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

Market Surveillance Panel Report 33

MONITORING REPORT ON THE IESO-ADMINISTERED ELECTRICITY MARKETS

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board (OEB). Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The Panel monitors, evaluates and analyzes activities related to the IESO-Administered Markets and the conduct of Market Participants to identify:

1. *inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;*
2. *activities of the IESO that may have an impact on market efficiencies or effective competition;*
3. *actual or potential design or other flaws and inefficiencies in the Market Rules and procedures; and*
4. *actual or potential design or other flaws in the overall structure of the IESO-Administered Markets and assess consistency of that structure with the efficient and fair operation of a competitive market.*

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations. The Panel does not have the legislative mandate to impose sanctions or other remedies in response to inappropriate conduct or market defects, but it does make recommendations for remedial action as it considers appropriate.

Executive Summary

This is the 33rd Market Surveillance Panel Monitoring Report published since market opening in 2002. The report includes a discussion of current issues with the market that the Panel recommends be addressed (Chapter 3). The report also notes recent electricity sector events (Chapter 1), as well as historical events for the monitoring period May 1, 2018 to October 31, 2018 – referred to as the Summer 2018 Period (Chapter 2 and Appendix A).

This Monitoring Report is broken down into three chapters and an appendix:

- Chapter 1: Market Developments and Status of Recent Panel Recommendations
- Chapter 2: Analysis of Anomalous Market Outcomes for the Summer 2018 Period
- Chapter 3: Matters to Report in the Ontario Electricity Marketplace
- Appendix A: Market Outcomes for the Summer 2018 Period

Chapter 1: Market Developments and Status of Recent Panel Recommendations

Two recent market developments are considered noteworthy by the Panel: the IESO's review of resource adequacy-related reliability standards and the IESO's decision to defer the capacity auction. Responses from the IESO to previous Panel recommendations are also presented.

Chapter 2: Analysis of Anomalous Market Outcomes for the Summer 2018 Period

The IESO's Real-Time Generation Cost Guarantee program (RT-GCG) has been the subject of analysis and recommendations by the Panel in the past. In this report, the Panel returns to an earlier concern relating to instances where a generation unit that qualifies for the RT-GCG program comes online, goes offline for a period of time and then re-starts for a second RT-GCG run in the same day. This is referred to as "Two-Shifting", and results in unnecessary costs if the cost of shutting down a generation unit only to restart it later the same day exceeds the cost of keeping the unit online at its Minimum Loading Point. The Panel is of the view that if a unit is required for two (or more) times in a day, the RT-GCG payments associated with these additional requirements should not exceed the estimated costs of keeping the unit at its Minimum Loading Point.

<u>Recommendation 2-1</u>: The IESO should eliminate the payment for start-up costs for second and subsequent RT-GCG runs in a day. Alternatively, when a generation unit has participated in the RT-GCG program once during a day, the IESO should consider ways to have the generation unit compensated on the basis of the lesser of the second and subsequent submitted start-up costs or the estimated cost of keeping the generation unit online between RT-GCG runs.

In addition, the Panel observed that in 2018 there were a number of instances in which the submitted costs of the second RT-GCG run were equal to or higher than the submitted costs of the first run. In the normal course, one would expect the costs of a second RT-GCG run that occurs within a short time after the first one should be lower than the cost of a cold generation unit starting at the beginning of the day.

<u>Recommendation 2-2</u>: The IESO should conduct an audit of RT-GCG cost submissions in situations when a generation unit has a second RT-GCG run within three hours of its first RT-GCG run and the submitted costs of the second run are equal to or higher than the submitted costs of the first run.

Simultaneous Activation Reserve (SAR) is a program between neighboring jurisdictions which allows for member jurisdictions to call on neighbours to provide reserve in the event of a significant and unexpected loss of supply. In this report, the Panel examines the activation of SAR in response to outages at the Pickering Nuclear Generating Station (PNGS) and identifies concerns with the impact that the activation of SAR can have on market prices.

In the summer of 2018, two outages were experienced at the PNGS, a 3,100 MW capacity facility that represents nearly 10% of all grid-connected capacity. The first occurred on July 22 and was a result of algae bloom in Lake Ontario. The algae bloom forced a sudden shutdown of the four Pickering B units, removing nearly 2,000 MW of energy (about 12% of all energy in Ontario at that time) in a matter of minutes, resulting in a more than 18-fold increase in the Hourly Ontario Energy Price. The price spike, however, was not sustained as this contingency led to the activation of SAR. By design, SAR suppresses energy prices at a time when, from the Panel's perspective, the prices should have remained elevated to signal a supply shortage. The Panel recommends that the IESO address this issue of price suppression by treating SAR activations as it does emergency imports.

