highest percentage of MP Failures relative to other interties. The volume of exports on the Manitoba intertie that failed by reason of MP Failures has remained steady between 4 and 5 GWh, an extremely high rate of failure considering the total volume of exports on that intertie during the Current Reporting Period (40.8 GWh). These MP Failures, related to a failure to acquire transmission, were more heavily concentrated during the lower demand months of the Current Reporting Period and during the hottest summer months in the Previous Reporting Period.

Comparing the Current Reporting Period with the Previous Reporting Period, the percentage of ISO Curtailments decreased for the New York, Manitoba and Minnesota interties. Similarly, the percentage of MP Failures decreased for all interties except the Minnesota intertie.

ISO Curtailments between Québec and Ontario increased significantly during the Current Reporting Period relative to the Previous Reporting Period. This is likely a seasonal effect; the same levels of ISO Curtailments occurred out during the Winter 2014 Period.

[31] SBG conditions arise when baseload generation (comprised of combined heat and power, embedded generation, NUGs, nuclear, must-run hydroelectric, solar, wind, and commissioning units) is greater than Ontario demand and forecasted exports. For a description of facilities that are classified as baseload, see: http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20120808-SBG_Explanation_FPFG.pdf.

Table 1-6: Average Monthly Import Failures by Interface Group and Cause (Constrained Schedule) May 2014 – October 2014 & November 2014 – April 2015 (GWh and %)

Description:

Table 1-6 reports average monthly import failures and curtailments over the Current and Previous Reporting Periods by interface group and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Interface Group	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate (%)			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	11.3	3.6	0.1	0.1	0.3	0.2	0.8	3.2	2.7	5.5
Michigan	14.5	1.9	1.9	0.2	0.9	0.3	13.1	12.0	6.1	13.4
Manitoba	20.7	24.9	2.9	7.3	0.2	0.1	14.0	29.1	0.8	0.4
Minnesota	1.1	0.2	0.2	0.0	0.1	0.0	21.0	2.4	9.0	21.0
Québec	123.7	118.6	4.0	7.1	0.4	0.4	3.3	6.0	0.3	0.4

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule 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:

Relative to the Previous Reporting Period, the Current Reporting Period saw a significant increase in the percentage of ISO Curtailments at the Minnesota intertie, and decreases at the Manitoba and Québec interties. The decrease in ISO Curtailments was accompanied by a decrease in average monthly imports on the Manitoba intertie. On the Québec intertie, the decrease in ISO Curtailments was accompanied by an increase in imports.

Chapter 2: Analysis of Market Outcomes

1 Introduction

The Panel is responsible for monitoring activities related to the IESO-administered markets. Market monitoring occurs over several timeframes, ranging from the day-to-day monitoring activities of the IESO’s Market Assessment Unit (which supports the Panel), to the longer term analysis by the Panel. Central to this monitoring function is the identification and study of market outcomes that fall outside the predicted patterns or norms. Analysis of these anomalous events contributes to greater transparency, enhances understanding of the market for market participants and other interested stakeholders, and often leads to recommendations aimed at improving the efficient and fair operation of a competitive market. This chapter discusses anomalous events for the period between November 1, 2014 and April 30, 2015 (Current Reporting Period), with comparisons to the period between May 1, 2014 and October 31, 2014 (Previous Reporting Period) and to other periods as relevant. A reference to a Winter Period is a reference to the period running from November 1 in one year to April 30 in the next.

Of particular interest to the Panel are energy prices that are higher or lower than normally observed. The Panel has previously defined higher-than-normal energy prices as Hourly Ontario Energy Prices (HOEP) that exceed $200/MWh (High HOEPs). HOEPs below $0/MWh meet the Panel’s threshold for lower-than-normal energy prices (Low HOEPs).

The Panel also reports on high uplift payments. Again, the Panel has set thresholds to identify uplift payments that exceed normally observed levels. The uplift payments for which thresholds have been set are Congestion Management Settlement Credit (CMSC) payments, Intertie Offer Guarantee (IOG) payments and Operating Reserve (OR) payments.

Table 2-1 sets out a summary of the anomalous price and uplift events that occurred during the Current Reporting Period and the previous two Winter Periods.

Table 2-1: Anomalous Events During the 2013, 2014 and 2015 Winter Periods (Number of Occurrences)

Event	Winter 2013 Period	Winter 2014 Period	Winter 2015 Period (Current Reporting Period)
HOEP > $200/hour	5	133	28
HOEP < $0/hour	43	120	324
CMSC > $1 million/day	7	30	3
CMSC > $500,000/hour	2	1	-
OR Payments > $100,000/hour	-	5	32
IOG > $1 million/day	-	12	-
IOG > $500,000/hour	-	-	-

While the number of High HOEPs (28) was less than during the exceptional Winter 2014 Period,[32] the number is nevertheless relatively high as historically there have only been a few High HOEPs per reporting period. The Current Reporting Period also saw the highest HOEP since the market opened, as well as the largest number of Low HOEPs during a Winter Period.

The Current Reporting Period had relatively few anomalous CMSC events compared with the Winter 2013 and Winter 2014 Periods. In contrast, the Current Reporting Period produced the greatest number of hours with high OR payments of any Winter Period on record.

In this report the Panel is also reporting on payments made under with the IESO's Real-time Generation Cost Guarantee and Day-Ahead Production Cost Guarantee programs. Payments under these programs are recovered through uplift charges. The IESO's stakeholder engagement regarding possible changes to the Real-time Generation Cost Guarantee program and the Panel's participation in that engagement is discussed in Chapter 3.

2 Anomalous Energy Prices

2.1 Analysis of High HOEPs

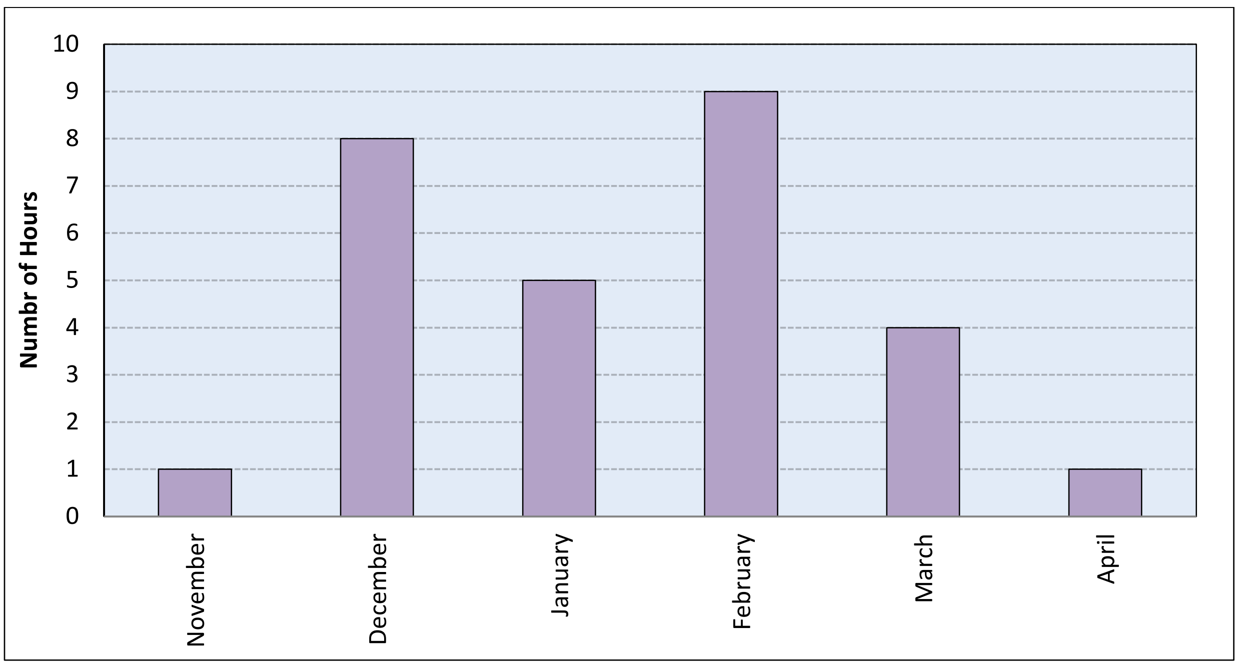
High HOEPs typically signal tight real-time supply conditions in the province. These conditions arise as a result of relatively high demand, relatively low real-time supply, or a combination of

[32] For more information, see the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf.

the two. High demand is often a consequence of weather conditions, while low supply conditions may be due to transmission outages, generator outages, import failures or ramping limitations. In addition, pre-dispatch scheduling plays an important role in setting the real-time price.[33] While real-time circumstances dictate the energy price that clears the market, events in pre-dispatch can have a direct impact on these prices. Specifically, pre-dispatch forecasts of demand and of output from variable generation resources (e.g. wind and solar facilities) play a key role in determining which dispatchable resources (non-quick start generators, dispatchable loads, imports and exports) are scheduled in pre-dispatch and therefore available in real-time.

Figure 2-1 displays the number of High HOEPs in each month of the Current Reporting Period.

Figure 2-1: Monthly Distribution of High HOEPs
November 2014 – April 2015
(Number of Hours)

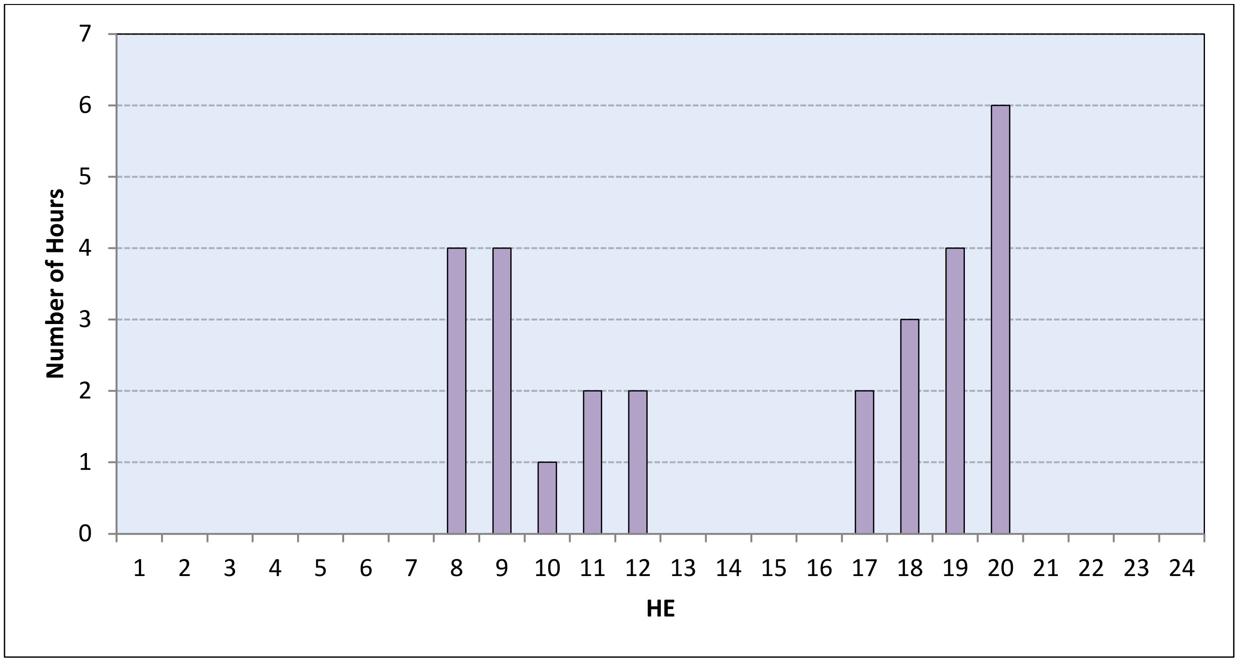


In total, there were 28 High HOEPs during the Current Reporting Period. In general, their occurrence was coincident with colder winter temperatures.

