Ontario Energy Board   Commission de l’énergie de l’Ontario

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2014 – October 2014

September 2015

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Executive Summary

On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that combines the OPA and IESO mandates. This report preserves references to the IESO or the OPA, since they existed as separate entities during the periods covered by this report.

1 *Matters to Report in the Ontario Electricity Marketplace*

Review of the IESO's Energy Market Pricing Review (SE-114)

In August 2013, the IESO launched a stakeholder engagement ("SE-114") to review the energy market pricing system in Ontario. The objective of SE-114 was to consider potential design alternatives to the "two-schedule price setting system" currently in place with an overall objective of providing "an efficient dispatch and pricing process that produces transparent prices".

With the launch of SE-114, the IESO released a discussion paper prepared by its consultant, Market Reform, that identified design elements that created inconsistencies between the actual marginal cost of generation and the price of electricity at a given location on the grid. It found that these conditions reduced efficient market signals and increased out-of-market compensation, specifically Congestion Management Settlement Credit ("CMSC") payments.

The discussion paper presented three options relative to the status quo: a look-ahead option, a uniform locational marginal price ("LMP") option, and a zonal LMP option. The look-ahead option would remain a two-schedule system but would incorporate foresight into commitments and use actual ramp rates in the unconstrained sequence. The uniform LMP option would determine prices and schedules with the constrained sequence and would dispense with the unconstrained sequence. Dispatchable resources would settle based on prices at their respective nodes, while non-dispatchable resources would settle on a uniform Ontario price. The zonal LMP option would be identical to the uniform LMP option, except non-dispatchable loads would be settled on prices determined within each zone.

These three alternatives were compared using a cost benefit model in Market Reform's final report, released in February 2015. Market Reform made the conservative assumption that the dispatch solution would not change under any of the design options, and so the final report did not consider changes in short term efficiency relative to the status quo. Long term changes in efficiency were also ignored, as the energy price plays a limited role in investment decisions in Ontario.

The results of the cost benefit evaluation indicate that, over 9 years, the look-ahead option would result in higher costs of $2.9 million, whereas the LMP options provide savings of $127.1 million for the uniform LMP option and $112.9 million for the zonal LMP option. The savings under the LMP designs are primarily achieved through the elimination of CMSC payments.

While not included in the results of its cost benefit analysis, Market Reform provided some additional analysis in its final report of the consequences of adopting each design change. Market Reform found that there are efficiency gains to be had by transitioning to a LMP market design. These benefits include changed generator offers, reduction in intertie seams issues, improvement in the efficiency of production and consumption, and a reduction in market complexity, which would facilitate further improvements to the market design.

The Panel supports the implementation of LMP as an essential step in enabling broader reforms, and encourages the IESO to pursue Market Reform's recommendations. The IESO has indicated that it will move forward with a new stakeholder engagement to consider a more holistic market re-design in 3 key areas.

2 *Summary of Market Outcomes*

The Panel's review of market outcomes covers the period from May 1, 2014 to October 31, 2014 ("Current Reporting Period").

Demand and Supply Conditions

During the Current Reporting Period, 943 MW of nameplate generating capacity was added to the IESO-controlled grid, consisting of wind, hydroelectric, and biofuel generation.

Ontario energy consumption in the Current Reporting Period was 69.4 TWh compared with 70.6 TWh in the period May 1, 2013 to October 31, 2013. This decline was most likely a result of the unseasonably cool summer months of 2014 which brought about the lowest monthly summer peak demand of the past five years.

Ontario was a net energy exporter on a monthly basis during the Current Reporting Period. Net exports totaled 8.8 TWh during the Current Reporting Period, an increase of 3.8 TWh (76%) compared to the period from November 1, 2013 to April 30, 2014 ("Previous Reporting Period"), which had lower exports due to higher Ontario demand in the early months of 2014.

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 $48.55/MWh for Class A consumers that are directly connected to the IESO-controlled grid ("Direct Class A") and $93.50 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 commodity price in the Current Reporting Period decreased for Direct Class A and increased for Class B and Embedded Class A consumers. The decrease in the effective price for Direct Class A consumers was driven by a decrease in the weighted HOEP; although the weighted HOEP and the average uplift also decreased for Class B and Embedded Class A consumers, these decreases were offset by a disproportionately larger increase in the GA, resulting in an effective price increase for these consumer classes.

3 *Analysis of Market Outcomes*

High-Price Hours

In the Current Reporting Period there were three hours in which the HOEP exceeded $200/MWh ("high-price hours"). These were primarily caused by under forecasts of demand and sudden losses of generation.

Negative-Price Hours

The Current Reporting Period also experienced the highest number of hours in which the HOEP was below $0/MWh ("negative-price hours") since market opening, a total of 656 hours, or approximately 15% of the total hours. High levels of output with negative offer prices from nuclear and wind generators coincided with below average demand, resulting in many hours with negative prices.

Uplift Payments

There was one day when the Panel's uplift screening thresholds were met in the Current Reporting Period, compared to 48 days in the Previous Reporting Period. On that day CMSC payments were larger than the Panel's $1,000,000/day threshold. These payments reflected the need to constrain on gas generation to provide operating reserve ("OR") when several hydroelectric facilities that typically provide OR were unavailable.

The Net Interchange Scheduling Limit

The interties that connect Ontario to its neighbours each have limits on how much energy they can transmit. When an intertie has more economic bids or offers than its capacity can accommodate, it becomes congested. In addition to the limits on each intertie, there is a general limit known as the Net Interchange Scheduling Limit (NISL). The NISL restricts the maximum change in the total energy flows between one hour and the next across all the interties. The NISL minimizes excessive ramping requirements on Ontario generators in response to changing flows on the interties.

If there are insufficient economic export bids (or import offers) to meet the NISL, then the NISL is said to be binding and the dispatch algorithm attempts to schedule uneconomic bids or offers in order to respect NISL. In the situation when there are not enough export bids to satisfy the NISL, the NISL is said to be violated. When the NISL is binding or violated, there is an upward effect on the intertie zonal price. In the most extreme case, the cost of exporting power at a congested intertie becomes $2,000/MWh, the maximum market clearing price in Ontario. This pricing tends to be counterproductive, in that the cost of exporting increases at a time when more exports are required.

The Panel has observed several instances in the Current Reporting Period where high intertie zonal prices signaled to traders that fewer exports and more imports were needed when the situation required exactly the opposite. In these circumstances intertie traders face a strong incentive to withdraw their bids or offers, exacerbating the problem.

<u>Recommendation 2-1</u>

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 Real-Time Generation Cost Guarantee Payments

This report includes statistics on payments made to generators under the IESO's generator cost guarantee programs (the Real-Time Generation Cost Guarantee ("RT-GCG") and Day-Ahead Production Cost Guarantee programs). These payments are made to ensure that generators are able to cover their start-up costs as well as costs over the generation facility's minimum generation block run-time. The Panel provides some statistics on the average and maximum payments made to generators under these programs, including a comparatively high RT-GCG payment made to a gas generator on September 14, 2014.

Generators submit RT-GCG costs to the IESO under two broad categories: fuel costs for start-up and ramping to the facility's minimum loading point; and incremental start-up operations and maintenance costs. Limiting the submitted cost categories to two makes it difficult to draw any specific conclusions about the reasonableness of the underlying costs. More specific cost categories would provide needed transparency and more specificity in the administration of the program.

<u>Recommendation 2-2</u>

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.

4 *Investigations*

The Panel has completed its gaming investigation in relation to the conduct of two related dispatchable loads, and its report has been posted on the Ontario Energy Board's website. The Panel currently has one gaming investigation under way in relation to a generator.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets for the period between May 1, 2014 and October 31, 2014 ("Current Reporting Period"), with comparisons to the period between November 1, 2013 and April 30, 2014 ("Previous Reporting Period"), as well as other periods where relevant.

1 Pricing

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

Table 1-1: Average Effective Commodity Price by Consumer Class November 2013 – April 2014 & May – October 2014 ($/MWh)

Description:

Table 1-1 summarizes the average effective commodity price[1] in dollars per megawatt hour by consumer class for the Current Reporting Period and the Previous Reporting Period. The effective commodity price is the sum of the weighted HOEP, the GA, and uplift charges. Results are reported for three consumer classes: "Direct Class A consumers" (Class A consumers that are directly connected to the IESO-controlled grid); "Class B & Embedded Class A consumers" (Embedded Class A consumers being Class A consumers that are connected at the distribution level); and "All Consumers", which 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, effective price information pertaining to Class A consumers relates only to Direct Class A consumers.[2]

[1] This price does not include delivery, regulatory, and debt retirement charges.
[2] 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

Consumer Class	Weighted HOEP	Average Global Adjustment	Average Uplift	Effective Price
Direct Class A – Current*	17.89	28.26	2.40	48.55
Direct Class A – Previous	48.76	14.96	4.20	67.92
Class B & Embedded Class A – Current	19.79	71.33	2.39	93.50
Class B & Embedded Class A – Previous	52.63	32.51	4.44	89.57
All Consumers – Current	19.55	65.96	2.39	87.90
All Consumers – Previous	52.19	30.48	4.41	87.08

*All references to "Current" in tables and figures in this report mean the Current Reporting Period. Similarly, all references to "Previous" mean the Previous Reporting Period.

Relevance:

In Ontario, the effective rate a consumer pays for electricity depends on its consumer class. Consumers are divided into two groups: Class A—consumers with an average peak demand of at least 5 MW[3] (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).[4]

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 choose to 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 interval meter, they pay a weighted average hourly spot market price 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 item on RPP consumer bills.

For reference purposes, the table displays the average effective price for "all consumers," which is calculated using the previous GA allocation methodology under which all consumers were

[3] Effective July 1, 2015, the government of Ontario expanded the definition of Class A 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 October 31, 2014, this report uses the former definition of Class A consumers.

[4] 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.

allocated the GA based on their pro rata share of total consumption during the period. As of January 2011, the GA payable by Class A consumers is determined based on their 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 in each of those hours. The GA continues to be charged to Class B consumers on a volumetric basis.[5]

Commentary and Market Considerations:

Relative to the Previous Reporting Period, the average effective commodity price decreased for Direct Class A and increased for Class B & Embedded Class A consumers in the Current Reporting Period.[6] For Direct Class A consumers, the decrease in the effective price was driven by decreases in the weighted HOEP and the average uplift. And although the weighted HOEP and the average uplift also decreased for Class B & Embedded Class A consumers, these decreases were offset by an increase in the GA, resulting in an effective price increase for this consumer class.

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.[7] Accordingly, the HOEP and the GA exhibit an inverse relationship—when the HOEP decreases the GA increases. As such, when the weighted HOEP decreased in the Current Reporting Period compared to the Previous Reporting Period, the average GA increased. 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 below discusses the reasons contributing to the increase in the GA.

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[5] 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

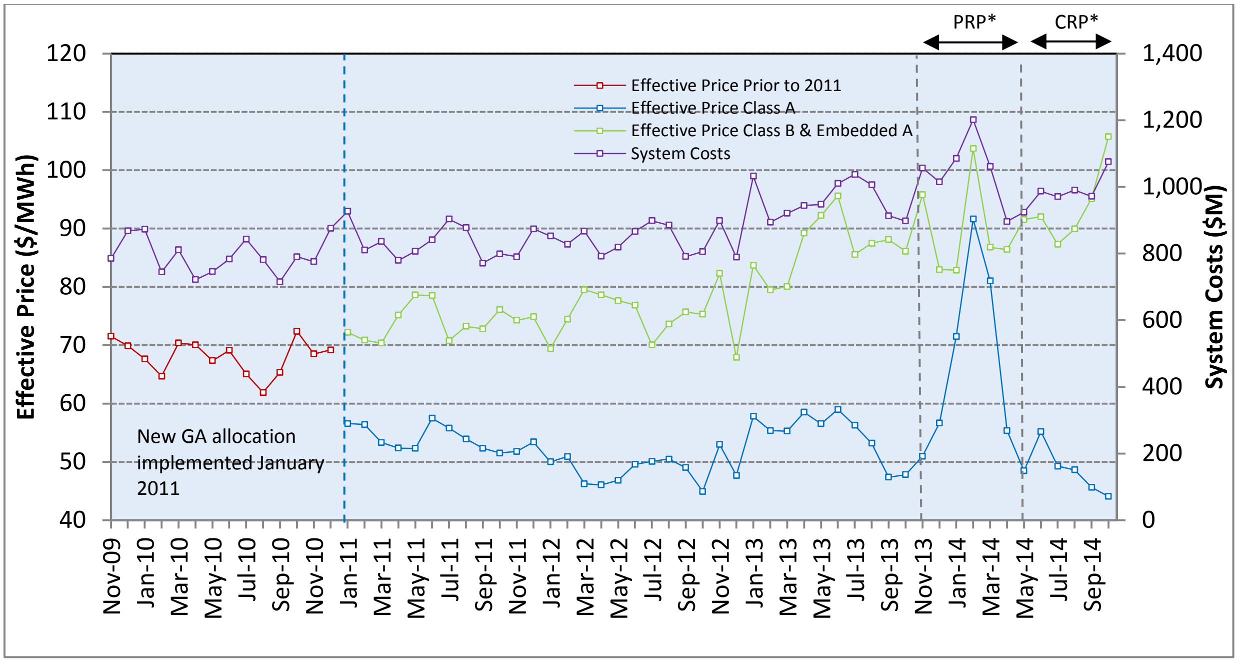
[6] Since Embedded Class A consumers pay on the same basis as Direct Class A consumers, the figures for Class B & Embedded Class A consumers understate the effective price for Class B consumers and overstate the effective price for Embedded Class A consumers.

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

Figure 1-1: Monthly Average Effective Commodity Price and System Costs Paid by Ontario Consumers November 2009 – October 2014 ($/MWh and $ millions)

Description:

Figure 1-1 plots the average effective commodity price for Direct Class A and Class B & Embedded Class A consumers (in dollars per megawatt hour), as well as the monthly system costs paid by Ontario consumers (in dollars)[8] ("System Costs"), for the previous five years.



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

Relevance:

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

Commentary and Market Considerations:

From January 2013 onwards, System Costs have exceeded historic levels. This upward trend corresponds with the increase in the effective price for Class B & Embedded Class A consumers in the Current Reporting Period. The average effective price for Class B & Embedded Class A consumers reached an all-time high of $106/MWh in October 2014, when the HOEP was low

[8] System Costs are the sum of the HOEPs, the GA, and the uplift charges paid by Ontario consumers for a given month. They do not account for costs borne by exporters.

and the GA correspondingly higher (shifting more costs from Class A to Class B). The average effective price for Direct Class A consumers reached a low of $44/MWh in the same month, an all-time low since the change in the GA allocation methodology took effect in January 2011.

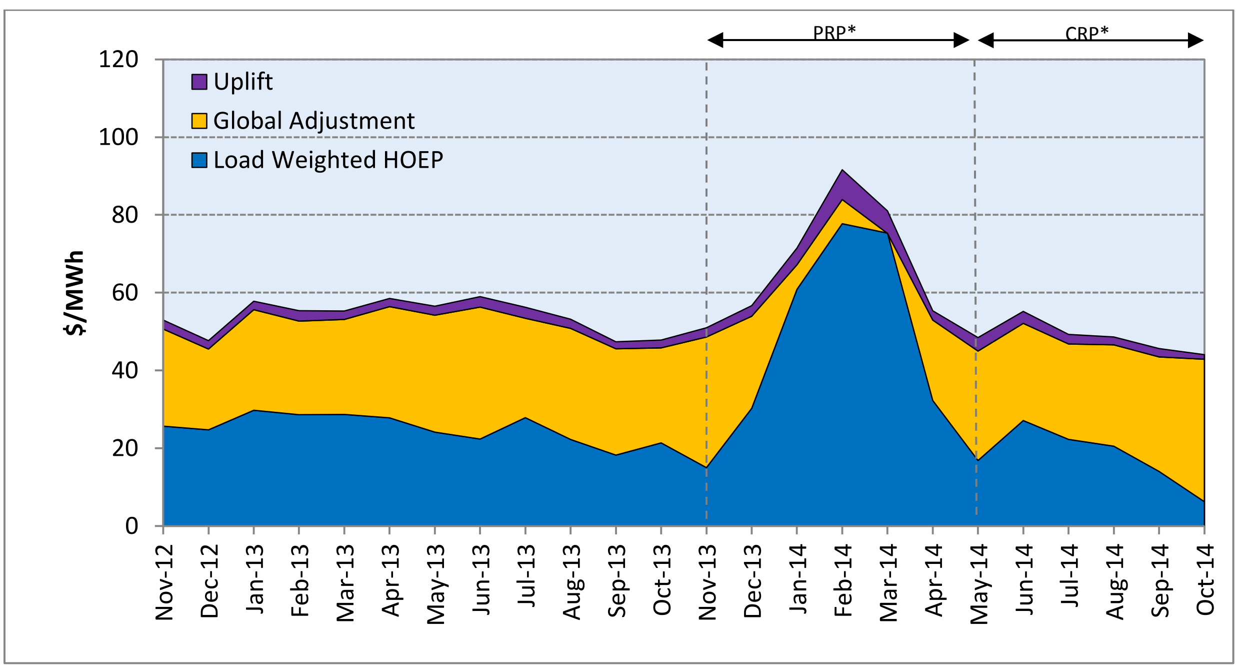
As the HOEP fell and the GA increased in the Current Reporting Period, the relative effective prices for the consumer groups diverged significantly starting in April 2014. This divergence was primarily a result of the GA allocation methodology.

Figures 1-2a & 1-2b: Average Effective Commodity Price by Consumer Class

Description:

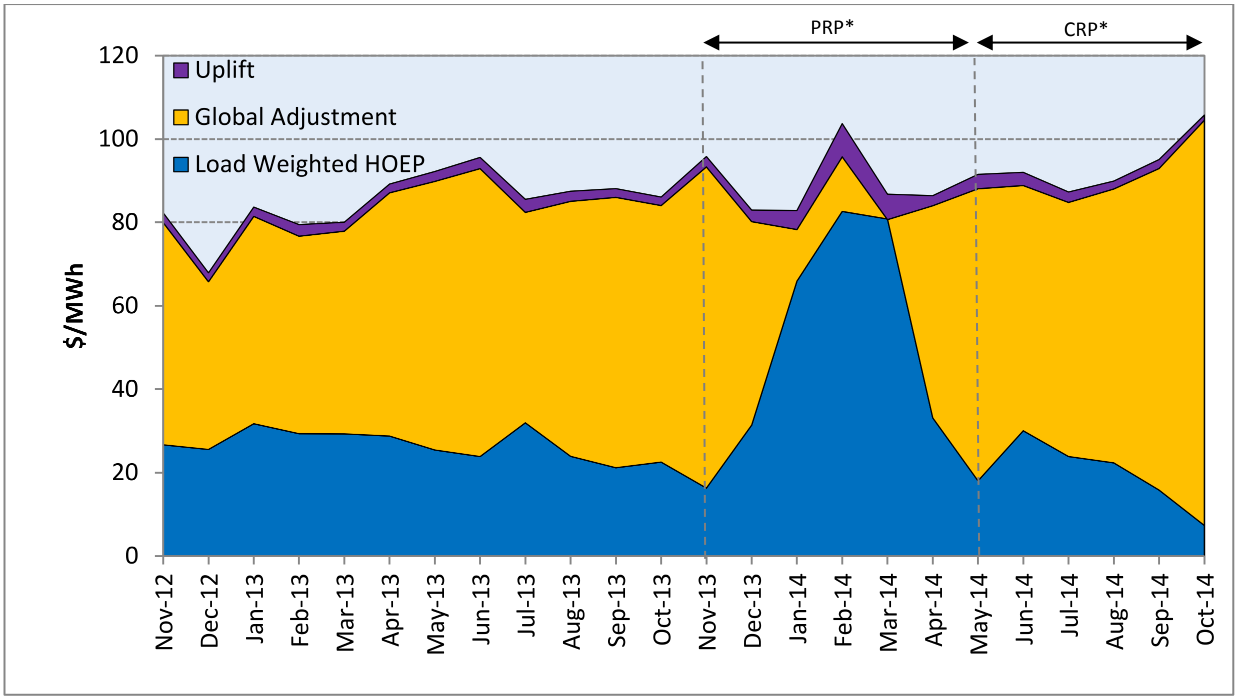
Figures 1-2a and 1-2b divide the monthly average effective commodity price into its three components (average load-weighted HOEP, average GA, and average uplift charges) for Direct Class A and Class B & Embedded Class A consumers, respectively, for the previous two years.

Figure 1-2a: Average Effective Commodity Price for Direct Class A Consumers by Component November 2012 – October 2014 ($/MWh)



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

Figure 1-2b: Average Effective Commodity Price for Class B & Embedded Class A Consumers by Component November 2012 – October 2014 ($/MWh)



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

Relevance:

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

Commentary and Market Considerations:

The GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA portion of System Costs 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 commodity 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,[9] Class A consumers can substantially reduce their GA by reducing their consumption during these hours. When the GA makes up an increasing portion of

[9] 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.

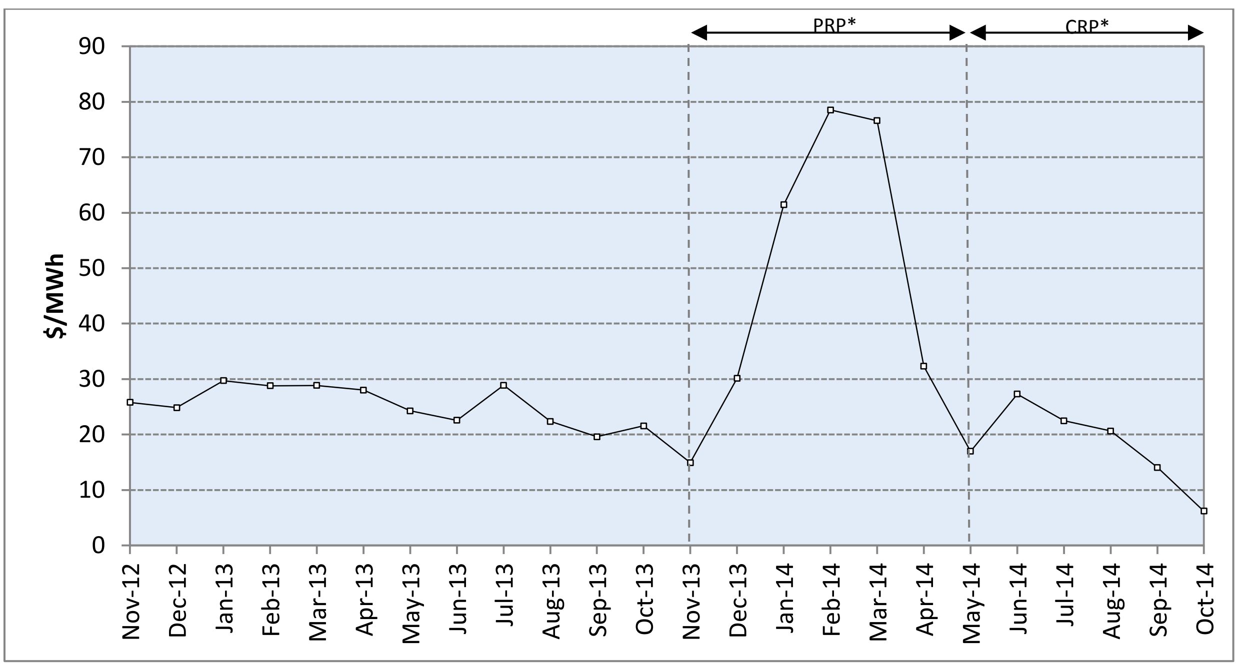
System Costs, the average effective commodity price paid by Class B consumers increases more, proportionately, than that paid by Class A consumers. This relationship is readily apparent in the Current Reporting Period.

In March 2014, the HOEP rose high enough that the average GA became negative at -$0.16/MWh.[10] However, as the HOEP experienced a rapid decline beginning in April and continuing into the fall of 2014, the GA increased. Due to the GA allocation methodology, a particularly significant increase in the GA was felt by Class B consumers, thus leading to an increase in the effective commodity price for this group. The effective commodity price for Class A consumers, on the other hand, experienced a decline over the same period.

Figure 1-3: Monthly (Simple) Average HOEP
November 2012 – October 2014
($/MWh)

Description:

Figure 1-3 displays the simple monthly average HOEP in dollars per megawatt hour, for the previous two years.



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

[10] A negative GA is a credit to consumers.