<u>Recommendation 2-3</u>: The IESO should treat SAR activations in much the same way as it treats emergency imports; namely, by adding demand back in to the unconstrained schedule.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

Ontario is moving towards a more market-based mechanism for procuring capacity. Recently, the IESO has been developing a capacity market, emphasizing the need for a stable process with clear and transparent information. In this report, the Panel examines the IESO's capacity planning and need assessment processes and identifies aspects that could be improved while still adhering to reliability standards.

The Panel notes that the IESO is inconsistent in its treatment of economic import assumptions. If some level of economic (i.e., non-firm) imports is assumed to be available to meet peak demand, the need to procure firm resources in Ontario would be reduced. Studies by the Northeast Power Coordinating Council demonstrate that significant support from economic imports can reasonably be assumed, and the IESO should integrate consideration of economic imports into its capacity planning process. The IESO should also reconcile, or at least explain, differences in the assumptions that underlie its different resource adequacy and planning documents.

<u>Recommendation 3-1</u>

The IESO should produce a report that probabilistically assesses the level of economic (i.e. non-firm) imports that would be appropriate to assume in their various resource adequacy studies for each year in the planning timeframe, with stakeholder input, using the Northeast Power Coordinating Council Review of Interconnection Assistance Reliability Benefits study as a reference.

<u>Recommendation 3-2</u>

The IESO should better align the assumptions used in planning documents on an ongoing basis or explain in detail the reason for remaining differences, with quantities. This should address, at a minimum, differences in economic import assumptions and different weather scenarios that lead to different capacity need outcomes.

The Panel is supportive of the IESO's initiative of opening up the planning process to stakeholders, and believes that the IESO should explore opportunities to enhance the engagement of stakeholders in that process. Stakeholder feedback to date indicates a desire for more granular data, greater clarity on the methodology and increased transparency in relation to resource adequacy assumptions. In the Panel's view, greater transparency is needed in relation to how capacity needs are determined and procurement targets are justified, and on the IESO's plans for evolving capacity auctions. Greater transparency will send clearer market signals to better support informed investment decisions by relevant stakeholders.

<u>Recommendation 3-3</u>

The IESO should examine and report on potential improvements to its communications with stakeholders regarding the process(es) used to assess the need for and procure resources to meet future capacity needs. The IESO should also provide greater clarity regarding the documents used to inform those procurements and how any auction or procurement targets are set. In particular:

- ***the IESO should publish the analysis and methodology for the Reliability Assurance concept, which appears to be the basis for procuring capacity for the Capacity Auction scheduled for the winter of 2020/21; and***
- ***the IESO should explain the purpose of the Reliability Outlook, including a clear indication of which sections of that report may be used for outage planning, which sections (if any) may be used to inform procurements, and which sections have been included for informational purposes only.***

Recommendation 3-4

The IESO should periodically make available clear descriptions of the range of potential resources that may need to be procured, including the volume (MW), timelines, any required characteristics other than capacity (e.g. energy, ramp, etc.) and expected procurement mechanism (e.g. through capacity auctions, and/or alternative mechanisms) as part of its communication of future capacity needs in reports such as the Annual Planning Outlook.

Recommendation 3-5

The IESO should signal its confidence in different planning assumptions by publishing the uncertainty values associated with relevant assumptions and elements used to calculate the capacity need, including at a minimum a range of economic imports and a range of possible demand forecasts based on underlying economic drivers.

Recommendation 3-6

The IESO should examine and report on potential improvements to its stakeholder engagements regarding the methods and assumptions used to develop capacity needs. Specific consideration should be given to a periodic streamlined process to review the case for procuring existing or new resources that involves stakeholders and is overseen by an objective third party.

The Panel acknowledges that the IESO has recently taken steps towards addressing some of the issues identified by the Panel in respect of the capacity planning and need assessment process.

Chapter 1: Market Developments and Status of Recent Panel Recommendations

This chapter contains an update on recent developments related to the IESO-Administered Markets and provides commentary on the IESO's responses to recommendations contained in the Panel's previous semi-annual Monitoring Report.

1.1 Developments Related to the IESO-Administered Markets

This section summarizes developments related to the IESO-Administered Markets that the Panel considers noteworthy.

1.1.1 Review of Resource Adequacy-Related Reliability Standards by the IESO

In January 2020, the IESO published its Annual Planning Outlook (APO), followed by a stakeholder presentation on February 19, 2020 as part of an associated Technical Planning Conference. One of the presentations was the "Review of Resource Adequacy-Related Reliability Standards", which requested feedback.

The Market Surveillance Panel (Panel) submitted comments on this topic.

The Panel supports the review of the assumptions used in the application of Resource Adequacy-Related Reliability Standards, specifically the proposed inclusion of economic (i.e. non-firm) imports.

