Chapter 2: Market Outcomes

This chapter reports on outcomes in the Independent Electricity System Operator (IESO)-administered markets for the period between May 1, 2016 and October 31, 2016 ("Summer 2016"), with comparisons to the period between November 1, 2015 and April 30, 2016 ("Winter 2015/16"), and the period from May 1, 2015 to October 31, 2015 ("Summer 2015"). Other periods are included when a more extensive comparison is helpful.

1 Pricing

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

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

Description:

Table 2-1 summarizes the average effective price in dollars per megawatt hour by consumer class. The effective price is the sum of the HOEP[1], the GA, and uplift charges. It therefore captures the hourly commodity and contractual capacity costs for generation as well as the costs of conservation and demand response programs. The effective price does not include the costs of transmission, distribution, regulatory or debt retirement charges. Results are reported for three consumer groups: "Class A consumers", "Class B consumers", and "All Consumers".

Customer Class	Average HOEP	Average Global Adjustment	Average Uplift	Effective Price
Class A – Summer 2016	16.46	49.73	2.77	68.96
Class A – Winter 2015/16	8.32	57.44	1.56	67.32
Class A – Summer 2015	19.27	42.55	2.39	64.22
Class B – Summer 2016	21.32	92.65	2.75	116.72
Class B – Winter 2015/16	10.31	102.14	1.63	114.08

[1] Average-weighted HOEP was calculated based on the assumption that embedded Class A follows the same load profile as directly-connected Class A consumers.

Class B – Summer 2015	22.84	82.05	2.48	107.37
All Consumers – Summer 2016				107.23
All Consumers – Winter 2015/16				104.79
All Consumers – Summer 2015				98.86

Relevance:

In Ontario, the effective price a consumer pays for electricity depends on its consumer class. Consumers are divided into two groups: Class A—being any consumer with an average monthly peak demand greater than 3 MW; and Class B—all other consumers.[2]

The "All Consumers" group in Table 2-1 represents a blended average price for Class A and Class B consumers and backs-out the cross-subsidization impacts associated with the change to the GA allocation methodology that took effect in January 2011. As of January 2011, the GA payable by Class A consumers is determined based on their peak demand factor, which is the ratio of their electricity consumption during the five peak hours in a year relative to total consumption by all consumers in each of those hours. The remaining and proportionately larger share of the GA, which includes the GA avoided by Class A consumers who reduced their consumption during the five peak hours of the year, is charged on a monthly basis to Class B consumers based on their total consumption in that month.[3]

It should be noted that in previous Panel reports, Class A consumers that are embedded within a distribution system, as opposed to being directly-connected to the grid, were combined with class B consumers. This was done because the Panel lacks hourly consumption data for Class A embedded consumers (only monthly consumption totals are available).

Recent changes to the regulation[4] defining Class A and B consumers have resulted in an increase in the number of embedded Class A consumers and it is therefore an even greater importance to

[2] 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.

[3] 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

[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.

the accuracy of the data to separate embedded Class A from Class B so Class B effective prices are not skewed lower by Class A results.

The Panel has assumed, for the purposes of calculating the effective price for all Class A consumers, that Class A embedded consumers have the same load profile as Class A directly-connected consumers. While this assumption is useful, data limitations obscure how effective embedded GA consumers are at avoiding GA costs and their method used to avoid GA, whether they are strictly reducing consumption or using behind-the-meter generation to offset their consumption.

The Panel's April 2015 Monitoring Report[5] explained the need to obtain generation and consumption data at an hourly level of granularity, specifically for embedded generation, behind-the-meter generation and embedded Class A consumption. The Panel noted that assessing the impacts of certain market changes – such as the 2011 change to the methodology for allocating the GA – loses precision without access to this data. In addition, assessing the province's overall demand for electricity becomes increasingly difficult as a larger portion of that demand is no longer serviced by the province's high-voltage power system. The need for this data is even more pronounced today.

Commentary and Market Considerations:

The average effective price increased for both Class A and B consumers during Summer 2016 compared to Winter 2015/16 and to Summer 2015. When compared to Summer 2015, the average effective price for Class A and Class B consumers increased by $4.74/MWh and $9.35/MWh respectively. Increasing total system costs were the primary driver of these increases in the effective price.

The HOEP and the GA have an inverse relationship because the GA is primarily[6] composed of payments to contracted and regulated generating resources that are intended to make up for shortfalls between market revenues and the contracted or regulated rates of those resources.

[5] 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

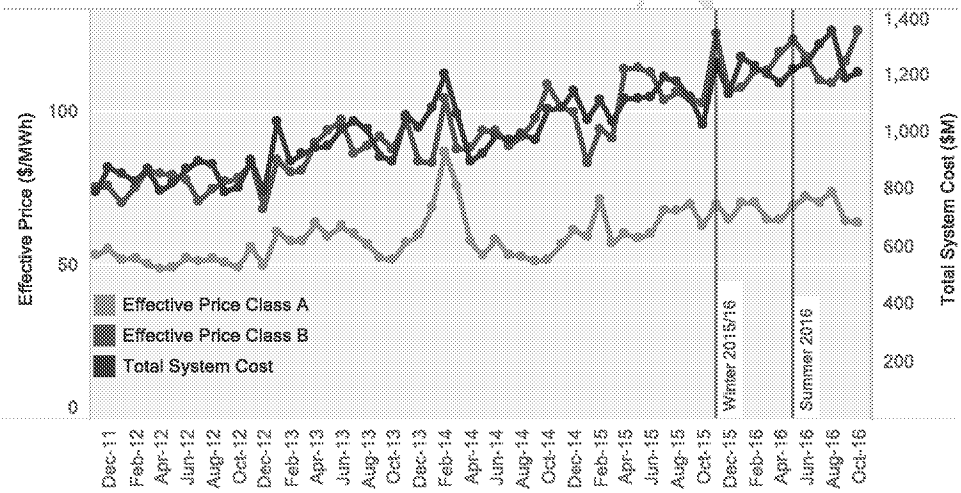
[6] The costs associated with compensating loads under the IESO's demand response programs and administering various other conservation programs (such as the saveONenergy program) are also recovered through the GA. Additional information regarding the GA is available at: http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges.

Compared to Winter 2015/16, in Summer 2016 the HOEP rose while the average GA fell for all consumer classes.

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

Description:

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



Relevance:

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

Commentary and Market Considerations:

In Summer 2016, there were both record high total System Costs (August 2016 at $1.35B) and a record high effective price for Class B consumers (October 2016 at $126.55/MWh). The Class A effective price increased modestly from Winter 2015/16.

Class A consumers can avoid GA costs by minimizing their consumption during peak system hours. The GA avoided by Class A consumers is allocated to Class B consumers. Over the past 5 years, Class A effective prices have not risen in step with system cost due to GA avoidance measures. Class B effective prices continue to bear the majority of increased system costs.

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

Description:

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

As already explained, the GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases. The GA allocation methodology and the extent to which Class A consumers respond to that methodology are responsible for the significant difference in the average effective price paid by each consumer class. When the average GA makes up an increasing portion of system cost, the average effective price paid by Class B consumers increases proportionately more than the price paid by Class A consumers. This relationship is readily apparent in the Summer 2016 period.

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

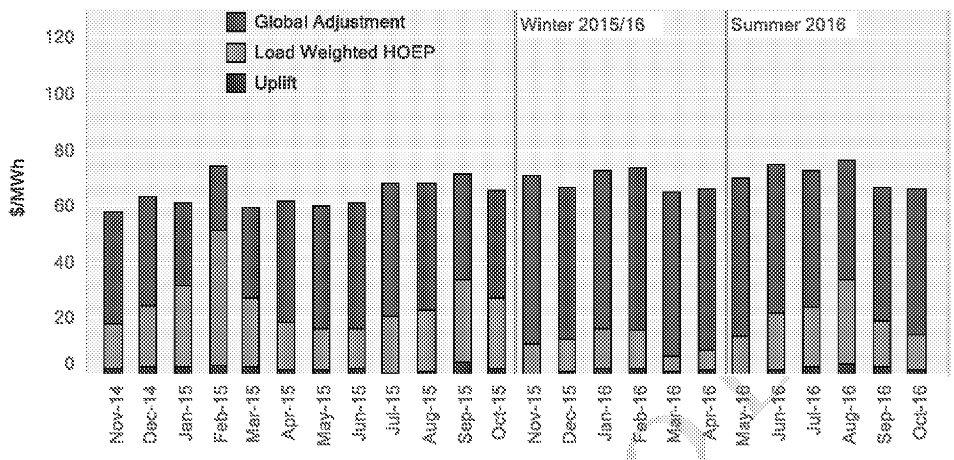
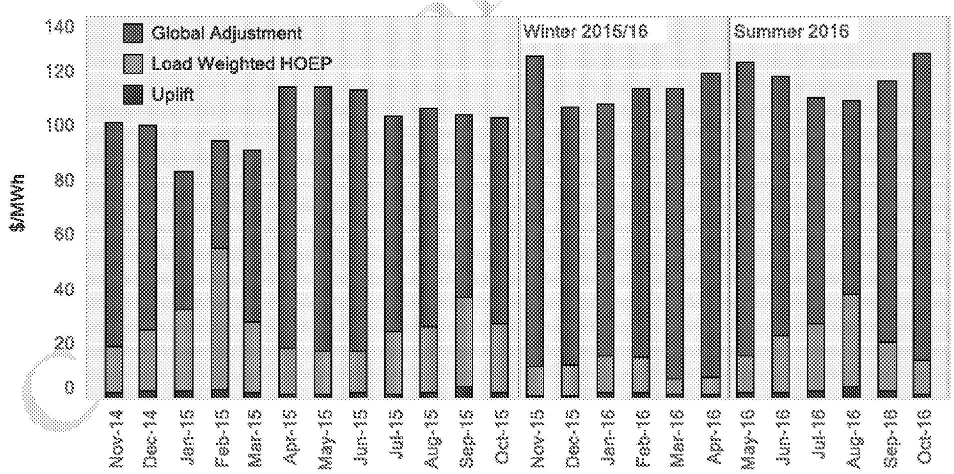