[33] High real-time prices are not always associated with high pre-dispatch prices; sometimes only pre-dispatch prices are high, and at other times only the real-time price is high.

Figure 2-2 displays the distribution of High HOEPs by hour during the Current Reporting Period. Each hour shown in the figure is the hour ending (HE).[34]

Figure 2-2: Distribution of High HOEPs by Hour of Day November 2014 – April 2015 (Number of Hours)



High HOEPs were concentrated around the highest demand hours. The highest number of High HOEPs occurred during HE 20, when temperatures are typically falling and consumers have generally returned home from work.

Many High HOEPs also occur as a result of several commonly observed circumstances beyond increased demand. Examples include forecasting variances in demand and in variable supply (e.g. wind and solar facilities), real-time curtailment of intertie transactions (which are scheduled one hour prior to real-time) and short-notice generator outages or de-ratings.

The pre-dispatch scheduling process requires a number of data inputs including data on demand, supply, outages and inter-jurisdictional transactions. However, due to their variable nature, conditions do not always match these forecasts in real-time. When real-time conditions do not align with forecasts, the market must accommodate last-minute changes using available

[34] Hour ending or HE means the hour that ends at the time stated. For example, HE 8 means the hour between 7 a.m. and 8 a.m.

resources that are capable of responding to dispatch instructions quickly. Such quick response resources are typically more expensive sources of supply (such as flexible hydroelectric facilities) and dispatching them tends to result in higher prices.

A more detailed discussion of how short-notice adjustments to supply or demand affect pricing, as well as a detailed analysis of the precise events surrounding the highest-priced hour during the Current Reporting Period (indeed, the hour in which the highest HOEP in market history occurred) follows.

2.1.1 *Comparison of the Winter 2014 Period to the Current Reporting Period*

The number of High HOEPs during the Current Reporting Period (28 hours) was significantly less than it was in the Winter 2014 Period (133 hours). February 2015 was colder than any month in the Winter 2014 Period, with an average temperature of -12.6 °C.[35] The coldest monthly average temperature in the Previous Reporting Period was -8.6 °C (January 2014).[36] Nevertheless, February 2015 had fewer High HOEPs (9) than January 2014 (32). In general, this discrepancy can be explained by the high price of natural gas during the Winter 2014 Period. Natural gas prices in the Current Reporting Period were much lower by comparison.

2.1.2 *Wind Shortfalls, Demand Under-forecasting and High HOEPs*

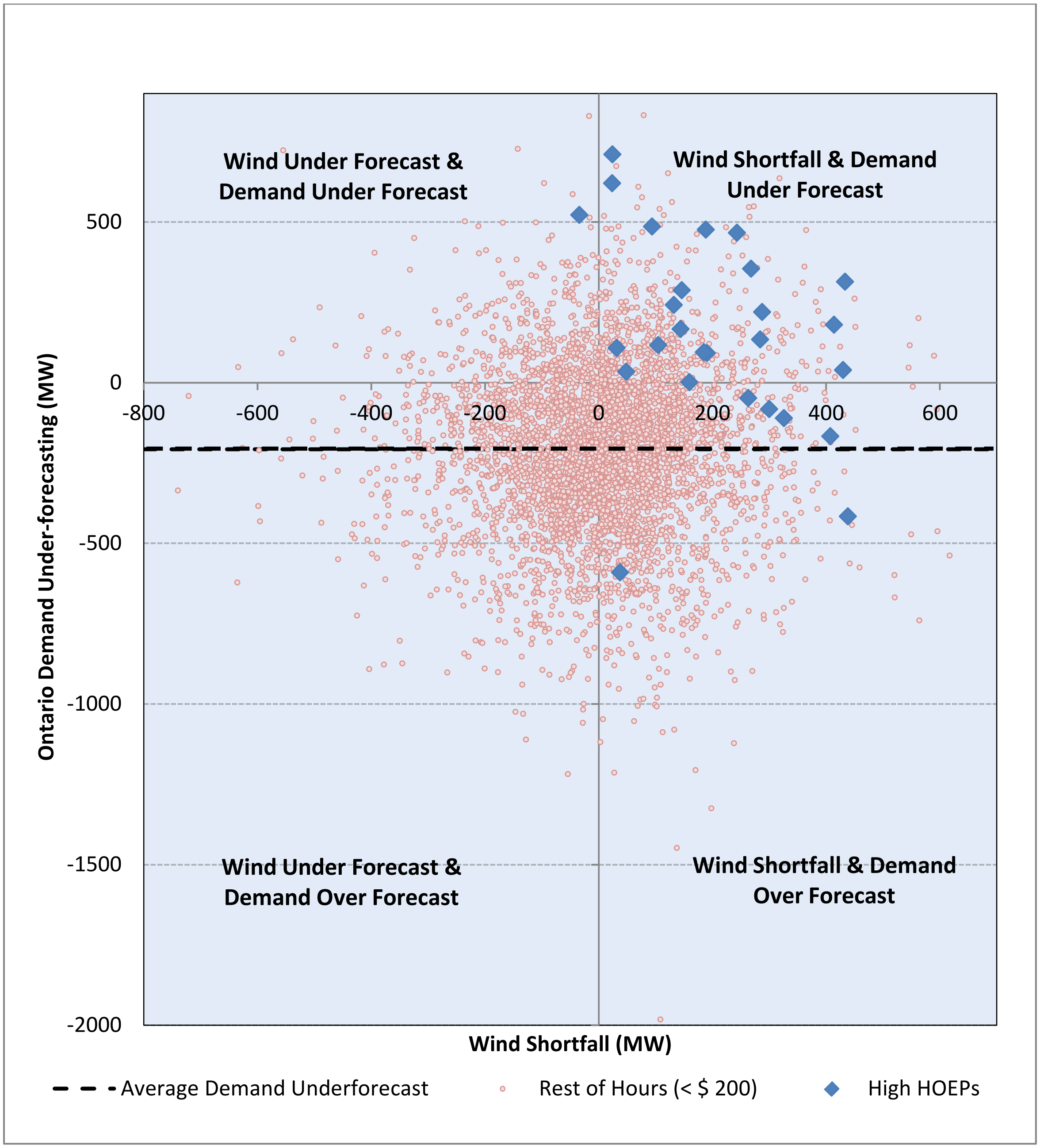
A 'wind shortfall' occurs when real-time wind output is less than the hour-ahead (PD-1) forecast. Conversely, under-forecasting of demand occurs when real-time demand is *greater* than the PD-1 forecast. Both of these conditions result in a greater need for supply in real-time than was contemplated in PD-1. There were wind shortfalls in all but one of the 28 High HOEPs during the Current Reporting Period, and an under-forecasting of demand in 22 of the 28 High HOEPs.

Figure 2-3 maps the HOEP against wind and demand forecasts, and shows a data point for each hour during the Current Reporting Period. The coordinates represent the degree of demand forecast error (on the y-axis) and wind forecast error (on the x-axis). If a data point lies above the x-axis, then real-time demand was higher than forecast (the forecast underestimated real-time

[35] According to Environment Canada, February 2015 was the first month on record (since 1840) during which the temperatures at the downtown Toronto station remained below freezing for the entire month; https://www.ec.gc.ca/eau-water/01AD4C5F-1797-4EA2-ADFE-161E890F8F56/GL-Winter2014-15_FINAL_updated.pdf.
[36] All temperatures measured at Pearson International Airport weather station. Data sourced from Climate Canada at: http://climate.weather.gc.ca/index_e.html.

demand). If a data point lies to the right of the y-axis, then real-time wind production was less than was expected in the PD-1 timeframe (real-time wind production fell short of expectations).

Figure 2-3: HOEP Map Against Ontario Demand Under-Forecasting and Wind Shortfall November 2014 – April 2015 (MW)



Most High HOEPs occur in the upper right quadrant because wind shortfalls and demand under-forecasts result in both tighter than expected supply conditions and higher than expected demand, creating upward pressure on the real-time price. The forecasting errors in the top left and bottom right quadrants have off-setting price impacts (with one error putting upward pressure on price and the other putting downward pressure on price). In the bottom left quadrant, both forecasting errors put downward pressure on price; there is more wind generation relative to forecast and less demand than forecast.

Wind shortfalls and demand under-forecasting are not the only causes of High HOEPs. Other events which force the market to turn to flexible (and typically more expensive) resources to supply demand in real-time also put upward pressure on prices. However, as shown in Figure 2-3, 75% of the High HOEPs in the Current Reporting Period occurred when there was both an under-forecast of demand and a wind shortfall.

The following sections examine the High HOEPs that occurred on February 20, 2015 and February 26, 2015.

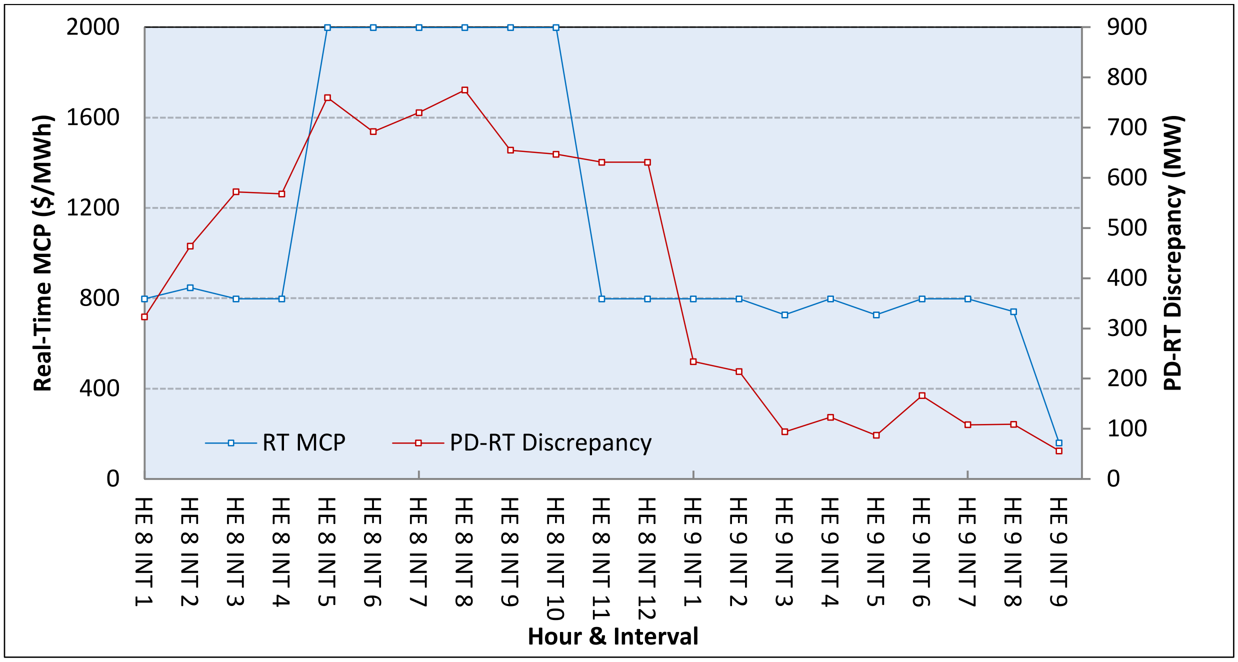
2.1.3 *Hour Ending 8 and Hour Ending 9, February 20, 2015*

On February 20, 2015, the HOEP in HE 8 and HE 9 was $1,402/MWh and $564.82/MWh, respectively. The HOEP in HE 8 was the highest HOEP on record.

February 20 was a particularly cold day with a mean temperature of -18.6 °C. Average market demand throughout the day was 23,240 MW, peaking at 25,127 MW in HE 8. Hour-ahead pre-dispatch prices for HE 8 and HE 9 were $135.46 and $150.00, respectively, reflecting in part higher-than-normal natural gas prices.