Currently, in the APO, the IESO assumes 0 MW of economic imports will be available. However, the IESO does rely on economic imports for other assessments of resource adequacy, and the analysis outlined in the most recent Northeast Power Coordinating Council

(NPCC) report on Interconnection Assistance Reliability Benefits indicates that there may be significant amounts of economic imports available to Ontario to address resource adequacy.[1]

This could considerably reduce the amount of capacity that would need to be procured, and reduce electricity system costs. The Panel encourages the IESO to include an appropriate level of non-firm imports in its resource adequacy analysis.

This review is related to material covered in Chapter 3.

1.1.2 Capacity Auction Deferral

The Capacity Auction planned for June 2020 has recently been deferred by the IESO until the fourth quarter of 2020. The deferral is based on the recent decline in demand brought on by impacts related to COVID-19. This deferral will also allow the IESO to revisit planning forecasts and update capacity needs for 2021.

The IESO also announced that further work on the evolution of the Capacity Auction would be suspended, with a planned review to ensure any enhancements would still add value.[2]

1.2 Status of Recent Panel Recommendations

Below are the recommendations made in the Panel's Monitoring Report 32 (Nov 2017-Apr 2018) published in July 2020 and the IESO's responses to them.[3]

[1] See the NPCC Review of Interconnection Assistance Reliability Benefits, published December 16, 2019: https://www.npcc.org/Library/Interconnections%20Assistance%20Reliability%20Benefits/RCC%20Approved%202019_December_16_Tie_Benefit_Report.pdf

[2] The IESO stated "We are also suspending work on further efforts to evolve the capacity auction and will reassess the value that these previously planned auction enhancements would bring to Ontario ratepayers and power system reliability later this year." For more information, see the IESO Engagement email, "Capacity Auction", sent April 3, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ca/ca-20200403-communication.pdf?la=en

[3] See the letter from Peter Gregg, President and CEO of the IESO, to Robert Dodds, Vice-Chair of the OEB, dated August 20, 2020: https://www.oeb.ca/sites/default/files/IESO-MSP-Ltr-OEB-20200820.pdf

Table 1-1: Status of Recent Panel Recommendations and IESO Responses

Recommendation	IESO Response
Recommendation 3-2 **In order to provide more consistent market outcomes, the IESO should give further consideration to improving how the need for additional system flexibility is addressed, such as specifying the conditions that require intervention and scheduling the required amount of spinning reserve explicitly in the normal OR market. Although it is acknowledged that no industry standard exists to address flexibility, alternative solutions should also be considered to ensure the most suitable approach is used.**	*Response letter re Panel's 32nd Monitoring Report (August 20, 2020)* Although no industry-standard approach exists to address system flexibility using market mechanisms, the IESO has looked at various approaches from other jurisdictions and believes it is on the right track to address system flexibility needs. Since May 24, 2018, the IESO has been explicitly increasing operating reserve (OR) requirements in the current OR market when the need for flexibility arises. OR is scheduled in the market on an economic basis and co-optimized with energy – as such, increasing OR requirements when the need for flexibility arises is a direct way to provide consistent market outcomes. In comparison to the previous IESO practice of manually committing resources for flexibility, scheduling additional OR provides a transparent signal to the market when there is a flexibility need anticipated, and moreover, this need is addressed on an economic basis through a market based solution. Initial assessments of the current flexibility solution were presented to the Market Development Advisory Group at the June 27, 2019 meeting, indicating that the solution results in significant savings in comparison to past practices to meet system flexibility requirements. The IESO agrees with the MSP that it is important to consider improvements to the existing solution and to assess alternative solutions. The IESO has started a review of the existing solution which includes reassessing the criteria utilized for increasing OR for flexibility and, if needed, further clarifying the conditions under which additional flexibility is required. In addition to the review that is underway, the Market Renewal Program – Energy project implementation includes changes that will further increase

	the transparency and efficiency of the flexibility solution where additional OR is scheduled to address flexibility needs. The improvements include specifying the flexibility need in the day-ahead timeframe and better optimization in the pre-dispatch timeframe should resources need to be economically committed for flexibility. The IESO agrees with the Panel on the need to do a fulsome review of the current solution and will consider when that review can be completed and update the Panel by Q4 2020.

1.3 Panel Commentary on IESO Response

The Panel questions certain elements of the IESO's response, given the conclusions set out in the Panel's Monitoring Report 32; namely:

- the interim flexibility solution does not reflect the specific need for spare energy, and since the design is not scalable, the desired product cannot be efficiently priced and acquired;
- the interim flexibility solution is not consistently effective; and
- out-of-market actions continue, and in fact increased in the year following the implementation of the interim flexibility solution.

The Panel therefore does not agree that the interim flexibility solution provides consistent, effective or economic outcomes. The Panel acknowledges the IESO's commitment to review the existing solution, and looks forward to the implementation of a more transparent and direct solution.