Figure 2-2b: Average Effective Price for Class B Consumers by Component November 2014 – October 2016 ($/MWh)



Relevance:

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

Commentary and Market Considerations:

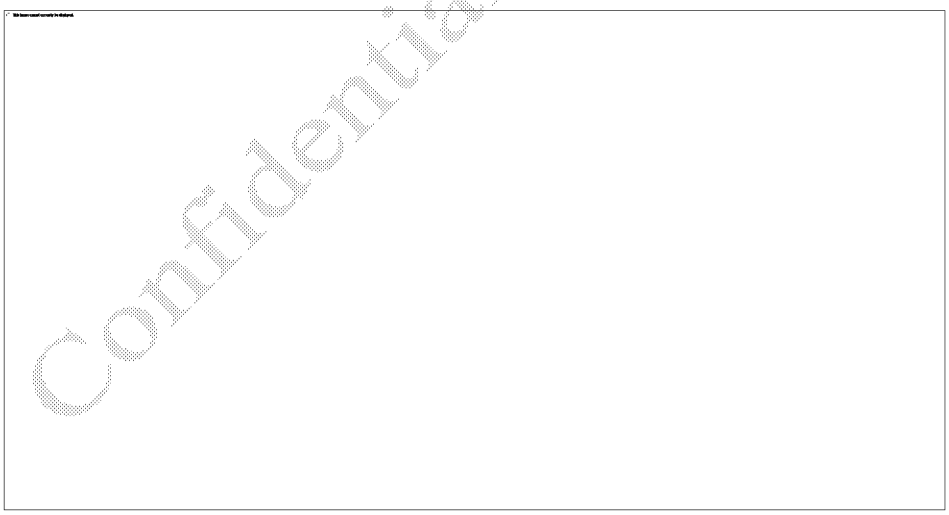
The average effective price for Class B consumers continues to be significantly higher than that of Class A consumers, a trend that began with a change in the GA allocation methodology introduced in 2011.

Notably, while Class A consumers can theoretically avoid GA charges completely by not consuming during the five peak hours of the year, as an aggregate class they have been unwilling or unable to do so.

***Figure 2-3: Monthly (Simple) Average Hourly Ontario Energy Price (HOEP)
November 2014 – October 2016
($/MWh)***

Description:

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



Relevance:

The HOEP is the market price for a given hour and is one component of the effective price paid by consumers. The HOEP is the simple average of the twelve Market Clearing Prices (MCPs) within the hour that are set every five minutes by balancing supply and demand. The HOEP is paid directly by consumers who participate in the wholesale electricity market, and indirectly by consumers who pay the OEB's Regulated Price Plan.

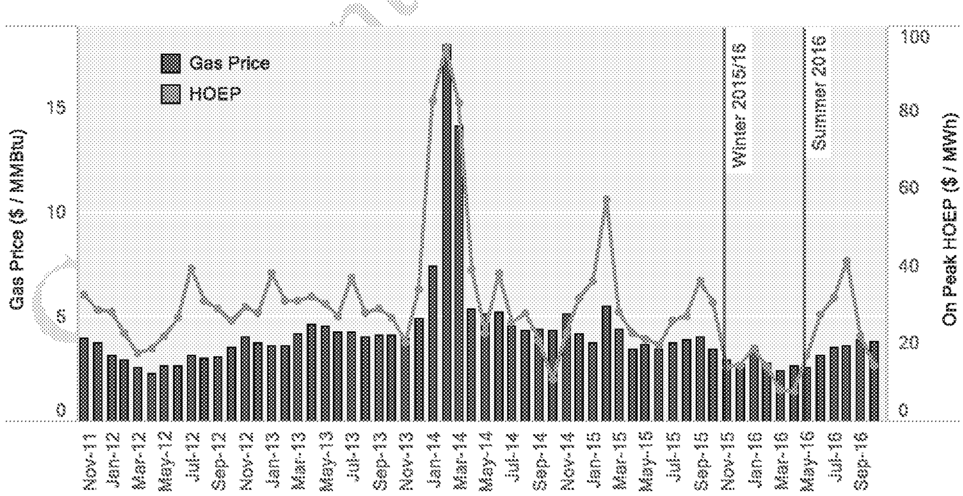
Commentary and Market Considerations:

Demand in the Summer 2016 was nearly 2 TWh higher than in Summer 2015. Despite higher demand, the average HOEP was lower ($18.14/MWh and $20.75/MWh respectively). The lower average HOEP is partially attributed to an additional 829 MW of low marginal cost wind and solar capacity added following the Summer 2015. Higher demand in Summer 2016 is partially attributable to higher temperatures for most of the period.

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

Description:

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



Relevance:

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

Commentary and Market Considerations:

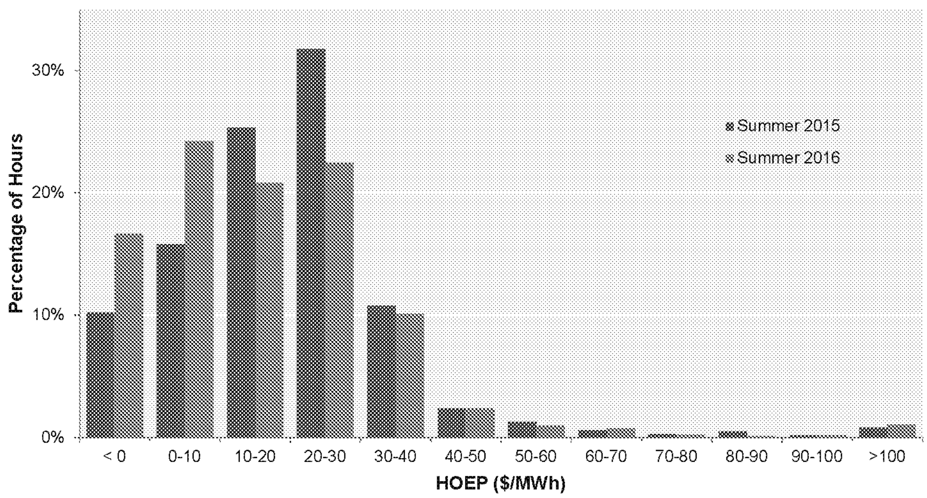
Dawn Hub gas prices, which had been in decline since the Winter 2013/14 period, rose modestly in Summer 2016 with an average day-ahead gas price of $3.42/MMBtu, compared to $2.84/MMBtu in Winter 2015/16. However, compared to Summer 2015, the average day-ahead gas price was $0.29/MMBtu lower.

In the past, daily changes in natural gas prices have been positively correlated with movements in the on-peak HOEP. The correlation coefficient in Summer 2016 was 0.0425 indicating that a correlation between these two prices currently does not exist. This can be attributed to a significant increase in the occasions when wind and hydro have replaced gas facilities as the marginal resource.

Figure 2-5: Frequency Distribution of Hourly Ontario Energy Price
Summer 2015 & Summer 2016
(% of hours, $/MWh)

Description:

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



Relevance:

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

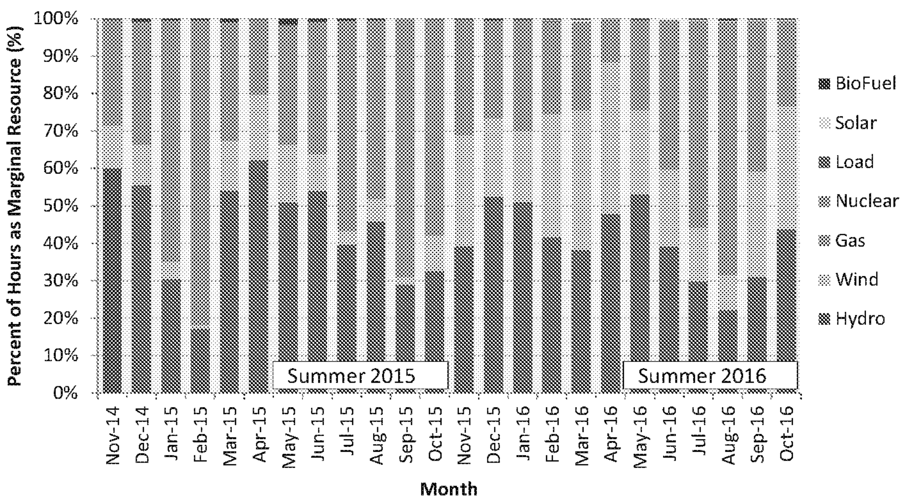
Commentary and Market Considerations:

The frequency distribution of prices shows an increase in the amount of non-positive price hours (zero and negative) in Summer 2016 compared to the Summer 2015. In Summer 2016, HOEP was non-positive in 17% of hours. Overall, prices were more frequently lower than in Summer 2015 despite higher demand due to higher than normal temperatures during most of the period. The addition of over 800 MW of renewable energy capacity since the Previous Summer Period was a main contributing factor to the increased frequency of lower prices.