There were three main factors contributing to these High HOEPs: differences between the pre-dispatch and real-time values for demand; an increase in net exports, due in part to import curtailments; and wind shortfalls. Figure 2-4 shows how the real-time MCP moved in concert with the changes in supply and demand between PD-1 and real-time. This figure highlights the relationship between forecast error and real-time prices.

Figure 2-4: Real-time Market Clearing Price and Pre-dispatch to Real-time Discrepancy February 20, 2015 HE 8 to HE 9 ($/MWh, MW)



The PD-1 demand forecast for the morning ramping hours (HE 6 to HE 9) is the peak demand forecasted for any interval during each of those hours. For HE 8, the peak demand forecast for the hour was 20,602 MW. The real-time demand was greater than the forecast peak during every interval starting in interval 3 of HE 8. An increase in the demand under-forecast in interval 5 of HE 8 corresponded with the price spike in MCP to $1,999/MWh (this price was set by a dispatchable load).

In HE 8 and HE 9, wind production decreased during most intervals; starting at 763 MW in interval 1 of HE 8 and ending at 565 MW in interval 12 of HE 9. The PD-1 forecasts for wind production during HE 8 and HE 9 were higher than actual production by 114.6 MW and 204.5 MW, respectively. 350 MW of imports for HE 8 (from Michigan and Québec) were curtailed just prior to real-time. This short-notice import curtailment meant that net exports increased by 511 MW from HE 7 to HE 8. This significant increase in net exports contributed to the increase in the MCP from interval 12 in HE 7 ($134.42/MWh) to interval 1 in HE 8 ($797.60/MWh). One reason for this increase in net exports was that 350 MW of imports from Michigan and Québec were curtailed for HE 8 just prior to real-time. 150 MW of exports from Ontario to New York were curtailed due to transmission issues in New York starting in interval 10 of HE 8, which resulted in the price decrease that started in that interval.

2.1.4 *Hour Ending 8 and Hour Ending 9, February 26, 2015*

On February 26, 2015, the HOEP in HE 8 and HE 9 was $490/MWh and $580/MWh, respectively. These hours are of particular interest due to operational issues experienced by various gas-fired facilities. The activation of OR in response to these operational issues is also of note.

February 26th was a cold day with a mean temperature of -14 °C. Hour-ahead pre-dispatch prices for HE 8 and HE 9 were $125.62/MWh and $104.80/MWh, respectively. The High HOEPs in these hours were the result of gas supply issues. At 3:30 a.m., Facility A informed the IESO control room that their facility would be unavailable due to a frozen hydraulic line. At 6:44 a.m., one unit from another gas-fired facility, Facility B, was forced out of service due to air system problems.

These issues forced the IESO to replace resources on relatively short notice. During HE 8 itself, the production from an entire gas-fired facility, Facility C, was lost due to technical issues.

During interval 9 of HE 8, the MCP was $2000/MWh, higher than the MCP reached during either of the High HOEP hours on February 20th. This sudden price spike was caused by the loss of Facility C. When the MCP reaches $2000/MWh, it means that there are no dispatchable resources left to respond and the only remaining alternative is to reduce demand through out-of-market actions (e.g. reducing voltage or curtailing load). This extreme scarcity condition was transitory; it persisted for only one interval.

In response to the loss of Facility C, 750 MW of OR was activated to provide energy. In addition, during interval 11 of HE 8 472 MW of exports were curtailed to address a projected shortfall in OR.

The price impact of the loss of Facility C was exacerbated by the earlier loss of 228 MW of combined capacity at Facilities A and B, and by the fact that this loss occurred or persisted during the morning ramp period when resources are typically already adjusting their output upwards to meet growing demand.

The high prices continued throughout HE 8 until Facility C returned to service during HE 9.

2.2 Analysis of Low HOEPs

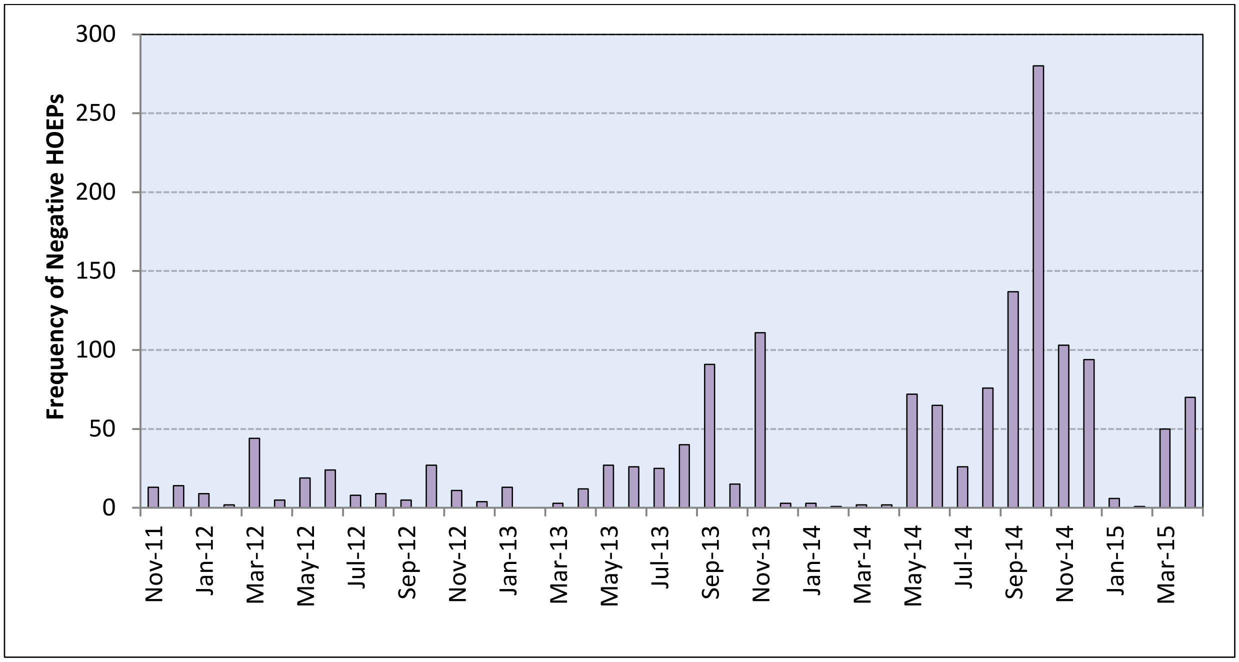
A total of 324 Low HOEPs occurred in the Current Reporting Period. The following table shows the distribution of Low HOEPs by month during the Current Reporting Period.

Table 2-2: Frequency of Low HOEPs by Month November 2014 – April 2015 (Number of Hours)

Month	Number of Low HOEP Hours
November	103
December	94
January	6
February	1
March	50
April	70

There was a significant increase in the number of Low HOEPs in the Current Reporting Period compared to the previous two Winter Periods (see Table 2-1 above). This increase was due to unseasonably mild temperatures during November and December 2014, coupled with year-over-year increases in energy production from nuclear facilities during March and April 2015.

Figure 2-5: Frequency of Low HOEPs by Month
November 2011 – April 2015
(Number of Hours)



The number of Low HOEPs per month has increased in recent years. This is due to decreasing demand for electricity and additional supply from baseload resources. The prices associated with energy offers from these resources are typically negative. Increases in the amount of supply offered from these resources puts downward pressure on the energy price.

3 Anomalous Uplift Payments

The Panel monitors anomalous uplift payments associated with the IESO-administered markets. To that end, the Panel has thresholds for three types of uplift payments - CMSC, IOG and OR payments – and reports on events of interest where those thresholds are exceeded.

3.1 Congestion Management Settlement Credit

The Panel reports on events that result in daily CMSC payments in excess of $1 million; during the Current Reporting Period, there were three such days – February 16, 17 and 19, 2015.

The Panel also reports on events that result in hourly CMSC payments in excess of $500,000. There were no such hours during the Current Reporting Period.

Table 2-3 shows the total CMSC payments per day for the days during which more than $1 million in CMSC payments were made.

Table 2-3: CMSC Payments Greater Than $1 Million/Day
February 16, 17 and 19, 2015
($)

Delivery Date	Total CMSC/Day
2015/02/16	$1,329,751
2015/02/17	$1,709,982
2015/02/19	$1,117,391

3.1.1 February 16, 2015

On February 16, $1.3 million in CMSC payments were made. $934,924 of these payments were made to exporters and importers. Table 2-4 shows the distribution of CMSC payments by resource or transaction type, and whether the payments were for being constrained on or constrained off.

Table 2-4: Distribution of CMSC Payments
February 16, 2015
($)

	Imports	Exports	Generation	Loads
Constrained-on	$151,938	$154,499	$115,667	-
Constrained-off	-$71,112	$699,598	$279,160	-

Constrained-off CMSC payments to exporters made up more than half of the total CMSC payments for the day.

Of the $699,598 in constrained-off CMSC payments to exporters, $588,327 was paid between HE 18 and HE 21. During these hours, nodal prices were above the intertie zonal prices. At the same time, prices in New York and Québec were above Ontario prices, indicating the existence of possible arbitrage opportunities.

The Panel has previously recommended the elimination of constrained-off CMSC payments for all interties for various reasons, including that they incent inefficient market behaviour such as nodal price chasing. The IESO has now eliminated constrained-off CMSC payments for intertie transactions effective September 18, 2015.[37]

Table 2-5 shows the following prices on February 16, 2015: the HOEP; nodal prices (from nodes located electrically close to the intertie); and prices in external jurisdictions.

Table 2-5: HOEP and Nodal & External Jurisdiction Prices by Intertie February 16, 2015, HE 18 – 21 ($/MWh & $)

		Intertie					
		New York		Michigan		Québec[38]	
HE	**HOEP ($/MWh)**	**Nodal Price ($/MWh)**	**External Price ($/MWh)**	**Nodal Price ($/MWh)**	**External Price ($/MWh)**	**Nodal Price ($/MWh)**	**External Price ($/MWh)**
18	82.33	309.47	381.31	288.24	37.86	294.00	243.21
19	41.13	480.00	240.00	447.06	42.58	456.00	261.20
20	44.39	494.13	458.50	460.22	42.20	469.42	362.04
21	93.26	304.32	219.94	283.43	43.80	289.10	248.52
Total Constrained-off CMSC ($)		$362,631		$163,096		$62,557	

The conditions that led to large constrained-off CMSC payments on the New York intertie were nodal prices significantly above the HOEP. In this case, a legitimate arbitrage opportunity existed as external prices were also significantly above the intertie zonal price.

One market participant received a total of $495,507 in constrained-off CMSC payments for all intertie transactions (imports and exports), $161,115 of which was constrained-off CMSC payments for exports on the New York intertie.

3.1.2 February 17, 2015

On February 17, $1,329,751 in CMSC payments were made. CSMC payments to importers and exporters totaled $1,041,881, constituting the majority of the CMSC payments that day.

Table 2-6 shows the CMSC payments on February 17, 2015 by type of constraint and recipient.

[37] For more information on this Market Rule amendment see: http://www.ieso.ca/Documents/Amend/mr2015/MR_00423_Amendment_Proposal%20v5.0.pdf.

[38] For exports from Ontario to Québec, the Panel has assumed a sale price equal to the highest price available at interfaces between Québec and New York or Québec and Vermont.

Table 2-6: Distribution of CMSC Payments
February 17, 2015
($)

	Imports	Exports	Generation	Load
Constrained-on	$155,411	$145,113	$164,779	-
Constrained-off	-$45,881	$896,768	$372,273	$ 13,772

The high constrained-off CMSC payments paid to exporters on February 17, totaling $896,768, occurred under similar circumstances as those noted above for the previous day. That is, a large difference between the HOEP and nodal prices resulted in export transactions being constrained off. These export transactions took place during hours when an arbitrage opportunity existed as external jurisdiction prices were also higher than the intertie zonal price. Payments on this day were larger than those on the previous day as the conditions giving rise to the payments prevailed during more hours.