Chapter 2: Analysis of Anomalous Market Outcomes for the Summer 2018 Period

2.1 Threshold Analysis

This section of the report discusses events which exceeded the Panel's thresholds for being considered anomalous. The Panel's analysis of anomalous events focuses on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of significant Congestion Management Settlement Credit (CMSC) payments, Operating Reserve (OR) payments and Intertie Offer Guarantee (IOG) payments, all of which are recovered from Ontario consumers and exporters through uplift charges. The relevant thresholds are outlined in Table 2-1, below.

Unless otherwise noted, the review period relevant to this Chapter is the Summer 2018 Period (May 1, 2018 to October 31, 2018), drawing comparisons to the Summer 2017 Period (May 1, 2017 to October 31, 2017) as appropriate.

Relative to the Summer 2017 Period, the Summer 2018 Period had twice as many high HOEP hours and approximately sixty percent fewer negative HOEP hours. It also had significantly more anomalous IOG payments, whether measured by daily or hourly totals. Other metrics, namely totals for CMSC and OR payments, were relatively similar between the two periods. Table 2-1 and Table 2-2, below, present the comparative statistics as well as the actual dates on which the anomalous events occurred during the Summer 2018 Period. The ensuing discussion explains how the events materialized.

Table 2-1: Summary of Anomalous Events

Anomalous Event Threshold	Number of Events	
	Summer 2018 Period (May 2018-Oct 2018)	Summer 2017 Period (May 2017-Oct 2017)
HOEP > $200/MWh	6	3
HOEP ≤ $0/MWh	687	1,584
Energy CMSC > $1 million/day	3	2
Energy CMSC > $500,000/hour	0	0
OR Payments > $100,000/hour	13	16
IOG > $1 million/day	4	1
IOG > $500,000/hour	12	2

The table above shows the number of anomalous events that occurred during two periods: Summer 2017 Period (May 2017-Oct 2017) and Summer 2018 Period (May 2018-Oct 2018).

Table 2-2: Date and Time of Anomalous Events

High HOEP	Daily CMSC	Hourly CMSC	High OR	Daily IOG	Hourly IOG
May 6 | HE 11		No Events	May 6 | HE 11		
			May 12 | HE 10, 19		
May 15 | HE 8			May 15 | HE 8, 10		
May 29 | HE 16			May 29 | HE 16		
				Jul 1	Jul 1 | HE 14-20
	Jul 4			Jul 4	Jul 4 | HE 15-16
				Aug 9	Aug 9 | HE 8
	Aug 22				
Sep 3 | HE 18	Sep 3			Sep 3	Sep 3 | HE 18-19
			Sep 10 | HE 7		
Sep 13 | HE 18			Sep 13 | HE 18		
			Sep 14 | HE 16		
Sep 30 | HE 10			Sep 30 | HE 10, 16		
			Oct 25 | HE 8		
			Oct 30 | HE 7		

The table above shows the date and time (hour ending, HE) when the anomalous events occurred during the Summer 2018 Period (May 2018-Oct 2018).

2.1.1 Anomalous Prices and OR Payments

Since energy and OR markets are co-optimized, prices in both markets typically move in the same direction.[4] As such, factors contributing to upward pressure on the five-minute Market Clearing Price (MCP), which leads to a high HOEP, also contribute to upward pressure on OR prices, which leads to higher OR payments. Upon reviewing the HOEP and OR-related events, the Panel determined that none warranted a detailed write-up. Instead the Panel has provided a succinct summary of its findings. Table 2-3 below lists the events in questions and identifies the main factors that contributed to each event in which the Panel's threshold was exceeded.

Regarding negative price hours, relative to the Summer 2017 Period, instances of the HOEP being below $0/MWh decreased significantly from 1,584 to 687 hours. In general, this can be explained by higher demand which was a result of higher temperatures during the Summer 2018 Period. Average temperatures increased from 18.8 to 19.6 degrees Celsius between the two periods while total demand increased by 5.6%.

[4] The IESO evaluates bids and offers in the energy market and offers in the OR market simultaneously, satisfying both the total electricity demand and the OR requirements. By utilizing the relative differences in energy and OR offers, the economic gains from trade are maximized across both markets. However, when an additional megawatt is scheduled in one market it become unavailable in the other. This leads to cross-market price effects. For additional information on co-optimization, see the IESO Quick Take: "Joint Optimization of Energy and Operating Reserve", available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/training/QT-Joint-Optimization-of-Energy-and-Operating-Reserve.pdf?la=en