Relevance:

The HOEP is the average market price for a given hour and is one component of the effective commodity price paid by consumers. The HOEP is determined by the Independent Electricity System Operator ("IESO") as the simple average of the twelve Market Clearing Prices ("MCPs") 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:

The monthly average HOEP was relatively high during the Previous Reporting Period, reaching $78.53/MWh in February 2014, the highest monthly average HOEP in eight years. The high prices were primarily driven by sustained extreme cold temperatures resulting in increased electricity demand, and tight natural gas supply conditions across much of North America.[11] Comparatively, the average monthly HOEP was significantly lower during the Current Reporting Period, in part due to mild summer temperatures which led to reduced electricity demand. In fact, average summer temperatures have been in decline since 2012. In that year, Ontario's yearly peak electricity demand occurred during the summer months, when the temperature averaged 22.6 °C. During the summer months of the Current Reporting Period, the average temperature was 20.6 °C, and following the trend which began in 2013 the province's yearly peak demand occurred during the winter months.[12]

The monthly average HOEP was also noticeably lower in the fall of the Current Reporting Period compared to the fall of 2013; primarily, this was driven by an increase in the number of negative-price hours (see Figure 1-5 and the discussion in Chapter 2). In October 2014, for example, the HOEP was negative in 37.6% of total hours. The reason for this was a large increase in the number of times that wind and nuclear resources set the pre-dispatch and the real-time MCP (see Figures 1-6 and 1-7), as these resources typically offer at negative prices. The increase in instances of wind and nuclear units setting the price was due to a considerable

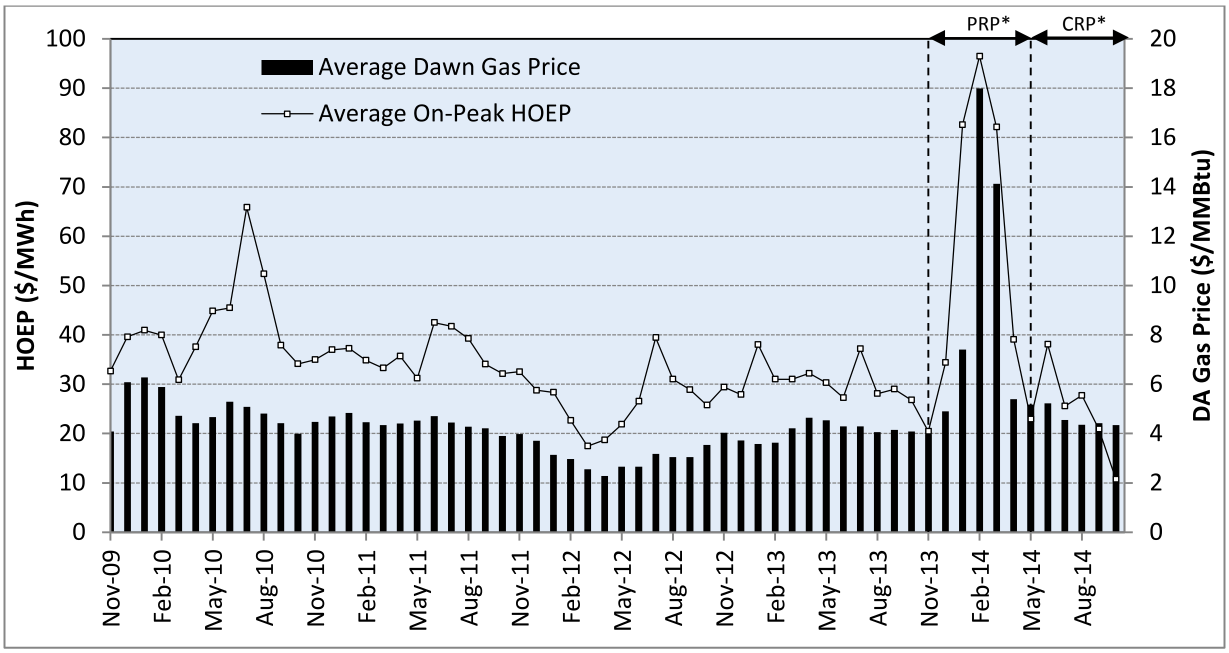
[11] For a detailed analysis of the electricity and gas market conditions that led to the high prices in the Previous Reporting Period see the Panel's April 2015 Monitoring Report, pages 57-76, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf
[12] Ontario's average temperature data was obtained from the Environment Canada webpage entitled "Climate", available at: http://climate.weather.gc.ca/

increase in dispatchable wind capacity and a reduction in outages for nuclear units in the Current Reporting Period, with these wind and nuclear resources displacing higher-priced resources.

Figure 1-4: Average Monthly Dawn Hub Day-Ahead Natural Gas Price and Average Monthly On-Peak HOEP November 2009 – October 2014 ($/MWh and $/MMBtu)

Description:

Figure 1-4 plots the monthly average Dawn Hub day-ahead natural gas price (in dollars per million British Thermal Units) and the average monthly HOEP (in dollars per megawatt hour) during 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 generators 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 on-peak HOEP, as gas-fired generators frequently set the price during these hours.

Commentary and Market Considerations:

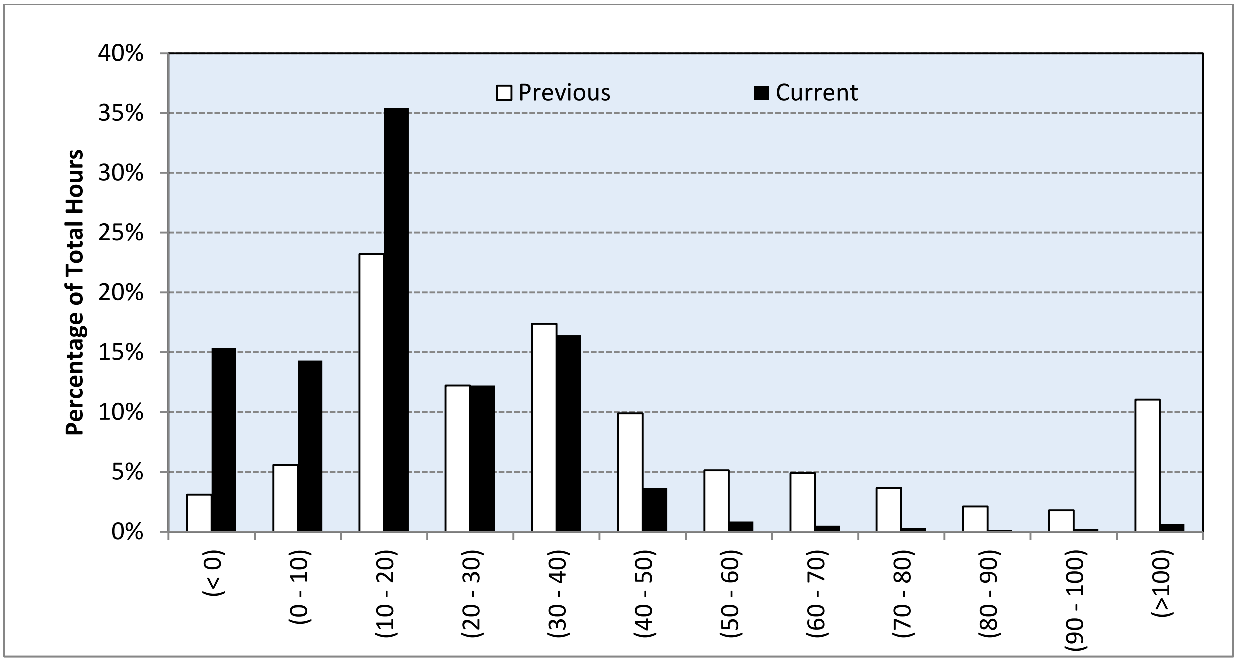
Movements in the on-peak HOEP are generally highly correlated with movements in the day-ahead gas price. Over the past five years, the simple correlation coefficient between the two variables was 0.82. From January to March 2014, tight supply conditions and increased demand due to extreme cold temperatures contributed to a significant increase in the day-ahead gas prices and, correspondingly, in the average monthly on-peak HOEP. Thereafter, the increase in temperatures with the beginning of spring corresponded with a decrease in both the day-ahead gas price and the average on-peak HOEP.

However, while the day-ahead gas price was relatively stable in the summer and fall months of the Current Reporting Period, the average on-peak HOEP decreased over the same period. The correlation coefficient between the two variables during these months was 0.59. One reason for the decrease in correlation between the two variables is that gas-fired generators set the real-time MCP less frequently during this period, compared to previous months (see Figure 1-6).

Figure 1-5: Frequency Distribution of HOEP
November 2013 – April 2014 & May – October 2014
(% of hours)

Description:

Figure 1-5 compares the frequency distribution of the HOEP for the Current Reporting Period and the Previous Reporting Period, as a percentage of total hours in each period.



Relevance:

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

Commentary and Market Considerations:

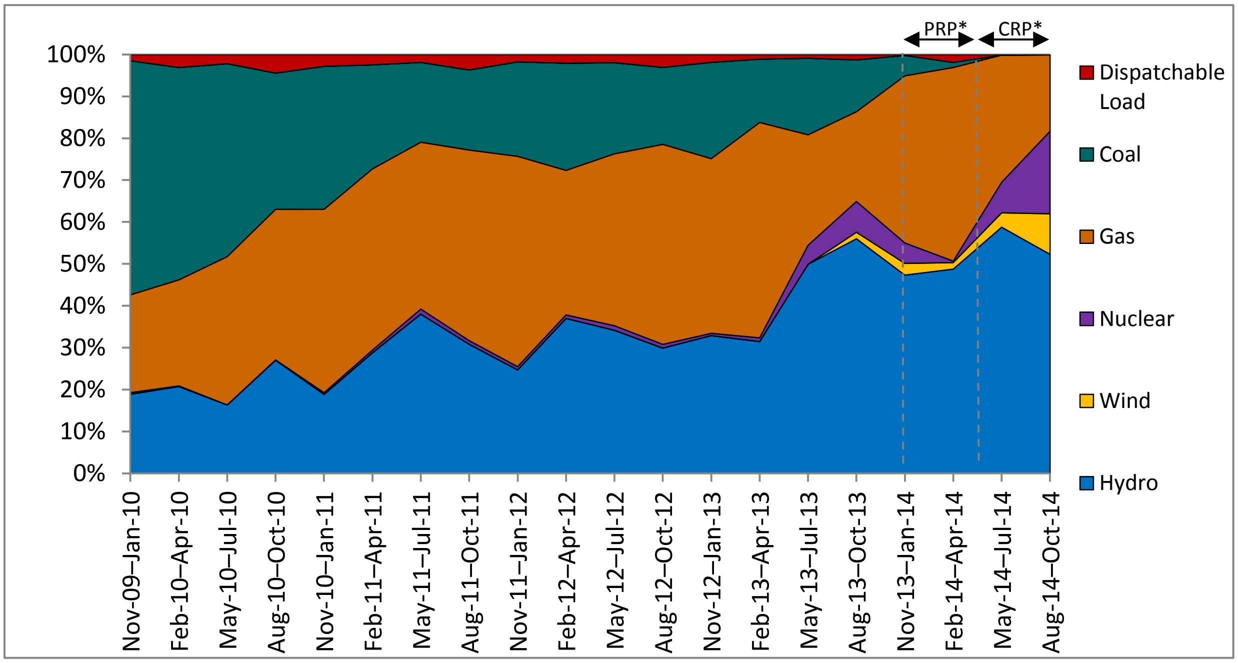
The distribution of prices was broader in the Previous Reporting Period than in the Current Reporting Period. The frequency of negative HOEPs increased from 3% of total hours in the Previous Reporting Period to 15% of total hours in the Current Reporting Period, while instances of the HOEP greater than $100/MWh decreased between these two periods from 11% to 1%.

As seen in Figure 1-6, the increase in instances of negative HOEPs during the Current Reporting Period was largely driven by: (i) increased capacity of dispatchable wind resources, which typically submit negative offer prices; and (ii) a reduction in nuclear outages, resulting in increased availability of nuclear power which is also typically offered at negative prices.

Figure 1-6: Share of Resource Type Setting the Real-Time MCP
November 2009 – October 2014
(% of intervals)

Description:

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



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

Relevance:

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

Commentary and Market Considerations:

Ontario's electricity generation supply mix has continued to evolve during the Current Reporting Period. The changes in the availability of different types of generators have affected the frequency with which each type set the real-time MCP. All coal generators were retired by May 2014 and therefore no longer set the MCP. By contrast, the Current Reporting Period saw an increase of 659 MW in dispatchable wind generation capacity. Prior to the third quarter of 2013,[13] wind generators never set the MCP. By the end of the Current Reporting Period, these resources were setting the MCP approximately 9.5% of the time.

The Current Reporting Period also saw an increase in the number of times nuclear resources set the real-time MCP. This was mostly due to a decrease in the number of nuclear outages (a

[13] Directly connected wind-powered generation became dispatchable in September 2013.

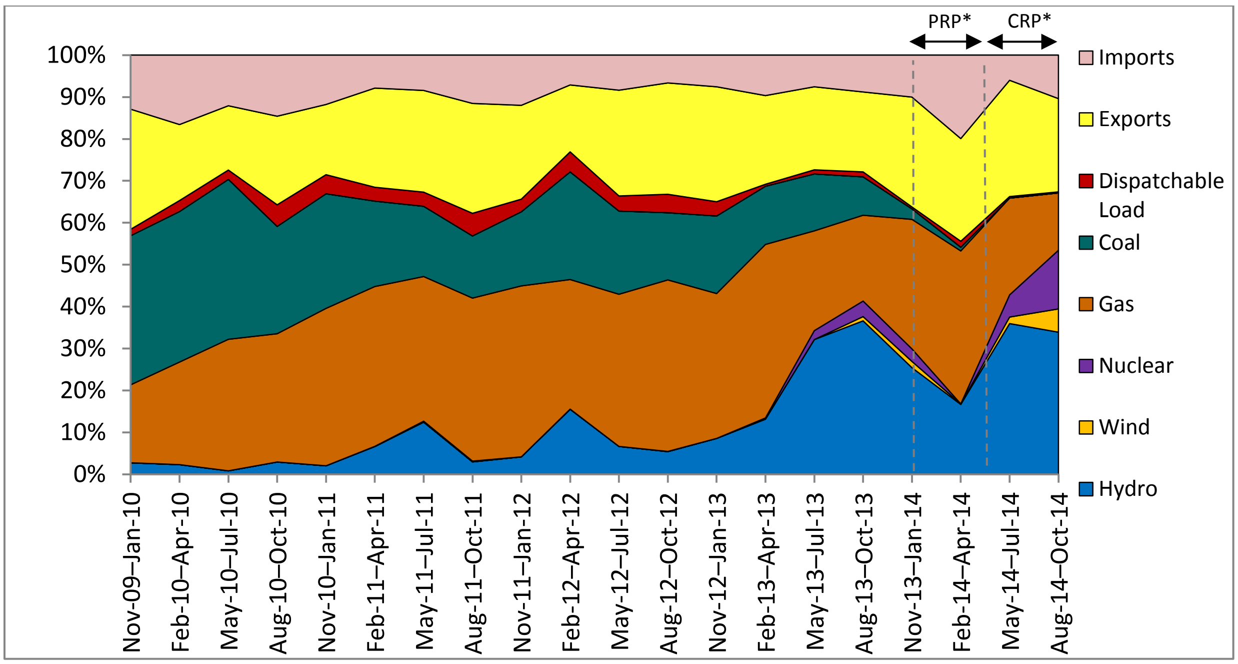
decrease of approximately 2.3 TWh relative to the Previous Reporting Period) and the establishment of a price floor for flexible nuclear generation, which moved some nuclear units up the supply offer stack.

An increase in lower-priced supply consisting of increased wind capacity and increased nuclear availability, in conjunction with lower overall demand during the fall months, resulted in fewer gas-fired units setting the MCP in the Current Reporting Period.

Figure 1-7: Share of Resource Type Setting the Pre-Dispatch MCP November 2009 – October 2014 (% of hours)

Description:

Figure 1-7 presents the quarterly share of hours in which each resource type set the pre-dispatch MCP, for the previous five 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 pre-dispatch 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 pre-dispatch MCP, as these transactions are unable to set the real-time MCP.[14] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP will occur.

Commentary and Market Considerations:

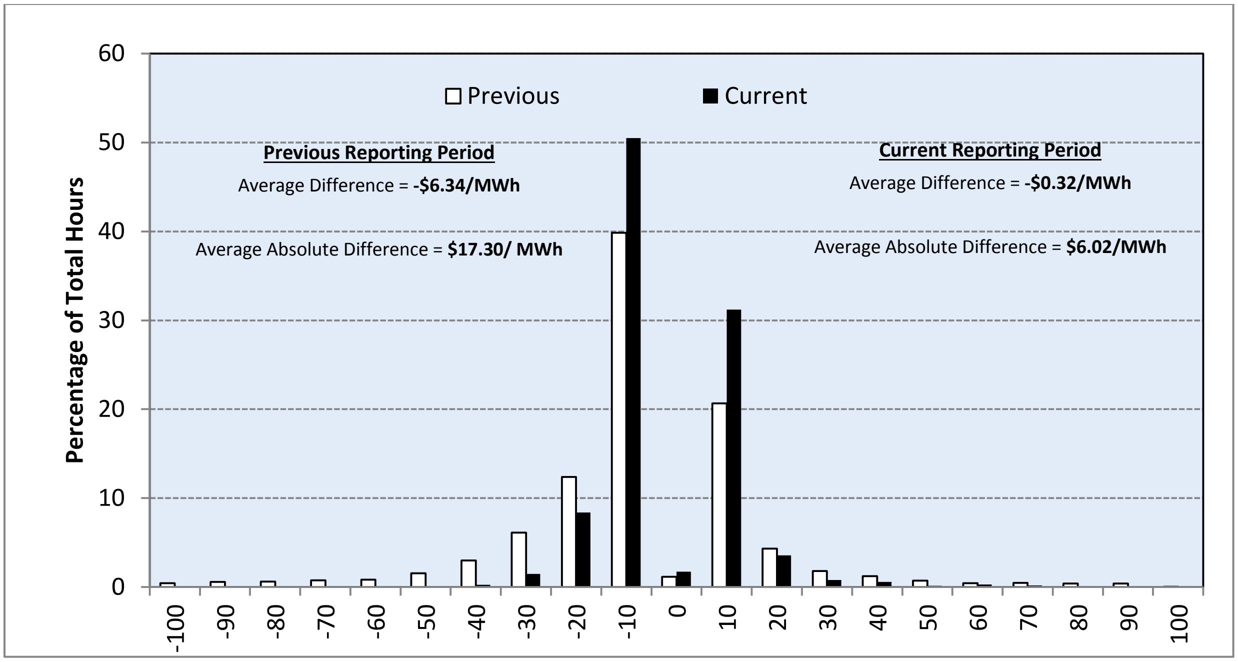
Imports and exports set the pre-dispatch MCP in 33% of the pre-dispatch hours in the Current Reporting Period, compared to 40% in the Previous Reporting Period. In February and March 2014, imports and exports set the pre-dispatch MCP 46% of the time, the highest monthly share of hours since October 2009.

Figure 1-8: Difference Between the HOEP and the One-Hour Ahead Pre-Dispatch MCP November 2013 – April 2014 & May – October 2014 (% of hours)

Description:

Figure 1-8 presents the frequency distribution of the difference between the HOEP and the one-hour ahead pre-dispatch ("PD-1") MCP for the Current and Previous Reporting Periods. The price differences are grouped in \$10/MWh increments, save for \$0/MWh which represents no change between the PD-1 price 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.

[14] Due to scheduling protocols, imports and exports are scheduled hour-ahead. Therefore, in real-time imports and exports are fixed for any given hour. This means that they are scheduled to flow for the entire hour regardless of the price. 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 instance, a generator outage 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 would gain more 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 narrower in the Current Reporting Period compared to the Previous Reporting Period; the average price difference and the average absolute price difference were also closer to zero in the Current Reporting Period, signifying less price volatility between the PD-1 MCP and the HOEP. The differences in the PD-1–HOEP price distribution between the two periods were due to extreme conditions in the Previous Reporting Period. Unexpectedly cold temperatures from January to March 2014 resulted in unfavourable gas supply conditions and exacerbated the impact of the various factors that can contribute to differences between the PD-1 MCP and the HOEP (see

Table 1-2). By contrast, volatility between the PD-1 MCP and the HOEP in the Current Reporting Period was comparable to volatility in the corresponding months of the previous year (May – October 2013), when the average price difference was $0.34/MWh and the average absolute price difference was $6.24/MWh.

Table 1-2: Factors Contributing to Differences Between One-Hour Ahead Pre-Dispatch and Real-Time MCP November 2013 – April 2014 & May – October 2014 (MWh and % of Ontario demand)

Description:

The Panel has identified six main factors that contribute to the difference between the PD-1 and the real-time MCP in any given hour. These factors are categorized as follows:

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 in megawatt hours between PD-1 and real-time, including as a percentage of Ontario demand, for the Current and Previous Reporting Periods. The effect of generator outages is not measured in this Table as they tend to be infrequent. Generator outages can have significant impacts on price, however, as shown in the analysis of high-price hours in Chapter 2 of this report.

Factor	Previous		Current	
	Average Absolute Difference (MWh)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MWh)	Average Absolute Difference (% of Ontario Demand)
Average Ontario Demand	16,901		15,118	
Pre-dispatch to Real-time Demand Forecast Deviation	217	1.29	213	1.41
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	29	0.17	51	0.33
Wind Forecast Deviation	116	0.69	97	0.64
Net[15] Export Failures/Curtailments	116	0.69	76	0.50

Relevance:

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

Commentary & Market Considerations:

Almost all of the factors listed above experienced a decrease in the average absolute difference between PD-1 and real-time quantities in the Current Reporting Period relative to the Previous Reporting Period, self-scheduling and intermittent forecast deviation being the exception. This led to the decreased price volatility in the Current Reporting Period seen in Figure 1-8.

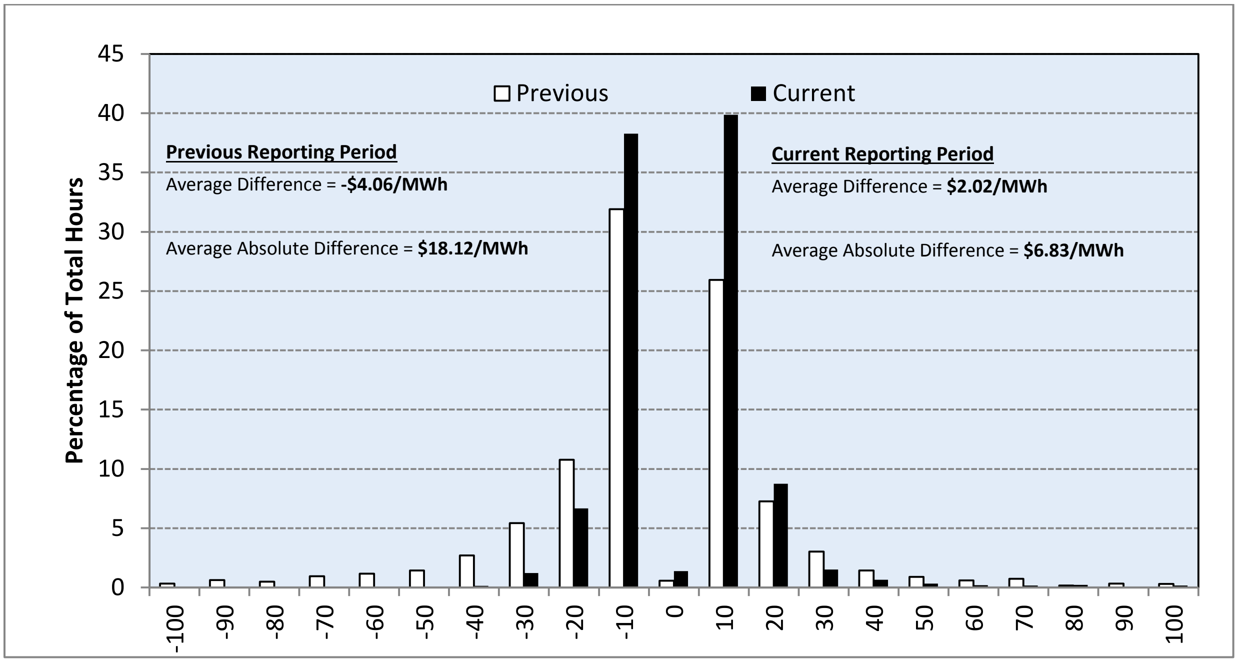
Figure 1-9: Difference Between the HOEP and the Three-Hour Ahead Pre-Dispatch MCP November 2013 – April 2014 & May 2014 – October 2014 (% of hours)

Description:

Figure 1-9 presents the frequency distribution of the difference 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 which represents no change between the PD-3 price and the HOEP. Positive differences on the x-axis represent a

[15] As both importers and exporters are price-takers in real-time, a quantity of failed/curtailed imports and an offsetting quantity of failed/curtailed exports should have no effect on the real-time MCP.

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 to the supply and demand conditions from PD-3 to real-time. The resultant changes in price are particularly important to non–quick-start facilities and energy limited resources,[16] 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:

As was the case with the PD-1 MCP, the distribution of the difference between the PD-3 MCP and the HOEP was narrower in the Current Reporting Period compared to the Previous Reporting Period. The average price difference and the average absolute price difference were closer to zero in the Current Reporting Period, signifying less price volatility between the PD-3 MCP and the HOEP. The volatility in the Current Reporting Period was somewhat less than in

[16] Energy limited resources constitute a subset of generation facilities that at times can be limited in the amount of energy they can provide during each day.

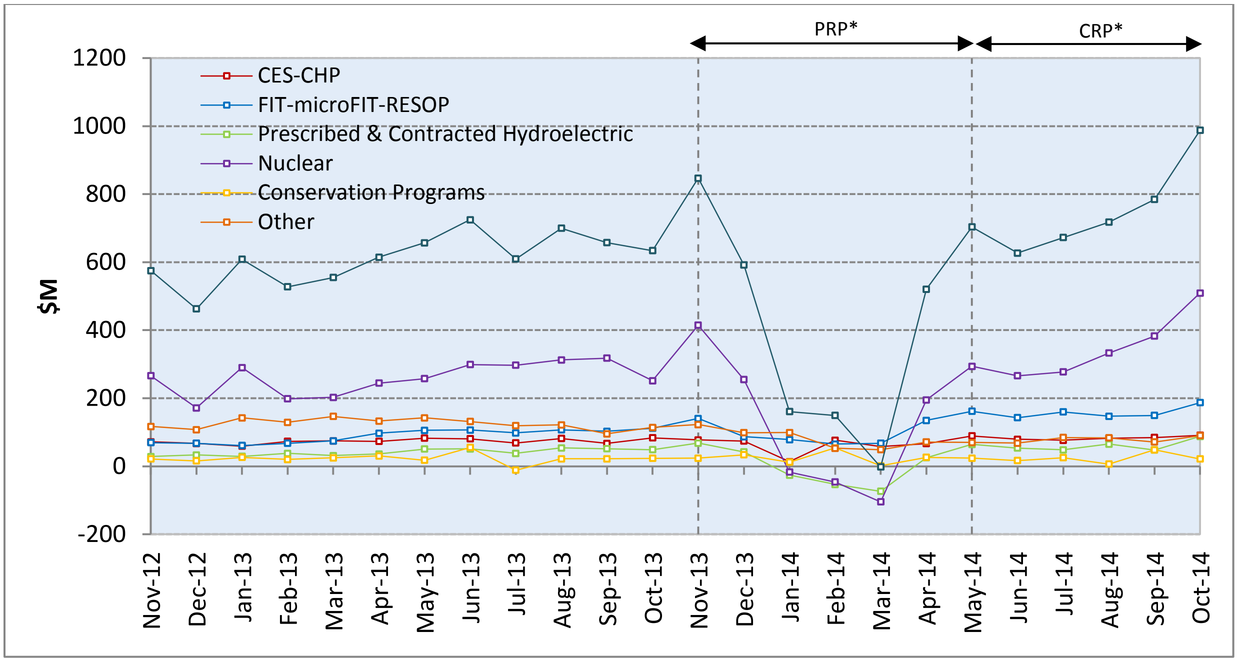
the corresponding months of the previous year (May – October 2013), when the average price difference was $3.34/MWh and the average absolute price difference was $7.12/MWh.