3.1.3 February 19, 2015

Unlike February 16 and 17, most of the CMSC payments on February 19 were made to generators in Ontario and not to intertie traders. A total of $1,117,391.22 in CMSC payments was made on that day, of which the overwhelming majority was paid to generators. Table 2-7 shows the CMSC payments on February 19, 2015 by type of constraint and recipient.

Table 2-7: Distribution of CMSC Payments
February 19, 2015
($)

	Imports	Exports	Generation	Loads
Constrained-on	$ 25,058	$ 21,225	$324,282	-
Constrained-off	$ -22,481	$ 44,310	$718,442	$ 6,555

The majority of the CMSC payments made on February 19 were constrained-off payments to generators ($718,442).

Gas-fired facilities which qualify for cost guarantees are committed prior to real-time (either through the day-ahead or real-time cost guarantee programs). Sometimes these facilities are not economic in real-time if real-time energy prices drop below their offer prices. However, because of the commitment they are constrained on to at least their minimum loading point, and they receive constrained-on CMSC payments as a result (these payments are deducted from any cost guarantee payments made to them). Moreover, in order to accommodate the megawatts generated by the constrained on gas-fired facilities, flexible hydroelectric facilities were constrained off. These facilities received more than half ($411,997) of the constrained-off CMSC payments made to generators on this day.

3.2 Operating Reserve Payments

OR payments in excess of $100,000 for a given hour are considered anomalous by the Panel. During the Current Reporting Period there were 32 such hours. Like CMSC payments, the cost of procuring OR is charged to market participants as part of the hourly uplift charge.

There are three classes of OR: 10-minute spinning (10S); 10-minute non-spinning (10N); and 30-minute (30R). The IESO procures OR as a function of its system operator duties. The amount of OR that the IESO procures is specified in reliability standards set by the North American Electric Reliability Corporation and the Northeast Power Coordinating Council. These reliability standards require the IESO to procure enough 10-minute reserve to cover the largest single contingency that can occur on the grid, given the current configuration. A minimum of 25% of the 10-minute reserve must be synchronized to the grid (10-minute spinning reserve). The remainder can be unsynchronized (10-minute non-spinning reserve). Suppliers of 10-minute OR must be able to provide the required energy to the grid within 10 minutes of being dispatched and must be available to provide the energy for up to one hour. The IESO's 30-minute requirement is equal to the greater of half of the second largest contingency on the grid or the largest commissioning unit. The suppliers of this class of OR do not have to be synchronized to the grid. 30-minute OR must be provided to the grid within 30 minutes of being dispatched and must be available for up to one hour.[39]

The markets for OR are jointly optimized with the energy market, with the dispatch algorithm attempting to minimize total cost across all markets. OR prices represent the incremental system cost of providing 1 incremental MW of OR.

Total OR payments, which equal the product of the price of OR and the quantity of OR scheduled, averaged at $299,828 for the 32 anomalous OR hours in the Current Reporting Period. The average HOEP during these hours was $372/MWh. The average prices for OR

[39] For more detail on the OR markets and how they operate, see *IESO,* Guide to Operating Reserve, October 2011. http://www.ieso.ca/Documents/training/ORGuide.pdf.

during the 32 anomalous hours were $313/MW, $306/MW and $294/MW for 10S, 10N and 30R, respectively. During relative shortage conditions, prices for energy and OR tend to converge due to the co-optimization of the markets. It follows that conditions that contribute to high prices in the energy market typically contribute to high prices in the OR markets as well, as was often the case in the Current Reporting Period. Of the 32 hours with anomalous OR payments during the Current Reporting Period, 26 were also High HOEP hours

The 32 anomalous OR hours in the Current Reporting Period is the highest during any Winter Period since market opening. The next highest number of such hours was 5, during the Winter 2014 Period. The Current Reporting Period also had the highest hourly OR payment amount in any Winter Period since market opening at $967,789, more than double the next-highest hourly OR payment amount of $420,168 on March 5, 2005. This latter OR payment amount was exceeded eight times during the Current Reporting Period.

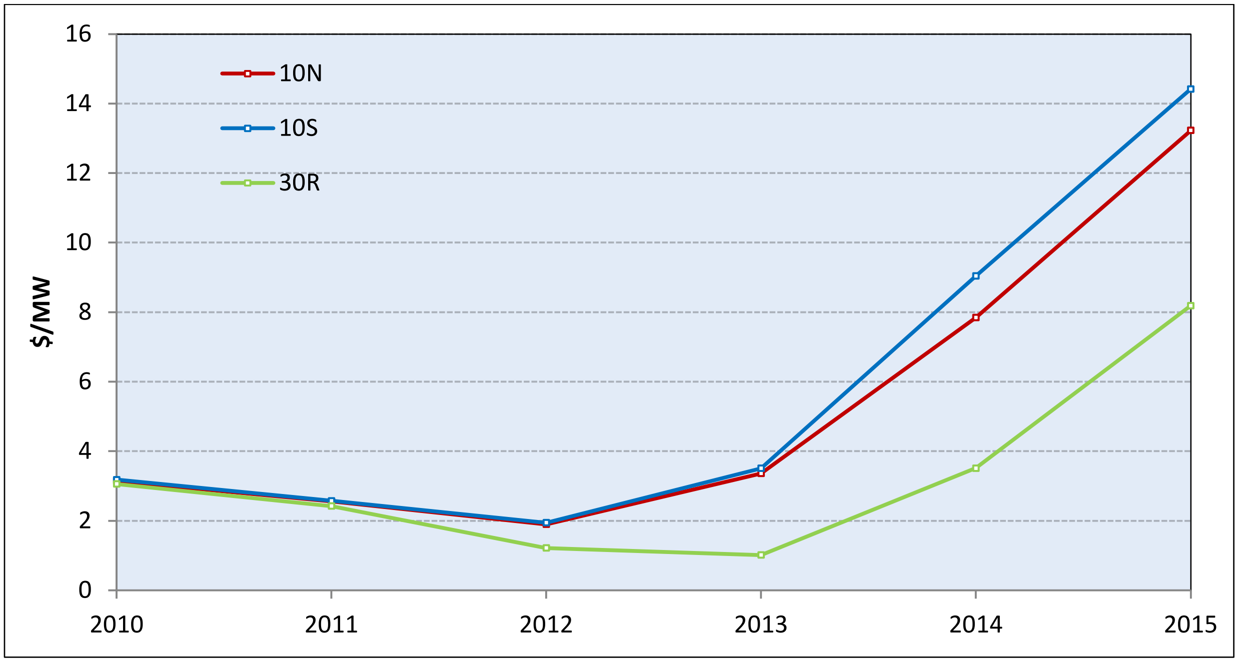
The following sections examine the supply and demand factors that contributed to the increased number of high OR payment hours, as well as the factors that contributed to higher average OR prices in all hours during the Current Reporting Period.

3.2.1 OR Price

OR prices during the winter months have been trending higher for a number of years, a trend that continued during the Current Reporting Period.

Figure 2-6 shows the average OR prices for the last six Winter Periods for all three OR markets. OR prices are calculated on a 5-minute basis. The average prices used in Figures 2-6 and 2-7 are the arithmetic averages of the 12 OR prices for each hour.

Figure 2-6: Average Hourly OR Prices for Winter Periods
Winter 2010 Period – Current Reporting Period
($/MW)

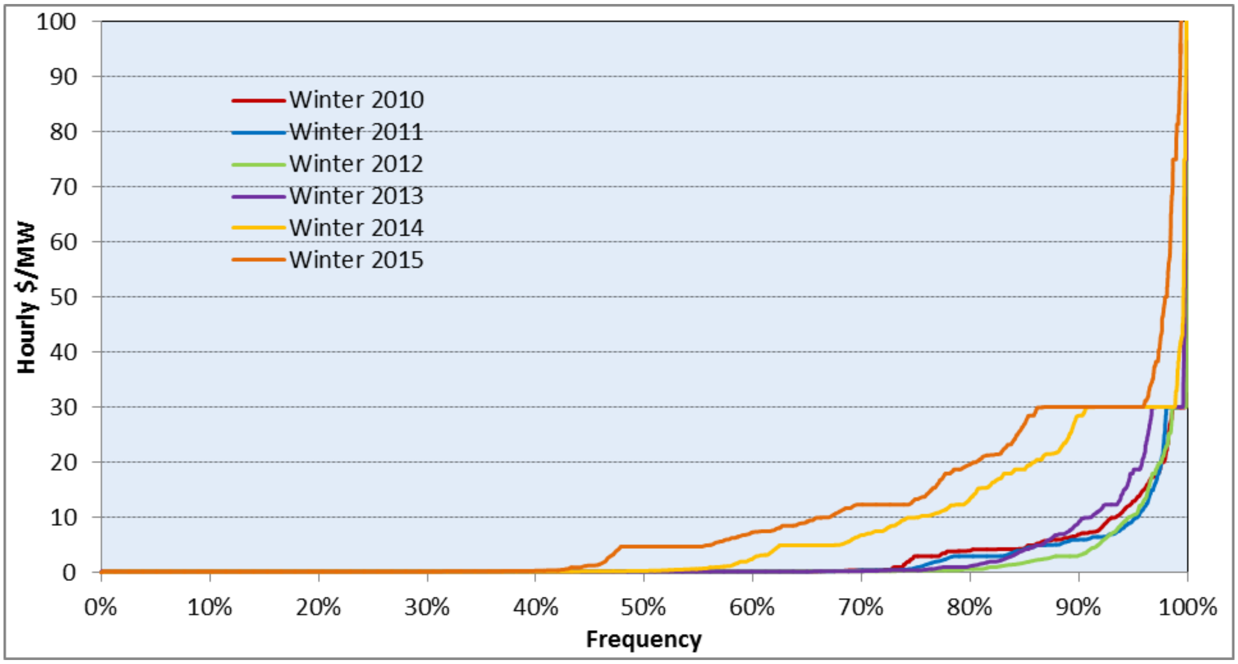


Average prices in all three OR markets have increased considerably in the past two Winter Periods in both the peak and off-peak periods.

Due to the relationship between the categories of OR, the discussion below focuses on prices in the 10S market, as effects in the 10S market tend to be reflected in the ‘downstream’ 10N and 30R OR markets.

Figure 2-7 shows the cumulative histogram of 10S OR prices during the past 5 Winter Periods and the Current Reporting Period, showing the percentage of time that those prices were at or below a certain dollar amount.