Table 2-3: Causes of Anomalous High HOEP and OR Payments

Event Date	Event Hour Ending	Anomaly[5]		Main Causes
		HOEP	OR	
May 6	11	**$213/MWh**	**$219,143/hr**	-Generator forced outage.
May 12	10	$161/MWh	**$176,805/hr**	-Limited gas generators online.
	19	$143/MWh	**$158,491/hr**	
May 15	8	**$265/MWh**	**$239,129/hr**	-Variable generation shortfall.
	10	$149/MWh	**$156,201/hr**	-Generator forced de-rate.
May 29	16	**$271/MWh**	**$178,244/hr**	-Under-forecast demand. -Failed imports. -Increased operating reserve requirement.
Sep 3	18	**$225/MWh**	$88,688/hr	-High demand due to high temperatures. -Variable generation shortfall. -Generator forced de-rate. -Intertie de-rate. -Failed imports.
Sep 10	7	$146/MWh	**$124,692/hr**	-Limited gas generators online.
Sep 13	18	**$295/MWh**	**$401,519/hr**	-Under-forecast demand. -Variable generation shortfall.
Sep 14	16	$178/MWh	**$180,639/hr**	-Under-forecast demand. -Failed imports.
Sep 30	10	**$236/MWh**	**$164,235/hr**	-Under-forecast demand. -Variable generation shortfall.
	16	$196/MWh	**$141,890/hr**	
Oct 25	8	$183/MWh	**$152,358/hr**	-Control Room Operator optimization tool error.
Oct 30	7	$168/MWh	**$101,224/hr**	-Limited gas generators online. -Variable generation shortfall.

The table above lists the factors contributing to anomalous high HOEP and/or OR payments for each relevant event.

[5] Bolded HOEP and OR payment figures exceed the thresholds for being considered anomalous by the Panel. HOEP below $200/MWh and OR payments below $100,000/hour are not considered anomalous by the Panel. In instances when these figures are included in this table, it is done so to give context to the anomalous figures appearing in the same hour.

2.1.2 Anomalous CMSC Events

The following is a review of the daily CMSC payments that were identified in Table 2-2 above as exceeding the Panel's threshold.

CMSC payments on July 4, 2018 were $1,207,373. A significant portion of the CMSC, approximately $600,000, was paid to a single gas generator. The generator was constrained on by the IESO's Control Room Operator (CRO) to provide additional flexibility. CRO deemed this action necessary for the following reasons: i) load uncertainty due to higher than seasonal temperatures; and ii) wind trending under forecast thus potentially limiting variable generation.

CMSC payments on August 22, 2018 were $1,632,074. The event which resulted in this payment, however, occurred on the previous day. A cracked hydro pole resulted in a forced outage to a major transmission line. This outage lasted until August 23, 2018. Among other impacts, the outage had major implications for the operations of a certain dispatchable load, effectively rendering it grid-incapable. The dispatchable load retained its bids for the duration of the outage, alternating between 40 MW and 80 MW. The bids were submitted at $1,999/MWh – almost the maximum possible bid price. The high bid prices, being significantly higher than the prevailing market prices, made the dispatchable load economic in the unconstrained sequence, while the outage forced the IESO to constrain it off. The three-day outage event resulted in CMSC payments of $2,598,865, of which approximately $2,000,000 was constrained-off CMSC paid to the aforementioned dispatchable load. This payment was almost entirely generated by the extreme differences between the load's bid prices and the prevailing market prices.

CMSC payments on September 3, 2018 were $1,226,750. The majority of the CMSC, approximately $900,000, was paid to a single gas generator. This was the same generator that was constrained on for July 4, 2018, referenced above. Similar to that event, the generator was constrained on by the CRO to provide additional flexibility. The CRO deemed this action necessary for the following reasons: i) load uncertainty due to higher than seasonal temperatures; ii) a de-rated intertie which lowered import capability (see discussion below); iii) limited spare generation capacity available for peak demand hours.

2.1.3 Anomalous IOG Payments

The following is a review of the anomalous IOG payments identified in Table 2-2 above.

The high hourly and daily IOG payments were all a result of extreme intertie congestion on the Québec interties. Importers scheduled day-ahead are guaranteed their day-ahead offer price if the scheduled MW amount flows in real-time. This guarantee provides an incentive for traders to lower import offers to -$2,000/MWh (the lowest allowable offer price) after they have been scheduled in the day-ahead. Lowering the offer price increases the likelihood that the energy will flow in real-time and that the trader will receive, at the minimum, their day-ahead offer price. In the current context, for all events associated with a high IOG payment, a Québec intertie import limit was reduced subsequent to a participant's day-ahead imports having their offer prices reduced to -$2,000/MWh. This led to extreme negative Intertie Zonal Prices (IZPs) – often around -$2,000/MWh. As such, imports that did flow were subject to paying the extremely negative IZP. However, due to the day-ahead IOG, these losses for this participant were offset by a payment that made them whole relative to their day-ahead offer price.