Figure 1-10: Monthly Global Adjustment by Component
November 2012 – October 2014
($ millions)

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 six components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation's ("OPG") nuclear assets);
- Payments to holders of Clean Energy Supply ("CES") contracts and Combined Heat and Power ("CHP") contracts;
- Payments to prescribed or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff ("FIT"), microFIT and holders of contracts under the Renewable Energy Standard Offer Program ("RESOP"));
- Payments related to the OPA's conservation programs; and
- Payments to others (including the OPA's demand response programs, holders of non-utility generator contracts, and 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, decreases in the HOEP, or any combination of the four.

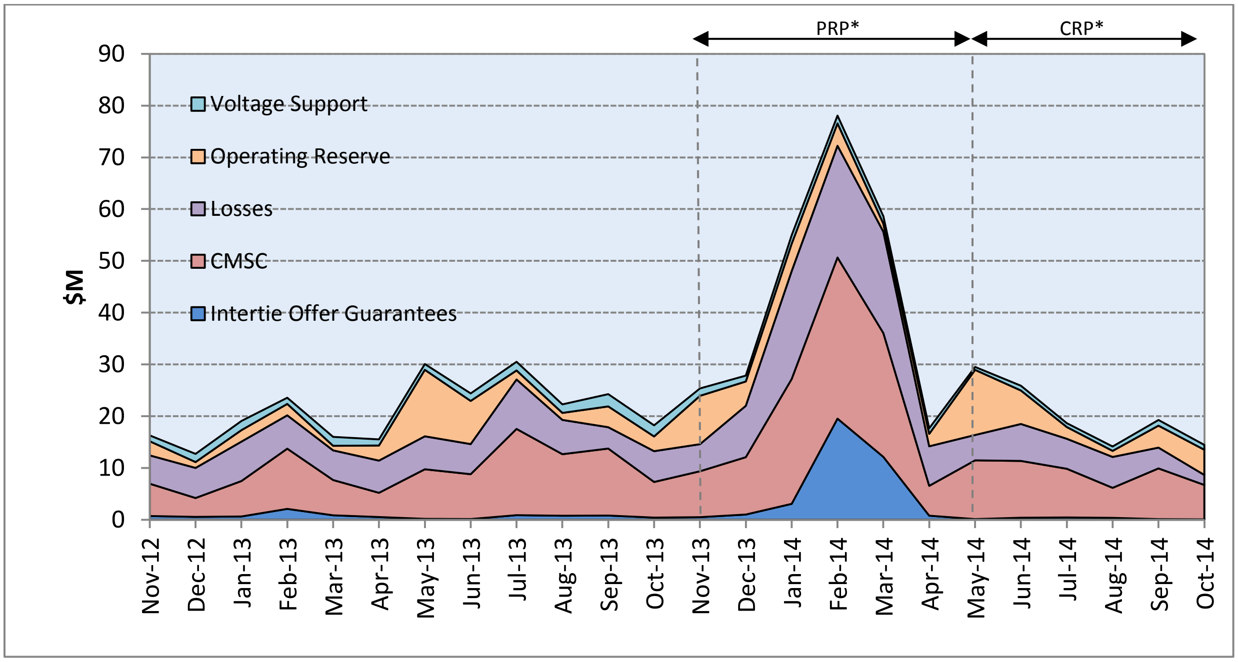
Commentary and Market Considerations:

The GA exhibited a significant though transitory decrease from January to March 2014, followed by a persistent increase over the Current Reporting Period. GA payments to contracted and regulated generation facilities are inversely related to the HOEP. As shown in Figure 1-3 above, from January to March 2014 the HOEP experienced a significant increase, followed by a steady decline over the spring and summer months and a rapid decline from September to October 2014. As a result of the decrease in the HOEP, a greater proportion of the compensation for contracted and regulated generation facilities was recovered through the GA.

Figure 1-11: Total Hourly Uplift Charge
by Component and Month
November 2012 – October 2014
($ millions)

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, Operating Reserve ("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 of electricity in Ontario. It is charged to wholesale consumers based on their share of total hourly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

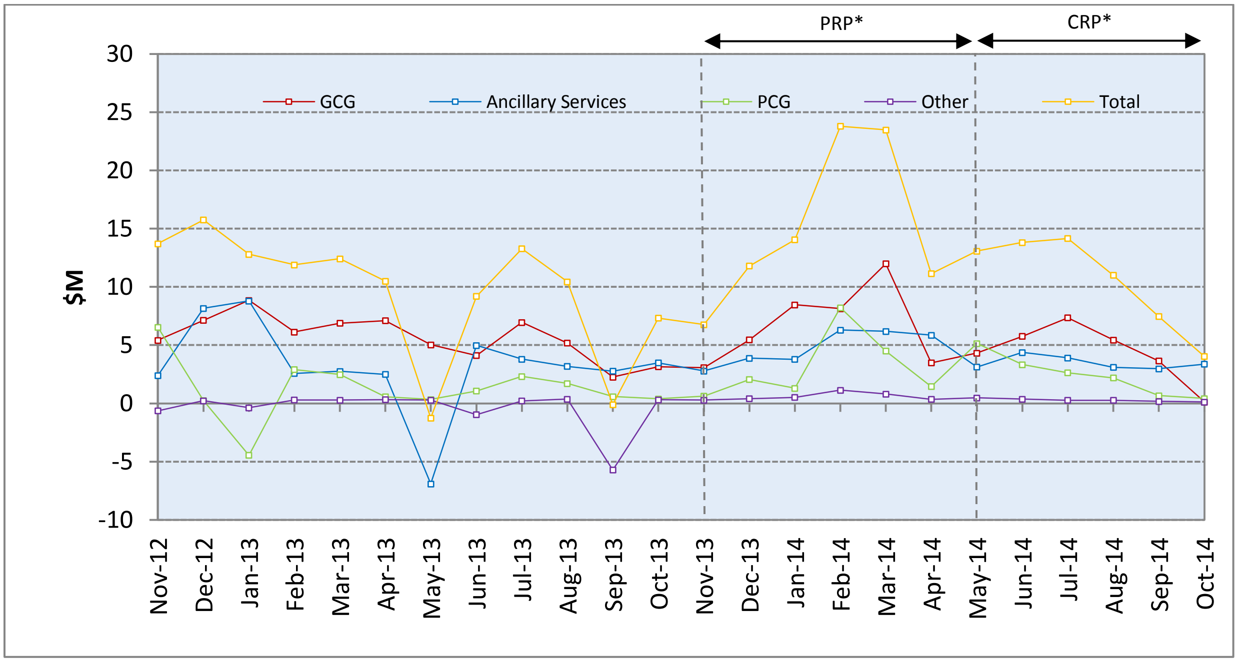
All components of Hourly Uplift relate to the HOEP, either directly or indirectly. For instance, the component of Hourly Uplift that accounts for losses is a function of the HOEP and loss factors, and OR prices tend to follow changes in the HOEP as the energy and OR markets are co-optimized. Thus, the trend in Hourly Uplift over the Current Reporting Period for the most part predictably matched the trend in the HOEP. May and September 2014, however, were notable exceptions to this pattern as increases in OR and CMSC payments contributed to an increased Hourly Uplift. As discussed in the Commentary section associated with Figure 1-13 below, OR prices typically spike in the spring due to freshet conditions and the inability of hydroelectric facilities to offer OR as a result of these conditions.

Figure 1-12: Total Non-Hourly Uplift Charge by Component and Month November 2012 – October 2014 ($ millions)

Description:

Figure 1-12 plots the total non-hourly uplift charges ("Non-Hourly Uplift") by component and month, for the previous two years. Non-Hourly Uplift components include three main categories:

- 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.

Relevance:

Non-Hourly Uplift is a component of the effective price of electricity in Ontario. It is charged to wholesale consumers based on their share of total monthly demand in order to recover the costs associated with various market programs and design features.

Commentary and Market Considerations:

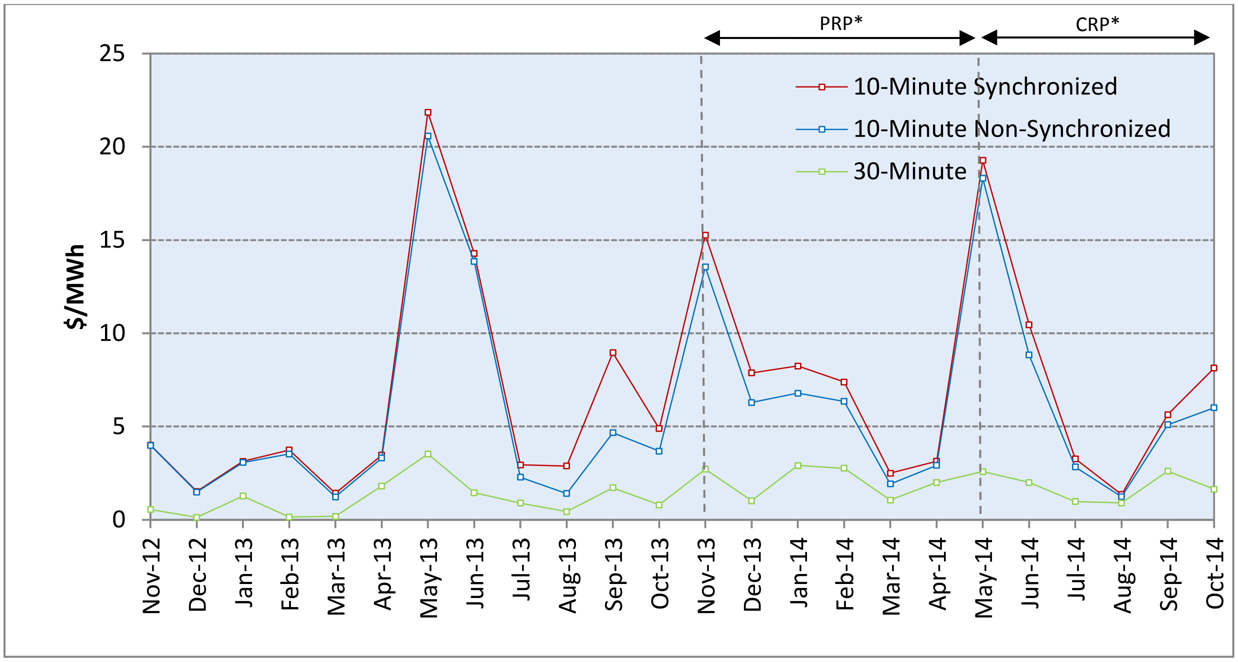
Changes in Non-Hourly Uplift within the Current Reporting Period were primarily driven by changes to GCG and PCG payments. As described in Chapter 2, GCG and PCG payments are made under IESO reliability programs that make provision for eligible fossil-fueled generators to recover certain of their costs in the event that their market revenues are insufficient for that purpose.

From May 2014 onward, there was a steady decline in PCG payments, and the same is true of GCG payments from July 2014 onward. Both reached their lowest points in October 2014. The declines were due to several factors, including a decrease in gas-fired units being scheduled and a considerable decrease in gas prices. As discussed in the Commentary section associated with Figure 1-6, the Current Reporting Period saw increased supply from wind and nuclear resources. As these resources typically offer at prices lower than those offered by gas-fired generators, the Current Reporting Period saw fewer gas-fired generators being scheduled. For the gas-fired units that were scheduled, smaller GCG and PCG payments were made in part due to the lower cost of fuel.

Figure 1-13: Average Monthly Operating Reserve Prices, by Category November 2012 – October 2014 ($/MWh)

Description:

Figure 1-13 plots the monthly average OR price in dollars per megawatt hour for the three OR markets: 10 minute synchronized (“10S”), 10 minute non-synchronized (“10N”), and 30 minute reserve (“30R”), for the previous two years.



*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 even in the event of large contingencies.

Commentary and Market Considerations:

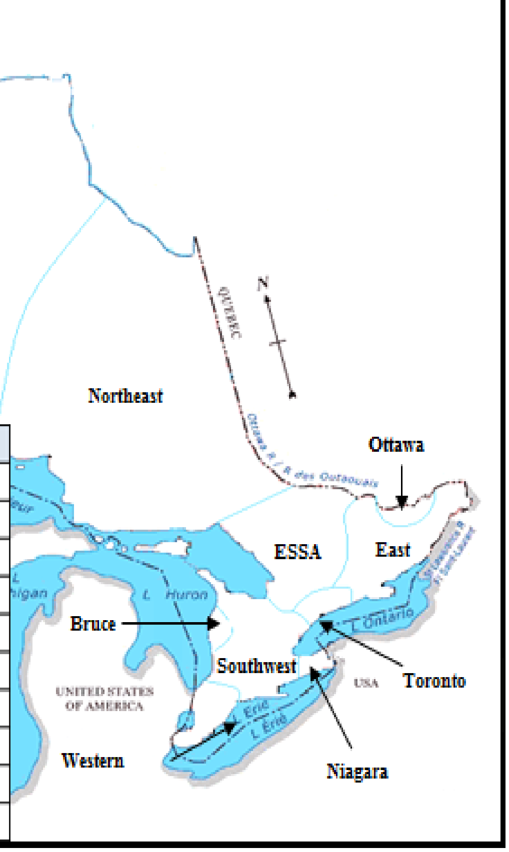
High OR prices at the beginning and end of the Current Reporting Period were, in part, a consequence of hydroelectric resources offering less OR due to limited operating flexibility during freshet conditions. Freshet, due to the spring thaw and rains, results in a rise in water levels which forces many hydroelectric resources to run at their full capacity (and unable to offer

OR). In addition, under these and certain other conditions some hydroelectric resources are unable to react to changing dispatch instructions. Such hydroelectric “lockouts” can last for several intervals and up to several hours. May 2014, for example, saw a significant spike in OR prices as the number of hydroelectric lockouts (420) during this month was substantial. By comparison, August 2014, a month with relatively low OR prices, had only 4 lockouts.

Figure 1-14: Average Internal Nodal Prices by Zone
November 2013 – April 2014 & May – October 2014
($/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	Previous	Current
Bruce	44.23	19.78
East	44.64	17.86
Essa	46.09	21.77
Niagara	44.39	22.47
Northeast	30.59	-65.03
Northwest	-104.03	-369.69
Ottawa	46.97	19.74
Southwest	45.5	21.71
Toronto	45	21.3
West	45.42	25.72

Relevance:

While the HOEP is the uniform wholesale market price across Ontario, the actual cost of 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 when respecting Ontario's internal transmission constraints. Differences in the average nodal prices across zones illustrate the discrepancies between supply and demand between different transmission-constrained geographic regions of Ontario.

Commentary and Market Considerations:

Relative to the Previous Reporting Period, average nodal prices in all zones decreased along with the average HOEP in the Current Reporting Period. In general, most zonal prices tend to move together, except when there are outages on major transmission lines. The Northwest and Northeast zones are the exception. The divergence between prices in these zones and prices in the rest of the province is due to the fact that there is low-cost generation in excess of demand in those areas and insufficient transmission to transfer the surplus to the southern part of the province.

The negative prices observed in the northern zones are attributable primarily to an increase in hydroelectric units operating under "must-run" conditions. Must-run conditions force the units to generate at certain levels of output due to safety, environmental, or regulatory concerns. Under such conditions, energy is offered at extreme negative prices in order to ensure that the units are scheduled. Furthermore, the significant drop in price to negative values observed in the Northeast is consistent with what has been observed in the past. The Previous Reporting Period had anomalously high prices during the winter months, leading to an uncommon average price of $30.59 in the Northeast.

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

Description:

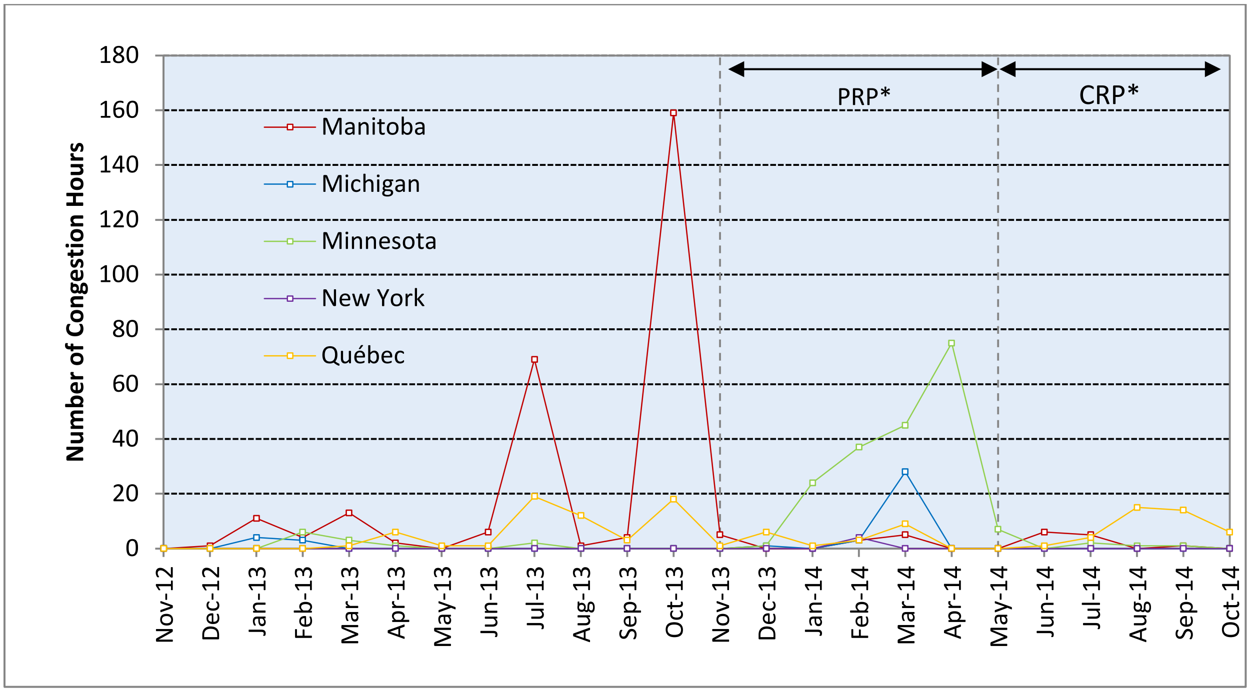
Figures 1-15 and 1-16 report the number of hours per month of import and export congestion, respectively, by interface for the previous two years.

Relevance:

The interties that connect Ontario to neighbouring jurisdictions have finite transfer capabilities. When an intertie has a greater amount of economic net import offers (or export bids) than its one-hour ahead pre-dispatch transfer capability, this intertie is considered to be import (or export) congested. Demand for intertie transfer capability is driven in part by price differences between Ontario and other jurisdictions. The supply of intertie transfer capability is dictated by the available capacity at each interface, though it may be affected by line outages and de-ratings.

While the HOEP is the wholesale market price for domestic consumers and producers, the price for import and export transactions can differ from the HOEP as it is based on the price in the zone where the transaction is taking place. For a given intertie, importers are paid the intertie zone price, while exporters pay the intertie zone 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 zone price decreases relative to the HOEP. When there is export congestion, importers receive more for the energy they supply while exporters pay more for the energy they purchase—the intertie zone price increases relative to the HOEP.

Figure 1-15: Import Congestion by Interface Group
November 2012 – October 2014
(number of hours in the unconstrained schedule)



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

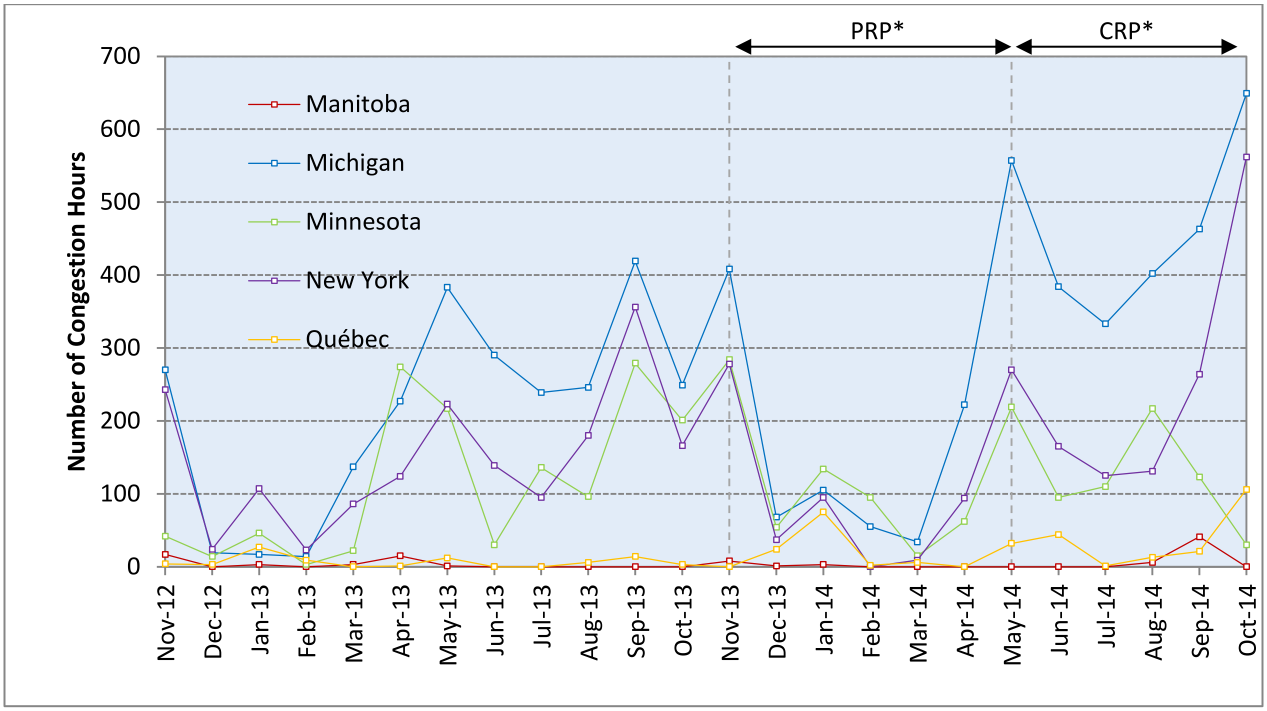
Commentary and Market Consideration:

Import congestion occurred relatively infrequently during the Current Reporting Period. The only notable instance of import congestion was at the Québec[17] intertie during August and September 2014. The sharp decrease in import congestion at the Minnesota intertie from the Previous to the Current Reporting Period can be attributed to two factors: (i) transmission lines returned to normal capacity (line outages led to reduced transfer capacity for the majority of the Previous Reporting Period); and (ii) in light of this relative capacity increase, transmission rights sold no longer exceeded the intertie transmission capacity. A transmission right provides a hedge against congestion-related price fluctuations. As such, market participants looking to trade over an intertie are more likely to do so when they own a transmission right. If the number of transmission rights sold exceeds the intertie capacity, congestion is more likely to occur: market participants who otherwise might not be trading due to the congestion price risk do so in light of

[17] Unless otherwise stated, all references to the Québec intertie in this Chapter refer to the Outaouais transmission interface.

the hedge provided by transmission rights. The Relevance section associated with Figure 1-17 below provides more information regarding transmission rights.

Figure 1-16: Export Congestion by Interface Group
November 2012 – October 2014
(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, Michigan, and Minnesota interties was relatively high during the Current Reporting Period compared to the Previous Reporting Period. The New York and Michigan interties, in particular, experienced a dip in the first half of the Current Reporting Period, followed by a sharp increase. For the Michigan intertie, the increased congestion was partly driven by a steady increase in net exports starting in June 2014 (see Figure 1-26), coupled with an average MW/hour export capability that was 5% lower compared to the Previous Reporting Period. For the New York intertie, although net exports were relatively steady throughout the Current Reporting Period, on average they were much higher compared to the Previous Reporting Period. The intertie also saw a significant increase in congestion hours towards the end of the Current Reporting Period because of a large decrease (31%) in the average MW/hour export capability between September and October 2014.

Another factor that contributed to increased net exports in general and thus a greater potential for export congestion was the relatively low HOEP in May and October 2014. This is because a low HOEP would likely have made Ontario's energy relatively cheaper than energy in neighboring jurisdictions. For example, the external price at the New York interface was lower than the HOEP for 94% of the hours in October 2014.[18] While it is important to remember that exporters do not see the real-time prices in Ontario and an outside market when scheduling their transactions, continually low prices in Ontario gives a price signal that this trend is likely to continue.