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

Description:

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



Relevance:

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

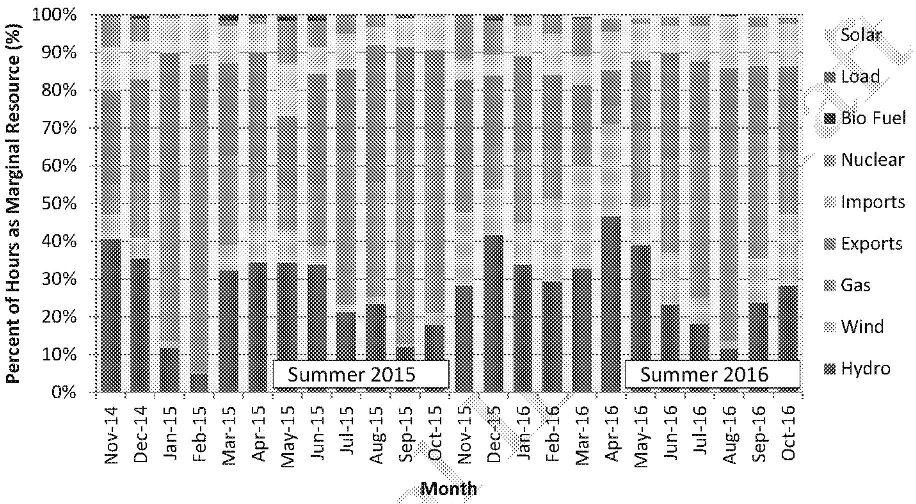
Commentary and Market Considerations:

Wind set the MCP in 21% of all intervals in Summer 2016, which is more frequent than in any previous summer period. As installed wind capacity continues to increase in Ontario, the Panel expects wind to continue to set the MCP with increasing frequency, especially during periods of low demand. There was a decrease in the share of gas generators setting the MPC compared to Summer 2015 (from 42.2% to 37.6% of all intervals) despite higher demand in Summer 2016.

Figure 2-7: Share of Resource type setting the One-Hour Ahead Pre-Dispatch Market Clearing Price November 2014 - October 2016 (% of hours)

Description:

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



Relevance:

When compared with Figure 2-6 (resources setting the real-time MCP), the relative frequency of each resource type setting the PD-1 MCP provides insight into how the marginal resource mix changes from pre-dispatch to real-time. Of particular importance is the frequency with which imports and exports set the PD-1 MCP, as these transactions are unable to set the real-time MCP.[7] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Commentary and Market Considerations:

Wind set the PD-1 MCP 10.6% of all hours in Summer 2016 compared to 3.6 % of all hours in Summer 2015. As installed wind capacity continues to increase in Ontario, the Panel expects

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

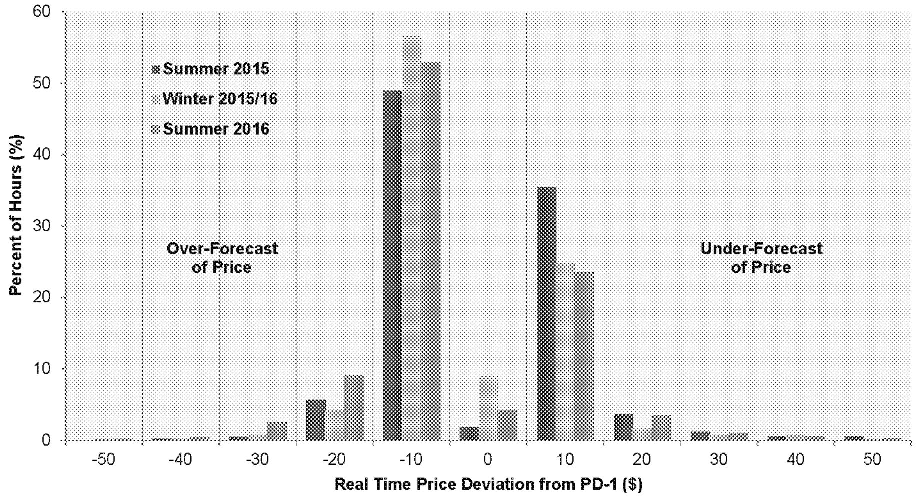
wind to continue to set the MCP with increasing frequency, especially during periods of low demand. Gas fueled resources set the PD-1 MCP 30.9% of all hours in Summer 2016 down from 32.9% of the time in Summer 2015.

Figure 2-8: Difference between the Hourly Ontario Energy Price and the One-Hour Ahead Pre-Dispatch Market Clearing Price Summer 2015, Winter 2015/16 & Summer 2016 (% of hours)

Description:

Figure 2-8 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for Summer 2016, Winter 2015/16, and Summer 2015. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP. The number of instances where the absolute difference between the PD-1 MCP and the HOEP exceeded $50/MWh is negligible and so is not included in Figure 2-8, and the same is true of Figure 2-9 in relation to the absolute difference between the three-hour ahead MCP and the HOEP.

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



Relevance:

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the HOEP if it is higher (due to, for example, a generator outage that occurs between PD-1 and real-time). In such a case, if the exporter was to pay the HOEP they could lose money on the transaction. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal.

Commentary and Market Considerations:

PD-1 prices in Summer 2016 were a less accurate predictor of real-time prices than in the previous two periods. In Summer 2016, the pre-dispatch sequence was within +/- $10/MWh of real-time HOEP 80.7% of the time compared to 86.3% in Summer 2015 and 90.4% in Winter 2015/16. The average absolute price difference is $8.39/MWh up from $6.58/MWh in Summer 2015 and $5.20/MWh in Winter 2015/16.

Table 2-2: Factors Contributing to Differences between One-Hour Ahead Pre-Dispatch Prices and Real-Time Prices Summer 2015, Winter 2015/16 & Summer 2016 (MWh & % of Ontario demand)

Description:

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

Supply

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

Demand

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

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

Factor	Summer 2016		Winter 2015/16		Summer 2015	
	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW)	Average Absolute Difference (% of Ontario Demand)	Average Absolute Difference (MW per hour)	Average Absolute Difference (% of Ontario Demand)
Ontario Average Demand	15,602		15,435		15,205	
Pre-dispatch to Real-time Demand Forecast Deviation	209	1.34	219	1.42	211	1.39
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	21	0.13	17	0.11	20	0.13
Wind Deviation	184.85	1.19	140	0.91	124	0.82
Net Export Failures/Curtailments	78	0.50	90	0.59	82	0.54

Relevance:

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

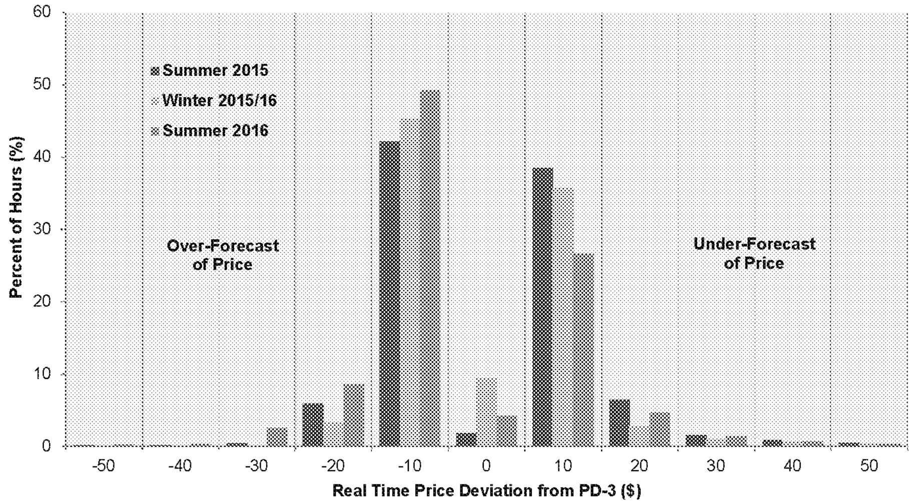
Commentary & Market Considerations:

Demand forecast deviation has remained more or less constant throughout the last three reporting periods. Wind forecast deviation increased significantly from Winter 2015/16. An increase in wind forecast deviation is expected when wind capacity increases. Wind capacity grew by more than 800 MW since Summer 2015.

Figure 2-9: Difference between the Hourly Ontario Energy Price and the Three-Hour Ahead Pre-Dispatch Price Summer 2015, Winter 2015/16 & Summer 2016 (% of hours)

Description:

Figure 2-9 presents the frequency distribution of differences between the HOEP and the three-hour ahead pre-dispatch (PD-3) MCP during Summer 2016, Winter 2015/16, and Summer 2015. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.



Relevance:

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

Differences between the HOEP and the PD-3 MCP indicate changes in the supply and demand conditions from PD-3 to real-time. The resultant changes in price are informative for non–quick start facilities and energy limited resources,[8] both of which rely on pre-dispatch prices to make operational decisions. Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Commentary and Market Considerations:

In Summer 2016 the PD-3 MCP was within +/- $10/MWh of real-time HOEP 80.1% of the time compared to 82.4% for Summer 2015 and 90.4% in Winter 2015/16.