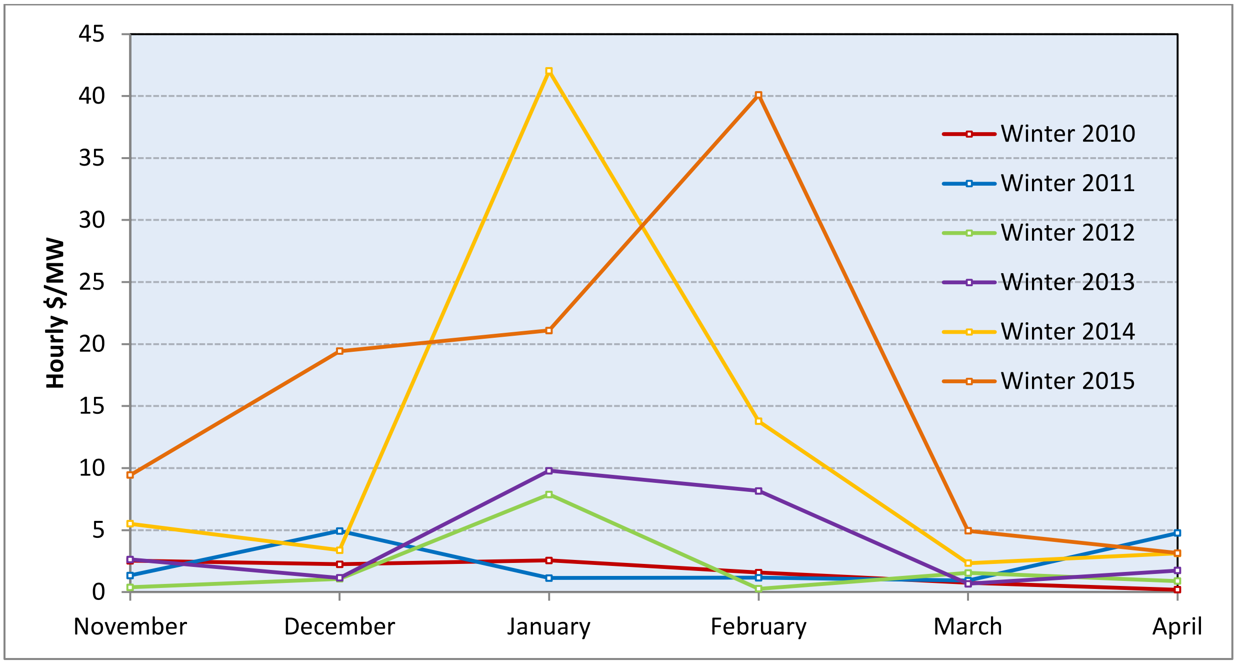
Figure 2-7: Cumulative Histogram of Hourly 10S OR Prices per Winter Period Winter 2010 Period –Current Reporting Period ($/MW, % Frequency)



There has been a significant increase in 10S OR prices starting in the Winter 2014 Period and continuing during the Current Reporting Period. For example, the frequency with which 10S OR prices cleared above $10/MWh during the Current Reporting Period was 33%; during the Winter 2014 Period, 10S OR prices cleared above $10/MWh 25% of the time and during the Winter 2013 Period they cleared above $10/MWh only 10% of the time. Likewise, the frequency with which the 10S OR price cleared at or above $30/MWh (at which price it is common for Control Action Operating Reserve (CAOR) to be scheduled) has increased from approximately 4% in the Winter 2013 Period to 13% in the Current Reporting Period. A reduction in the amount of CAOR available has steepened the supply stack at prices of $30/MWh and above, and contributed to the increase in high OR prices.

Not only are OR prices increasing from year to year, but the price forecast error between PD-1 and real-time OR prices is also increasing. Figure 2-8 shows the hourly average absolute price forecast error by month for the 10S OR market during on-peak hours; the pattern is similar for off-peak hours and for the 10N and 30R OR markets.

*Figure 2-8: 10S OR Hourly Average Absolute Price Forecast Error per Month
Winter 2010 Period – Current Reporting Period
($/MW)*



This increase in OR price forecast error coincides with the addition of significant variable energy supply in recent years. The IESO must now accommodate more volatility in matching real-time energy demand to real-time energy supply. Hydroelectric facilities are flexible and can change their production levels quickly to accommodate this volatility in the energy market; these facilities are also significant suppliers of OR. As more capacity from hydroelectric facilities is required in the energy market, it is necessary to schedule more expensive OR supply.

3.2.2 Quantity of OR Requirement

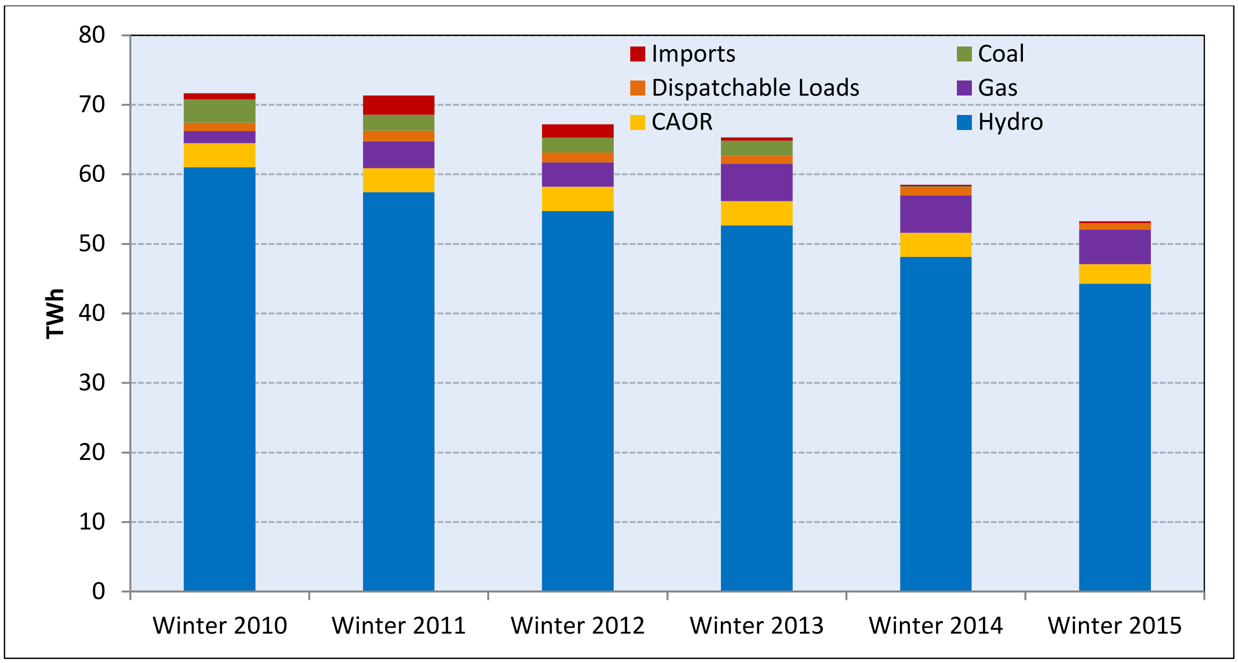
As noted earlier, the OR requirement is set according to North American Electric Reliability Corporation and Northeast Power Coordinating Council reliability standards. The OR requirement is based on the availability of the generation fleet and the configuration of the transmission network, and is largely unaffected by transient system conditions such as the current level of Ontario demand or exports. In the Current Reporting Period, the OR requirement was most commonly 1,418 MW and varied little from previous reporting periods.

Changes in the OR markets are therefore not playing a significant role in the observed increase in OR prices; these increases are primarily the result of changes in the supply of OR.

3.2.3 OR Supply

During the Current Reporting Period, the quantity of OR that was offered in real-time was less than during previous Winter Periods. The total quantities of 30R, 10N and 10S offered have been significantly decreasing over the last five Winter Periods and continuing into the Current Reporting Period. Figure 2-9 shows the real-time OR offers by resource or transaction type for the Current Reporting Period and the previous five Winter Periods.[40]

Figure 2-9: Real-time OR Offers by Resource or Transaction Type
2012 – 2015 Winter Reporting Periods
(TWh)



There has been a significant decrease in the quantity of OR offered by hydroelectric resources, coal-fired facilities and imports. All coal-fired generation has been eliminated in Ontario. The reduction in the quantity of OR offered by imports is primarily the result of one participant significantly reducing its OR offers on the Québec-Ontario interties.

The quantity of CAOR available also decreased in the Current Reporting Period. In every hour of the year there is a standing offer for 800 MW of CAOR, representing two out-of-market control actions available to the IESO: a temporary reduction in the 30R requirement; and a voltage reduction. The IESO may schedule CAOR in lieu of market participant offers in order to meet

[40] Offers for gas-fired, oil-fired and steam-fired facilities are presented together in the "Gas" category.

the OR requirement. In instances where the out-of-market control actions will not provide the full 800 MW of OR, the IESO may reduce the offered quantity of CAOR. In May 2013, the IESO began regularly reducing the CAOR offers; the process was formalized in response to a recommendation contained in the Panel's September 2014 Monitoring Report.[41]

During the Current Reporting Period, there was 18% less CAOR available than the amount that was available before the IESO began curtailing CAOR.

Hydroelectric Offers

The significant decrease in real-time offers from hydroelectric facilities is spread equally across the 3 classes of OR. As seen in Figure 2-9, the level of OR offers from hydroelectric facilities has been in steady decline since the Winter 2010 Period.

In addition to a reduction in the quantity of OR offers from hydroelectric facilities, there has been a change in the price of offers that remain in the market. OR offers priced at $0/MW have decreased while OR offers at prices up to $25/MW have gradually increased. Offers between $30/MW and $60/MW are significantly fewer than their highs during the Winter 2011 Period and Winter 2012 Period, while offers above $60/MW have increased in the Winter 2014 Period and the Current Reporting Period

In combination with reductions in the total quantity of OR offered by hydroelectric facilities, these facilities appear to be altering the prices at which they are offering OR. This shift in OR quantities offered at higher prices places upward pressure on OR prices.

The Panel will continue to monitor and report on changes in OR prices.

4 Generation Cost Guarantee Programs

Operating an electricity system reliably requires that sufficient resources (generation capacity, imports and/or demand response) be available to meet demand at all times. To ensure that generators are willing to start when needed, the IESO has developed cost guarantee programs for fossil-fueled non-quick start facilities. The IESO-administered market has two cost guarantee programs: the Real-time Generation Cost Guarantee (GCG) program; and the Day-ahead

[41] See the Panel's September 2014 Monitoring Report, page 69, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf.

Production Cost Guarantee (PCG) program.[42] The guaranteed costs paid to generators under these programs are ultimately recovered from Ontario consumers (and exporters).

For the purposes of this report, a consecutive series of hours during which a generator qualifies for, and receives, a real-time or day-ahead guarantee is referred to as a 'run'. Each 'run' has associated cost submissions; the guarantee payments for each 'run' are based on these submissions and the market outcomes during the relevant hours of operation.

4.1 Real-Time Generation Cost Guarantee Payments

The GCG program is a voluntary program that was introduced in 2003 and that remains in effect today. The guarantee covers start-up costs as well as costs over the generation facility's minimum run-time (MRT). A generator will receive a payment under the program to the extent that the market revenues earned on output up to the generator's minimum loading point (MLP) are less than the generator's submitted and offered costs. One of the key features of the program is that the IESO schedules eligible generators under the GCG without advance knowledge of the amount of the generator's start-up costs; those costs are submitted to the IESO up to 16 business days after the end of a guaranteed run.

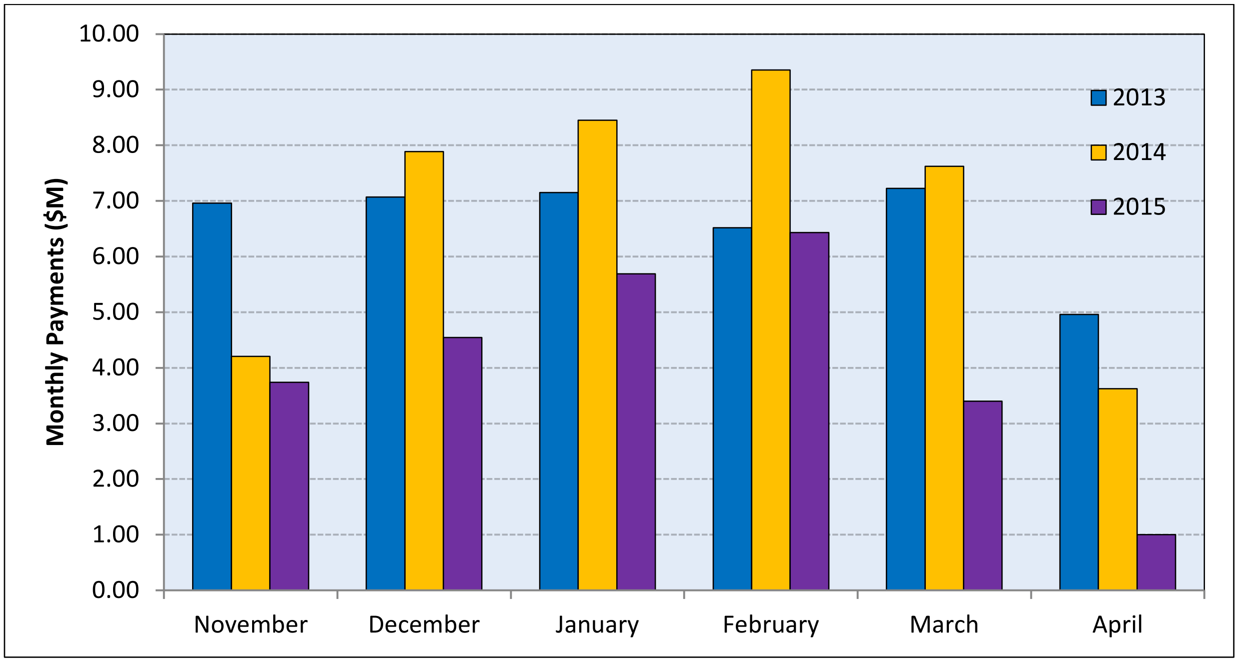
Overview

A total of $24.8 million in GCG payments were made during the Current Reporting Period. These payments were made for the 1,362 runs which occurred over a total of 148 days during the Current Reporting Period. The average payment of $18,216 made per run was considerably less than the $33,241 average from the Previous Reporting Period and the $27,967 average from the Winter 2014 Period.