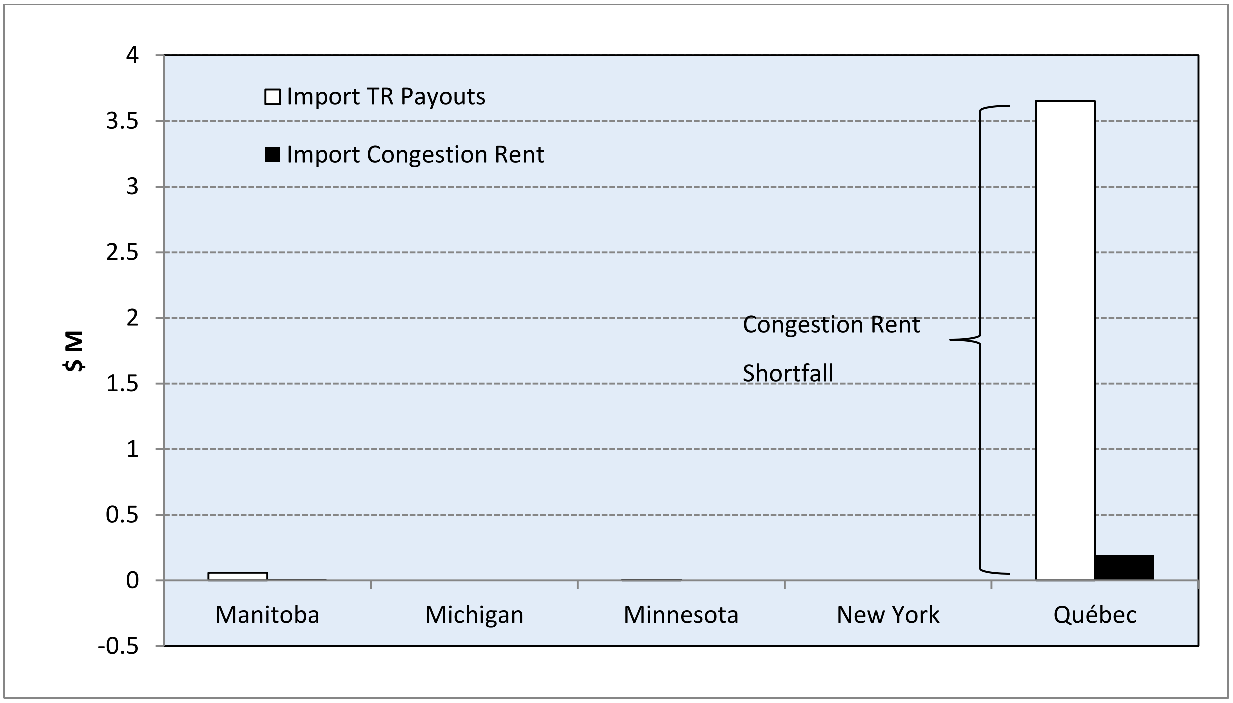
Additionally, for the majority of the Current Reporting Period, the number of transmission rights sold was greater than the export transmission capability at the New York and Michigan interties. This increased the frequency of export congestion.

Figure 1-17: Import Congestion Rent & Transmission Rights Payouts by Interface Group May – October 2014 ($ millions)

Description:

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

[18] External prices at NY were obtained from the NYISO's website, available at: http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp?report=tw_int_rt_lbmp_zonal



Relevance:

As discussed in the Relevance section associated with Figures 1-15 and 1-16, an intertie zone price is less than the Ontario price when an intertie is import congested; the difference in prices is referred to as the Intertie Congestion Price ("ICP") and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1 intertie zone price. While the importer is paid the lesser intertie zone price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the consumer and the amount paid to the importer is known as "congestion rent." Congestion rent accrues to the IESO's 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 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. This product allows a trader to hedge against congestion-related price fluctuations, ensuring they are settled on the HOEP and not the intertie zone price. For instance, a 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 exactly offset price differences between the Ontario price and the price in the intertie zone. Payments to TR holders are disbursed from the TR Clearing Account.

While TR payouts are theoretically offset by congestion rent collected, in practice this is often not the case. And although there may be a number of reasons for this outcome, one of the main reasons is due to 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 rents exceed TR payouts.

In addition to congestion rent collected and TR payouts, there is a third input to the balance of 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 consumers.

[19] Intertie congestion (and thus the ICP and TR payouts) is calculated based on the pre-dispatch unconstrained schedule, while congestion rent collected is based on the real-time constrained schedule. To the degree 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 (say import) in the pre-dispatch unconstrained schedule, but the real-time constrained schedule has scheduled net transactions in the opposite direction (say export). In this case negative 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 the 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

Note that interties with relatively high frequency of congestion hours (see Figure 1-15) do not necessarily correlate with relatively high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

Commentary and Market Consideration:

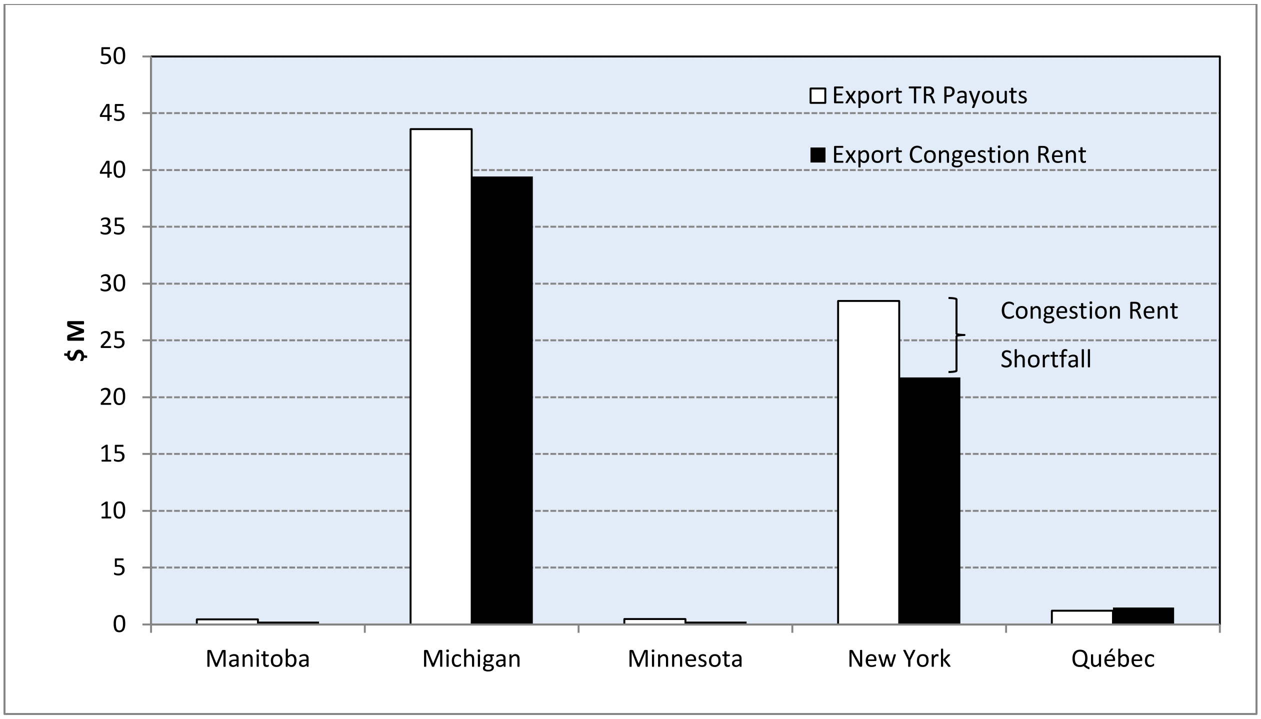
During the Current Reporting Period, the only intertie which experienced a notable congestion rent shortfall (of approximately $3.4 million) was the Québec intertie.

There was $0 in TR payouts and congestion rent for the Michigan and New York interties, as these interties did not experience import congestion during the Current Reporting Period (see Figure 1-15). Similarly, there were very few congestion hours on the Manitoba and Minnesota interties, which translated to very few transactions (and thus small absolute values of both TR payouts and congestion rent). Congestion rent shortfall was effectively negligible for these interties.

Figure 1-18: Export Congestion Rent &
TR Payouts by Interface Group
May 2014 – October 2014
($ millions)

Description:

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



Relevance:

For a detailed explanation of TRs and congestion rent, see the Relevance section associated Figure 1-17. As discussed, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario consumers in the form of a reduction in transmission charges.

Commentary and Market Consideration:

During the Current Reporting Period there were export congestion rent shortfalls on all interties except the Québec intertie; however, the shortfalls were only significant at Michigan and New York, totalling $4.2 million and $6.8 million respectively.

The relatively larger export congestion rent shortfalls at the Michigan and New York interties compared to other interties can be attributed to TRs sold in excess of eventual intertie capability and relatively more congestion hours occurring on these interties (see Figure 1-16). Although, as indicated before, interties with relatively high frequency of congestion hours do not necessarily correlate with high TR payouts and export congestion rent, the Michigan and New York interties also have relatively high intertie capacities, and, as such, have more TRs sold. The combination of the high number of TRs and high frequency of congestion does lead to higher TR payouts.

Table 1-3: Average Long-Term (12-month) Transmission Right Auction Prices by Interface and Direction November 2013 – October 2014 ($/MW)

Description:

Table 1-3 lists the average auction prices of one MW of long-term (year-long) TRs sold for each interface, in either direction, since November 2013 (these TRs would have been valid during the Current Reporting Period) .

Direction	Auction Date	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-13	Jan-14 to Dec-14	5,334	809	2,715	758	637
	Feb-14	Apr-14 to Mar-15	-	716	3,766	780	725
	May-14	Jul-14 to Jun-15	-	1,396	5,506	1,214	828
	Aug-14*	Oct-14 to Sep-15	-	-	-	-	-
Export	Nov-13	Jan-14 to Dec-14	2,521	31,170	30,200	25,819	3,530
	Feb-14	Apr-14 to Mar-15	-	34,217	-	30,043	4,281
	May-14	Jul-14 to Jun-15	-	38,836	-	32,216	9,211
	Aug-14*	Oct-14 to Sep-15	-	-	-	-	-

*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 of 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:

For the most part, auction prices for long-term TRs increased in each successive auction for the same type (i.e. direction and intertie) of TR since November 2013,as market participants likely anticipated future congestion.

Table 1-4: Average Short-Term (One-month) Transmission Right Auction Prices by Interface and Direction November 2013 – October 2014 ($/MW)

Description:

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

Direction	Period TRs are Valid	Manitoba	Michigan	Minnesota	New York	Québec
Import	Nov-13	376	37	104	16	160
	Dec-13	263	57	125	42	160
	Jan-14	229	67	197	6	81
	Feb-14	264	62	349	31	170
	Mar-14	291	301	332	83	202
	Apr-14	451	190	354	60	744
	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
Export	Nov-13	165	3,000	-	2,053	201
	Dec-13	194	2,894	1,501	1,450	400
	Jan-14	210	2,620	-	1,885	746
	Feb-14	232	2,801	-	2,463	577
	Mar-14	157	1,455	-	1,613	525
	Apr-14	123	2,662	901	1,674	525
	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

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.

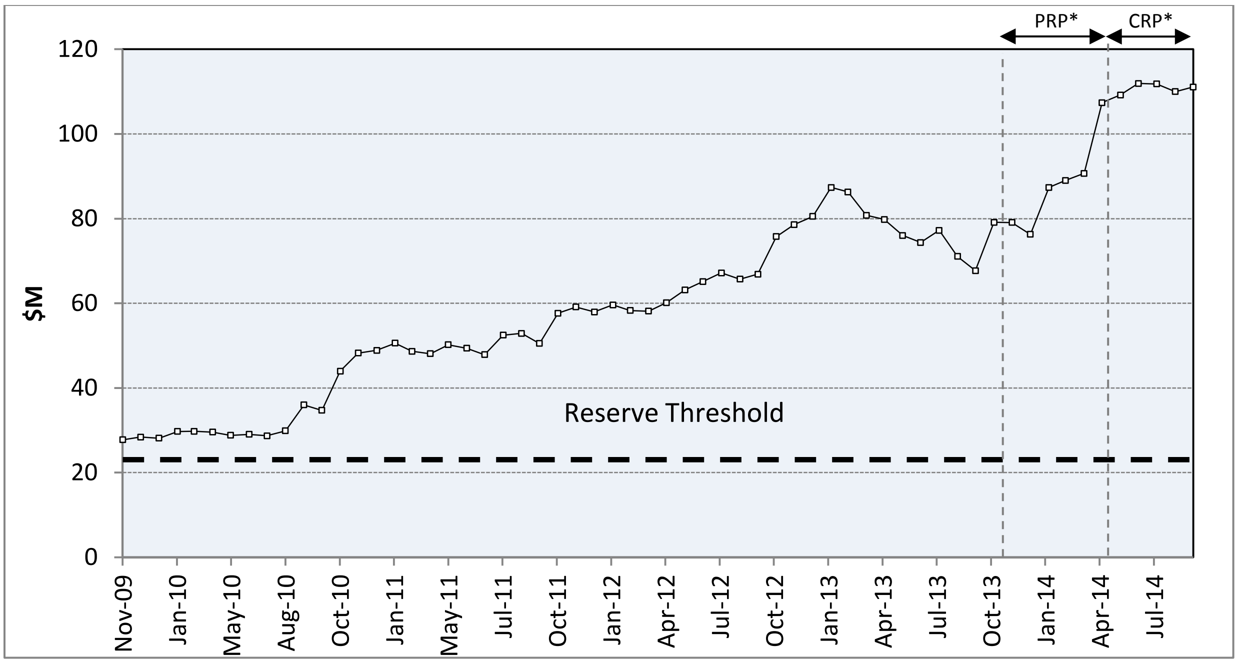
Commentary and Market Consideration:

Relatively high export congestion on the New York and Michigan interties during the Current Reporting Period contributed to relatively high prices of short-term TRs for these interties, as market participants likely expected that the congestion would be sustained throughout the Current Reporting Period.

Figure 1-19: Transmission Rights Clearing Account November 2009 – October 2014 ($ millions)

Description:

The TR Clearing Account is an account administered by the IESO. Figure 1-19 shows the estimated balance of 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 TR Clearing Account balance

<u>Debits</u>

- TR payouts to rights holders
- Disbursements to Ontario consumers

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 (“Reserve Threshold”); funds in excess of this threshold can be disbursed to Ontario consumers 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 $20.4 million (from $90.7 million to $111.1 million), resulting from:

- $98.3 million in credits
    - $63.4M in congestion rent collected
    - $34.3M in auction revenues
    - $0.6M in interest
- $77.9 million in debits
    - $77.9M in TR payouts to rights holders

The TR Clearing Account was therefore approximately $91.1 million above the Reserve Threshold. The Panel has previously expressed the view that any amount in excess of the Reserve Threshold should be disbursed to consumers on a regular basis. In March 2015, the IESO Board of Directors approved the disbursement of $100 million accumulated in the TR Clearing Account in six monthly installments, beginning April 2015.[21] As part of a recently approved amendment to the Market Rules, going forward the IESO intends to evaluate the balance in the TR Clearing Account semi-annually and recommend that the IESO Board of Directors authorize disbursements for material surplus amounts in the account.[22]

2 *Demand*

[21] 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

[22] For more information on the market rule amendment see: http://www.ieso.ca/Documents/Amend/mr2015/MR_00421_TRCA_Amendment_Proposal%20v5_0.pdf

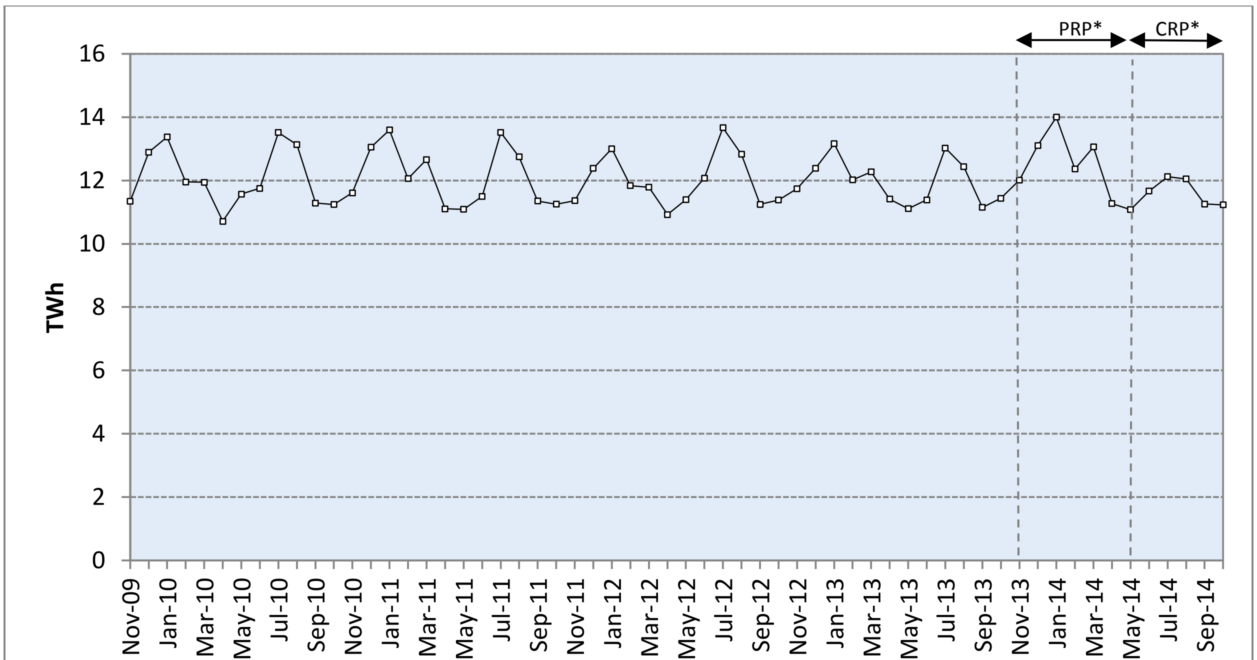
This section discusses Ontario energy demand for the Current Reporting Period relative to previous years.

***Figure 1-20: Monthly Ontario Energy Demand
November 2009 - October 2014
(TWh)***

Description:

Ontario energy consumption in the Current Reporting Period was 69.4 TWh compared with 70.6 TWh in the period May 1, 2013 to October 31, 2013. This decline was most likely a result of the unseasonably cool summer months of 2014 which brought about the lowest monthly summer peak demand of the past five years.

Figure 1-20 presents the total energy consumption of Ontario consumers in each month in the past five years.



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

Relevance:

Ontario monthly consumption shows the seasonal variations in consumption and the year-to-year change in consumption patterns.

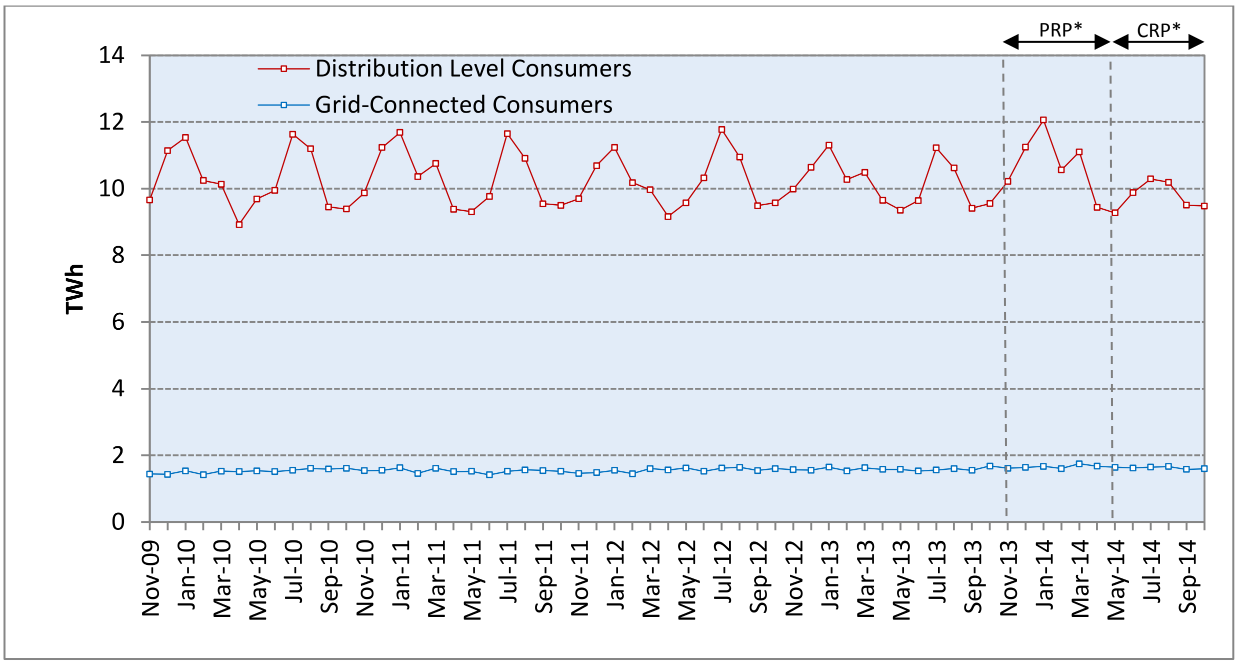
Commentary and Market Consideration:

After the highs experienced during the 2014 winter months (particularly in January 2014), monthly Ontario demand returned to average levels in the spring. The unseasonably cool 2014 summer months brought about the lowest monthly summer peak demand of the past five years. As noted in the Commentary section associated with Figure 1-3, 2014 was the second consecutive year that the province's peak monthly demand in the winter was higher than its peak monthly demand in the summer.[23]

Figure 1-21: Monthly Total Energy Withdrawals by Distributors and Wholesale Loads November 2009 – October 2014 (TWh)

Description:

Figure 1-21 charts the demand of two categories of consumers: market participants that are directly connected consumers (grid-connected consumers), and consumers connected to distribution systems (distribution level consumers).



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

[23] Ontario has historically been a summer peaking province.

Relevance:

The breakdown of consumers into these two categories helps identify their monthly demand profiles. From this, any seasonal variations in behavior can be observed.

Commentary and Market Consideration:

Seasonal changes in Ontario demand were attributed almost entirely to distribution level consumers. These include residential, small and medium commercial, and small industrial loads. Low demand on the part of these consumers is particularly evident in the spring (April and May) and fall (September and October) months. The primary reason for the lower demand during these seasons is the milder weather, resulting in a reduced need for heating or cooling. Meanwhile, demand from grid-connected consumers, a group that primarily comprises industrial loads and large commercial consumers, has increased slightly over the past five years, but exhibits little of the seasonality of distribution level consumers.

3 *Supply*

This section discusses electricity supply for the Current Reporting Period relative to previous years.

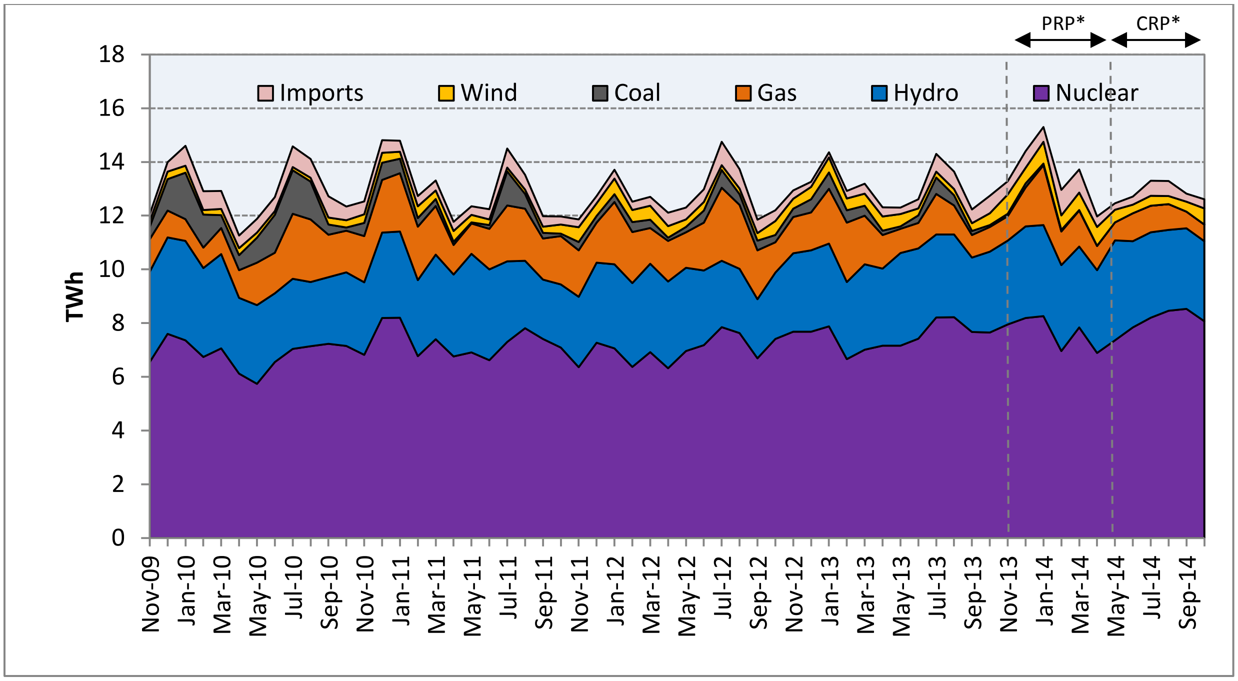
During the Current Reporting Period, 943 MW of nameplate generating capacity was added to the IESO-controlled grid.[24] New capacity consisted of an increase in wind (659 MW), hydroelectric (106 MW) and biofuel (178 MW) generation.[25]

Figure 1-22: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule November 2009 – October 2014 (TWh)

Description:

Figure 1-22 illustrates the cumulative share of energy scheduled in the real-time market schedule by resource type (wind, coal, gas, hydro, nuclear, and imports) in terawatt hours for each month from November 2009 to October 2014.