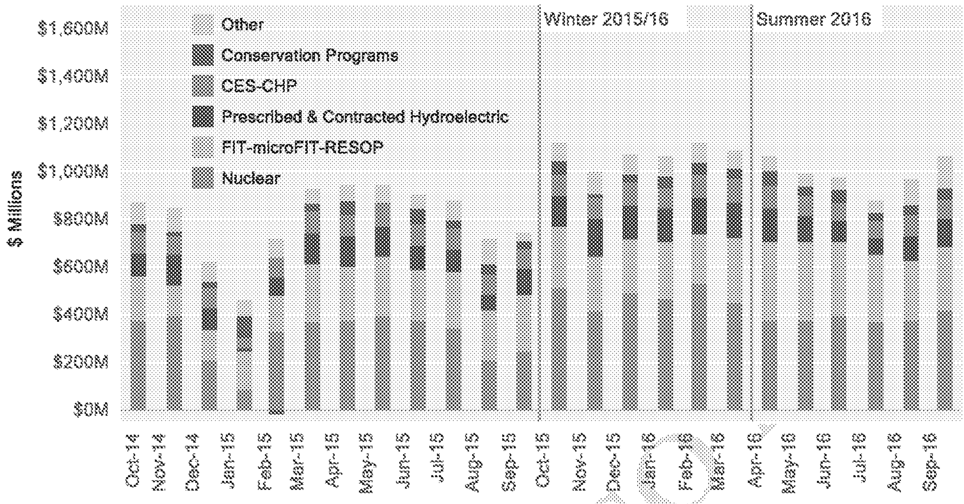
[8] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day; instead, they must optimize their production across the highest-priced hours. For example, some hydroelectric facilities regularly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

When comparing the PD-3 MCP forecast to the PD-1 MCP forecast of HOEP, the forecast accuracy is similar. In Summer 2016 there was only a 0.6% difference in accuracy when price were forecast within +/- $10/MWh of the HOEP compared to 3.9% in the Summer 2015 and no difference in Winter 2015/16. This similarity in accuracy is likely due to significant increases in wind capacity over the past several reporting periods. Over four thousand MW of wind capacity are currently offered within a narrow price range so when demand forecasts are off, prices tend to deviate less, especially when wind is the marginal resource meeting demand.

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

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

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



Relevance:

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

Commentary and Market Considerations:

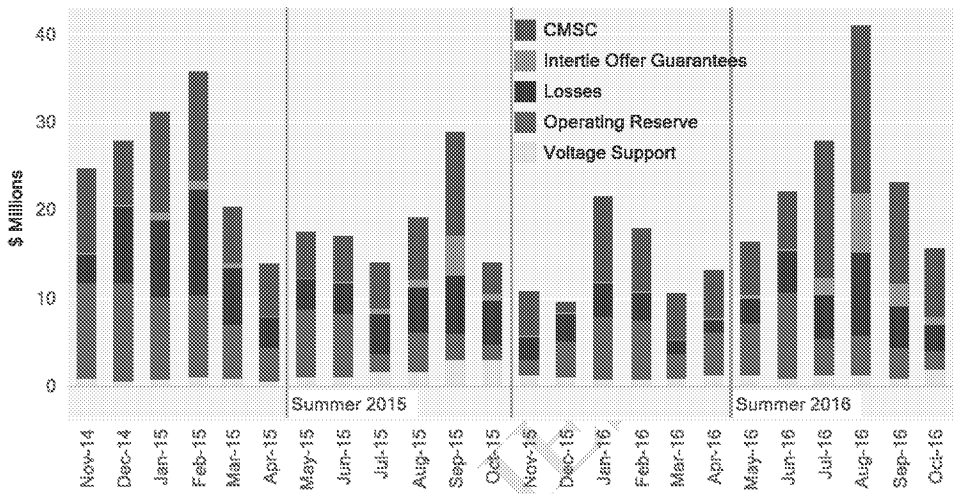
Two GA components, payments to FIT-microFIT-RESOP and payments to Others, increased in Summer 2016 while the remaining four fell. FIT-microFIT-RESOP payments surpassed $300 million/month for the first time in May of 2016. It is expected that these payments will continue to increase as renewable capacity in Ontario continues to grow. The Payments to Others component also reached a new high of $131 million/month during Summer 2016.

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

Description:

Figure 2-11 presents the total hourly uplift charges (Hourly Uplift) by component and month, for the previous two years. Hourly Uplift components include Congestion Management Settlement

Credit (CMSC) payments, day-ahead and real-time Intertie Offer Guarantee (IOG) payments, OR payments, voltage support payments, and losses.



Relevance:

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

Commentary and Market Considerations:

Hourly uplift peaked in August during Summer 2016, primarily driven by an increase in CMSC payments ($18.9 million), Losses ($9.6 million) and IOG ($6.8 million). The increase in payments is largely attributable to higher demand during Summer 2016 when compared to Summer 2015 Period.

Figure 2-12: Total Monthly Uplift Charge by Component and Month

November 2014 – October 2016
($)[9]

Description:

Figure 2-12 plots the total monthly uplift charges (Monthly Uplift) by component and month, for the previous two years. Monthly Uplift has the following components:[10]

- 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.

Relevance:

[9] The Panel has amended the manner in which it classifies monthly uplift charges to more closely align reported costs with the month in which they were incurred rather than the month in which they were settled; this primarily impacts the monthly reported totals for GCG payments. For example, in Figure 2-12 below, all costs submissions to the GCG program for starts occurring between August 11 and September 9, 2015 were settled at the end of September. However, the bulk of the settlements pertain to starts that occurred in August 2015. As such, the Panel reports these costs below to have occurred in August 2015, rather than …September 2015. As a result of this change, monthly totals reported in this report will not match those previously reported by the Panel.

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

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

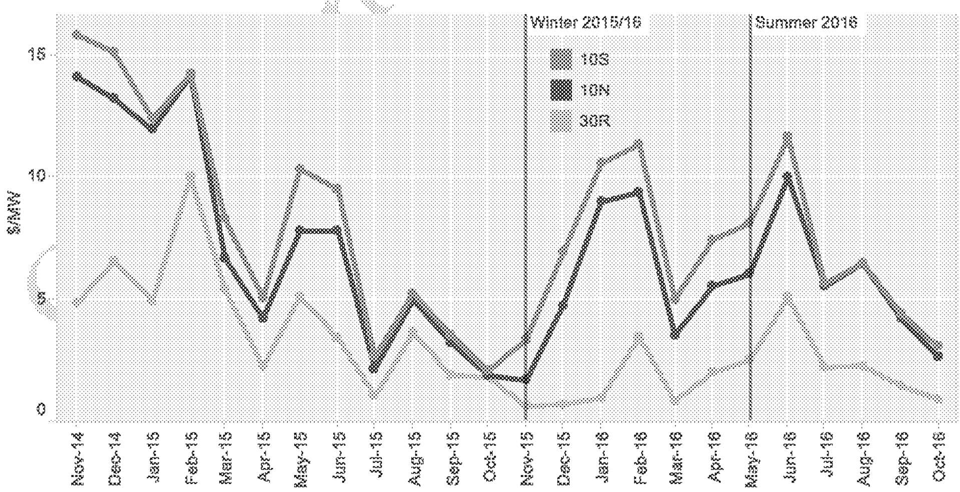
Commentary and Market Considerations:

The total uplifts increased in Summer 2016 due to an increase in guarantee payments to generators. Total DA-PCG payments were $25.9 million in the period, notably higher compared to $15.1 million in Summer 2015 Period. Conversely, RT-GCG payments were lower at $9 million versus $36.3 million in Summer 2015 Period. This is likely a result of generators offering higher costs along with an increase in commitments in the DACP. This issue is discussed further in Chapter 3.

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

Description:

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



Relevance:

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

Resources offer supply into the OR markets just as they offer supply into the energy market; however, OR demand is set unilaterally by the IESO's total OR requirement. The 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 IESO- controlled grid can operate reliably.

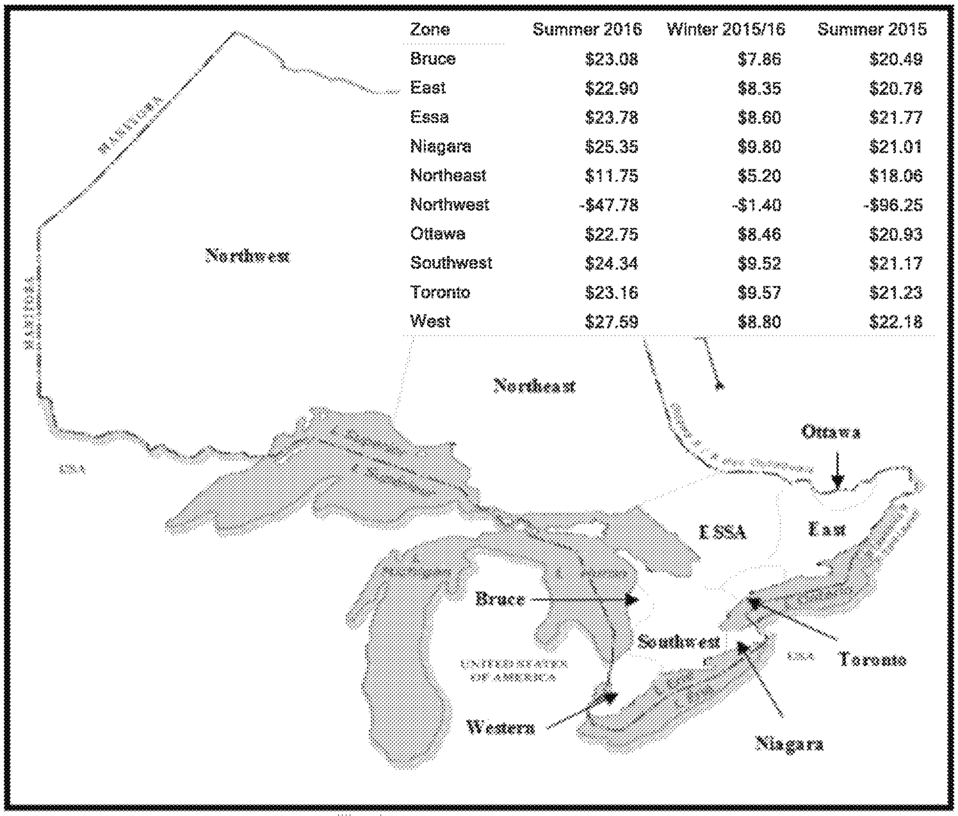
Commentary and Market Considerations:

Combined OR prices were moderately higher when compared to the Summer 2015. Average OR prices for Summer 2016 were \$6.54/MW, \$5.80/MW and \$2.38/MW for 10S, 10N and 30R respectively, compared to \$5.53/MW, \$4.62/MW and \$2.70/MW in the Summer 2015. The high OR prices in June reflect a single high price event occurring within a two hour period. In that case, demand was under forecast and wind resources were over forecast leaving an energy shortfall that could only be met with faster ramping more expensive resources. Since energy and operating reserve are co-optimized, this energy shortfall translated into high OR prices.