On July 1, 2018, the IESO paid out $12,282,165 in IOG payments. The payments were primarily a result of a 1,000 MW reduction in import limit on the Outaouais Intertie between HE 14 and HE 20. The intertie was de-rated due to forest fires in Northern Québec which were affecting transmission inside that province.

On July 4, 2018, the IESO made $3,570,997 in IOG payments. The payments were a result of a 600 MW reduction in import limit on the Outaouais Intertie. The intertie was de-rated due to a forced outage to Hydro-Québec-owned equipment.

On August 9, 2018, the IESO made $1,088,302 in IOG payments. The payments were a result of the Chats Fall-Paugan Intertie being forced out of service for a loss of 350 MW. The intertie was forced out of service due to a forced outage to Hydro-Québec-owned equipment.

On September 3, 2018, the IESO made $1,207,185 in IOG payments. The payments were a result of the Outaouais Intertie being de-rated by 900 MW. The de-rates were due to outages being conducted by Hydro-Québec; these outages were extended several times throughout the day.[6]

2.2 RT-GCG Two-Shifting

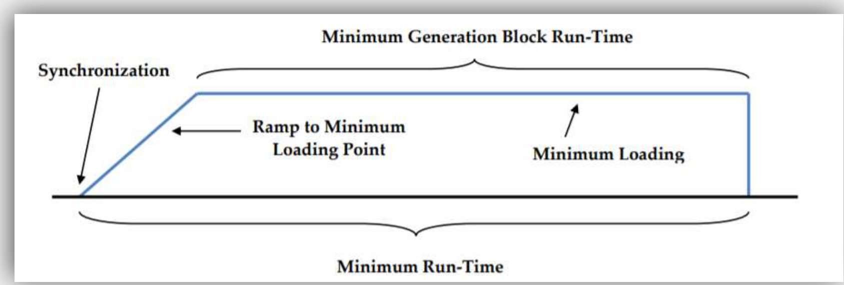
The Real-Time Generation Cost Guarantee Program (RT-GCG) is a voluntary IESO-administered cost-recovery program that, subject to eligibility criteria, allows non-quick start generators to recover certain costs associated with start-up, ramping, and operating at their Minimum Loading Point (MLP) until the earlier of the end of their Minimum Generation Block Run Time (MGBRT) or the end of their Minimum Run Time (MRT). From the IESO's perspective, the program is necessary for reliability reasons as, the IESO contends, it ensures that start-up costs are covered for non-quick start facilities so they can economically meet dispatch instructions when they are needed. The Panel has questioned the need for this program previously and has made numerous recommendations to the IESO to address the program's deficiencies.

Overview of the Real-Time Generation Cost Guarantee Program (RT-GCG)

RT-GCG is an incentive program that guarantees eligible Market Participants recover certain costs associated with start-up and minimum run-time operations. The program mitigates the risk of Market Participants not starting their generation units in times when they are not certain they will be dispatched sufficiently to recover those costs. Participation in RT-GCG is voluntary, but requires that the participating facility is: i) not a quick-start facility; and ii) a dispatchable generation facility. As of the date of this report, the majority of facilities that have met the requirements of the program are gas generators (some combined with steam turbines).

[6] These are planned outages that were extended.

To register for RT-GCG, a Market Participant must submit the following information for each of its eligible generation units: i) **Minimum Loading Point (MLP)**; ii) **Minimum Generation Block Run Time (MGBRT)**; and iii) **Minimum Run Time (MRT)**.



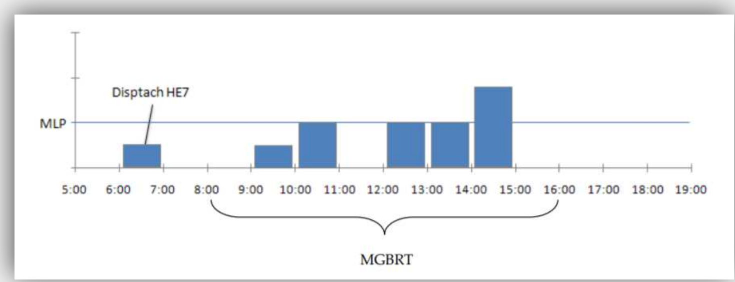
The Market Participants with eligible and registered generation units must notify the IESO of their intent to have these units participate in RT-GCG for each RT-GCG run.

To qualify for an RT-GCG run the following criteria must be met:

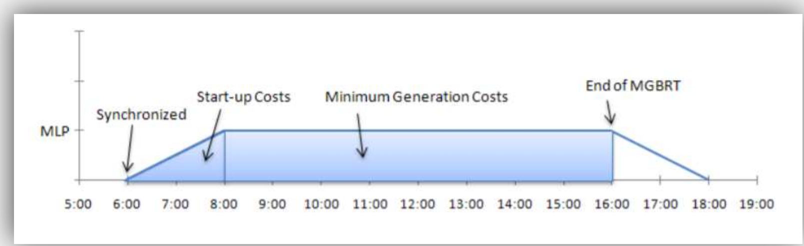
1) The generation unit cannot be synchronized to the grid.