[24] This figure does not account for new embedded generation capacity.
[25] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's latest 18-Month Outlook, available at: http://www.ieso.ca/Pages/Participate/Reliability-Requirements/Forecasts-%26-18-Month-Outlooks.aspx



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

Relevance:

This figure displays the evolution of Ontario's changing supply mix of real-time energy. Changes in the resources scheduled may be the result of a number of factors, such as changes in energy policy or seasonal variations.

Commentary and Market Considerations:

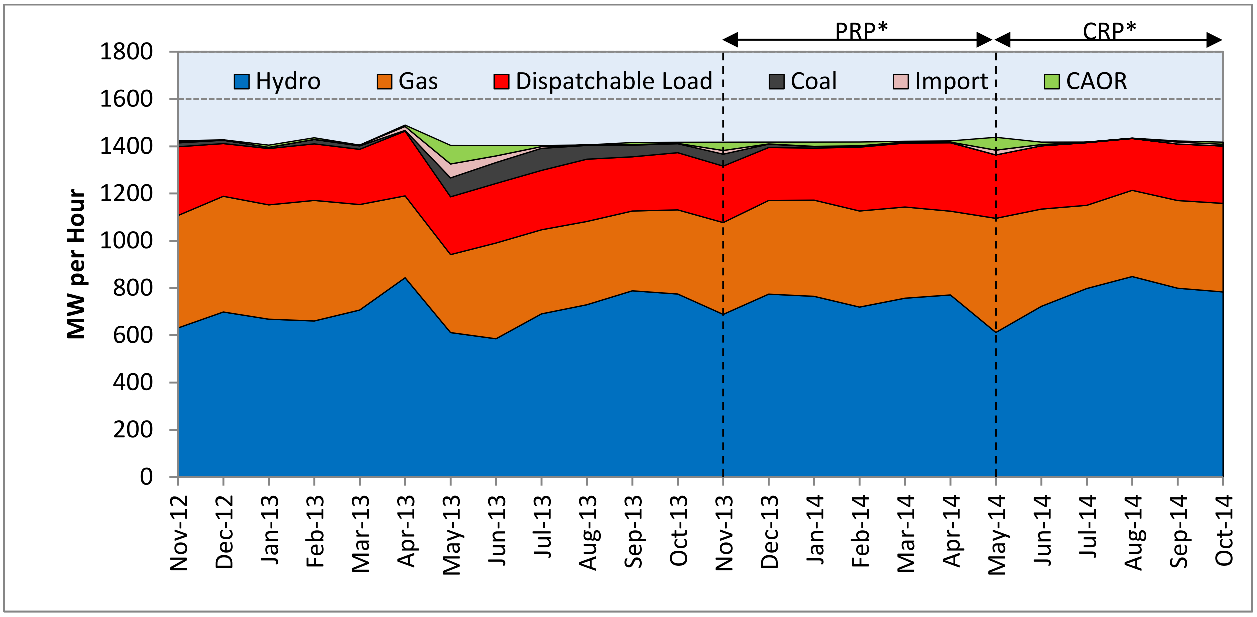
The total energy scheduled in the Current Reporting Period was 77.8 TWh. Nuclear units continued to be the predominant resources scheduled, comprising on average 62.3% of all scheduled supply. Hydroelectric generators comprised the second highest percentage of scheduled resources at 24.5%, followed by gas, wind, and imports each at less than 10%.

The most significant change relative to the Previous Reporting Period resulted from the fact that all coal-fired units were retired by May 2014 they therefore did not contribute to the real-time market schedule in the Current Reporting Period. Also of note is the reduction in the scheduling of gas-fired units. In the Previous Reporting Period, on average gas-fired units comprised 9.8% of all resources scheduled; this fell to 6.3% in the Current Reporting Period as gas-fired units were displaced by lower-priced resources.

Figure 1-23: Average Hourly Operating Reserve Scheduled by Resource or Transaction Type November 2012 – October 2014 (MW per hour)

Description:

Figure 1-23 plots the average hourly amount of OR in the unconstrained schedule for each resource or transaction type, including hydroelectric, gas, coal, imports, dispatchable loads, and Control Action Operating Reserve ("CAOR").[26] As OR quantity requirements can vary from hour to hour, monthly average scheduled OR per hour is reported to show changes in the average OR requirement.



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

Relevance:

This figure reflects the evolution in Ontario's changing supply mix for OR 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.

[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 uses standing offers in the OR offer stack to represent three of the more common control actions. These offers 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 always available to the market.

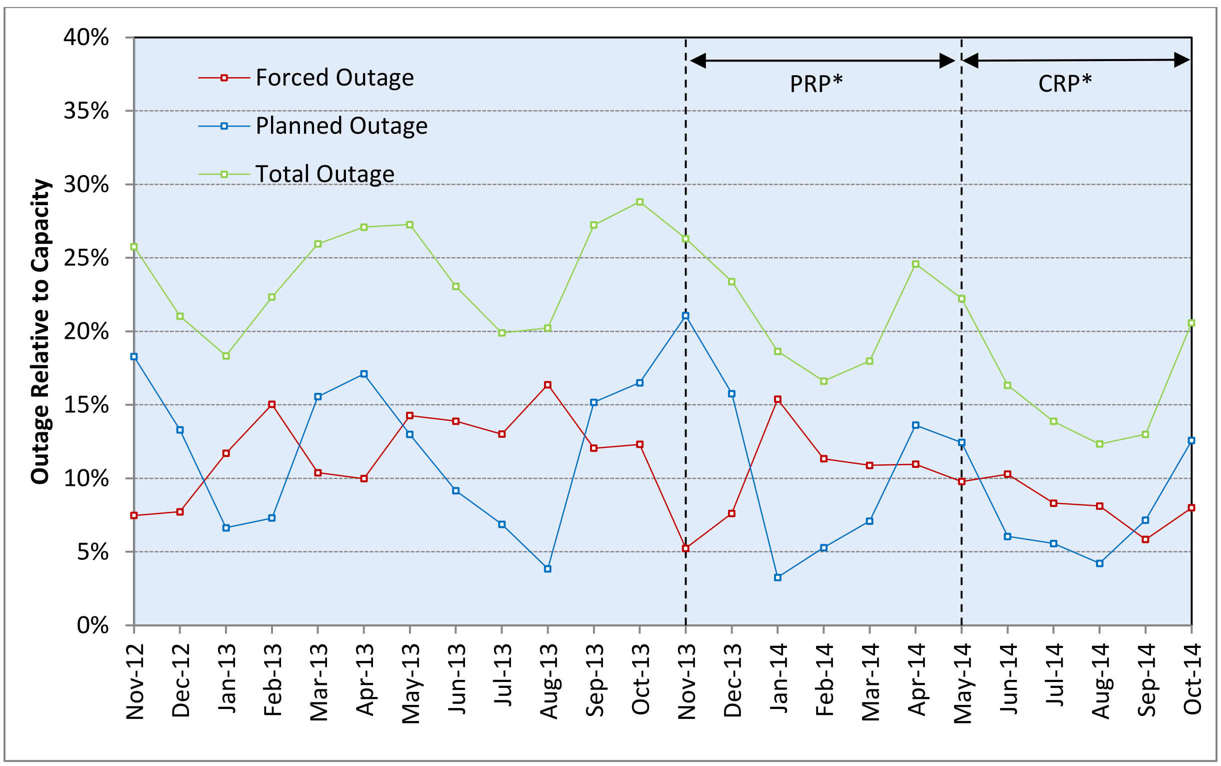
Commentary and Market Considerations:

In the Current Reporting Period, approximately 6.2 TWh of OR was scheduled in the unconstrained schedule. Hydroelectric resources accounted for 53.4% of this scheduled OR, while gas-fired generators and dispatchable loads were scheduled for 27.6% and 17.6%, respectively. As noted earlier, coal generation was retired by May 2014 and thus had no impact on OR scheduled in the Current Reporting Period.

Figure 1-24: Planned & Forced Outages Relative to Capacity November 2012 – October 2014 (% of capacity)

Description:

Figure 1-24 plots planned and forced (i.e. unforeseen) outages as a percentage of total capacity from November 2012 to October 2014.



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

Relevance:

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

Commentary and Market Considerations:

Planned outages followed the typical seasonal pattern in which the majority of planned outages occur during the shoulder periods when demand and the HOEP tend to be lower.

Following a period of significant increases in forced outages during the winter of 2014 when extremely cold temperatures contributed to icing which affected the operation of wind and nuclear units, the rate of occurrence decreased substantially in the spring and summer months.

4 *Imports, Exports and Net Exports*

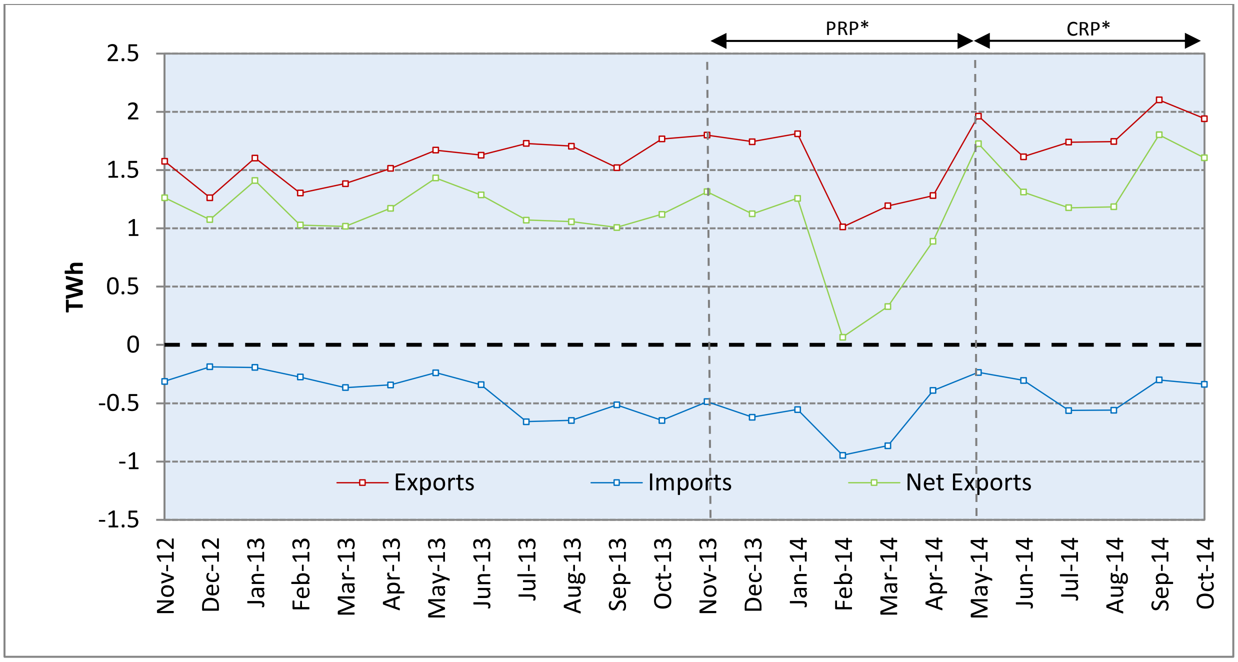
This section reports on intertie trading activity. The data used in this section is based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules, however, do not necessarily reflect actual power flows.[27]

Figure 1-25: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule) November 2012 – October 2014 (TWh)

Description:

Figure 1-25 plots total monthly imports, exports, and net exports in terawatt hours from November 2012 to October 2014. Exports are represented by positive values while imports are represented by negative values.

[27] Although the constrained schedules provide a better representation of actual flows of power on the interties, they are not related to intertie congestion prices or to 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.

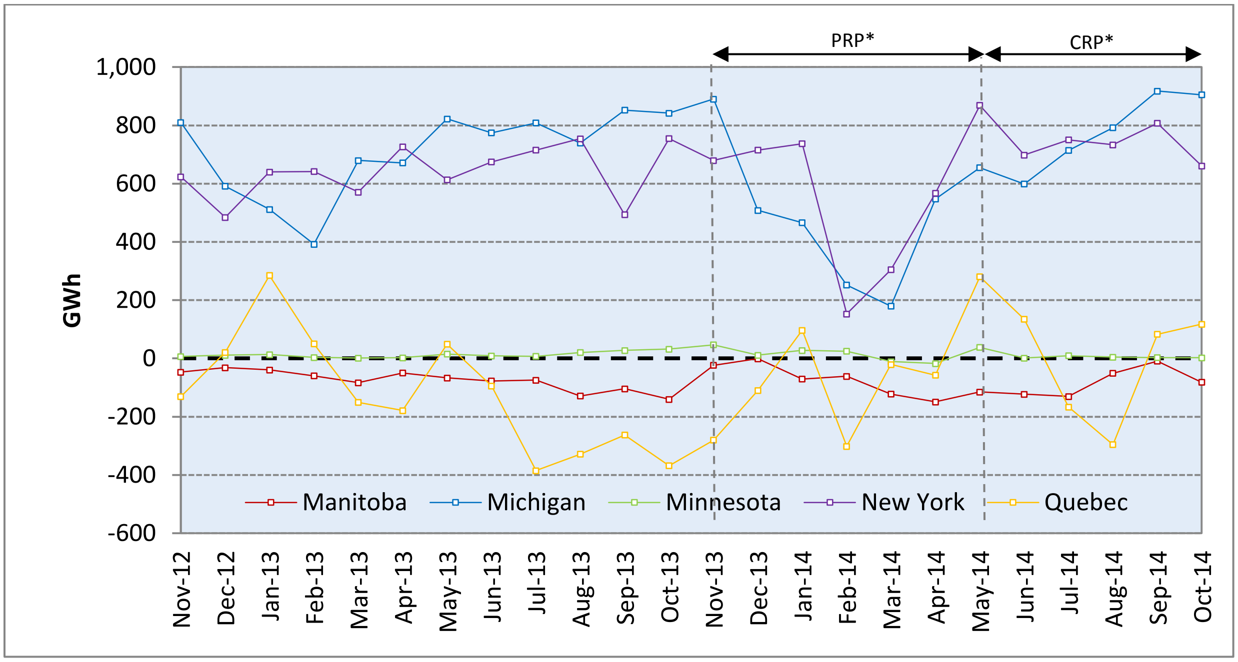
Commentary and Market Considerations:

Ontario was a net energy exporter on a monthly basis from November 2012 to October 2014. Net energy exports totaled 8.8 TWh during the Current Reporting Period, an increase of 3.8 TWh (76%) from the Previous Reporting Period but only slightly higher than historic levels. Net exports in the Previous Reporting Period were unusually low due to increased Ontario demand during the winter 2014 months.

Figure 1-26: Net Exports by Interface Group
November 2012 – October 2014
(GWh)

Description:

Figure 1-26 presents a breakdown, in gigawatt hours, of net energy exports to Ontario's five neighboring jurisdictions (Manitoba, Michigan, Minnesota, New York, and Québec) from November 2012 to October 2014. As the figure is expressed in terms of net exports, 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 was a net exporter on a monthly basis during the Current and Previous Reporting Periods, but experienced a significant drop in net exports during the months of February and March 2014 due to higher domestic prices and curtailed export transactions. Across the Minnesota intertie, Ontario continued to be a near net-zero trader, while Manitoba remained a consistent, modestly-sized importer into Ontario.

Ontario's trade with Québec 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 was due to Ontario's load typically peaking in the summer, with Québec's load typically peaking in the winter. However, in 2013 and 2014 Ontario was a winter-peaking province (see Figure 1-20), affecting the historic trend in trading with Québec. Exports to Québec in winter 2014, for example, were very low, which led to net imports of 84.11 GWh from December 2013 to March 2014, compared to 51.35 GWh of net exports in the same months one year prior.

Table 1-5: Average Monthly Export Failures and Curtailments by Interface Group and Cause November 2013 – April 2014 & May – October 2014 (GWh and %)

Description:

Table 1-5 reports average monthly export curtailments and failures over the Current Reporting Period by interface group and cause. The failure and curtailment rates are expressed as a percentage of total exports over each interface, excluding linked wheel transactions.[28]

Interface Group	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate (% of total exports)			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current
New York	264.3	348.4	1.1	1.4	13.2	6.1	0.4	0.4	5.0	1.8
Michigan	216.7	324.3	3.9	1.7	1.7	4.1	1.8	0.5	0.8	1.3
Manitoba	10.4	14.2	0.8	1.9	0.4	4.0	7.8	13.1	3.9	28.3
Minnesota	6.7	9.6	0.4	1.3	0.9	0.1	6.3	13.6	13.6	1.3
Québec	166.2	149.0	13.6	3.1	7.3	1.9	8.2	2.1	4.4	1.3

Relevance:

Curtailment (whether of exports or imports) refers to an action taken by a system operator (either Ontario or an external jurisdiction), typically for reliability or security reasons. A failure, on the other hand, refers to a transaction (again, export or import) that fails due to a failure on the part of a market participant (such as an inability to obtain transmission service).

Export failures and curtailments reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a suboptimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to surplus

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

baseload generation ("SBG") conditions.[29] The IESO may dispatch down domestic generation or curtail imports to compensate for export failures or curtailments.

Commentary and Market Considerations:

The Current Reporting Period saw the Manitoba intertie experience the highest percentage of market participant failures relative to other interties. This may have resulted from the new scheduling interface that Manitoba started using in the summer of 2014; the new interface provides market participants with the option to cancel exports without incurring an export failure charge.

The percentage of ISO curtailments increased on the Manitoba and Minnesota interties relative to the Previous Reporting Period. Most of these curtailments were decisions made by system operators outside of Ontario.

Table 1-6: Average Monthly Import Failures and Curtailments by Interface Group and Cause November 2013 – April 2014 & May 2014 - October 2014 (GWh and %)

Description:

Table 1-6 reports average monthly import failures and curtailments over the Current Reporting Period by interface group and cause. The failure and 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 (% of total exports)			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current
New York	40.3	3.6	0.4	0.1	1.5	0.2	1.1	3.2	3.7	5.5
Michigan	34.1	1.9	3.0	0.2	3.5	0.3	8.7	12.0	10.3	13.4
Manitoba	16.7	24.9	1.7	7.3	0.2	0.1	10.3	29.1	1.0	0.4
Minnesota	4.4	0.2	0.4	0.0	0.5	0.0	8.4	2.4	12.4	21.0
Québec	126.3	118.6	2.4	7.1	0.6	0.4	1.9	6.0	0.5	0.4

[29] SBG conditions arise when baseload generation (comprised of nuclear, must-run hydroelectric, self-scheduling, intermittent, and commissioning units) is greater than Ontario demand and forecasted exports.

Relevance:

Import failures and curtailments represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This unforeseen change in supply can lead to a suboptimal level of intertie transactions given the market prices that prevail in real-time, which may contribute to supply adequacy concerns and increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for the import failures and curtailments.

Commentary and Market Considerations:

Relative to the Previous Reporting Period, the percentage of imports curtailed during the Current Reporting Period increased on the New York, Michigan, Manitoba, and Québec interties (although the absolute number of imports curtailed increased significantly only on the Manitoba and Québec interties). There was also a large increase in the percentage of market participant failures on the Minnesota intertie, but this was primarily due to a significant drop in average monthly imports (and subsequent drop in absolute market participant failures) during the Current Reporting Period.

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 market efficiency and effective competition. This chapter deals with the period from May 1, 2014 to October 31, 2014 (the "Current Reporting Period") with comparisons to the period between November 1, 2013 and April 30, 2014 ("Previous Reporting Period"), as well as other periods where relevant.[30]

Of particular interest to the Panel are prices that are higher or lower than normally observed. The Panel has previously defined a high-price hour as an hour when the Hourly Ontario Energy Price ("HOEP") exceeds $200/MWh. Hours when the price is below $0/MWh are defined as negative-price hours.

The Panel also reports on high uplift payments. Again, the Panel has set thresholds to identify uplift payments that exceed normal 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.

[30] References to periods other than the Previous Reporting Period will be described as, for example, the "summer 2013 period" which covers May 1, 2013 to October 31, 2013.

Table 2-1: Anomalous Price and Uplift Events
May 2013 – October 2013 & May 2014 – October 2014
(Number of Hours and Days)

Anomalous Event	Panel Threshold	Summer 2013 Period	Current Reporting Period
HOEP	> $200/MWh	8	3
	< $0/MWh	224	656
CMSC	> $1 million/day	8	1
	> $500,000/hour	2	0
IOG	> $1 million/day	0	0
	> $500,000/hour	0	0
OR Payments	>$100,000/hour	6	0

In addition, in this report the Panel is also reporting on an issue relating to intertie congestion pricing, as well as 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 also recovered through uplift charges.

2 *Anomalous Prices*

2.1 *Analysis of High-Price Hours*

High-price hours 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 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 prices. While real-time circumstances dictate the price that clears the market, events in pre-dispatch have a direct impact on these circumstances. Specifically, pre-dispatch forecasts of demand and of output from variable generation resources (e.g. wind, solar) play a key role in determining which dispatchable resources (non-quick start generators, loads, imports and exports) are scheduled in pre-dispatch and therefore available in real-time.

Table 2-2 displays the number of hours in each month in the Current Reporting Period and the preceding four summer reporting periods[31] when HOEP exceeded $200/MWh.

[31] These are the periods from May 1 to October 31 in 2010, 2011, 2012 and 2013.

Table 2-2: Number of High-price Hours May – October 2010 to May – October 2014 (Number of Hours)

Month	2010	2011	2012	2013	2014
May	0	2	0	3	0
June	1	3	0	0	2
July	4	0	1	1	0
August	0	1	0	0	0
September	1	0	0	3	0
October	1	0	0	1	1
Total	**7**	**6**	**1**	**8**	**3**

There were three high-price hours in the Current Reporting Period. As noted in Chapter 1, the average HOEP has fallen (particularly in September) as a result of decreased demand and increased low-priced supply. This has led to fewer high-price hours. An analysis of the three hours when the high price threshold was reached is set out below.

2.1.1 *HE 16 and HE 17, June 27, 2014*

On Friday June 27, 2014, the HOEP in hour ending ("HE") 16[32] and HE 17 was $535.28/MWh and $531.15/MWh, respectively. These high prices were primarily driven by the sudden loss of 840 MW of generation. In addition, an under-forecast of real-time demand also put additional upward pressure on prices. Table 2-3 displays the prices, demand and available generation together with notes of events that occurred during these hours.

Table 2-3: Real-time MCP, Ontario Demand and Net Exports HE 15-HE 17 June 27, 2014 (MW & $/MWh)

Delivery Hour (HE)	Interval	Real-time MCP ($/MWh)	One-hour ahead Pre-dispatch Price ($/MWh)	Real-time Ontario Demand (MW)	Real-time Ontario Generation (MW)	Net Exports (MW)	Notes
15	8	59.00	49.00	19,376	20,348	972	
15	9	59.00	49.00	19,373	20,345	972	Shut down of a gas unit
15	10	59.00	49.00	19,411	20,383	972	
15	11	517.18	49.00	20,168	21,140	972	
15	12	552.45	49.00	20,126	21,098	972	Shut down of a nuclear unit
16	1	585.33	48.77	19,431	20,649	1,218	OR activated
16	2	495.05	48.77	19,113	20,331	1,218	

[32] HE 16 refers to the time period from 15:00 to 16:00; in other words, the 'hour ending' at 16:00.

16	**3**	589.94	48.77	19,210	20,428	1,218	OR deactivated
16	**4**	525.00	48.77	19,559	20,287	728	Exports curtailed to mitigate OR shortfalls
16	**5**	492.99	48.77	19,579	20,307	728	
16	**6**	492.99	48.77	19,590	20,318	728	
16	**7**	525.00	48.77	19,632	20,360	728	
16	**8**	525.00	48.77	19,641	20,369	728	
16	**9**	525.00	48.77	19,633	20,361	728	
16	**10**	527.45	48.77	19,642	20,370	728	
16	**11**	552.55	48.77	19,697	20,425	728	
16	**12**	587.08	48.77	19,753	20,481	728	
17	**1**	492.99	62.40	19,689	20,284	595	Exports curtailed due to Ontario demand trending higher than predicted
17	**2**	524.90	62.40	19,784	20,379	595	
17	**3**	524.90	62.40	19,798	20,393	595	
17	**4**	511.92	62.40	19,725	20,320	595	
17	**5**	524.90	62.40	19,740	20,335	595	
17	**6**	524.91	62.40	19,758	20,353	595	
17	**7**	527.45	62.40	19,748	20,343	595	
17	**8**	524.91	62.40	19,736	20,331	595	
17	**9**	552.45	62.40	19,769	20,364	595	
17	**10**	587.08	62.40	19,823	20,418	595	
17	**11**	552.45	62.40	19,780	20,375	595	
17	**12**	524.91	62.40	19,739	20,334	595	

In the early morning of June 27, the pre-dispatch forecast of Ontario demand was revised down several times for a total reduction of 2,000 MW for HE 16 and HE 17. As HE 16 and HE 17 approached, the demand forecasts were revised back upwards for an increase of 1,200 MW and 1,000 MW, respectively, in forecasted demand. The effect of these late upward revisions was more material to the real-time energy price than the earlier reductions since there was no time to call on non-quick start generators to supply the increased demand in real-time. Real-time demand in HE 16 and HE 17 was 500 MW and 700 MW higher than the hour-ahead forecast, respectively. Real-time demand was therefore 1,700 MW higher in both hours than the demand that had been anticipated in the early morning.