Figure 2-10 compares total GCG payments per month for the Current Reporting Period, the Winter 2013 Period and the Winter 2014 Period.

[42] For more information on the two cost guarantee programs and their history, see section 3.2 of the Panel's January 2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf#page=164

Figure 2-10: Comparison of Monthly GCG Payments
2013 – 2015 Winter Periods
($)



There has been a significant drop in the total amount of monthly payments across most months in the Current Reporting Period relative to the Winter 2014 Period. Decreases in the commodity cost of gas are likely a contributing factor in the reduction in guarantee payments.

Guarantee Payments by Size

The five highest payments during the Current Reporting Period were made to the same facility (Facility A), and the same is true for the Previous Reporting Period and the Winter 2014 Period. All five of the highest payments made during the Current Reporting Period were, however, lower than any of the five highest payments made in the Previous Reporting Period.

The average payment made to Facility A during the Current Reporting Period was $46,270, significantly lower than the average payment of $91,807 during the Previous Reporting Period.

Table 2-8 shows Facility A's GCG cost submissions and guarantee payments over time.

Table 2-8: Average Payment & Cost Submission Information for Facility A Winter 2014 Period, Previous Reporting Period & Current Reporting Period ($)

	Winter 2014 Period	Previous Reporting Period (Summer 2014)	Current Reporting Period
Average Start-up Fuel Cost Submission	64,604	49,748	41,876
Average Start-up Operation and Maintenance (O&M) Cost Submission	49,980	46,940	12,624
Average Total Guaranteed Cost[43]	156,095	123,418	79,937
Average Total Guarantee Payment	101,405	91,807	46,270

The notable decrease in average guarantee payments can be attributed to the lower operating and maintenance (O&M) submitted costs. O&M costs submitted in the Current Reporting Period are approximately only a quarter (26.9 %) of the O&M costs submitted during the Previous Reporting Period. There was also a slight decrease in submitted fuel costs.

4.2 Day-Ahead Production Cost Guarantee Payments

The PCG program which guarantees that a resource will, at a minimum, recover its costs as offered and scheduled in the Enhanced Day-ahead Commitment process. Under the PCG program, three-part offers are submitted that cover start-up costs, speed no-load costs, and incremental energy costs. All of these costs are taken into consideration when the IESO determines which resources are economic and receive a commitment. If the market revenue earned by the generator for its committed schedule is less than that guaranteed, a payment is made to make up the difference.

In the Current Reporting Period there were a total of 115 days when PCG payments were made, with an average payment of $42,687 per resource. This compares to 123 days when payments were made with an average of $117,987 in the Previous Reporting Period.

A total of $4,897,490 in PCG payments was made during the Current Reporting Period, compared to $14,512,421 in the Previous Reporting Period.

Table 2-9 shows the aggregate amount of PCG payments made on the five days on which PCG payments reached the highest levels in the Current Reporting Period.

[43] The average total guaranteed cost is the average of the sums of the total guarantees for which Facility A qualified. This amount is the sum of three components: start-up fuel costs, start-up O&M costs; and the energy offer price for the MW up to the Facility's MLP.

Table 2–9: Five Days with Highest Aggregate PCG Payments November 2014 – April 2015 ($)

Delivery Date	Total PCG Payments ($)
25/02/2015	$268,820
23/02/2015	$249,198
26/04/2015	$196,903
13/01/2015	$195,809
25/04/2015	$194,439

On April 25 and April 26, large PCG payments were made to the same facility. This facility was committed day-ahead on the basis of its lower OR offer price. Of the options available in the day-ahead timeframe, the lowest cost option was to commit this facility and guarantee its relatively expensive energy and start-up costs in return for its lower cost OR.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel summarizes its activities in relation to ongoing and completed investigations, provides an overview of the Panel's participation in the IESO's stakeholder engagement on the framework for cost recovery under the Real-time Generation Cost Guarantee program, and notes other Panel work that will be featured in future reports.

2 Panel Investigations

The Panel may conduct an investigation into the conduct of market participants, including in relation to inappropriate or anomalous market conduct, when it considers such an investigation is warranted. The Panel currently has one gaming investigation under way in relation to a generator.

In August 2015, the Panel published its report on its investigation into the conduct of Abitibi-Consolidated Company of Canada (Abitibi) and its affiliate Bowater Canadian Forest Products Inc. (Bowater) (Resolute FP Canada Inc. had become the successor in interest to Abitibi and Bowater when the Panel's report was published), which concluded that the market participants engaged in gaming while operating as dispatchable loads. The public version of the investigation report, redacted to address confidentiality considerations, is available on the Ontario Energy Board's website, and a summary of the Panel's findings follows.[44]

2.1 Investigation into Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.

The Panel's gaming investigation related to Congestion Management Settlement Credit (CMSC) payments received by the two market participants from January to August 2010 when their facilities were operating as dispatchable loads. The Panel defines gaming as obtaining a profit or benefit, at the expense or disadvantage of the market, through conduct that exploits a defect in the design, rules, or procedures governing the wholesale electricity markets. The Panel found that both market participants engaged in gaming, and in doing so received $20.4 million in

[44] See the Panel's "Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.", available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf

unwarranted CMSC payments over the eight-month period in question. These CMSC payments were recovered through uplift and ultimately paid by Ontario consumers.

Most of the CMSC payments received by Abitibi and Bowater were triggered in hours when their pulp and paper mills were voluntarily reducing (ramping down) or increasing (ramping up) power consumption. Abitibi also received substantial constrained-on CMSC payments. These payments arose when Abitibi submitted an extremely negative bid price, indicating it was only willing to consume if paid to do so, and then either was constrained on (when the nodal price fell below their negative bid price) or consumed above the level of its dispatch instructions.

These kinds of behaviours were used to obtain CMSC payments in a manner and in amounts that go beyond what is intended by the wholesale market design and the rules that govern the markets. The documents and materials obtained by the Panel for the purposes of the investigation reveal that Abitibi's and Bowater's conduct was deliberate, and was understood by the companies to be inconsistent with the principles underlying the CMSC framework and as having the potential to constitute gaming behaviour. In addition, the bidding practice that led to Abitibi receiving constrained-on CMSC payments exploited a known defect in the market design that had been publicly identified as such by the Panel and that the IESO had announced would be the subject of Market Rule amendments.

The CMSC payments received by Abitibi and Bowater during ramping hours exceeded the cost of the electricity consumed during those hours and as a result they were effectively being paid, rather than paying, to consume electricity during those hours.

The Panel provided a draft of its report to the market participants to provide them with an opportunity to discuss the findings with the Panel, to respond to the findings and to comment on matters of factual accuracy and confidentiality. A written response to the draft report was provided that was directly aimed at addressing some of the Panel's findings and more generally called into question the integrity of the Panel's process, including claims that the Panel had acted in a manner that is biased and unfair. The market participants' written response is reproduced in the report in its entirety save for the redaction of information that the market participants identified as confidential, as are the Panel's comments on that response.

The Panel's report notes that the IESO moved expeditiously in 2010 to deal with two of the major sources of CMSC payments that had been made to Abitibi and Bowater and that are described in the report. However, in light of its findings the Panel's report contains a recommendation that the IESO review ongoing CMSC payments to dispatchable loads and consider further amendments to the Market Rules to eliminate such payments to the extent that they are unwarranted.

While noting that a number of actions have been taken in the past to address unwarranted CMSC payments to dispatchable loads, the IESO has agreed that continuing CMSC payments for dispatchable loads warrant further review, with specific regard to the application of the business rules associated with the payment and automated clawback of CMSC payments.[45] The IESO also indicated that it intended to complete its review by the end of 2015. The Panel understands that the review is still ongoing.

The Panel does not have the legislative mandate to impose sanctions or remedies when it finds that gaming has occurred. In its report, the Panel encouraged the IESO to take whatever action may be open to it to recover the amounts paid to Abitibi and Bowater as a result of their gaming behaviour. To date there has been no recovery of unwarranted CMSC amounts paid to Abitibi and Bowater in 2010.

As noted in the Panel's report, the IESO has introduced a "general conduct rule" into the Market Rules that became effective as of August 5, 2014.

3 New Matters

3.1 IESO Stakeholder Engagement on Generation Cost Guarantees

Since market opening, the IESO has introduced reliability programs intended to encourage generators and importers to supply electricity when they otherwise might not. One such program is the Real-time Generation Cost Guarantee (GCG) program, and others include the Day-ahead

[45] See the IESO's September 18, 2015 reply to the Panel's recommendation, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_MSP_20150918.pdf

Production Cost Guarantee (PCG) program for fossil-fired facilities that are committed in the day-ahead commitment process,[46] and Intertie Offer Guarantees.

In its January 2014 Monitoring Report the Panel recommended that the IESO provide an analysis to confirm whether or not the GCG program continues to be necessary.[47] The Panel reiterated the need for such an analysis in its October 2015 Monitoring Report. While the Panel also recommended that the IESO require generators to make more specific cost submissions, that recommendation was qualified by the caveat that the IESO in the first instance believe that the GCG program continues to be necessary.

The IESO is currently undertaking a stakeholder engagement in relation to cost recovery under the GCG program.[48] That stakeholder engagement is responsive to one of the Panel's recent recommendations, as it is examining the costs eligible to be submitted for recovery under the GCG program.

The Panel is participating in the stakeholder engagement, and has pressed for an analysis of the need for the program in its current form given the high cost of the program, and for an examination of whether lower cost alternatives are available. As noted in Chapter 2, the IESO made $24.8 million in GCG payments in the period between November 2014 and April 2015. One of the Panel's submissions to the stakeholder engagement contains an analysis to the effect that, in 2014, commitments under the GCG program were needed to meet domestic demand and operating reserve needs in real-time in less than 1% of the hours in which a commitment actually occurred. These needs were therefore met at a cost of $61 million in 2014, and over $420 million since 2006, a cost that has ultimately been borne by consumers.[49]

The IESO indicated that the scope of the stakeholder engagement would not be expanded in the manner suggested by the Panel, instead proposing that this foundational concern with the GCG

[46] For more information see the Panel's January 2014 Monitoring Report, which provided an assessment of the Enhanced Day-ahead Commitment process, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf
[47] For more information see section 3.2 of the Panel's January2014 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf page 174.
[48] For more information see the IESO's stakeholder engagement web page, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/RT-GCG-Program-Cost-Recovery-Framework.aspx
[49] For more information see the Panel's first submission, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-Market-Surveillance-Panel.pdf/

program could be addressed with an enhanced intra-day unit commitment program. However, the Panel notes that such a solution is at least 3 to 5 years away.