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

Description:

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



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

Relevance:

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

Commented [A1]: This may be the case. However, two zones that have identical reserve margins may have much different zonal prices due to the supply mix and associated incremental costs.

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

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

Commentary and Market Considerations:
With the exception of the Northwest, nodal prices within all zones were higher during the Summer 2016 period than in the Summer 2015 period. Higher prices are attributed to hotter summer conditions and increased demand during the period. In general, most nodal prices tend to move together, except when there are outages on major transmission lines. With respect to the Northwest, decreased net exports to Manitoba as noted in Figure 2-26, were likely contributors to the price decrease. Nodal prices are largely affected by demand as can be seen during the Winter 2015/16 period where lower demand translated into lower nodal prices throughout the province.

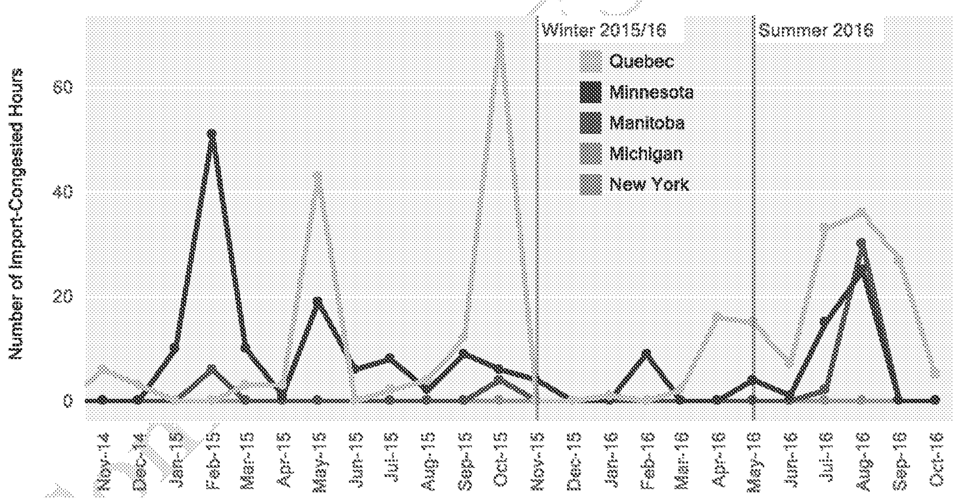
Figures 2-15 & 2-16: Congestion by Interface Group

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

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

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

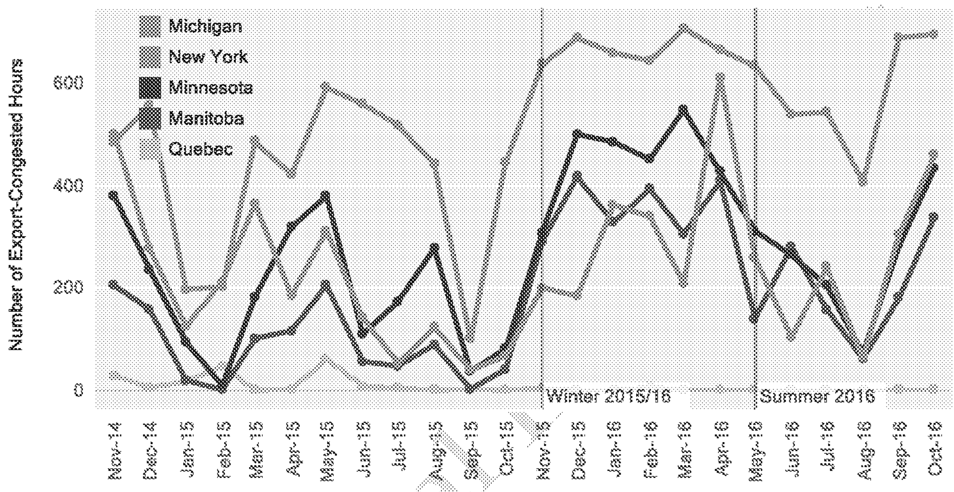
Figure 2-15: Import Congestion by Interface Group
November 2014 – October 2016
(number of hours in the unconstrained schedule)



Commentary and Market Consideration:

As shown by Figure 2-15 import congestion rose between June and August before declining in September and October. These variations were noted at the Manitoba, Minnesota, and Quebec interties. The higher HOEP in Ontario during August was a major cause of the increase in import congestion. As prices in Ontario came down during September and October there were fewer import opportunities available and consequently import congestion decreased.

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



Commentary and Market Consideration:

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

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

Description:

Table 2-3 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA and uplift. Absent congestion at an interface, importers receive, and exporters pay, the HOEP when transacting in Ontario.

The external prices reported are the real-time location-marginal prices ("LMPs") that correspond with the node on the other side of Ontario's interface with each jurisdiction. A proxy price was calculated for Québec as it does not operate a market; Québec typically acts as an intermediary for Ontario power to be exported to either New York's or New England's markets.

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

All prices listed for each jurisdiction reflect the marginal price of energy. Costs associated with capacity, such as Ontario`s global adjustment or NYISO, PJM, or MISO`s capacity markets, are not considered in inter-jurisdictional trade.
* The Panel assumed that the real-time LMPs published by MISO, NYISO and PJM at nodes at the respective interfaces are representative of the external prices at the interface.

Relevance:
One objective of energy trading is to exploit arbitrage opportunities. Intertie traders attempt to purchase (export) low-priced power from one jurisdiction and sell (import) that power to another jurisdiction at a higher price to capture the price differential.[11] Note that traders are not exposed to the GA cost which is a component of the effective price in Ontario.

Price differences between jurisdictions can change from one hour to the next due to changes in any of the numerous factors which determine demand (e.g. weather) and supply (e.g. outages). Changes in the price differential will impact the direction of energy trade between those jurisdictions. Energy trade may not always flow from jurisdictions with low prices to jurisdictions with high prices; imperfect information, timing issues and rapidly changing

[11] Differences exist in terms of the specific costs that are included in the spot price of electricity between jurisdictions. For example, in Ontario, the HOEP is not reflective of a gas-fired generation unit's start-up costs, as these costs are a component of uplift, which is settled out-of-market. The specific components that comprise the spot price will vary from jurisdiction to jurisdiction, but they are still the most accurate and readily available indicators of economic decision making in real-time for intertie traders.

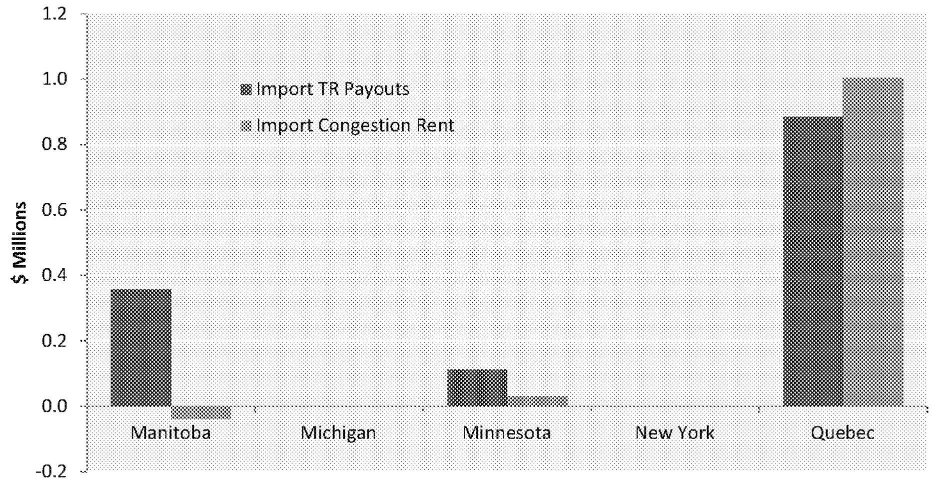
conditions can lead to energy trade that appeared efficient beforehand but are inefficient or unprofitable afterward. However, average prices over longer time horizons are informative on trends in the direction of energy trade between jurisdictions. Over the course of a month if the average energy price in Ontario is lower than another jurisdiction, energy trade should flow from Ontario to that jurisdiction in that month on a net basis.

As discussed in the Relevance section for Figures 2-15 and 2-16, importers and exporters in Ontario do not receive or pay the HOEP if congestion exists at an interface in a given hour. Congestion can erode or even reverse the original arbitrage opportunity between the HOEP and the external jurisdiction's price. However, the HOEP and the spot price in the external jurisdiction remain two key pieces of information in determining whether to import to or export from Ontario..

Commentary and Market Considerations:
In line with observations from Figures 2-15 and 2-16, Ontario's HOEP was significantly lower than the energy price in all of the surrounding jurisdictions; hence it was a net exporter during Summer 2016.

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

Description:
Figure 2-17 compares the total collection of import congestion rent to total payouts under transmission rights (TRs) by interface group for Summer 2016.