In interval 7 of HE 15, there was an issue with transmission equipment that a nuclear unit relied on to access the grid. In order to maintain grid reliability, the nuclear unit was immediately ordered out-of-service. The unit completed an emergency shut down in interval 12 of HE 15. In an unrelated but concurrent incident, a gas generation unit was unexpectedly shut down in interval 9 of HE 15 due to equipment issues. Combined, these two events resulted in the loss of

840 MW of generation. This loss required the IESO to call on operating reserves in interval 1 of HE 16.

In summary, the high prices on June 27, 2014 in HE 16 and HE 17 were the result of a combination of factors. The under-forecasting of real-time demand led to the under-commitment of non-quick start supply which led to the unavailability of such resources in real-time. Had these generators been online, the system would have experienced a smaller price shock. When 840 MW of generation was suddenly lost, tighter supply conditions precipitated price increases because of the need to schedule higher priced quick start supply; namely, peaking hydroelectric resources.

2.1.2 *HE 21, October 14, 2014*

In HE 21 on October 14, 2014, the HOEP reached $219.07 due to over-forecasting of wind production and a scarcity of low-priced supply in real-time. In the three hours prior to HE 21, real-time demand had consistently been less than pre-dispatch forecasts by approximately 400 MW. If Ontario loads had continued to consume significantly less than forecasted, the province would have entered a state of surplus baseload generation. In order to manage this risk, 403 MW of imports from Quebec were curtailed by the IESO. In real-time, demand was 390 MW less than forecasted in pre-dispatch, which was offset by the 403 MW import curtailment. However, wind production in real-time was approximately 99 MW less than forecast, and there was insufficient available inexpensive quick start generation available to fill the void created by the wind shortfall.

Furthermore, the hour ahead pre-dispatch price of $35/MWh was set by an export. However, because export bid prices are treated as $2,000/MWh in real-time (in order to ensure dispatch), the export that set the price in pre-dispatch was no longer the marginal resource. During some intervals in the hour, resources priced in the order of $400/MWh set the price due to an extremely steep supply stack. The price sensitivity to changes in demand is reflected in Table 2-4. The price in interval 1 of HE 21was $380/MWh but fell several hundred dollars over subsequent intervals with small decreases in demand. This pattern appears again in interval 10, when prices spiked due the effective loss of almost 500 MW of inexpensive hydroelectric supply that became unavailable due to safety concerns. Again, prices dropped substantially in the subsequent intervals with only small reductions in demand.

Table 2-4: Real-time MCP, Ontario Demand and Net Exports HE 21 October 14, 2014 (MW & $/MWh)

Delivery Hour (HE)	Interval	Real-time MCP ($/MWh)	One-hour ahead Pre-dispatch Price ($/MWh)	Real-time Ontario Demand (MW)	Real-time Net Exports (MW)	One-hour ahead Pre-dispatch Net Exports (MW)	Notes
21	1	380	35	16,801	1,170	767	
21	2	239.93	35	16,789	1,170	767	
21	3	239.93	35	16,745	1,170	767	
21	4	239.93	35	16,685	1,170	767	
21	5	194.99	35	16,543	1,170	767	
21	6	185	35	16,476	1,170	767	
21	7	135	35	16,357	1,170	767	
21	8	135	35	16,352	1,170	767	
21	9	87.58	35	16,270	1,170	767	
21	10	424.90	35	16,250	1,170	767	Loss of 494.4 MW of Hydro Generation
21	11	194.99	35	16,086	1,170	767	
21	12	171.60	35	15,855	1,170	767	
Average		**219.07**	**35**	**16,434**	**1170**	**767**	

2.1.3 *HE 21, September 17, 2014*

On September 17, 2014, during HE 21, the price of 10 minute spinning operating reserve ("10S") was $151.85/MWh. The HOEP in this hour was $172.40 and therefore does not meet the Panel's threshold of $200/MWh. However, the OR price cleared above the highest OR offer, which itself is an anomalous result. The high OR price was the result of reducing the energy supply from one resource to satisfy OR requirements while simultaneously increasing output from another generator at higher prices to make up the difference in the energy market.

Table 2-5 shows prices and available supply for the hour. For intervals 1 to 9, prices are greater than $100/MWh for both energy and 10S OR due to tight real-time supply conditions. Several non-quick start gas generators had offered into both markets below $100/MWh, but had not been committed ahead of time and were therefore unable to provide their relatively low cost energy or OR. The average real-time excess supply available for the combined energy and 10S OR market was 424 MW or 2.2% of total available supply. The majority of the available supply consisted of higher priced hydroelectric generation which set the price for the first half of the hour.

Table 2-5: Breakdown of the Energy and OR10S Market
HE 21 September 17, 2014
(MW & $/MWh)

Delivery Hour (HE)	Interval	Real-time MCP ($/MWh)	OR 10S Price ($/MWh)	Real-time Ontario Demand (MW) [A]	OR 10S Requirement (MW) [B]	Net Exports (MW) [C]	Total Demand for Energy and OR 10S (MW) [A+B+C]	Available Supply for Energy and OR 10S (MW) [D]	Available Excess Supply (MW) [D-A-B-C]
21	**1**	$400	$361.07	16,720	237	2,047	19,004	19,574	570
21	**2**	$241.90	$202.97	16,896	237	2,047	19,180	19,497	317
21	**3**	$241.89	$215.41	16,721	237	2,047	19,005	19,270	265
21	**4**	$196.99	$170.51	16,702	237	2,047	18,986	19,268	282
21	**5**	$196.99	$170.50	16,627	237	2,047	18,911	19,256	345
21	**6**	$187.00	$160.51	16,501	237	2,047	18,785	19,265	480
21	**7**	$196.99	$170.51	16,311	237	2,360	18,908	19,186	278
21	**8**	$196.99	$170.50	16,199	237	2,360	18,796	19,182	386
21	**9**	$167	$140.51	16,066	237	2,360	18,663	19,171	508
21	**10**	$14.37	$19.89	16,023	237	2,360	18,620	18,935	315
21	**11**	$14.37	$19.89	16,020	237	2,360	18,617	18,934	317
21	**12**	$14.32	$19.89	15,715	237	2,360	18,312	18,913	601
Average		**$172.40**	**$151.85**	**16,375**	**237**	**2,204**	**18,816**	**19,204**	**389**

10S OR prices cleared above $100/MWh in HE 21 even though the highest offer in the 10S OR market during HE 21was $47.85/MWh. Prices in the 10S OR market were several times higher than the highest offer because the marginal cost to provide another MW of 10S OR was based not on the marginal offer in the OR market but on the marginal offer in the energy market (energy and OR markets are "jointly optimized"). In this instance, the marginal cost to procure more 10S OR involved reducing the energy output from a resource that was dispatched in both the energy and 10S OR markets and increasing the output of another resource scheduled in the energy market. Figures 2-2a and 2-2b provide an illustration of this kind of event:

Figure 2-2a: Example of a Resource Being Scheduled in Two Markets (MW)

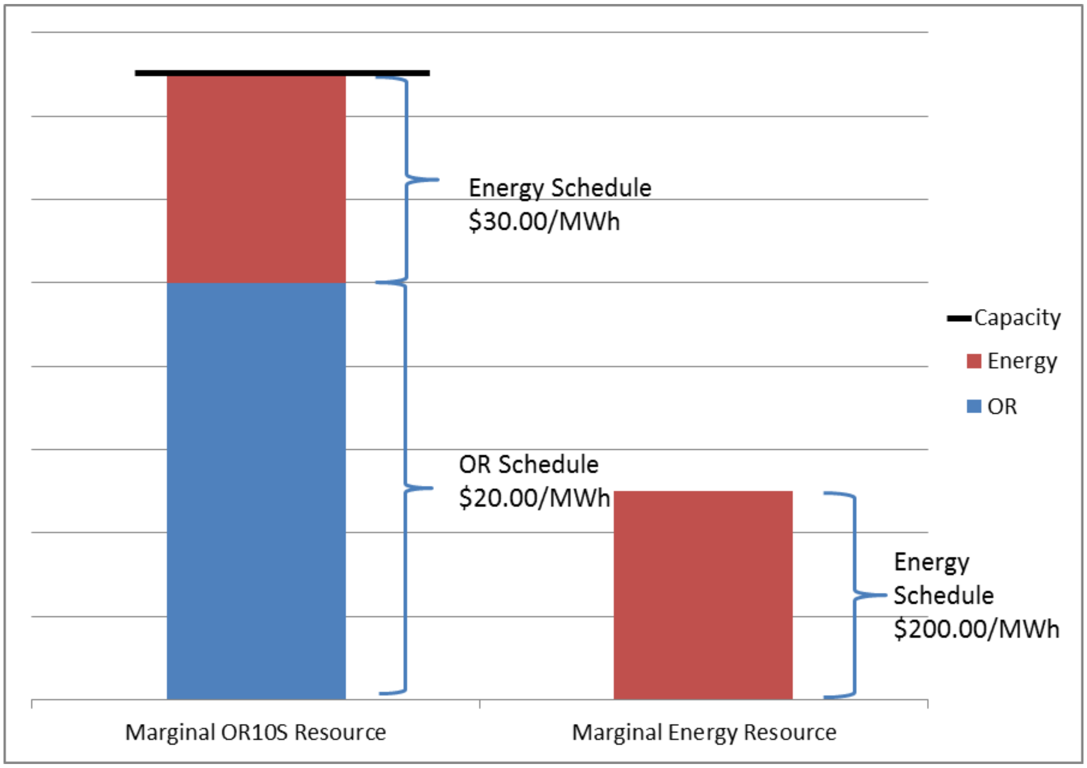
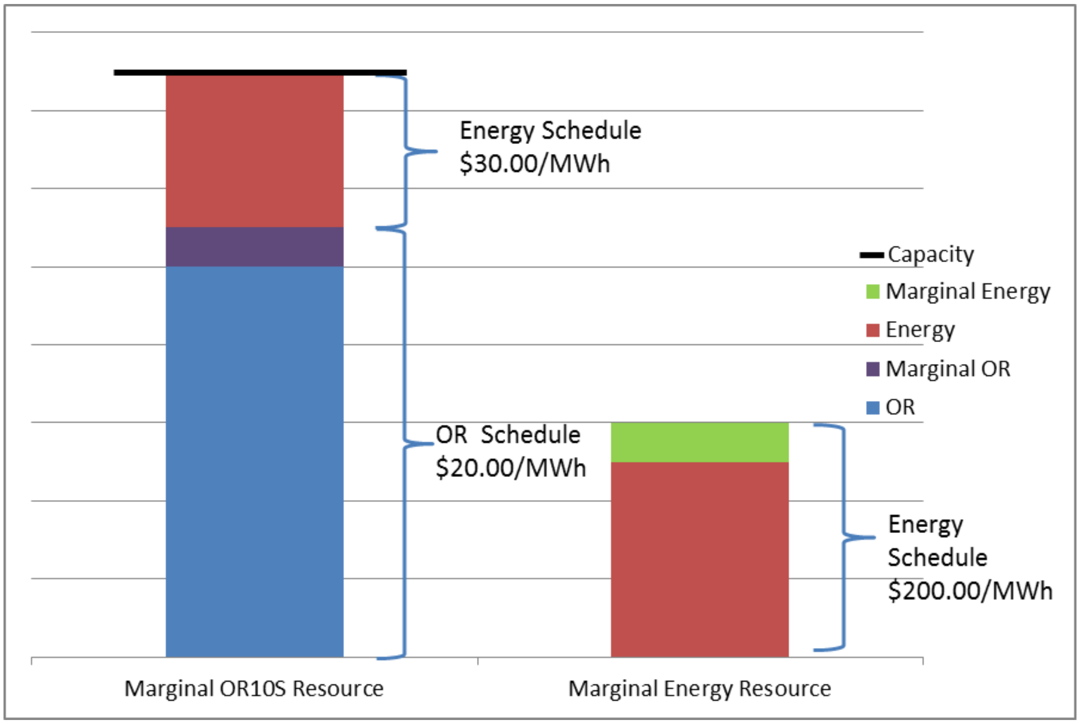


Figure 2-2b: Effects of Adding an Additional MW of OR (MW)



Marginal OR Cost= Marginal OR cost + Marginal Energy Cost - Energy Reduction Cost

Marginal OR Cost= $20/MWh + $200/MWh - $30/MWh

Marginal OR Cost= $190/MWh

Figure 2-2a shows that the capacity of the resource that is on the margin for 10S OR is fully utilized between the energy and 10S OR markets. Meanwhile, the marginal resource for the energy market has available capacity. Figure 2-2b shows that scheduling another MW of 10S OR displaces 1 MW of energy production from the marginal 10S OR resource. This MW of energy is produced by the marginal unit for the energy market. Thus the cost of procuring the additional MW of 10S OR is greater than the marginal offer price for 10S OR because higher energy costs were incurred in order to make the additional MW of OR available.

2.2 *Analysis of Negative-Price Hours*

Typically, negative prices signal an abundance of supply relative to demand. There are many events that contribute to the occurrence of negative-price hours such as low Ontario demand, failed export transactions or an abundance of supply offered at negative prices.

As shown in Table 2-6, negative-price hours increased significantly in the Current Reporting Period compared to the preceding four summer reporting periods, with more negative-price hours occurring in each month compared to the summer 2013 reporting period. In October 2014, there were negative prices in 280 hours of a possible 744 hours (37.6% of hours). This is the most ever in a month.[33] As explained further below, the increased number of negative-price hours can be primarily attributed to an increase in supply offered at negative prices and low electricity demand.

Negative Offer Prices

The Ontario wholesale electricity market allows generators to submit offer prices as high as $2,000/MWh and as low as -$2,000/MWh. A generator will typically offer at a negative price for one of two reasons. The first is that the generator is strategically offering into Ontario's market to ensure it is dispatched to generate. These generators have an incentive to generate under all market conditions, which makes hem indifferent to the prevailing market price. These incentives include contracts or regulations that guarantee revenue on a per-unit of energy (per MWh) basis. For example, generators with Feed-In-Tariff contracts, such as wind resources, may want to maximize their energy output under all market conditions. These market participants regularly offer at negative prices to ensure they are dispatched.[*]

The second reason why a generator may offer a negative price is to signal a cost that would be incurred if the generator was dispatched down. That is, the generator would prefer to pay consumers to take their power than to have to reduce their output and incur the cost. For example, negative offers associated with nuclear facilities can indicate an opportunity cost if the unit must remain shut down for an extended period of time (up to72 hours) once dispatched off-line.

[*] Wind offers are limited by the IESO's price floors. For more information on price floors, see the IESO's Market Manual 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets available at: http://www.ieso.ca/Documents/marketOps/mo_DispatchDataRTM.pdf

Table 2-6: Number of Negative-Price Hours
May to October, 2010 – May to October, 2014
(Number of Hours)

Month	2010	2011	2012	2013	2014
May	0	31	19	27	72
June	0	23	24	26	65
July	0	4	8	25	26

[33] The previous record was 111 negative-price hours in November 2013.

August	0	17	9	40	76
September	9	6	5	91	137
October	10	17	27	15	280
Total	**19**	**98**	**92**	**224**	**656**

Table 2-7 shows the distribution of negative-price hours in four ranges for the Current Reporting Period and the preceding four summer reporting periods. The ranges are based on the price floors established by the IESO: the flexible portion of nuclear generation capacity can be priced as low as -$5.00/MWh, 90% of a wind resource's capacity can be priced as low as -$10.00/MWh and the remaining 10% of a wind resource's capacity can be priced as low as -$15.00/MWh. [34]

Table 2-7: Distribution of Negative-Price Hours
May – October, 2010 to May – October 2014
(Number of Hours)

Price Range ($/MWh)	2010	2011	2012	2013	2014
< $0 to -$5	7	12	6	219	594
< -$5 to -$10	5	11	11	2	56
< -$10 to -$15	2	4	9	0	2
< -$15	5	71	66	3	4

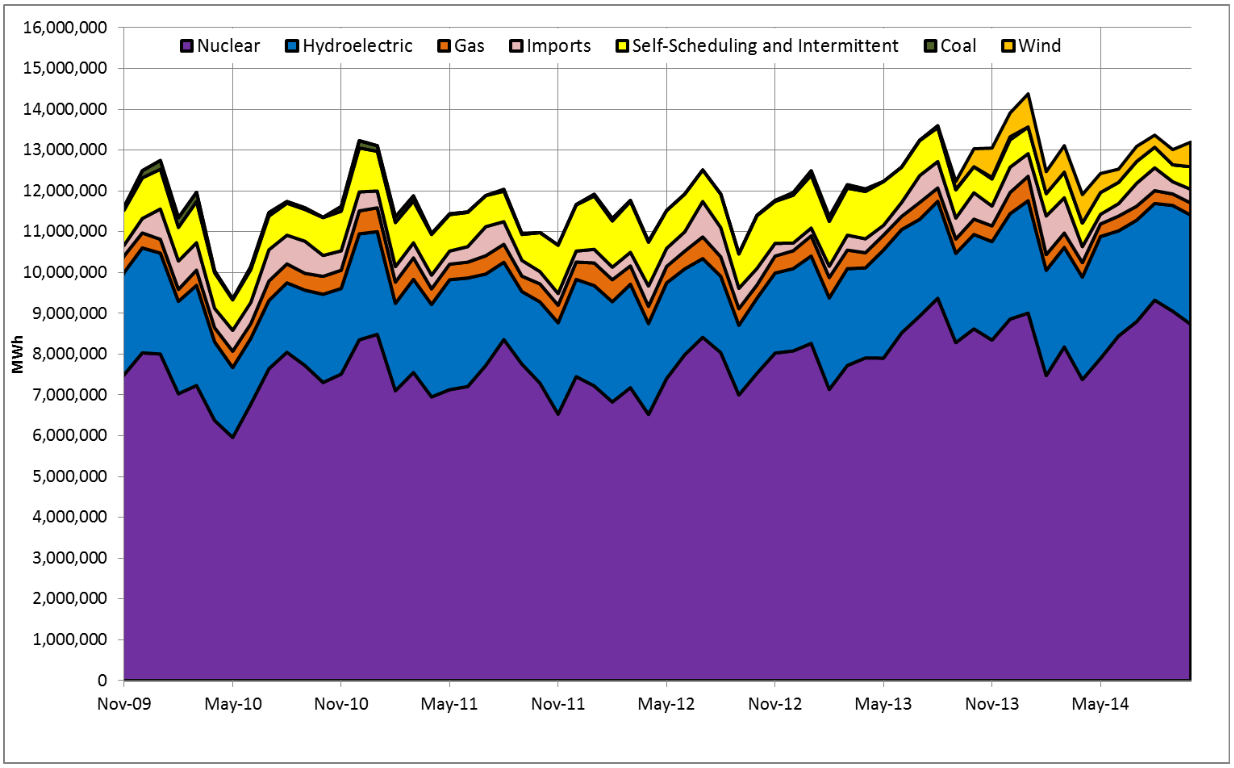
There was a sharp increase in the number of hours in the $0/MWh to -$5/MWh price range in the summer 2013 reporting period which continued into the Current Reporting Period. This increase coincided with the establishment of price floors for flexible nuclear resources in February 2013, and the reclassification of renewable generation (including wind) as dispatchable in September 2013. The introduction of the price floors and the change that made variable generation resources dispatchable added a significant amount of supply priced between -$5/MWh and -$15/MWh that is available to set the real-time MCP. Before these changes, hydroelectric and nuclear resources more frequently set prices below -$15/MWh. When comparing 2012 and 2014 (2013 was a transition year), the distribution of the negative prices has visibly changed, coinciding with the establishment of the price floors and the dispatch of wind generation.

As noted earlier, there was a significant increase in the number of negative-price hours from the summer 2013 reporting period to the Current Reporting Period, principally due to an increase in supply offered at negative prices and low demand.

[34] For more information on price floors, see the IESO's Market Manual 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets available at: http://www.ieso.ca/Documents/marketOps/mo_DispatchDataRTM.pdf

On the supply side, there were large additions of wind resources in the summer 2013 reporting period. In addition, nuclear generators produced, on average, more energy in the Current Reporting Period than they had in the preceding four summer reporting periods. Figure 2-3 shows the number of MW offered below $0/MWh on a monthly basis since 2009.

Figure 2-3: Negative-Priced Offers by Month and Resource or Transaction Type[35]
November 2009 – October 2014
(MW)



Between April 2014 and August 2014, 659 MW of nameplate wind capacity entered commercial operations. On average, wind generation contributed 120 MW more in each hour in the Current Reporting Period than in the summer 2013 reporting period.

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[35] For imports, the quantities reported are scheduled quantities, not offered quantities. Imports scheduled in pre-dispatch are priced at -$2,000/MWh in real-time to ensure their pre-dispatch schedules are respected. While priced at -$2,000/MWh for price setting purposes in real-time, these imports may have been originally offered at positive prices.
In September 2013, wind generators became dispatchable resources. For wind generators, the quantities reported are also scheduled quantities, not offered quantities. Quantities offered by these facilities are generally not accurate predictors of attainable delivered quantities; measuring delivered quantities instead provides a more useful estimate of the extent to which these resource types contributed to the occurrence of negative-price hours.

Table 2-8 shows the amount of nuclear generation in the Current Reporting Period and the preceding four summer reporting periods. Nuclear generation has climbed in recent years due to the return of two Bruce units in 2012. Also, the Current Reporting Period experienced fewer nuclear outages and deratings compared to the summer 2013 reporting period, specifically in the months of September and October. The greater availability of nuclear power added to the amount of negative-priced supply.

Table 2-8: Nuclear Energy Production
May – October, 2010 to May – October 2014
(TWh)

Month	2010	2011	2012	2013	2014
May	5.70	6.91	6.93	7.15	7.33
June	6.53	6.61	7.17	7.38	7.82
July	7.04	7.31	7.85	8.21	8.22
August	7.17	7.83	7.63	8.21	8.44
September	7.26	7.43	6.69	7.58	8.34
October	7.19	7.09	7.40	7.66	8.01
Period Totals	40.89	43.19	43.67	46.19	48.17

On the demand side, Ontario demand was relatively low during the Current Reporting Period, particularly in the months of July and August. Table 2-9 provides the average hourly demand for electricity in Ontario for the Current Reporting Period and the preceding four summer reporting periods.

Table 2-9: Average Hourly Ontario Demand by Month
May – October, 2010 to May – October 2014
(MW)

Month	2010	2011	2012	2013	2014
May	15,344	14,556	14,949	14,518	14,327
June	16,121	15,672	16,388	15,507	15,642
July	17,936	17,900	18,061	17,113	15,765
August	17,451	16,880	16,952	16,249	15,747
September	15,437	15,534	15,327	15,080	15,081
October	14,819	14,848	14,942	14,983	14,568

The Current Reporting Period had mild temperatures throughout. Electricity demand in summer is positively correlated with temperatures, which means that relatively cool summer days will generally exhibit lower electricity consumption. The months of July 2014 and August 2014 had an average of 2.29 and 2.64 cooling degree-days,[36] respectively, compared to the average of 4.31 and 3.03 cooling degree-days in the same months of the previous year.

Additionally, the average hourly Ontario demand in the Current Reporting Period decreased by approximately 400 MW compared to the summer 2013 reporting period. A portion of this decrease can be attributed to an increase in power provided by embedded resources,[37] which contributed an average of 125 MW more each hour than they did in the summer 2013 reporting period. Other factors that can cause electricity demand to fall include increased behind-the-meter generation,[38] energy conservation and permanent industrial load loss.

In summary, the significant increase in negative-price hours in the Current Reporting Period can be attributed to an increase in supply offered at negative prices and a decrease in demand. The increase in negative-priced supply is due to the addition of dispatchable wind resources into the supply stack as well as a decrease in nuclear outages relative to the previous summer reporting period.

2.3 *The Net Interchange Scheduling Limit*

Market prices normally adjust to reduce discrepancies between amounts demanded and amounts supplied. As demand increases so does the price, all else being equal. It appears, however, that in one aspect of intertie pricing for the IESO-administered market, this normal market adjustment process is not occurring. Instead prices are changing in the opposite way, sending the wrong price signals and resulting in counter-productive incentives. The price in question is the price for intertie transactions as calculated when the Net Interchange Scheduling Limit (NISL) is binding or violated.

The NISL is the maximum allowed change in net exports (or net imports) across all interties from one hour to the next, and the default value is 700 MW.[39] For example, if in a given hour net exports were 1,500 MW, the NISL stipulates that the next hour must have net exports no less

[36] Cooling degree-days for a given day are the number of degrees Celsius that the mean temperature is above 18°C. If the temperature is equal to or less than 18°C, then the number will be zero.
[37] Embedded generation resources are generation facilities that generally have less than 10 MW of capacity. They are connected to distribution systems that are connected to the IESO-controlled grid.
[38] Behind-the-meter generation is electricity generation that serves on-site load. The load appears to have reduced its electricity consumption from its meter readings since it is drawing less energy from the distribution or transmission grid.
[39] For more information, see the Quick Takes published by the IESO entitled “Net Interchange Scheduling Limit,” available at: http://www.ieso.ca/Documents/training/QT2_NISL.pdf

than 800 MW, and no greater than 2,200 MW. The purpose of the NISL is to prevent excessive ramping requirements on Ontario generators in response to changing demand on the interties.

2.3.1 *The NISL and Prices*

When there is an economic import or economic export that cannot be scheduled due to the NISL, the NISL is considered a binding limit. The NISL is also considered a binding limit when an uneconomic export or uneconomic import is scheduled in order to respect the NISL. Thus, the NISL is a binding limit when it alters the schedule of intertie transactions relative to the economic solution that would have resulted absent the NISL constraint. When the NISL is binding, Ontario generators are ramping at the 700 MW limit, but no more.

When there are insufficient export bids or import offers to meet the NISL, the NISL is said to be violated. When the NISL is violated, Ontario generators are ramping in excess of the 700 MW limit.

When the NISL is binding or violated it gives rise to a "NISL Price". The NISL Price is the cost of trying to keep the electrical system within the 700 MW NISL when there are insufficient economic exports or imports to do so. The NISL Price affects the intertie zonal price that exporters and importers pay on congested interties only. For example, when there are insufficient net exports to meet NISL, the NISL price increases the intertie zonal price charged to exporters (and paid to importers) on all congested interties.