The Panel also made a second submission to the stakeholder engagement, recommending that the IESO reconsider the criteria by which it determines whether a cost is recoverable under the GCG program to better align with the reliability objectives of the program. The Panel noted in that regard that the IESO has not to date established that the costs that it has proposed as recoverable are consistent with the principle that costs should only be guaranteed recovery to the extent necessary to ensure that the ultimate reliability objective is achieved, and no more.[50] The Panel also recommended that the findings from the IESO's ongoing audit of the RT-GCG program should be reported publicly, both to enhance transparency and to provide for more informed consideration of the IESO's proposals in the stakeholder engagement.

In its third submission to the stakeholder engagement, the Panel reiterated that the scope of off-setting revenues considered when calculating RT-GCG payments should be expanded to include any profit earned on output above a generation facility's minimum loading point and any profit on output generated after the end of the facility's minimum generation block run-time. The Panel also recommended that the same approach be taken in relation to operating reserve revenues earned, as well as CMSC payments received (to the extent that these payments are not already used as off-sets).[51]

3.2 Panel Analyses for Future Reports

The Panel is conducting a review of the GCG and PCG programs with a view to reporting on their cost and effectiveness in ensuring reliable supply to meet Ontario's power needs. This review will take account of the existing and planned availability of other resources to address fluctuations in supply and demand from day-ahead to real-time, including capacity from resources committed day-ahead, quick start gas-fired facilities, demand response, imports and storage.

The Panel is also currently reviewing the history of, and experience with, the CMSC regime. CMSC payments were considered a temporary feature at market opening but have endured and

[50] For more information see the Panel's second submission, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20151120-Market-Surveillance-Panel.pdf.

[51] For more information see the Panel's third submission, available at: http://www.ieso.ca/Documents/consult/RTGCG/RTGCG-20160415-Market-Surveillance-Panel.pdf.

been the subject of recurring concern for the Panel as discussed in both its monitoring and investigation reports. CMSC payments since market opening have averaged over $100 million per year, with total CMSC payments over the life of the market nearing $1.3 billion. While moving from the current market design to an alternate market design, such as locational marginal pricing, would not completely eliminate the need to compensate market participants for certain market outcomes currently compensated for through CMSC payments, the Panel remains of the view that a significant portion of the CMSC payments that have been and continue to be made do not contribute to the efficient operation of the market, and are too readily susceptible to gaming.

Although the IESO has made several changes to the Market Rules to address specific CMSC issues, more comprehensive reform is needed. Changes such as the introduction of locational marginal pricing for dispatchable resources and the development of a day-ahead market with binding schedules and prices for participants would enable a material reduction in CMSC payments, more closely align the IESO-administered markets with market designs in neighbouring jurisdictions and enhance market efficiency.

The Panel plans to release its review of the CMSC regime in a future report, and hopes that it will assist in documenting the need for market reform.

Chapter 4: Market Assessment and Panel Recommendations

1 General Assessment

The Panel is required to provide a general assessment of the state of the IESO-administered markets at least once annually.

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 due regard to several design features and policy decisions that affect market participant behaviour and market outcomes. As noted frequently in past Panel reports, these features include:

- A uniform Ontario price for energy, which is the reason for the two-schedule system. Under this system, the prices faced by wholesale market participants can diverge (sometimes significantly) from the incremental cost of supplying another MW of energy at a particular location.
- Virtually all generation in Ontario is now subject to long-term contracts with government agencies or price regulation by the Ontario Energy Board; contracted and regulated prices can result in offer prices from generators that deviate from the generators' short-run marginal cost.
- The use of the 3 times ramp rate multiplier in the calculation of the unconstrained market clearing price, which distorts the Hourly Ontario Energy Price (HOEP).

The Panel acknowledges the effects of these design features and policy decisions on market efficiency, but recognizes that they have been ingrained as fundamental features of the current market design. Accordingly, the scope of the Panel's assessment has been on the fairness and efficiency of the IESO-administered markets having regard to these fundamental features. On that basis, the Panel has concluded that the IESO-administered markets operated in a reasonably satisfactory manner for the year ended April 2015.

That said, the Panel has made, and will continue to make, recommendations aimed at improving efficiency and eliminating inappropriate payments. The Panel continues to view certain payments as contributing to inefficient outcomes in the market. Of particular and recurring concern are excessive and unwarranted Congestion Management Settlement Credit (CMSC) payments and the effect that CMSC payments can have on the bidding/offering behaviour of market participants and the resulting impact on the efficiency and fairness of the market for all participants. The extensive reliance on programs that entail other out-of-market cost recovery mechanisms, such as guarantees under the Real-time Generation Cost Guarantee program, will also continue to be a focus of the Panel's attention.

2 Future Development of the Market

The IESO has taken action to address a number of issues that have been identified by the Panel as warranting reform. The IESO recently eliminated constrained-off CMSC payments on the interties[52] and has committed to revising the way in which CMSC payments are calculated for facilities that are ramping down to come offline.[53] The IESO has also announced plans to make an additional positive change by changing floor prices so that variable generation will be dispatched down before the flexible portion of nuclear output is dispatched down when mitigating surplus baseload generation (SBG) conditions.[54]

These reforms contribute to enhancing the efficient operation of the market in the short term and within the current design. As an initiative for the longer term, the IESO is taking steps to procure capacity with more reliance on market-based mechanisms. The first step in this direction was the launch of the capacity auction for demand response resources, with the first auction being held in December 2015. The IESO has also introduced stakeholders to plans for a capacity auction that would be open to all resources to meet the need for incremental capacity in the future. Other developments in the market relate to ongoing discussions that have the potential to expand the use of Ontario's interconnections. The Panel reports on all of these initiatives below, and will continue to monitor their progress.

3 Changes to Current Market Mechanisms

3.1 Floor Price Review

The IESO has made changes to the price floors for grid-connected variable facilities (wind and solar) that it predicted will improve market efficiency. The IESO had committed to reviewing the

[52]For more information see the IESO stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Addressing-Constrained-Off-Payments-for-Ontario-Interties.aspx
[53] For more information see the IESO stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-111.aspx
[54]For more information see the IESO stakeholder engagement webpage, available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Floor-Price-Review.aspx

price floors following their implementation in September 2013, and a stakeholder engagement was carried out to discuss with stakeholders the implications of the IESO's review for current floor prices and dispatch order. In July 2015, the IESO posted its analysis of the impact of changing the floor price for renewable resources, and its proposal to change the price floors for these facilities so that they would be dispatched down before flexible nuclear when output is reduced to manage SBG conditions. The IESO's analysis indicates that this change in the dispatch order will help alleviate the kinds of over-curtailment that have occurred in the past, where large (300 MW) blocks of flexible nuclear generation have been dispatched off to deal with a smaller volume of SBG. The stakeholder engagement concluded in December 2015, and implementation of the revised price floors became effective on February 18, 2016.[55] The IESO expects the change in price floors to result in $8 million in savings per year in 2016 and 2017, with those savings and any future savings dependent on levels of SBG.[56]

3.2 Changes to CMSC Regime

Two recent changes to the Market Rules are expected to contribute to reducing unwarranted CMSC payments: the elimination of constrained-off CMSC payments for intertie transactions and changes to the CMSC regime for payments to generators when they are ramping down to come offline. Initiatives to address these issues were undertaken in response to recommendations made by the Panel.

The elimination of constrained-off CMSC payments for intertie transactions is responsive to a recommendation made by the Panel in its April 2015 Monitoring Report.[57] The IESO acknowledged in the stakeholder engagement dealing with this subject that "the two schedule uniform market price system has the potential for unwarranted CMSC payments".[58] The Panel's analysis regarding nodal price chasing was among the information considered through the stakeholder engagement. The IESO analyzed the consequences of eliminating these constrained-off CMSC payments, and concluded that the potential for inefficient trades that might ensue is

[55] For more information, see page 2 of the IESO's March 2, 2016 Baseline Plan for Market Facing Documents Changing in Baseline: 35, available at: http://www.ieso.ca/Documents/imowebpub/201606%20_%20BL35.1/baselineplan_BL35.0.pdf.
[56] For more information see slide 14 of the IESO's July 17, 2015 stakeholder presentation, available at: http://www.ieso.ca/Documents/consult/FPR/FPR-20150717-Overview.pdf.
[57] For more information see the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf
[58] For more information see the IESO's May 20, 2015 stakeholder presentation, available at: http://www.ieso.ca/Documents/consult/ACOP/ACOP-20150520-Impacts-Efficiency-Reliability.pdf

"acceptable compared to the reduction in unwarranted CMSC payments".[59] The IESO has implemented the Market Rule change as of December 11, 2015.[60] The new rule applies retroactively to September 18, 2015, so any payments made will be automatically reversed to that effective date once the automated system is in place.

The IESO has also taken steps in relation to the recommendation in the Panel's June 2013 Monitoring Report to eliminate ramp-down CMSC payments.[61] Under the current market design, constrained-on CMSC payments are made to generators when they ramp down to come offline at the end of a run. In order to signal their intention to come offline, generators may need to raise their offer price in the final hour of their production run. However, generators that raise their offer prices beyond what is necessary to ensure that they can come offline can self-induce unwarranted CMSC payments. In August 2011, the Panel issued a Monitoring Document to provide guidance in relation to shut-down offer prices that would not normally trigger a gaming investigation.[62] Specifically, where there are *bona fide* business reasons for a generator to come offline, the Panel normally would not consider a gaming investigation to be warranted if the generator's offer price does not exceed the greater of (i) 130% of its 3-hour ahead pre-dispatch constrained schedule price or (ii) the generator's marginal (or other incremental or opportunity) cost.

The Monitoring Document was issued by the Panel to provide guidance pending the development by the IESO of a permanent, rule-based solution. This issue became the focal point of the IESO's SE-111 stakeholder engagement.[63] The IESO proposed that any rule-based solution should provide flexibility to generators to signal their intention to come offline through their offer prices, and provide incentives for generators to operate efficiently. The IESO also indicated that any proposed solution should define the ramp-down period and create a methodology for allowing appropriate compensation.

[59] For more information see slide 12 of the IESO's May 20, 2015 stakeholder presentation, available at: http://www.ieso.ca/Documents/consult/ACOP/ACOP-20150520-Impacts-Efficiency-Reliability.pdf slide 12
[60] For more information see the IESO's September 23, 2015 stakeholder communication, available at: http://www.ieso.ca/Documents/consult/ACOP/ACOP-20150923-Communication.pdf
[61] For more information see the Panel's June 2013 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf
[62] For more information see the Panel's Monitoring Document on Generator Offer Prices Used to Signal an Intention to Come Offline, available at: http://www.ontarioenergyboard.ca/oeb/Industry/About%20the%20OEB/Electricity%20Market%20Surveillance/Monitoring%20Document%20-%20Generator%20Offers.
[63] For more information see the IESO's stakeholder engagement webpage for SE-111, at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-111.aspx.

To this end, as part of SE-111 the IESO proposed to replace ramp-down CMSC payments with a "ramp down settlement amount" calculated based on 130% of a generator's offer in the hour before shut down. The settlement amount would be paid each time the generator ramps offline, regardless of its offer in the shutdown hour, allowing the generator to offer at a high price to signal its intention to shut down.

The Panel participated in SE-111, and in its first submission observed that the IESO's proposed solution used as a basis a price similar to that set out in the Panel's Monitoring Document as described above; namely, 130% of the generator's previous offer price. In that regard, however, the Panel noted that it did not view 130% of a generator's 3-hour ahead pre-dispatch constrained schedule price, or any other price, as an appropriate price for the purposes of calculating ramp-down CMSC payments. The Panel also reiterated its longstanding view that ramp-down CMSC payments are susceptible to gaming and should be eliminated altogether, and that if compensation for higher costs during ramp down legitimately needs to be made this should be addressed other than through the use of the CMSC mechanism.[64]

Later in the stakeholder engagement, the IESO confirmed its view that generators have additional costs during unit ramp down.[65] In its second submission, the Panel observed that the IESO's proposed solution would effectively recreate ramp-down CMSC payments under a different name.[66] In its response, the IESO stated that it had "confirmed with original equipment manufacturers that there can be higher operating costs during ramp-down" and that the ramp-down settlement amount is "an 'out-of-market' payment with the advantage of being based on a competitive offer price from the period prior to ramp-down."[67]

The IESO eventually adopted its proposed solution, with an effective date upon implementation of the required changes in IESO systems, contemplated for the fourth quarter of 2015.[68] Subsequently, the IESO stated that it was postponing the implementation of the Market Rule

[64] For more information see the Panel's submission to the stakeholder engagement, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20141010-MSP.pdf

[65] For more information see the IESO's November 27, 2014 stakeholder presentation, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20141127-CMSC_Webinar.pdf slide 8

[66] For more information see the Panel's second submission to the stakeholder engagement, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20141212-MSP.pdf

[67] For more information see the IESO's response to stakeholder comments, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20150122-IESO_Respone_to_Stakeholder_Feedback.pdf.