Relevance:

As discussed in the relevance section associated with Figures 1-15 and 1-16, an intertie zonal price is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 Ontario price and the PD-1 intertie zonal price. While the importer is paid the lesser intertie zonal price, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer is known as import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TR Clearing Account). This account is discussed in greater detail in the Relevance section associated with Figure 2-19.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold on the basis of intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or "payout") equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR. TRs therefore allow an intertie trader to hedge against congestion-related price fluctuations by ensuring that intertie traders are settled on the HOEP and not the intertie zonal price. An intertie trader that holds the exact same amount of import TRs as the amount of energy they are importing is perfectly hedged against congestion, as TR payouts will exactly offset price differences between the Ontario price and the price in the intertie zone. Payouts to TR holders are disbursed from the TR Clearing Account.

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

In addition to congestion rent collected and TR payouts, there is a third input to the TR Clearing Account—TR auction revenues. TR auction revenues are the proceeds from selling TRs (a payment into the TR Clearing Account). Due to Ontario's two-schedule price system,[12] 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.[13] In that context, every dollar of congestion rent shortfall represents a dollar that does not accrue to the benefit of Ontario customers. The IESO has recently made changes to its TR auction process to address recurring congestion rent shortfalls, which is discussed further in the Relevance section associated with Figure 2-19.

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

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

Note that interties with a high frequency of import congestion hours (see Figure 2-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

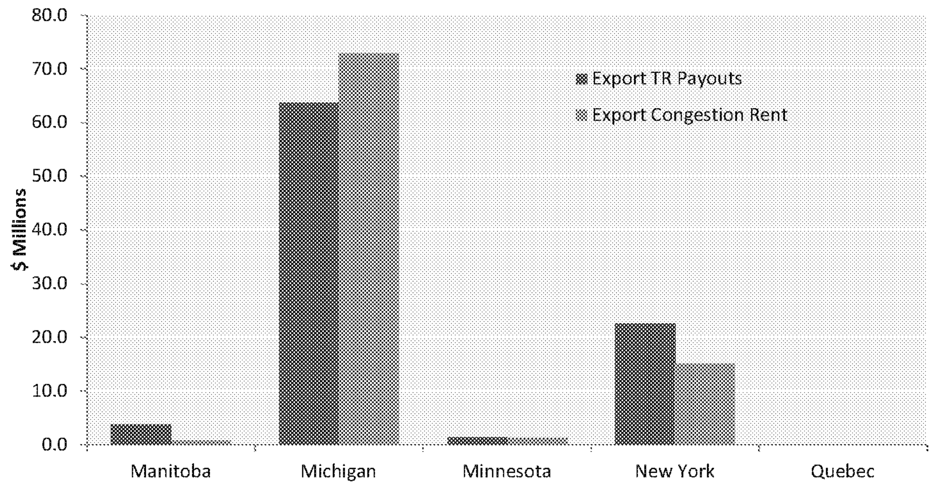
Commentary and Market Consideration:

Across all interfaces, TR payouts were in excess of import congestion rents by $1.6 million in Summer 2016. TR payouts exceeded rents primarily at the Quebec interface as it was the most heavily import congested interface (see Figure 2.15) and, during times of congestion, the intertie capacity occasionally fell causing congestion rents to fall short of the amounts needed to offset TR payouts.

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

Description:

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



Relevance:

When there is export congestion, an intertie zonal price is more than the Ontario price. See the Relevance section associated with Figure 2-17 which describes the relationship between congestion rents and TR payments in regards to import congestion. The relationship between congestion rents and TR payments for export congestion is the converse of that for import congestion. In general, if there are less congestion rents collected, there is a congestion rent shortfall (and the TR Clearing Account balance decreases); if there are more congestion rents collected than TR payments, there is a congestion rent surplus (and the TR Clearing Account balance increases).

Commentary and Market Consideration:

Across all interfaces, export payouts were in excess of congestion rent by $1.5 million. The Michigan interface, which was the most heavily export congested interface in Summer 2016 (see Figure 2-16), saw congestion rents exceeding payouts by $9.1 million while conversely the New York interface saw TR payouts exceeding congestion rents by $7.5 million. The Michigan export path also saw the highest Transmission Rights long term auction MCP to date during the period indicating auction participants were anticipating current levels of congestion to continue.

Manitoba experienced a shortfall in congestion rents of $3.1 million. Manitoba also experienced the highest rate of export failures during Summer 2016 (see Table 2-6) which contributed to the under collection of congestion rents. If a scheduled export transaction fails in an hour where congestion existed, congestion rent goes uncollected as no energy is purchased, though the transaction contributed to congestion at the interface in pre-dispatch.

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

Description:

Table 2-4 lists the average auction prices of 1 MW of long-term (year-long) TRs sold for each interface, in either direction, since November 2015 (these TRs would have been valid during Summer 2016).

Direction	Auction	Period TRs are	Manitoba	Michigan	Minnesota	New	Quebec

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

Relevance:

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

Commentary and Market Consideration:

With the exception of Quebec interface, long-term export TR prices increased in each auction over the period indicating that TR holders expected export congestion on the interties would not only persist but likely increase through to the summer of 2017. In the auctions held from November 2015 to August 2016, the highest export TR prices occurred for the Michigan interface reaching $113,934/MW; significantly higher when compared with the price of $72,534 in the auctions for long term export TR's in the period November 2014 to August 2015.

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

Description:

Table 2-5 lists the auction prices for 1 MW of short-term (month-long) TRs sold at each interface, in either direction, during Summer 2016 and Previous Reporting Period.

Direction	Period TRs are	Manitoba	Michigan	Minnesota	New York	Quebec

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

Relevance:

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

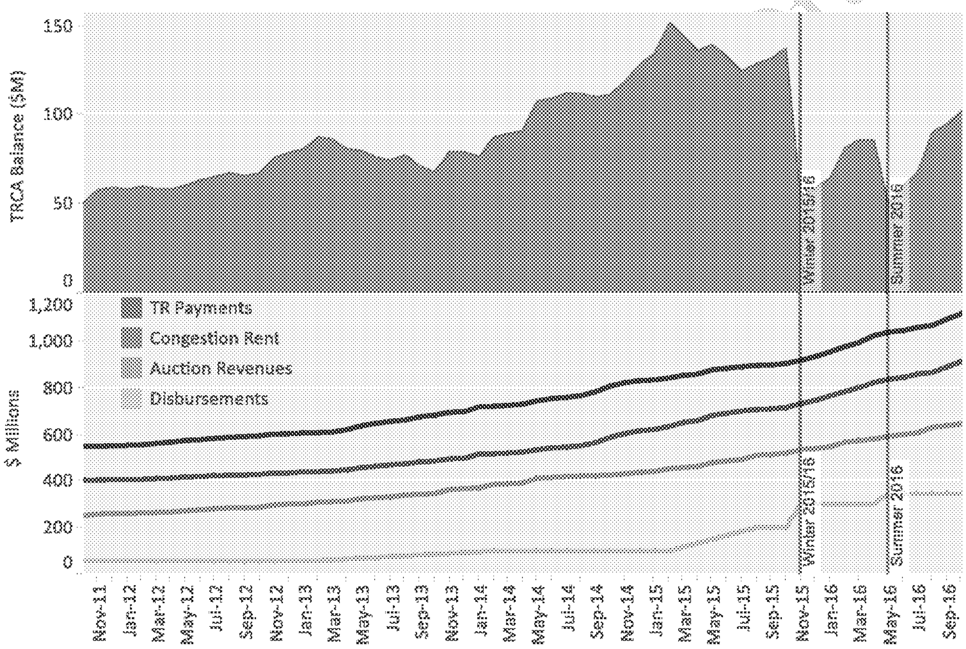
Commentary and Market Consideration:

Short-term auction prices in Summer 2016 were reflective of the relative frequency of congestion experienced at each interface. Michigan had the most frequently congested interface and the highest TR prices throughout Summer 2016 (see Figure 2-16).

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

Description:

The TR Clearing Account is an account administered by the IESO to record various amounts relating to TRs. Figure 2-19 shows the estimated balance in this account at the end of each month for the previous five years.



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

Relevance:

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

<u>Credits</u>

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

Debits

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

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

Commentary & Market Considerations:

In Summer 2016, the balance in the TR Clearing Account increased by $16.9M, from $85.53M at the end of Winter 2015/16, to $102.45M, more than $82.45M million above the Reserve Threshold.[14]

This change was composed of:

- $156 million in revenue
    - $91M in congestion rent collected
    - $64.8M in auction revenues
    - $0.2M in interest
- $139.1 million in disbursements
    - $94.1M in TR payments to rights holders
    - $45M in disbursement to Ontario consumers

When compared to Winter 2015/16, total revenue fell by $12.3 million due to lower congestion rents which fell by $16 million. The fall in congestion rents was offset by rising TR auction revenues which moved up $3.8 million due to higher TR Auction clearing prices.

2 Demand

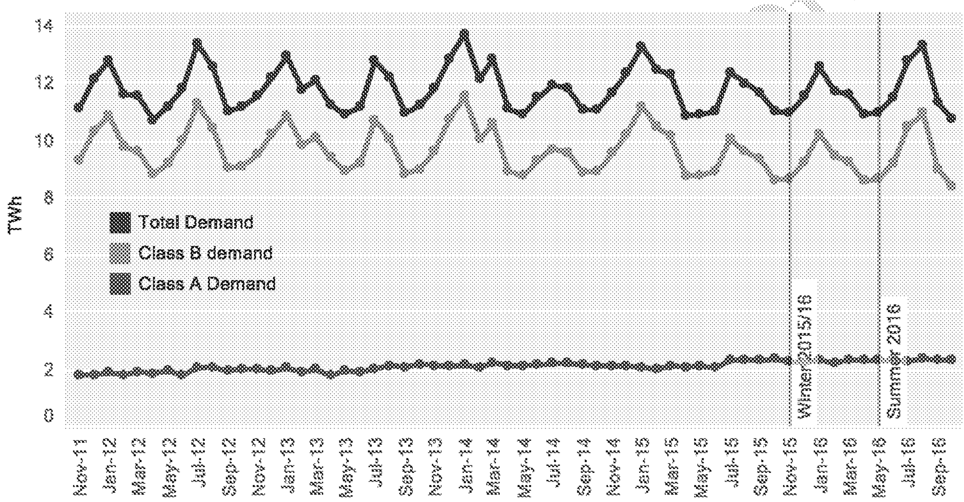
This section discusses Ontario energy demand for Summer 2016 relative to previous years.