In the most extreme case, when the NISL is violated, the NISL price is set at $40,000/MWh and causes the intertie zonal price of a congested intertie to reach the maximum market clearing price of $2,000/MWh. The next sections will provide an example of such a scenario and describe the effect such a result has on the incentives for exporters.

2.3.2 *Implications of a violated NISL*

When there are insufficient export bids (or import offers) in the current hour to respect the NISL, then the dispatch algorithm must create a schedule in violation of the NISL. To reflect the undesirability of this outcome there is a large ($40,000/MWh) penalty applied to the NISL Price. This penalty has significant consequences on settlement outcomes for congested interties.

October 10, 2014 provides a useful example of such consequences. On that day there were 3,126 MW of net exports scheduled in HE 6. In the following hour (HE 7), there were only 2,352 MW of total export bids available. With the NISL requiring at least 2,426 MW (3,126 MW-700 MW) of net exports, it was impossible for the dispatch algorithm to respect the limit. Table 2-10 summarizes this event.

Table 2-10: Summary of Violated NISL Conditions
October 10, 2014
(MW)

HE 6 Net Exports	**(A)**	3,126
HE 7 Max Interchange	**(B)**	700
HE 7 Minimum Allowable Net Exports	**(C=A+B)**	2,426
HE 7 Total Number Exports Bid	**(D)**	2,352
HE 7 Additional Export Quantity Needed to Fulfill NISL	**(E=D-C)**	74

As discussed in the previous section, when NISL is violated the NISL Price is set at $40,000/MWh, which has the effect of making the intertie zonal price at a congested intertie reach the maximum market clearing price of $2,000/MWh.

The intertie congestion price ("ICP") is made of up two components, the intertie zonal price ("IZP"), and the pre-dispatch market clearing price ("PD-MCP"), and can be described by the following equation:

ICP = IZP – PD-MCP

In PD-2 of HE 7, the New York intertie was export congested with an ICP of 19.43/MWh.[40] The NISL violation occurred in PD-1 of this hour, and resulted in the New York IZP increasing to $2,000/MWh. The MCP for PD-1 was $14.38/MWh, therefore the ICP at the New York intertie was $1,985.62.[41] Exporters pay the HOEP + ICP for power at a given intertie, therefore at New York in this hour, exporters paid $14.13 (HOEP) + $1985.62 (New York ICP) = $1,999.75/MWh, or $1,985.62 more compared to exports trading on other interties where the zonal price was not affected by the NISL Price.

[40] In PD-2 of HE 7, Ontario PD-MCP was $14.31/MWh, and the New York IZP was $33.74/MWh resulting in an ICP of $19.43/MWh.
[41] This result is from ICP = IZP – PD-MCP: $1,985.62/MWh = $2,000/MWh - $14.38/MWh.

This very high ICP is counter-productive under these circumstances. The New York IZP of $2,000/MWh signaled to traders that fewer exports and more imports were needed, when in fact the situation required exactly the opposite as Ontario did not have enough net exports to respect the NISL. A lack of net exports in this hour (compared with the previous hour) should not result in pricing that is punitive for existing exports while simultaneously deterring additional exports. In total, during HE 7 on October 10 exporters paid an additional $1.29 million in energy costs due to the NISL violation at a time when Ontario needed more net exports to respect the NISL.

2.3.3 *NISL Violations in the Reporting Period.*

During the Current Reporting Period, there were five hours when the NISL was violated. Table 2-11 provides the details of those NISL violations.

Table 2-11: Breakdown of Hours with NISL Violations May 2014 – October 2014 (MW)

Date	HE	Previous Hour Schedule	Available Export Bids	Export Bid Shortfall[42]	Current Hour Schedule	Inter-hour Scheduling Difference
August 10, 2014	**7**	3,060	2,165	195	2,165	895
August 17, 2014	**9**	3,389	2,653	36	2,653	736
September 07, 2014	**8**	3,885	2,744	441	2,744	1,141
September 29, 2014	**7**	2,988	2,263	25	2,263	700
October 10, 2014	**7**	3,126	2,352	74	2,352	774

When NISL is violated in the net export direction, the dispatch algorithm will schedule all exports regardless of their bid price. As a result, exporters are exposed to the risk of being scheduled to export at a price greater than they were willing to pay, as indicated in their bids.[43] For example, if the PD-MCP was $20/MWh and an exporter bid at $5/MWh, that exporter could be scheduled due to a binding or violated NISL and have to purchase power at a higher price than their bid suggested they were willing to pay. In the extreme, this exporter could be required to pay $2,000/MWh when NISL is violated and the intertie they are trading on is congested, despite indicating a willingness to buy only at prices of $5/MWh or less. With this added risk, exporters face a strong incentive to avoid an unprofitable transaction by withdrawing their bids prior to hours when the NISL is, or is at risk of, binding or being violated. When exporters

[42] In these hours, all economic imports are curtailed.
[43] Importers are protected from such risks via the Intertie Offer Guarantee .

withdraw their bids and no new export bids emerge, the dispatch algorithm must try to meet the NISL with less available exports, therefore increasing the absolute value of the NISL Price until eventually NISL becomes violated. This self-reinforcing cycle of cancelled exports bids and punitive NISL prices ultimately widens the difference between the previous hour's net export schedule and the current hour's net export schedule, thus increasing the ramping burden on the IESO-controlled grid and exacerbating the problem.

In summary, there appears to be a disconnect between the incentives provided to traders and the needs of the energy market.

The NISL is in place to ensure reliable operation of the IESO-controlled grid and can affect outcomes in the IESO-administered markets. The Panel recognizes that a lasting solution will need to consider all possible effects on those markets.

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.

3 *Anomalous Uplift Payments*

The Panel monitors uplift payments associated with the IESO-administered markets. In previous reports, the Panel discussed events that generated large CMSC, IOG and OR payments. While the Panel will continue to report on these categories, the Panel will also report on two other categories of uplift payments; namely, payments under the IESO's Real-time Generation Cost Guarantee and Day-Ahead Production Cost Guarantee programs.

3.1 *CMSC*

CMSC payments in excess of $1,000,000 for a given day are considered anomalous. During the Current Reporting Period, there was one such day – May 13, 2014.

CMSC payments in excess of $500,000 for a given hour are also considered anomalous. There were no such hours during the Current Reporting Period.

3.1.1 *May 13, 2014*

On May 13, 2014 a total of $1,226,289 in CMSC payments were made. The average HOEP on this day was $21.61/MWh.

Table 2-12 sets out the CMSC payments by type of CMSC and by type of recipient. The largest portion of CMSC payments were made to constrained-on generators.

Table 2-12: Distribution of Congestion Management Settlement Credit Payments May 13, 2014 ($)

CMSC Type	Generator	Imports	Loads	Exports
Constrained-On	$837,575	$31,624	$14,392	$141,521
Constrained-Off	$235,861	$12,062	-	$19,485

The primary reason for the CMSC payments made to constrained-on generators was IESO actions that brought on generators ahead of time to alleviate a forecasted shortfall in operating reserve during HE 18 to HE 21. During these hours, several hydroelectric facilities that frequently offer OR were unavailable due to operating constraints and transmission constraints. In addition, Control Action Operating Reserve[44] (CAOR) was de-rated in real-time to reflect the actual amount of OR available through system control action. In order to meet the demand for OR, two gas-fired facilities (A and B) were constrained on and collectively were paid 50% of the total CMSC payments for the day.

3.1.1.1 Facility A

Facility A was manually constrained on by the IESO over the evening peak so that the IESO could increase the available supply in both the energy and OR markets. Facility A was providing a combined total of 500 MW of energy and 331 MW of OR. In the energy market, Facility A was offering energy between $310/MWh and $614/MWh. As a result of the difference between the HOEP (which ranged from $25/MWh to $50/MWh during the relevant hours) and the offer price, the CMSC payments that resulted from constraining on this Facility were significant ($572,436 for the day).

[44] For more information on CAOR, see the Panel's September 2014 Monitoring Report (page 60) available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf#page=66

3.1.1.2 Facility B

Facility B was constrained on to its minimum loading point for two hours over the evening peak so that the Facility could provide 10S OR. The entire capacity at this Facility was offered at \$176/MWh. As a result of the difference between the HOEP (which was \$29.62/MWh and \$28.95/MWh during these two hours) and the offer price, the CMSC payments that resulted from constraining on this Facility totalled \$70,524.

3.2 *Intertie Offer Guarantee Payments*

IOG payments are payments that protect import transactions from incurring a loss if the real-time price falls below the offer price. IOGs can apply to imports that are committed by the Day-Ahead Commitment Process ("DACP") as well as those committed in the final pre-dispatch schedule. If the real-time price falls below the offer price, the IOG ensures that the importer is kept whole by compensating the importer for the difference between the importer's offer price and the real-time price.

IOG payments in excess of \$1,000,000 for a given day or \$500,000 in a given hour are considered anomalous by the Panel. There were no such days or hours in the Current Reporting Period.

3.3 *Operating Reserve Payments*

Operating Reserve (OR) payments in excess of \$100,000 for a given hour are considered anomalous by the Panel. There were no such hours during the Current Reporting Period.

4 *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 generators. The IESO-administered market has two cost guarantee programs: the Real-time Generation Cost Guarantee program ("RT-GCG") and the Day-ahead Production Cost Guarantee ("DA-PCG") program.[45] The costs of the programs are recovered from Ontario consumers.

[45] For more information on the two cost guarantee programs and their history, see Section 3.2 of the Panel's January 2014 Monitoring Report (page 154) available at:

4.1.1 *Real-Time Generation Cost Guarantee Payments*

The RT-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 RT-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.

There were 124 days (of 184) when the IESO made a RT-GCG payment to at least one generator during the Current Reporting Period. The average RT-GCG payment per start was $35,613.[46] Table 2-13 shows the five highest RT-GCG payments in the Current Reporting Period. All of the top five payments were made to one facility (Facility C). The IESO makes guarantee payments by unit, not by facility. A generator with multiple units can receive multiple RT-GCG payments in a single day, which was the case on September 9 and May 21, 2014. Additionally, a single unit can receive more than one RT-GCG commitment in a single day; for example, one commitment in the morning, and one in the late afternoon or early evening. However, this was not the case on either September 9 or May 21, 2014.

Table 2-13: Five Highest RT-GCG Payments
May 2014-October 2014
($)

Date	RT-GCG Payment
September 9, 2014	244,422
September 9, 2014	242,660
May 5, 2014	132,411
May 21, 2014	131,452
May 21, 2014	129,838

http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf#page=164

[46] The average RT-GCG cost submission was $63,696, and the $28,082 difference with the average payments is the average revenue that a generator earned per start from the energy market and in the form of CMSC payments.

4.1.1.1 September 9, 2014

On September 9, 2014, two gas-fired generation units at Facility C received RT-GCG commitments to run between HE 13 and HE 20, which is a typical occurrence. However, the two gas-fired units also ran between HE 7 and HE 12 by offering a quantity that was below each unit's MLP at -$132/MWh. Table 2-14 provides details of Facility C's actions.

Table 2-14: Breakdown of Facility C's RT-GCG Run
September 9, 2014
($/MWh)

Hour Ending	Offer Price ($/MWh)	Comments
5	n/a	Start-up: The two gas units were producing at a level just below their MLP and therefore they remained in start-up mode.
6	n/a	
7	-132	
8	-132	
9	-132	
10	-132	
11	-132	
12	-132	
13	35.5	MGBRT: The RT-GCG run guarantees that the two gas units will be paid the cost of energy production up to their MLP.
14	35.5	
15	35.5	
16	35.5	
17	35.5	
18	35.5	
19	35.5	
20	35.5	
21	59	Shut down hour

By staying below the MLP during the hours preceding HE 13, Facility C was considered by the Market Rules to be operating under "start-up" conditions. The two gas-fired units took almost five hours from when they first began injecting electricity into the grid to when they began producing at a level above their MLP. Comparatively, Facility C's units took just over two hours in its previous 10 start-ups to reach the same output level.

Since the units were in start-up mode for these hours, the period from HE 7 to HE 12 was not considered a part of the facility's minimum generation block run-time[47] ("MGBRT") which is the period over which the RT-GCG program guarantees a generator's costs implied by its offers

[47] A facility's MGBRT is the minimum number of hours that a generation facility must be operating at or above its MLP. It differs from the MRT which is the minimum number of hours that a facility requires to ramp up to its MLP plus the time that a facility must be operating at or above its MLP.

up to its MLP. However, the RT-GCG program also covers the costs incurred during the start-up period. The costs guaranteed during a start-up period are:

1. the fuel costs for start-up and ramping to MLP; and
2. the incremental start-up operation and maintenance costs.

These costs are submitted by the generator after the RT-GCG run has ended ("after-the-fact RT-GCG submitted costs").[48] In this case, both gas-fired units ramped up to an output level below their MLP at the beginning of HE 8 and remained there until HE 12, after which they ramped beyond their MLP. Facility C submitted fuel and incremental operations and maintenance costs for its start-up period that were much higher than the revenues earned. Facility C was operating out of economic merit during its prolonged start-up, but recouped the implied operating loss through RT-GCG program payments.

Facility C's after-the-fact RT-GCG submitted costs for each unit were $85,982 in start-up fuel costs and $169,037 in incremental start-up operation and maintenance costs. The offer prices of each unit implied a running cost of $24,120 per unit at its MLP for its MGBRT. Together, these three figures (the two after-the-fact RT-GCG submitted costs and the MGBRT offer price) form the total costs which are guaranteed for each unit. In comparison, the combined energy and CMSC revenue earned below the unit's MLP between HE 7 and HE 20 totalled $35,597 per gas-fired unit. The total RT-GCG payment to Facility C on this day was $487,082. Table 2-15 compares Facility C's average after-the-fact RT-GCG submitted costs on this day to the average of Facility C's other after-the-fact RT-GCG submitted costs made during the Current Reporting Period.

[48] For more information, see section 4.7B.1.2A in Chapter 9 of the Market Rules available at: http://www.ieso.ca/Documents/marketRules/mr_chapter9.pdf#page=84

Table 2-15: After-the-Fact RT-GCG Submitted Costs Facility C
May 2014 – October 2014
($/per unit)

	Start-up Fuel Costs	Start-up Incremental Operation and Maintenance Costs	Total Submitted Costs
September 09, 2014	85,982	169,037	255,018
Average of all other Facility C submissions	49,634	46,340	95,973

4.1.1.2 RT-GCG Submission Costs per Guaranteed MWh

Larger generating units will have larger start-up fuel and operation and maintenance costs and therefore are more likely to receive larger guarantee payments on account of their size. To account for large RT-GCG payments that may be the result of the large capacity of a unit, after-the-fact RT-GCG submitted costs during the Current Reporting Period were normalized to account for the size of the facility. This normalized cost is calculated by dividing the total after-the-fact RT-GCG submitted costs by the total number of MWh which the RT-GCG guarantees. The number of guaranteed MWh is the unit's MLP multiplied by the MGBRT.

Table 2-16 shows the highest normalized after-the-fact RT-GCG submitted costs at each gas-fired combined cycle facility.

Table 2-16: Highest Normalized RT-GCG Submitted Costs at Combined Cycle Facilities
May 2014 – October 2014
($/Guaranteed MWh)

Unit	Date	Normalized Cost
Facility C	September 9, 2014	411.79
Facility D	June 18, 2014	186.25
Facility E	June 13, 2014	127.01
Facility F	June 15, 2014	117.95
Facility G	June 2, 2014	114.46
Facility H	September 26, 2014	96.39
Facility I	May 5, 2014	83.57
Facility J	June 13, 2014	74.39

Using the normalization methodology, Facility C's after-the-fact RT-GCG submitted costs for September 9, 2014 remain outliers. The cost submission and resulting RT-GCG payment on September 9, 2014 are disproportionately large even after accounting for the Facility's capacity. The next highest normalized after-the-fact RT-GCG submitted costs were more than $225/MWh below those of Facility C. Most of the RT-GCG payment made to Facility C was to cover its after-the-fact RT-GCG submitted costs. As discussed below, the composition of these costs is not transparent, which makes it more difficult to readily assess whether inefficiencies or exploitation are occurring.

4.1.1.3 GCG Submission Cost Categories

The Panel has previously reported on problems inherent in the IESO's RT-GCG program.[49] In particular, the after-the-fact submission of costs has been identified as a process that is both non-transparent and non-competitive.[50]

Additionally, the Panel has previously recommended that the IESO should provide a detailed analysis to confirm whether the RT-GCG continues to be needed in light of the implementation of the Enhanced Day-Ahead Commitment Process ("EDAC"), of changes in Ontario's generation capacity, and of other changes in the market since the RT-GCG program was introduced.[51] The IESO's response to the Panel's recommendation, that the program is desirable and consistent with industry practice, does not address any of the specific Ontario market circumstances identified in the Panel's recommendation.[52] The Panel continues to support its previous recommendations to the effect that the IESO should establish a mechanism that would allow all RT-GCG costs to be factored into scheduling decisions on the basis that this would reduce commitment inefficiency.[53]

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[49] See the following Panel reports: August 2007 Monitoring Report (page 107) available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf; January 2010 Monitoring Report (page 106) available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_200901.pdf; August 2010 Monitoring Report (page 128) available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20100830.pdf; and March 2011 Monitoring Report (page 128) available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf

[50] The IESO's own analysis indicates that the RT-GCG program leads to more than $3 million in inefficiencies per year. See the IESO's September 26, 2014 presentation at SE-111 available at: http://www.ieso.ca/Documents/consult/se111/SE111-20140926-Presentation.pdf

[51] See the Panel's Recommendation 3-1 in its January 2014 Monitoring Report (page 174) available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf#page=184

[52] See the IESO's response to the Panel's Recommendation 3-1 in its January 2014 Monitoring Report available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_Letter_MSP_Report_20140131.pdf

[53] See the following Panel recommendations: Recommendation 3-3 in the August 2007 Monitoring Report (page 123) available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf#page=141;

The Panel's analysis in the section above highlights that, while the RT-GCG program remains in place, more transparency of generator cost submissions is needed. Since the program's current form was established in December 2009, generators have submitted costs to the program under two cost categories, (1) start-up fuel and (2) incremental operation and maintenance. Limiting the submitted cost categories to two makes it difficult to draw any specific conclusions about the reasonableness of the underlying costs. More specific cost categories would provide needed transparency and more specificity in the administration of the program.

The IESO has issued an Interpretation Bulletin on the costs that are appropriate to include in an after-the-fact RT-GCG cost submission.[54] The Panel is of the view that the IESO should replace the two current cost categories for RT-GCG submissions with more specific cost categories, in keeping with the approach reflected in the Interpretation Bulletin.

<u>Recommendation 2-2</u>

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.

To identify any after-the-fact RT-GCG cost submissions that are inconsistent with the guarantees intended to be provided by the RT-GCG program, the Panel has previously encouraged the IESO to exercise its authority under the Market Rules to audit the cost submissions that generators have made under the RT-GCG program.[55] The Panel understands that the IESO is presently undertaking such audits.

Recommendation 3-3 in the January 2010 Monitoring Report (page 107) available at: http://
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf; Recommendation 3-4 in the August 2010 Monitoring Report (page 140) available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20100830.pdf#page=165; and

Recommendation 3-4(i) in the March 2011 Monitoring Report (page 96) available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf#page=117

[54] See the IESO's Interpretation Bulletin issued on August 25, 2014 available at:
http://www.ieso.ca/documents/interpretBulletins/ib_IESO_MKRI_0001.pdf

[55] See the Panel's August 2010 Monitoring Report (page 133) available at:
http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20100830.pdf#page=158

4.1.2 *Day-Ahead Production Cost Guarantee Payments*

Unlike the RT-GCG program, the DA-PCG program under the enhanced Day Ahead Commitment Process ("DACP") does not allow for after-the-fact cost submissions. Instead, the IESO uses three-part offers (start-up, speed-no-load, and incremental energy costs) submitted day-ahead by market participants to optimize the energy and operating reserve markets for the next 24-hour dispatch day. The guarantee under the DA-PCG program covers costs for the generator's full day-ahead schedule. If a generator's market revenues from production are less than its offered costs through the DA-PGC program the generator will receive a payment to make up the difference between earned revenues and offered costs. Participation in the DACP is mandatory, though generators can avoid getting a day-ahead commitment by submitting uneconomic day-ahead offers.

Table 2-17 shows the days with the highest DA-PCG payments in the Current Reporting Period. There were 123 days when DA-PCG payments were made. The average daily payment was $117,987 (the average excludes the days when no DA-PCG payments were made). DA-PCG payments totalled $14,512,421 in the Current Reporting Period.

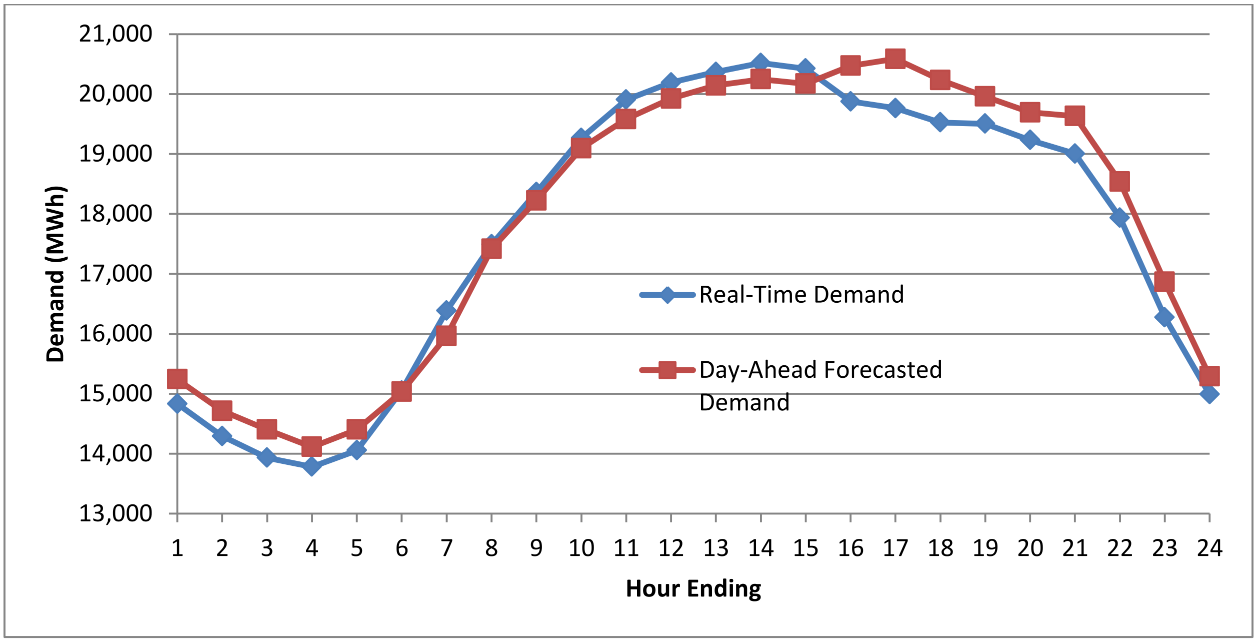
Table 2-17: Highest Daily Aggregate DA-PCG Payments
May 2014-October 2014
($)

Delivery Date	Total PCG
July 02, 2014	700,997
June 30, 2014	486,610
July 22, 2014	481,725
June 23, 2014	417,128
May 27, 2014	369,178

4.1.2.1 July 2, 2014

On July 2, 2014, seventeen generators eligible for DA-PCG payments were scheduled through the DACP to produce a total of 23.6 GWh. The load forecasts predicted the actual demand with little forecast error until HE 16 when the real-time demand for the remainder of the day fell below forecasts by 400 MWh to 750 MWh, which is shown in Figure 2-4.

Figure 2-4: Real-time Demand and Day-Ahead Forecasted Demand July 2, 2014 (MWh)



The deviation between real-time demand and the day-ahead forecasts in HE 16 to HE 21 put downward pressure on prices relative to the offers that were guaranteed through the DACP. In addition, when generators receive day-ahead commitments, it is a permitted practice for them to reduce their offers to ensure that they are scheduled. Both of these factors increased the spread between the HOEP and the generators' day-ahead offers. The day-ahead schedule guarantees these generators the costs that they offered into the DACP and they are compensated for the shortfall between those costs and their real-time market revenues. Given the amount of generation with DA-PCG commitments (17 generators), the result was the largest daily aggregate DA-PCG payments in the Current Reporting Period, $700,996.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1 Introduction

In this chapter, the Panel summarizes notable changes and developments that affect the efficient operation of the IESO-administered markets, and makes recommendations where relevant to promote market objectives. Section 2 provides an update on Panel investigations. In Section 3, the Panel reviews the IESO's energy market pricing review, which included a study of the cost and benefit of moving to a locational marginal pricing market design.

2 Panel Investigations

The Panel has completed its gaming investigation in relation to the conduct of two related dispatchable loads, and its report has been posted on the Ontario Energy Board's website. The Panel currently has one gaming investigation under way in relation to a generator.

3 New Matters

3.1 Review of the IESO's Energy Market Pricing Review (SE-114)

In 2011, the IESO established the Electricity Market Forum (the "Forum"), composed of electricity sector stakeholders, to identify issues and opportunities for Ontario's energy market. Following extensive consultation, the Forum issued its final report in the fall of 2011. The report provided recommendations for the reform of the Ontario wholesale electricity market as well as a roadmap for the implementation of those reforms. A central recommendation, aimed at improving the efficiency of the market and eliminating opportunities for market participants to target inefficient side-payments, was a review of the two-schedule price setting system. The Forum recognized that replacing the two-schedule price setting system would provide an opportunity to address Congestion Management Settlement Credit ("CMSC") payments, reduce design complexity, improve compatibility with other markets and enable the creation of an efficient day-ahead market.[56]

[56] For more information see the Chair of the Forum's December 2011 report titled "Reconnecting Supply and Demand: How Improving Electricity Pricing Can Help Integrate a Changing Supply Mix, Increase Efficiency and Empower Customers", page 8, available at: http://www.ieso.ca/Documents/consult/Market_Forum_Report.pdf

In response to this recommendation and to similar recommendations from the Panel over the years, the IESO launched a stakeholder engagement process ("SE-114")[57] and commissioned the consulting firm Market Reform to examine the costs and benefits associated with replacing the two-schedule price setting system. The Market Reform study found net benefits for consumers under both of the variations of a locational marginal pricing ("LMP") market design considered.