2) In the pre-dispatch report published within three hours of dispatch:
   a. The generation unit must be scheduled for at least 1 MW in the hour in which the Market Participant wants to synchronize to the grid.
   b. The generation unit must be scheduled at MLP for at least half of its MGBRT.
   c. The Market Participant must have the same offer price for the generation unit for all hours of its MGBRT.

The following graphic shows a sample pre-dispatch schedule of a generation unit that qualifies for RT-GCG. In this example, the pre-dispatch report is available in Hour Ending (HE) 4 and the Market Participant intends for the unit to synchronize to the grid in HE 7. The unit's MGBRT starts in HE 9 and ends in HE 16; the offer price is the same for all MGBRT hours. The unit is scheduled at MLP for half its MGBRT (four hours).



The costs that could be recovered through RT-GCG fall into two categories: i) incremental start-up and ramping costs; and ii) minimum generation costs.



Costs in the former category are based on pre-approved values for each qualifying generation unit and account for the cost of fuel as well as operating and maintenance (O&M) costs incremental to the unit starting-up and ramping to its MLP. The latter category accounts for costs incurred during the generation unit's MGBRT up to its MLP; these costs are calculated by the IESO by multiplying the unit's MLP offer price ($/MWh) by its MLP (MW) and then by its MGBRT (hrs). Both the incremental costs and the minimum generation costs are offset by market revenues that the unit generates up to its MLP.

Various aspects of RT-GCG have been scrutinized by the Panel including a strategy employed by some generators referred to in an earlier report as "Two-Shifting".[7] Two-Shifting occurs

[7] The Panel first looked at Two-Shifting in the Summery 2010 Period. For more information, see the Panel's Monitoring Report 17 (May 2010-Oct 2010) published March 2011, pages 86-95: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf

when a generation unit qualifies for RT-GCG, comes online, comes offline for a short period of time and then re-starts for a second RT-GCG run in the same day. The previous analysis of Two-Shifting focused only on instances when the time between the two runs was less than two hours. In this analysis we track all instances of Two-Shifting that occurred in 2018, but highlight instances when the time between one RT-GCG run and another was three hours or less since RT-GCG eligibility is established within three hours of dispatch.

One of the Panel's recommendations from its previous analysis was that the IESO alter RT-GCG to limit generators to one start-up cost guarantee submission per day.[8] The IESO did not implement this recommendation indicating that doing so may prevent the use of the least-cost option later in the day. Instead the IESO would ensure that the costs recovered from any second start-up are limited to a level that reflects that the unit is already hot.[9] In addition, as part of Stakeholder Engagement (SE) 111: Review of Generation Guarantee Programs (SE-111), the IESO concluded that the frequency of "touch and go starts" has decreased significantly since the issue was first identified by the MSP.[10]

The Panel acknowledges that the frequency of Two-Shifting has decreased relative to the figures it had previously reported. In addition, in December 2016 the IESO took steps to mitigate self-induced ramp-down CMSC – a major source of costs associated with Two-Shifting identified in the past. Also, along with SE-111, the IESO conducted another

[8] Ibid, page 96.

[9] See the IESO's response to MSP recommendations in a letter to the OEB dated December 15, 2011, page 8: https://www.oeb.ca/oeb/_Documents/MSP/Response_to_Chair-OEB_MSP-Monitoring-Report_201112.pdf

[10] See the IESO's Stakeholder Engagement "Review of Generation Guarantee Programs" (SE-111): http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Review-of-Generation-Guarantee-Programs

Stakeholder Engagement to review cost submissions under RT-GCG.[11] These engagements resulted in the IESO introducing the concept of pre-approved values for certain costs. Notably, as of August 2017, Market Participants' operating and maintenance cost (O&M) submissions are now based on the type of start the generation unit incurred: cold start (most expensive), warm start, or hot start (least expensive). The fuel costs are still based on actual fuel consumption during start-up and, in situations when the unit was operating at full speed no-load (FSNL) prior to synchronization, only fuel from the point of synchronization to MLP is eligible.[12]

Despite all the changes to RT-GCG, however, as the Panel notes below the costs associated with Two-Shifting are still not insignificant.

In 2018, there were 182 instances of Two-Shifting. Of that total, 76 runs (42%) occurred within three hours of the end of the first run.