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

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

Description:

Figure 2-20 presents energy consumption by all Ontario consumers in each month in the past 5 years represented by the demand of Class A and Class B consumers. The figure represents Ontario demand that includes demand satisfied by behind-the-meter (embedded) generators[15].



Relevance:

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

Commentary and Market Consideration:

The monthly peak consumption during Summer 2016 was 13.35 TWh, which was the highest monthly peak since the Winter 2014 Period. Similarly, overall demand of 70.71.19 TWh was

[15]Monthly Embedded Class A consumption data may be slightly understated as available data does not identify the quantity of behind-the-meter generation by consumer class. For more information, see pages 105-109 of the Panel's April 2015 Monitoring Report, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf

also highest since the Winter 2014 Period. Above normal temperatures in Summer 2016 were the principal factors driving overall demand up 1.34 TWh higher than in Winter 2015/16.

Seasonal changes in Ontario demand are attributed almost entirely to Distribution Level Consumers, which include residential, small and medium commercial, and small industrial loads. Demand from Grid-connected consumers, a group primarily composed of industrial loads and large commercial consumers, exhibit little of the seasonality evident of distribution-level consumption. The consumption for Grid-connect consumers fell slightly in the period.

3 Supply[16]

During the second and third quarters of 2016, 119 MW of nameplate generating capacity completed commissioning and was added to the IESO-controlled grid's total installed generator capacity. This new grid-connected capacity consisted of gas (0.8 MW), wind (99.3 MW) and hydro (18.9 MW) generation. At the end of the third quarter of 2016, grid connected generation capacity totalled 36,070 MW, consisting of nuclear (12,978 MW), gas-fired (9,934 MW), hydroelectric (8,451 MW), wind (3,923 MW), biofuel (495MW) and solar generation (280 MW)[17].

During the second and third quarters of 2016, 146 MW of nameplate IESO contracted generating capacity was added at the distribution level. This new distribution-level capacity (or 'embedded' capacity) consisted of solar (50 MW), wind (36 MW), gas-fired and combined heat and power (46 MW) and energy from waste (14 MW). At the end of the third quarter of 2016, IESO contracted embedded capacity totalled 3,119 MW, consisting of solar (1,926 MW), wind (534 MW), hydroelectric (268 MW), gas-fired and combined heat and power (259 MW), biofuel (108 MW) and energy from waste (24 MW)[18].

Figure 2-21: Resources Scheduled in the Real-Time Market (Unconstrained) Schedule by Reporting Period

[16] For a more detailed examination of the medium-term supply capacity in Ontario, see the IESO's 18-month outlook, released in December 2017 and available at: http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlook_2016dec.pdf?la=en

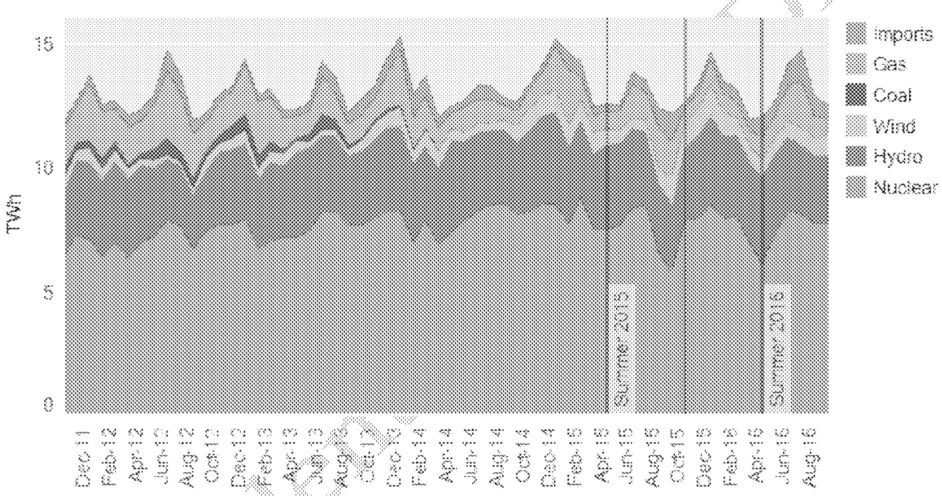
[17] Capacity totals were obtained from the IESO 18 month outlook reports which can be found at: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook.

[18] Embedded capacity totals were obtained from the Ontario Energy Board's quarterly Ontario Energy Reports. Added embedded capacity totals were calculated from 2015's Q1, Q2 and Q3 reports, which can be found at: http://www.ontarioenergyreport.ca/index.php.

November 2011 – October 2016
(TWh)

Description:

Figure 2-22 illustrates the cumulative share of energy in the real-time unconstrained schedule from November 2011 to October 2016 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear, and imports. Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time.



Relevance:

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

Commented [A2]: It may be helpful to be more specific on what is meant by energy policy.

Commentary and Market Considerations:

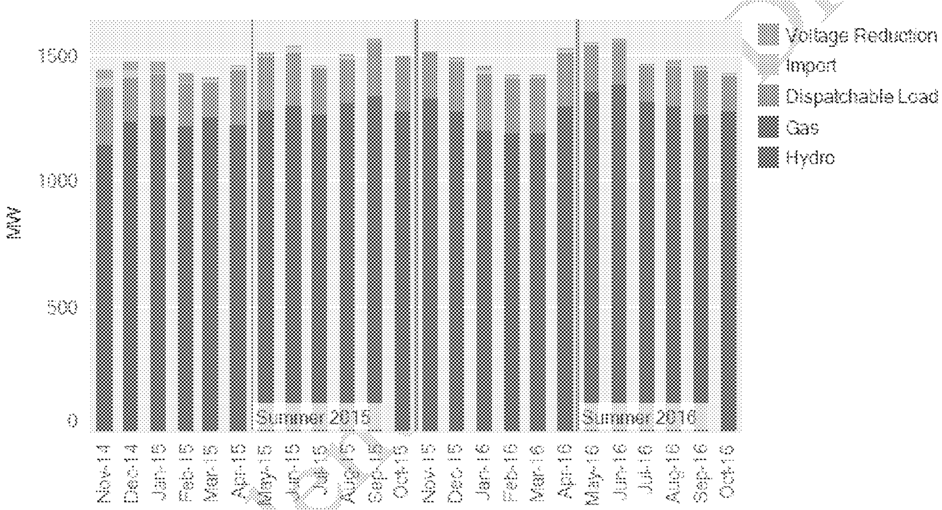
Comparing Summer 2016 to the Summer 2015, overall output increased by nearly 2 TWh. Nuclear output rose 0.99 TWh while both hydro and gas fell 0.39 TWh and 0.44 TWh respectively. Wind output and imports increased 0.44 TWh and 1.58 TWh respectively.

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

Description:

Figure 2-22 plots the average hourly amount of OR in the unconstrained schedule from November 2014 to October 2016 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads and voltage reduction[19]. Changes in the total average hourly operating reserve scheduled reflect changes in the OR quantity requirements.

Commented [A3]: Is this referring to CAOR? If yes, CAOR includes voltage reduction and other control actions.



Relevance:

This figure reflects the evolution in Ontario's changing mix for OR supply as well as changes in the OR requirement over time. Changes in scheduled OR may result from a variety of factors

[19] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only used in real-time, never in pre-dispatch. Voltage reduction 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.

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[20].

Commentary and Market Considerations:

The amount of OR scheduled in Summer 2016 (6.6 TWh) increased relative to Winter 2015/16 (6.4 TWh) but slightly decreased relative to the Summer 2015 (6.7 TWh). Hydroelectric resources supplied 53.3% of all OR, followed by gas-fired resources and dispatchable loads at 34.8% and 11.1%, respectively. Imports, biofuel and voltage reduction comprised the remainder of the OR supply mix, together contributing less than 1% of the total OR supply.

When compared to the Summer 2015, the amount of OR supplied by gas-fired resources increased by 6.8% while the amount supplied by hydroelectric and dispatchable load resources combined fell by 6%.

Figure 2-23: Unavailable Generation Relative to Installed Capacity November 2014 – October 2016 (% of capacity)[21]

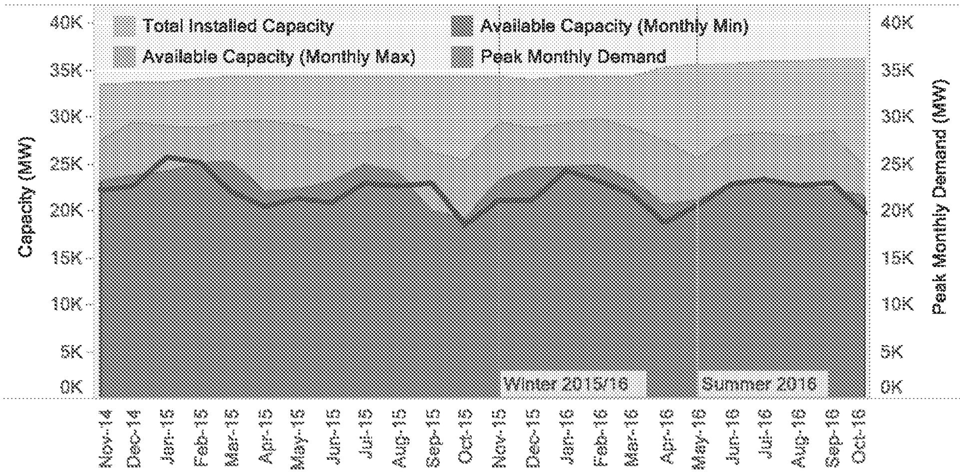
Description:

Figure 2-24 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and derates, along with unavailable capacity from intermittent, self-scheduling and transitional generators, and constrained generation capacity due to operating security limits. The figure also includes the monthly peak market demand, excluding imports, for reference., as a percentage of total grid-connected installed generation capacity from November 2014 to October 2016[22].