[68] For more information see the IESO's August 21, 2015 stakeholder communication, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20150821-Communication.pdf

amendment to accommodate other priorities, and that it would provide another update once new implementation timelines are established.[69]

4 New Market Mechanisms to Procure Capacity

The IESO is planning to introduce new market mechanisms for procuring additional capacity to meet future system needs. Over the course of 2015, the IESO has advanced initiatives in this direction: capacity auctions for demand response (DR), as a first stage in the development of capacity auctions for other resources, and the consideration of capacity exports to other jurisdictions.

The IESO held its first capacity auction for DR in December 2015 for delivery starting in the summer of 2016. This first auction had a target of 367 MW, equal to the capacity expiring from the IESO's current DR programs. The outcome of the auction was the award of DR capacity to seven of the seventeen registered participants, for 391.5 MW of capacity at a price of $378.21/MW-day in the summer (May 1 to October 31) and 403.7 MW of capacity at a price of $359.87/MW-day in the winter (November 1 to April 30).[70]

The IESO plans to hold DR auctions once each year to procure capacity for two six-month commitment periods— summer and winter. Registered DR auction participants will bid their capacity and the availability payment they will accept, and the IESO will clear the market (in several zones across the province) with a downward sloping demand curve for each commitment period.

Participants who clear the auction will be required to offer into the real-time market as DR resources, and will receive a monthly availability payment equal to their capacity times the clearing price times the number of business days in the month. Participants who respond to the dispatch will save the energy costs when they are activated to provide DR. Activations of these DR resources is expected to reduce peak demand.

The DR capacity auction is intended to be the first phase of the IESO's efforts to introduce capacity markets for all resources. The IESO conducted several information sessions on this

[69] For more information see the IESO's October 9, 2015 stakeholder communication, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20151109-Communication.pdf
[70] For more information see the IESO's Demand Response Auction webpage, available at: http://www.ieso.ca/Pages/Participate/Demand-Response-Auction/default.aspx

topic over the course of 2014, and published details of design elements in a September 18, 2014 Discussion Paper.[71] The Discussion Paper describes the role of a capacity auction as enabling "all resources to compete on a frequent basis to meet the province's future incremental resource adequacy needs". Although the IESO has not committed to firm implementation timelines for the capacity auction, the development of detailed design elements and the launch of the DR auction have set the groundwork for further market development in this area.

In November 2010, the Minister directed the IESO (then the Ontario Power Authority) to enter into negotiations with non-utility generators (NUGs) for new contracts. In December 2014, in light of changing supply conditions, the Minister directed the IESO (then the Ontario Power Authority) to suspend any pending negotiations with NUGs and prepare an assessment of the framework for NUG recontracting in the Province, having regard to a number of considerations including the IESO's work to develop a capacity auction in Ontario. The IESO's September 1, 2015 report to the Minister of Energy recommended that the current pause on recontracting with the NUGs be continued given the current strong supply outlook and pending clarification of evolving sector conditions.[72] The IESO identified the continued operation of the Pickering nuclear generating station, the development of the capacity auction and capacity export opportunities, and the introduction of cap-and-trade legislation as potential changes in the sector that would have a bearing on recontracting efforts. The IESO also recommended that the development of the capacity auction and capacity export markets be continued with consideration given to facilitating broad participation, including by the NUGs, as a more effective means of meeting future resource needs. By letter dated December 14, 2015, the Minister of Energy directed the IESO to discontinue negotiations for new contracts for NUGs and to continue engaging stakeholders in the IESO's development of an Ontario capacity auction and rules and protocols for Ontario-based capacity exports.[73]

Capacity markets in some other jurisdictions accept exports of capacity from neighbouring jurisdictions. Beginning in 2015, the IESO opened a stakeholder engagement on the subject of

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[71] For more information see the IESO's September 18, 2014 Discussion Paper, available at: http://www.ieso.ca/Documents/consult/capacity-20140918-Design_Element_Discussion_Paper_Agenda.pdf
[72] For more information see the IESO's NUG Framework Assessment report, available at: http://www.ieso.ca/Documents/generation-procurement/NUG-Framework-Assessment-Report.pdf
[73] For more information on the Minister of Energy's December 14, 2015 Directive, see: http://www.ieso.ca/Documents/Ministerial-Directives/2051214-Directive-NUG_CHPSOP_ChaudiereFalls_WhitesandFirstNation.pdf.

capacity exports. This IESO continues to work towards establishing the market need for such a program, assessing the feasibility and timeline of implementation, and continues to engage with stakeholders.[74]

5 Developments Relating to Ontario's Interconnections

Several developments during this reporting period have had or will have an impact on the IESO's interconnections with other jurisdictions. These include a seasonal electricity capacity sharing agreement with Québec, discussions around enhancing trade in electricity products with Québec and Newfoundland and Labrador, and ongoing developments in the proposed interconnection between the Ontario and parts of the United States that fall within the jurisdiction of PJM.[75]

The capacity sharing agreement between the IESO and Hydro Québec Energy Marketing is in force from December 1, 2015 to September 30, 2025.[76] Ontario has an initial two year obligation to provide 500 MW to Québec during the first two winter periods (December to March), with an option to reduce the quantity after that time. Ontario may elect to receive up to 500 MW from Québec in any given summer period (June to September). Québec's obligation is to "repay in kind the equivalent amount of capacity it received in the winter periods to Ontario in the summer periods." The capacity is to be shared "like for like", with no monetary exchange. The jurisdiction receiving the power must make a "Reliability Declaration", which in Ontario will be made when there is a shortfall in the market. If Hydro Québec makes a Reliability Declaration, it will be responsible for scheduling an export transaction in the IESO-administered market, which will clear based on the economics of the bid.[77]

The IESO is also planning to study and provide reports on expanding trade in electricity between Ontario and Québec, and between Ontario and Newfoundland and Labrador. This is in response to the April 22, 2015 direction from the Minister of Energy to investigate "other opportunities to obtain electricity products from Hydro-Québec, and other Market Participants, where the

[74] For more information, see the IESO's stakeholder engagement webpage at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/Capacity-Exports.aspx.
[75] PJM is a regional transmission operator that coordinates the movement of wholesale electricity in the USA in all or parts of 13 states and the District of Columbia. For more information on PJM, see: http://www.pjm.com/.
[76] For more information see the IESO's summary of the agreement, available at: http://www.ieso.ca/Documents/corp/Summary-Capacity-Sharing-Agreement-Ontario-Quebec.pdf
[77] For more information see the IESO's backgrounder, available at: http://www.ieso.ca/Documents/Ontario-Quebec-Capacity-Sharing-Agreement-Backgrounder-20151112.pdf

electricity products could be obtained on terms that would benefit and align with Ontario electricity system needs."[78]

On July 20, 2015 the Ontario Minister of Energy and the Newfoundland and Labrador Minister of Natural Resources announced that they were committed to exploring opportunities for importing clean and reliable electricity from Newfoundland and Labrador into Ontario. To that end, an inter-provincial working group with representatives from both governments and their agencies, the IESO and Nalcor Energy, was formed to study "the potential for firm electricity trade between the two provinces".[79] The IESO's Stakeholder Advisory Committee reports that "throughout these discussions the IESO and the Ministry are guided by 3 principles. If any arrangement is to be concluded it must: reduce Ontario's greenhouse gas emissions; reduce costs for the ratepayers of Ontario; and be consistent with policy objectives."[80] These objectives are consistent with other government efforts in the sector to reduce emissions and reduce costs.

Another recent development related to Ontario's interconnections with other jurisdictions is a proposed 1,000 MW, bi-directional, High-Voltage Direct Current (HVDC) underwater merchant transmission line that would provide the first direct link between Ontario and PJM. The new line would enable additional trade in capacity and energy between the two jurisdictions. In late May 2015, the project proponent filed applications for approval to construct and operate the line with the National Energy Board (NEB) in Canada and with the U.S. Department of Energy.[81] If approved, it is anticipated that the line would enter into commercial operation in 2019.[82]

All of the developments described above are likely to affect the IESO-administered markets, and the Panel expects to report further on these developments as and when their impact on the operation of the IESO-administered markets becomes apparent.

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[78] For more information see the Ministerial Directive, available at: http://www.ieso.ca/Documents/Ministerial-Directives/MC-2015-904-Outgoing-IESO-Letter-of-Direction-1.pdf

[79] For more information see the Ontario Ministry of Energy and Infrastructure's July 20, 2015 news release, available at: https://news.ontario.ca/mei/en/2015/07/ontario-and-newfoundland-and-labrador-agree-to-evaluate-clean-electricity-trade-opportunities.html

[80] For more information see the IESO's Stakeholder Advisory Committee October 1, 2015 business update, available at: http://www.ieso.ca/Documents/consult/sac/SAC-20151001-Ontario-Quebec-Capacity-Sharing.pdf

[81] For more information see the project owner's website, available at:http://www.itclakeerieconnector.com/

[82] For more information on the Lake Erie Connector, see a presentation from the project owner available at: http://www.itclakeerieconnector.com/images/pdfs/ITCLakeErieConnectorPresentation.pdf

6 IESO Responses to Prior Panel Recommendations

Recommendation	IESO Response
Recommendation 2-1 *The Panel recommends that the IESO assess the methodology used to set the intertie zonal price for a congested intertie when the Net Interchange Scheduling Limit is binding or violated, in order to make the incentives provided by the intertie zonal price better fit the needs of the market.*	The IESO is currently assessing how changes to the intertie zonal price setting methodology would address the concerns noted by the [Panel]. The results of this work will be used to determine whether a modification to the methodology is both warranted and feasible. Due to the complexity of the intertie zonal price setting methodology, any modifications will require careful analysis of the impacts, stakeholder engagement, system tool changes and possible market rule amendments. The IESO is in the process of determining the expected timeline which is subject to several dependencies and will provide an update once a firm schedule has been established.
Recommendation 2-2 *To the extent that the IESO believes the Real-Time Generation Cost Guarantee program continues to be needed, the Panel recommends that the IESO require generators to make more specific cost submissions under that program.*	The IESO has initiated a stakeholder engagement, "RT-GCG Program Cost Recovery Framework," commenced on October 27, 2015, which will address [Panel] recommendation 2-2. Under this engagement, the IESO will present a more clearly defined cost recovery framework aimed at clarifying and increasing the detail of submissions by market participants of costs eligible for recovery under the program. The implementation of proposed changes is targeted for Q3 of 2016. These changes to the current GCG program are intended to be transitional until a more permanent market design solution can be developed. The IESO'S longer-term plan while not part of this initiative, is to explore the implementation of an intra-day unit commitment program comprised of three part offers and multi-hour optimization in place of the current GCG program.

Panel Commentary on IESO Response

The Panel appreciates that the IESO is working on developing a change to the methodology used to set the intertie zonal price, and recognizes that any proposed solution will need to be studied before implementation to ensure that all consequences can be fully understood. The Panel will continue to monitor this issue in its future reports.

As noted in Chapter 3, the Panel is currently participating in the IESO’s stakeholder engagement on cost recovery under the Real-time Generation Cost Guarantee program.