Market Reform's report describes the features of the current market design which could be improved upon, with an eye towards potential design alternatives.

Market Reform identified current design elements that drive a wedge between the actual marginal cost of generation and the price of electricity at a given location on the grid. It found that these conditions reduced efficient market signals and increased out of market payments, specifically CMSC payments. Market Reform identified the following current market design elements as drivers of these outcomes:

- The two-schedule price setting system itself, which the Panel notes serves the explicit purpose of creating a uniform market price, which has the effect of separating the price of electricity from the cost of producing it at any given point on the grid
- The absence of foresight in the unconstrained sequence in order to anticipate ramp needs, and the use of the three times ramp rate multiplier
- Issues associated with the intertie scheduling process, the granularity of pre-dispatch scheduling, and the modelling of transmission losses

Market Reform indicated that the Ontario market design fails to provide prices reflective of the marginal cost of generation, and that the design relies on out of market payments to compensate generators, when more efficient and competitive design features are feasible. These findings are consistent with the long held views of the Panel. Since market opening the Panel has been critical of the efficiency and uplift implications of the two-schedule price setting system. Inefficient intertie transactions,[58] nodal price chasing,[59] ramp down CMSC,[60] and gaming

[57] The IESO's SE-114 webpage is available at: http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-114.aspx
[58] For more information see the Panel's June 2006 Monitoring Report, pages 68-79, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf
[59] For more information see the Panel's April 2014 Monitoring Report, pages 119-151, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

behaviour targeting CMSC payments[61] are just some of the issues related to the two-schedule price setting system identified by the Panel. Put simply, the Panel believes:

> *A regime, such as the present one, in which we sell energy at one price while producing it at another price is bound to be problematic.*[62]

The Panel believes that replacement of the two-schedule price setting system is an essential step in enabling broader reforms, like the development of a day-ahead market and more efficient intertie trade. A true day-ahead market would increase the efficiency of the market by eliminating the need for most generator and import guarantees. It would also allow and encourage exporters to become active participants in a day-ahead market by allowing them to schedule firm export sales. At the same time, better aligning Ontario's market structure with neighbouring markets would facilitate the more frequent scheduling of intertie transactions, reducing the market's reliance on non-quick start resources to meet real-time supply and demand mismatches. The Panel supports these reforms and believes they would materially improve the efficiency of the Ontario wholesale electricity market.

3.1.1 Design Options Considered

Guided by the principles and objectives laid out by the IESO, Market Reform identified the following four market design options, including the status quo as a baseline measurement.

1. The Status Quo
    - Two-schedule price setting system, with a three times ramp rate in the unconstrained sequence
2. Look-Ahead
    - Two-schedule price setting system, with foresight and true ramp rates in the unconstrained sequence to better align with the current constrained sequence
3. Locational Marginal Pricing – Uniform
    - No unconstrained sequence

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[60] For more information see the Panel's June 2013 Monitoring Report, pages 61-67, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

[61] For example, see the Panel's July 2014 "Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Greenfield Energy Centre LP" available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Investigation_Greenfield_20140717.pdf

[62] From the Panel's December 2006 Monitoring Report, page 110, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf

- Constrained pre-dispatch sequence to determine intertie schedules and price differences across interties
- Constrained real-time dispatch sequence to determine dispatch schedules and nodal prices
- Dispatchable resources settled at respective nodal prices
- Non-dispatchable resources settled at a uniform Ontario price derived from the load-weighted average nodal price of non-dispatchable loads across the province

4. Locational Marginal Pricing – Zonal
    - Identical to LMP-uniform except non-dispatchable loads are settled based on zonal prices derived from the load-weighted average nodal prices of non-dispatchable loads within each internal zone

3.1.2 Assessment Criteria

Market Reform considered the design options in the context of a cost benefit analysis, measuring the net benefit gain or loss associated with each design option relative to the status quo. While a cost benefit analysis often involves quantifying changes in efficiency, elements assumed by Market Reform to be common to all design options effectively disregarded this measure.

Short-term (allocative and productive) efficiency involves maximizing the benefit derived from consumption and minimizing the cost of producing energy to serve that consumption. With efficiency based on the actual production and consumption of energy, the determination of efficiency is limited to the constrained sequence of the current two-schedule price setting system. Under the current market design, the constrained sequence is intended to produce transparent dispatch signals reflective of the "as-offered" costs of generation and the limits of the transmission system. Through these signals the constrained sequence determines who consumes and who generates.

The non-binding, and at times unachievable schedules produced by the unconstrained sequence serve as a financial overlay to the constrained sequence. Despite not directly impacting dispatch, the unconstrained sequence does indirectly affect efficiency. The financial incentives created by payments conditioned on the unconstrained sequence, such as CMSC, can distort the incentives that would otherwise motivate offers and bids. In cases where offers and bids no longer reflect marginal cost or benefit, the constrained sequence, which treats offers and bids as inputs, can produce less than efficient dispatch schedules and prices.

Common to both the status quo and the three alternate design options under consideration is the real-time constrained dispatch of resources. If the choice of market design did not influence the offer and bid behaviour of market participants (i.e. the inputs to the market), the four design options would share a common dispatch solution. This simplifying assumption alleviates the need to assess changes in short term efficiency amongst design options. While Market Reform considered some of the implications of the design choice on offer and bid behaviour in a separate analysis, anticipating participant behaviour is inherently difficult to do and was not incorporated in its cost benefit modelling. As a result, short term efficiency remains unchanged across design options in Market Reform's cost benefit analysis.[63]

Long-term (dynamic) efficiency involves minimizing the cost of investment required to support changes in consumption over time. In Ontario, energy pricing plays little role in driving private investment decisions, as generators' capital costs are primarily recovered through payments made under contracts signed with the Ontario Power Authority (now the IESO). The need for, and location of, new generating capacity and unit refurbishment is identified by the IESO as part of its long-term planning duties. This continues to be true under all four design options considered. Consequently, Market Reform's model assumes long term-efficiency remains unchanged across design options.

In light of the above, the Market Reform cost benefit analysis focused not on changes in short- and long-term efficiency, but on the change in the net present value of "total cost", which in this context includes the cost to consumers and the implementation cost associated with a market design change. Changes in total cost can materialize in two ways:

1. A change in the cost to the consumer in response to a design change. The measure of the cost to consumers includes charges to recover energy payments, contract payments, payments to regulated assets, and CMSC payments (among other payments recovered

[63] While the Market Reform model assumed no change in efficiency, the Panel believes the existence of side payments such as CMSC can influence market participant offer and bid behaviour, and in turn efficiency. Many of these incentives would be eliminated or mitigated under an LMP design. As will be discussed later, Market Reform supplemented its cost benefit analysis with further analysis to incorporate considerations for efficiency gains and losses.

through uplift), collectively "market and contract costs". A reduction in the cost to consumers represents an equal decrease in total revenues to generators, and to a lesser extent intertie traders and dispatchable loads.[64]

2. The cost of implementing a design change relative to no change. Implementation costs include costs incurred by both the IESO and market participants to implement, learn and manage new systems. Implementation costs incurred by the IESO are ultimately recovered from consumers through the IESO Administration fee, while implementation cost incurred by generators and dispatchable loads would be borne by those participants.

To assess the net benefit gain or loss associated with a design change Market Reform utilised various sources of historic and forecasted information to create a complex simulation of market outcomes. Simulations were run for each of the design options considered, covering a nine-year period from 2018 to 2026.[65] The cost of implementing design changes was estimated by Market Reform and the IESO using available industry information and historical data.

3.1.3 The Results

Table 3-1 presents the results of Market Reform's simulations. Specifically, the results under the three design options represent the change in net consumer benefit under each option relative to the status quo, as measured by the change in total cost.

Table 3-1: Net Benefit Results of Market Reform's Simulations
2018 – 2026
($ millions)

	Look-Ahead	LMP – Uniform	LMP – Zonal
Net Market and Contract Cost Reduction (1)	5.4	260.4	246.1
Implementation Cost (2)	8.4	133.2	133.2
Change in Total Cost (=2-1)	2.9	(127.1)	(112.9)
Change in Net Benefit	(2.9)	127.1	112.9

[64] Decreases in consumer costs will not be exclusively at the expense of reduced generator revenues, but of reduced intertie trader and dispatchable load revenues as well. For instance, generators, intertie traders and dispatchable loads are eligible to receive CMSC payments; eliminating CMSC payments under the LMP design options would reduce revenues for all those market participants.

[65] The Market Reform simulation included 2017, however the results from that year were excluded from the final measure of net benefit change because the assumed implementation date of a design change was 2018.

Look-Ahead

The look-ahead design option showed a net benefit loss of $2.9 million over the nine-year study period, representing an increase in total cost over the status quo.

The look-ahead design option achieved a $5.4 million reduction in market and contract costs, driven primarily by a decrease of $12.2 million in CMSC payments. The CMSC reduction was in part due to the elimination of ramping CMSC associated with the elimination of the three times ramp rate in the unconstrained sequence. These CMSC savings were in part offset by increases in energy, contract, and guarantee payments to transmission-connected market participants. The $8.4 million cost of implementing the solution marginally outweighed the small reduction in market and contract costs.

LMP – Uniform

The LMP-uniform design option showed a net benefit gain of $127.1 million over the same nine-year study period, representing a decrease in total cost over the status quo.

The LMP-uniform design option achieved a net market and contract cost reduction of $260.4 million, which would accrue to consumers. The cost of implementing this design is estimated at $133.2 million (of which $50.7 million is IESO costs funded by consumers), resulting in the $127.1 million net benefit gain.

Market and contract cost savings were primarily realised by the elimination of CMSC payments, which resulted in a $277.7 million reduction in the cost to consumers relative to the status quo – far and away the primary driver of total cost savings. Net savings associated with energy and contract costs totalled $74.6 million which, while significant in the context of justifying the implementation cost, is minor relative to the total quantum of these costs. Total energy and contract rate costs remain largely unchanged under all design options due to the relationship between energy prices and contracts, with contract payments increasing as energy prices decrease, and vice versa. While changes in energy costs and contract costs largely offset each other when measured across all consumers, the composition of the two costs affects how much specific consumer groups pay.

Holding total cost equal, when contract costs make up an increasing portion of the total cost, the total cost paid by Class B consumers (typically small consumers) increases, while total cost paid by Class A consumers (typically large industrial consumers) decreases.[66] The opposite is true when energy costs make up an increasing portion of total cost.[67] Any trade-off between contract costs and energy costs brought about by a change in market design will impact the total cost paid by Class A and Class B consumers.

All told, the LMP-uniform design option achieved the greatest net benefit gain of all the design options considered.

LMP – Zonal

The LMP-zonal design option resulted in a net benefit gain of $112.9 million over the study period, representing a decrease in total cost over the status quo.

Just as with the LMP-uniform design option, the elimination of all CMSC payments under the LMP-zonal option resulted in a reduction in the cost to consumers of $277.7 million. The LMP-zonal option achieved slightly lower net market and contract cost savings of $56.7 million than the LMP-uniform option, although the reasons for this were not elaborated on in the Market Reform report. The LMP-zonal design option had the same cost of implementation as the LMP-uniform option.

The findings of the Market Reform simulation suggest that an LMP market design, be it with a uniform or zonal price for consumers, could result in modest total cost savings accruing to consumers.

Sensitivity of CMSC Results

The $277.7 million in CMSC payments made in the status quo simulation, and saved in the two LMP design options, was calculated assuming that offers and bids at marginal cost or benefit drive efficient outcomes. In reality, the two-schedule price setting system often presents market participants with opportunities to raise or lower their offer or bid price away from marginal cost or benefit in order to maximize CMSC payments. To estimate the potential increase in CMSC payments associated with this behaviour above and beyond the $277.7 million calculated for the status quo, Market Reform established the price bounds in which a market participant can change

[66] For a more detailed explanation of the classification of Class A and Class B consumers, see the "Relevance" section associated with Figure 1-1 in Chapter 1 of this report.
[67] For a more detailed explanation of the cost allocation methodology, see the Commentary section associated with of Figures 1-2a and 1-2b in Chapter 1 of this report.

their offer to increase CMSC payments, without changing their constrained schedule. It found that CMSC payments could be increased by $364 million over the study period if market participants had perfect foresight of market outcomes and fully implemented the nodal price chasing strategy. Given the uncertainty of market outcomes, Market Reform speculated that in reality only 10% of these additional CMSC payments could actually be obtained. This $36.4 million, or $4 million per year, represents potential additional savings (on top of the $277.7 million) in the cost to consumers associated with a move from the status quo to either LMP design option.[68]

In its April 2015 Monitoring Report, the Panel found that, between January 2013 and April 2014 (a 16 month period), constrained-off exports received $31.6 million in CMSC payments. Of that total, the Panel found that $21.8 million (69%) was overcompensation associated with exporter bids priced higher than their ex post marginal benefit.[69] This finding suggests that the additional CMSC payments made in the status quo simulation, and saved in the two LMP design options, is much larger than the $36.4 million estimated in the Market Reform analysis, and that market participants can capture greater than 10% of the potential CMSC payments associated with nodal price chasing.

Past experience with the two-schedule price setting system also suggests that, under the status quo, CMSC payments over the course of the study period might far exceed the $277.7 million found in the Market Reform study. The Panel notes that it is often transient transmission outages that produce significant CMSC payments; it is unclear whether such outages were part of the Market Reform model.

Over $1.1 billion in net CMSC[70] payments were made from 2005 through 2013 (a period equal in length to the Market Reform study period). While the Panel does not necessarily expect that such high CMSC payments will persist into the future, experience suggests that CMSC payments well in excess of $277.7 million are possible. Consequently, a transition to a LMP market design

[68] By comparison, moving from the status quo to the look-ahead design option was only estimated to save $2.2 million of extra CMSC payments, with $34.2 million in CMSC payments still being made.
[69] For more information see the Panel's April 2014 Monitoring Report, pages 119-151, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf
[70] "Net CMSC" is the sum of positive and negative CMSC payments, minus any CMSC payment claw backs (such as claw backs under the local market power mitigation framework). Note that the $1.1 billion in net CMSC payments is in nominal dollars, while Market Reform's $277.7 million is the net present value of future CMSC payments.

without CMSC payments could result in a net benefit gain to consumers far greater than found in the Market Reform study.

3.1.4 Other Benefits

While not included in its cost benefit analysis model, Market Reform supplemented its analysis by examining the additional consequences of adopting each design change. This analysis included consideration of how market participants might respond to market design changes, and the resultant effects on efficiency and the cost to consumers. Market Reform found, and the Panel agrees, that there are efficiency gains to be had by transitioning to a LMP market design. The following sections discuss some of these benefits.

Changed Generator Offers

Similar in principle to the CMSC sensitivity analysis above, Market Reform notes that with node specific pricing under the LMP design options, and without the CMSC payment incentive, gas-fired generators might offer more competitively to increase the likelihood of being scheduled. This potential reduction in price could increase consumer benefit by way of scheduling additional consumption at lower prices, and could increase producer surplus by replacing more expensive sources of supply (particularly imports) with the less costly, competitively offered gas-fired units. The Panel notes that the potential increase in competitive behaviour extends beyond gas-fired generators to other resources, including intertie traders. More competitive pricing would have positive impacts on efficiency in addition to decreasing the cost to consumers.

Reduction in Intertie Seams Issues

Seams issues are features that increase the difficulty or risk associated with trading energy across jurisdictions. Discrepancies in market complexity, timing, and settlement are examples of seams issues. To the degree aspects of the market can be harmonized amongst interconnected markets, seams issues can be reduced. Currently, the jurisdictions neighbouring Ontario either have a wholesale electricity market with LMP settlement or no market at all. Adopting a LMP market design would better align pricing across interties, something the Panel believes would help reduce seams issues. This could encourage more efficient pricing from importers as they may be adding a risk premium to their offers under the current design to cover seams issues risk. Market

Reform found that offers with reduced risk premiums will lead to more efficient pricing and a decrease in the cost to consumers.

Market Signals, Efficient Production and Consumption, and Investment Planning

The Panel notes that the two-schedule price setting system has the effect of separating the price of electricity from the cost of producing it at any given point on the grid. At any given time the financial incentive created by the unconstrained price may be inconsistent with the actual economics of consuming or producing at a given location. That is to say, what is privately profitable may not be socially efficient. As the Panel has stated in previous reports, this can result in inefficient offer and bid behaviour, such as nodal price chasing, which may result in private profits but social inefficiencies.

The Panel identified one such example of privately profitable transactions leading to social inefficiency in its June 2006 Monitoring Report. It found that energy is frequently exported on a net basis from Ontario to New York when the incremental cost of producing the energy in Ontario (as represented by the constrained nodal price) is higher than the price in New York (which presumably represents the incremental cost of producing in New York). A net trade flow from a high cost region in Ontario to a low cost region in New York is inefficient. These transactions were largely a result of the incentives created by the two-schedule price setting system in Ontario, as these trades were privately profitable on the basis of the unconstrained price despite being socially inefficient on the basis of the constrained nodal price.[71]

In its August 2007 Monitoring Report the Panel estimated that the efficiency of export transactions to New York could be increased significantly by adopting a LMP design, which would better align private profitability with social efficiency. Specifically, the Panel estimated that the efficiency of export transactions to New York could have been increased by upwards of $66 million (from January 2006 to April 2007) if a form of LMP design existed in place of the two-schedule price setting system.[72] While the Panel's analysis was limited to the New York intertie, a move to a LMP design could improve efficiency across all interties.

[71] For more information see the Panel's June 2006 Monitoring Report, pages 68-79, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf
[72] For more information see the Panel's August 2007 Monitoring Report, pages 145-153, available at: http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf

A LMP market design includes an explicit, transparent measure of the value of generation by location, the cost of increased load by location, and the value of incremental transmission investment by location. By incorporating these factors into the price, what is privately profitable is also socially efficient. The benefits of such a pricing system allow for more informed and efficient decisions regarding production and consumption, as well as investment in generation, transmission and load siting. These benefits only increase as more resources are exposed to LMP.

Reduced Market Complexity and the Facilitation of Further Improvements

Ontario is the only wholesale electricity market with a two-schedule price setting system. Such a system introduces complexity and side payments far beyond what is present in a LMP market design. In the Panel's view, complexity begets complexity as more complex market rules, tools, and settlement systems are needed. Market complexity can also introduce further gaming opportunities to the market, as identified in a number of the Panel's reports. The Panel considers that the IESO's solution to these gaming opportunities has often been to introduce further complexity to the market, such as its solution to limit CMSC payments to dispatchable loads[73] or to limit ramp down CMSC payments.[74] A transition to LMP would considerably simplify the market design and its associated elements.

Associated with reduced market complexity is the facilitation of further market design improvements under a LMP design. Among other things, LMP would facilitate the transition to a full day-ahead market by allowing for resources to be fully settled on day-ahead prices. Such improvements have the potential to produce benefits throughout the rest of the market. For instance, a day-ahead market would eliminate the need for day-ahead generator and import guarantees and reduce the market's reliance on the Real-Time Generation Cost Guarantee program, a program the Panel has argued can lead to inefficient unit commitment and

[73] CMSC payments to dispatchable loads are limited by section 3.5.1D of Chapter 9 of the Market Rules, available at: http://www.ieso.ca/Documents/marketRules/mr_chapter9.pdf

[74] For more information see the IESO's Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr2015/MR_00414_R00_Amendment_Proposal_Ramp_Down_CMSC_v5.0.pdf. This Market Rule amendment was approved by the IESO Board of Directors in June, 2015.

unwarranted uplift payments.[75] LMP would also help simplify and standardize the Ontario market design with neighbouring jurisdictions, likely increasing the gains from trade.

For each design option, Market Reform summarized the benefits not explicitly considered in the cost benefit analysis. The results of which are shown in Table 3-2.

Table 3-2: Assessment of Additional Benefits

	Look-Ahead	LMP – Uniform	LMP – Zonal
Efficiency improvements that could be achieved	Low	Medium	High
Reduced need for CMSC	Low	High	High
Reduced design complexity	Low	Medium	Medium
Opportunities to facilitate other improvements	Low	Medium	High

Under all of the "Additional Benefit" categories, Market Reform found the LMP-zonal option realised equal or greater benefits relative to the LMP-uniform option, and that both LMP options realised far greater benefits than the look-ahead option.

3.1.5 Market Reform's Recommendations

Market Reform recommended that the IESO take further steps to explore the implementation of a LMP design. These steps would include:

- refining details of how energy and reserve pricing would actually be determined if determined on a locational basis,
- considering the implications of LMP on intertie scheduling, including whether there are opportunities to standardize scheduling processes with other markets,
- exploring synergies between LMP pricing and other reviews being undertaken by the IESO,
- forming a view of preferences for an LMP-zonal or LMP-uniform design and the associated processes for hedging price differentials, and
- refining implementation cost estimates.

The Panel supports the conclusions in the Market Reform report and encourages the IESO to pursue Market Reform's recommendations.

[75] For more information see the Panel's August 2010 Monitoring Report, pages 128-140, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20100830.pdf

The IESO has indicated that it intends to initiate a stakeholder engagement that will consider a more holistic market redesign in three key areas: real time unit commitment, intertie scheduling and market and dispatch scheduling efficiency, which will include consideration of locational pricing for dispatchable resources.

Chapter 4: Panel Recommendations

This chapter contains an update on future developments in the market, as well as the IESO's responses to recommendation made by the Panel in its April 2015 Monitoring Report. The chapter concludes with a restatement of the recommendations contained in this report.

1 Future Development of the Market

1.1 Limiting CMSC Payments during Ramp-Down

In its June 2013 Monitoring Report the Panel recommended that the IESO implement a permanent, rule-based solution to eliminate self-induced congestion management settlement credit ("CMSC") payments to ramping down generators.[76] Through its stakeholder engagement process the IESO developed a Market Rule amendment that will mitigate, but not eliminate ramp-down CMSC payments.[77] The amendment was presented to the Technical Panel on April 28, 2015, where it was unanimously voted that the amendment be presented to the IESO Board for approval. The IESO Board approved the Market Rule amendment on June 24, 2015; the IESO anticipates the amendment will be effective by the fourth quarter of 2015.[78]

2 IESO Responses to Prior Panel Recommendations

Following the release of each of the Panel's semi-annual monitoring reports, the Ontario Energy Board posts on its website the IESO's responses to any Panel recommendations that have been directed to it.[79]

The Panel's April 2015 Monitoring Report[80] contained one recommendation that related to uplift, specifically constrained-off CMSC payments for intertie transactions. The IESO's response to that recommendation is set out in Table 4-1.

[76] For more information see the Panel's June 2013 Monitoring Report, pages 61-67, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

[77] For more information on the Panel's views regarding the Market Rule amendment proposed by the IESO, see its submission to the stakeholder engagement process, available at: http://www.ieso.ca/Documents/consult/se111/SE111-20141212-MSP.pdf and the Panel's update on the status of the stakeholder engagement from its April 2015 Monitoring Report, page 164, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

[78] For more information see the IESO's Market Rule Amendment Proposal, available at: http://www.ieso.ca/Documents/Amend/mr2015/MR_00414_R00_Amendment_Proposal_Ramp_Down_CMSC_v5.0.pdf

[79] The IESO's responses to the recommendation in the Panel's April 2015 Monitoring Report are set out in a letter from the President & CEO of the IESO to the Chair & CEO of the Ontario Energy Board, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Reply_to_OEB_20150505.pdf

Table 4-1: IESO Response to the Recommendation in the Panel's April 2015 Monitoring Report

Recommendation	IESO Response
Recommendation 3-1 *The Panel recommends that the IESO eliminate constrained-off Congestion Management Settlement Credits (CMSC) payments for all intertie transactions, with due consideration to the interplay between the elimination of negative CMSC payments and Intertie Offer Guarantee payments.*	"The IESO shares the MSP's concerns that the current two-schedule system facilitates "nodal price chasing behaviour" and that this behaviour is undesirable. In the recently concluded Energy Market Pricing System Review, the final report identified modest savings that could be realized if Ontario moved to a locational pricing system. While work on this is expected to start later this year, the IESO acknowledges that a stakeholder and implementation process will take time and hence a more immediate solution is required. Therefore, the IESO has initiated a stakeholder engagement, Addressing Constrained-Off Payments for Ontario Interties in order to develop and implement a solution to address constrained-off CMSC payments at the interties. In this engagement, the IESO will review the Panel's findings from the April 2015 Monitoring Report, provide analysis and invite discussion from stakeholders as it completes its understanding of any impacts that arise as a result of eliminating these payments. The IESO invites the Panel to participate in this engagement. At the time of completion of this stakeholder initiative, the IESO expects to bring a market rule amendment to the Technical Panel."

3 Panel Commentary on IESO Response

The Panel commends the IESO's efforts to expeditiously address the recommendation by initiating a stakeholder engagement to develop and implement a solution to address constrained-off CMSC payments at the interties, with due consideration for the interplay with the intertie offer guarantee. The Panel welcomed the IESO's invitation to participate in a May 20, 2015 stakeholder engagement meeting. The IESO subsequently proposed a Market Rule amendment that eliminates constrained-off CMSC on the interties. The amendment was approved by the IESO Board of Directors on August 26, 2015.

[80] See the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

4 Recommendations in this Report

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.

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.