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

[21] In Previous Panel Reports, Figure 2-23 reported planned and forced outages and derates relative to capacity. The Panel has decided to report on all unavailable generation capacity. As such, the data reported in Figure 2-24 will not align with similar data published in previous Panel Reports for the period of November 2013 through April 2015. The Panel did this intentionally as it has revised the methodology by which it reports on unavailable generation capacity to also include unscheduled capacity from self-scheduling resources and capacity that is made unavailable due to security limits on the high-voltage grid, in addition to planned and forced outages and derates.

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



Relevance:

Statistics regarding unavailable generation capacity provide an overview of how much of the time facilities in the province were able to provide supply, a key factor in the determination of market prices.

Commentary and Market Considerations:

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

4 Imports, Exports and Net Exports

The data used in this section is based on the unconstrained schedules as these directly affect market prices. The unconstrained schedules may not reflect actual power flows.[23]

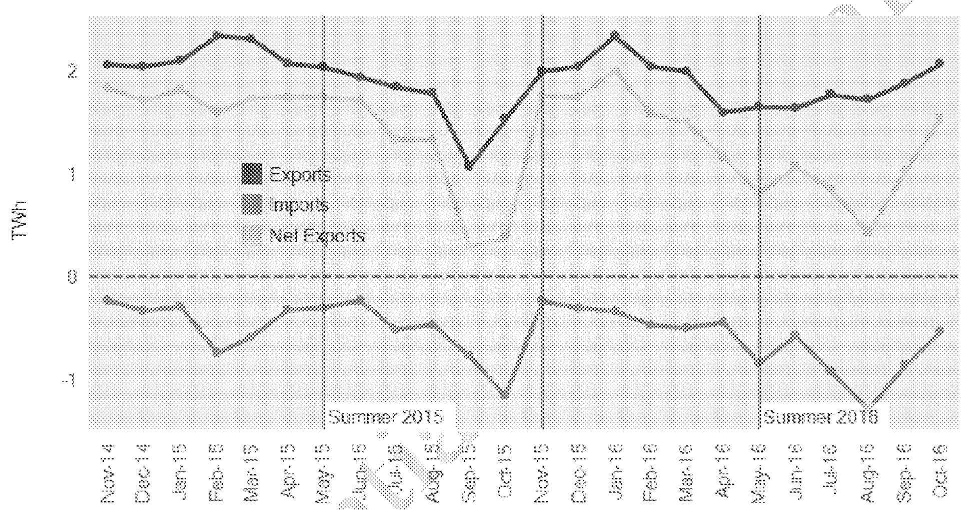
Figure 2-24: Total Monthly Imports, Exports & Net Exports (Unconstrained Schedule)

[23] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not provide information on intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).

November 2014 – October 2016
(TWh)

Description:

Figure 2-25 plots total monthly energy imports, exports and net exports from November 2014 to October 2016. Exports are represented by positive values while imports are represented by negative values.



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 Summer 2016, 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.

Commented [A4]: This may be the case, but could also be simply a function of the types of resources setting price rather than scarcity.

Commentary and Market Considerations:

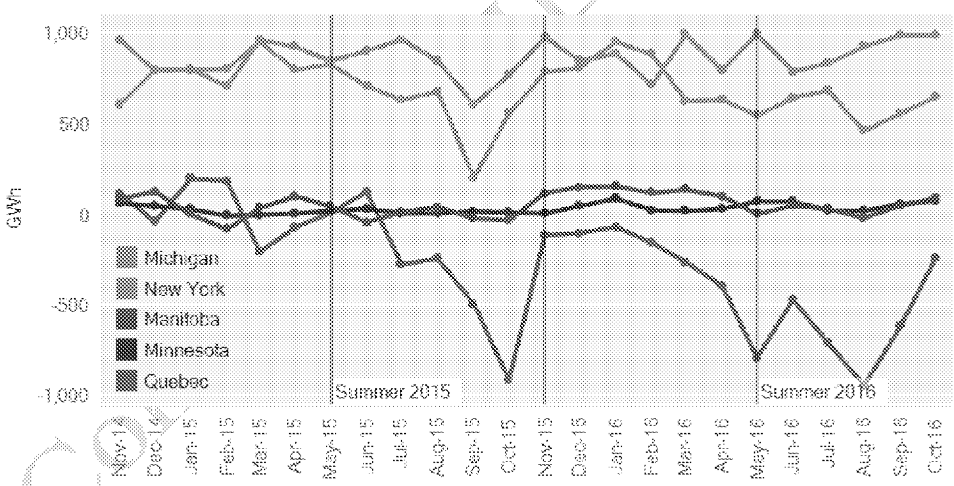
Ontario was a net exporter in each month of Summer 2016, totalling 5.742 TWh. This was lower than the Summer 2015 where the net export total was 6.798 TWh. July and August held the lowest monthly net export totals in Summer 2016 at 0.855 TWh and 0.436 TWh respectively.

August is when imports reached their highest monthly total of 1.287 TWh. Similar to the Summer 2015, Quebec was the primary source of imports.

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

Description:

Figure 2-26 presents a breakdown of net energy exports from November 2014 to October 2016 to each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. Net exports are represented by positive values while net imports are represented by negative values.



Relevance:

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

Commentary and Market Considerations:

During Summer 2016, both the Quebec and Michigan interface monthly totals reached a two year high. Quebec was a net importer delivering a high of 945.99 TWh in August and Michigan net exports reached a high of 992.85 TWh in May while nearly achieving that high again in August and September.

Compared to the Summer 2015, net exports at Michigan, Minnesota, Manitoba and New York interfaces were all higher, together increasing by 786 TWh while net imports from Quebec more than doubled with 1,862 TWh flowing across the interface. Despite the increase in imports and exports in Summer 2016, net exports fell by 1076 TWh.

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

Description:

Table 2-6 reports average monthly export curtailments and failures over the Current and Previous Reporting Periods by interface group and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each interface, excluding linked wheel transactions.[24]

Interface Group	Average Monthly Exports GWh		Average Monthly Export Failure and Curtailment GWh				Export Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	277.8	386.3	1.0	1.8	5.7	8.3	0.4	0.5	2.0	2.1
Michigan	326.3	348.1	1.4	1.5	4.7	3.2	0.4	0.4	1.4	0.9
Manitoba	50.6	79.9	3.7	2.6	14.8	16.3	7.2	3.2	29.1	20.4
Minnesota	20.4	6.0	0.6	0.2	0.5	0.2	2.7	2.7	2.6	3.7
Quebec	60.6	93.2	0.6	4.2	0.4	1.3	1.1	4.5	0.7	1.4

Relevance:

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

Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure), on the other hand, refers to a transaction that fails due to a failure on the part of a market participant (such as an inability to obtain transmission service).

MP failures and ISO Curtailments in respect of exports reduce demand between the hour-ahead pre-dispatch schedule and real-time. These short-notice changes in demand can lead to a sub-optimal level of intertie transactions given the market prices that prevail in real-time, and may contribute to SBG conditions. The IESO may dispatch down domestic generation or curtail imports to compensate for MP Failures or ISO Curtailments.

Commentary and Market Considerations:
As in both Winter 2015/16 and the Summer 2015, the Manitoba interface continues to experience the highest percentage of MP Failures: 29.1% in Summer 2016 vs. 20.4% in Winter 2015/16 and 31.1% in the Summer 2015.

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

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

Interface Group	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate %			
			ISO-Curtailment		MP-Failure		ISO-Curtailment		MP-Failure	
	Current	Previous	Current	Previous	Current	Previous	Current	Previous	Current	Previous
New York	20.9	1.4	0.1	0.0	0.2	0.1	0.4	0.6	1.1	3.8
Michigan	5.9	1.2	0.1	0.2	1.6	0.4	1.1	16.6	27.5	34.7
Manitoba	28.4	34.8	5.6	5.9	0.4	0.3	19.7	16.9	1.3	0.8
Minnesota	2.0	8.2	0.1	0.9	0.2	0.7	7.4	11.5	11.8	8.8
Quebec	196.5	85.7	2.5	2.6	0.2	0.1	1.3	3.1	0.1	0.1

Relevance:

MP Failures and ISO Curtailments in respect of imports represent a reduction in supply between the hour-ahead pre-dispatch schedule and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for MP Failures and ISO Curtailments.

Commentary and Market Considerations:

The average monthly imports through the Quebec interface has increased to 196.5 GWh significantly higher than in Winter 2015/16 and the Summer 2015 where imports were 85.7 GWh and 136.1 GWh respectively. Despite the increase, curtailments quantities and rates on the Quebec interface were lower than in the previous two periods.

Michigan continues to experience a high MP-Failure curtailment rate of 27.5% on relatively low volume. This is less than Winter 2015/16 where the rate was 34.7%. When compared to the Summer 2015, average monthly import volume at 5.4 GWh was the same as in Summer 2016 however the MP-Failure curtailment rate was less than half at 13.1%.