The average time between RT-GCG runs occurring on the same day was just more than four hours. The total cost of all Two-Shifting for the year was $6.4 million.[13] Once energy and CMSC revenues earned by the Market Participants up to MLP were accounted for, the total net payments to generators associated with Two-Shifting was $1.9 million. On average, the net payment to Market Participants for a second run was $10,500.[14]

[11] See the IESO's Stakeholder Engagement "Real-Time Generation Cost Guarantee Program Cost Recovery Framework": http://ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/RT-GCG-Program-Cost-Recovery-Framework

[12] This means that the unit de-synchronizes from the grid (opens its breaker), but continues to keep its rotor spinning, consuming some fuel and keeping the turbine in a "hot" or ready-to-ramp-up state.

[13] This figure amounts to the sum of the total combined costs of all second RT-GCG runs in 2018. Combined costs comprise i) incremental start-up and ramping costs; and ii) minimum generation costs.

[14] $1.9 million divided by 182 instances.

Table 2-4: Overview of Two-Shifting in 2018

Hours between first and second RT-GCG run	Number of occurrences in 2018	% of total occurrences in 2018
1	3	2%
2	13	7%
3	60	33%
4	29	16%
5	37	20%
6	25	14%
7	7	4%
8	2	1%
9	4	2%
10	2	1%
Total of Second RT-GCG Runs	182	100%

The table above shows the number of instances that generators qualified for a second RT-GCG run within a single day. The data is broken down by the number of hours between the two runs.

As indicated in a previous monitoring report,[15] the Panel's primary concern is that Two-Shifting results in unnecessary costs, as the cost of shutting down a generation unit only to restart it later in the same day results in efficiency losses.

If the IESO insists on keeping RT-GCG runs for a second start during a day, the Panel's secondary concern is that, in some cases, the cost of the second start exceeds the cost of keeping that unit online at its MLP. The Panel, however, recognizes that if the unit was to remain online between the RT-GCG runs, the IESO would still guarantee the unit's costs for operating at MLP for the duration of the second run. The Panel's concerns are thus focused on the costs of taking the unit offline and then paying that unit to restart and ramp to MLP. The costs of taking the unit offline are estimated by the IESO through the Ramp Down Settlement

[15] For more information, see the Panel's Monitoring Report 17 (May 2010-Oct 2010) published March 2011, page 96: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf

Amount; the costs of restarting the unit are submitted by the Market Participant.[16] In 2018, these costs in total were approximately $100,000 and $2,513,000, respectively; the averages per run were $553 and $13,866, respectively.[17] When considering situations when the second RT-GCG run occurred within three hours of the first, the total costs for 2018 were approximately $53,000 and $880,000, respectively.

To illustrate a situation when keeping the unit running at MLP would have been more efficient for the market, consider the following example of a three-hour Two-Shift.[18,19] One day in January 2018, a generation unit came offline after its first RT-GCG run only to come back online (re-synchronize) for a second run, three hours later. Considering that the time of the second run was within three hours of the end of the first run, the Market Participant and the IESO could have anticipated that the unit could be eligible for RT-GCG prior to the unit coming offline. The IESO paid the unit approximately $500 to ramp down, while the costs of ramping that unit back up to its MLP were approximately $25,000 – this was approximately $1,000 more than what the Market Participant submitted for the first run. Yet, had the IESO retained

[16] As indicated above, prior to December 2016 the IESO used to make significant payments to market participant as a result of self-induced ramp-down CMSC. The magnitude of these payments was mitigated by the IESO based on the Panel's recommendations, specifically Recommendation 3-1 of the Panel's Monitoring Report 21 (May 2012-Oct 2012) published June 2013 (pages 61-67). As of December 2016, the IESO pays a Ramp Down Settlement Amount. This ramp-down compensation is the lesser of ramp-down CMSC and an IESO-calculated ramp-down settlement. The calculation for the latter uses a generator-specific offer price taken from the hour before the hour ramp-down begin and applies a standard fixed factor for the ramp-down intervals. In situations when the unit is taken offline, the factor is 1.3. For more information on the Panel's recommendations, see the Panel's Monitoring Report 21 (May 2012-Oct 2012) published June 2013: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf

[17] This figure amounts to the sum of the incremental start-up and ramping costs associated with the second RT-GCG run.

[18] Three hours between the end of the first RT-GCG run (end of MRT) and the start of the second RT-GCG run (hour of re-synchronization).

[19] The figures in this example are based on real amounts submitted by the market participant, but have been simplified for confidentiality reasons.

the unit online at MLP for those three hours, essentially extending its first RT-GCG run, the cost – based on the unit's MLP multiplied by its average offer in the first run – would have been approximately $16,000. As such, in this simplified example, Two-Shifting generated at least $9,500 of unnecessary costs. If one considers that if the RT-GCG unit were to have run at its MLP between two runs it would have displaced another generating unit and if both units' costs were the same, then the efficiency loss to the market would have been the entirety of the ramp-down and ramp-up costs – $25,500.

The Panel also understands that some Two-Shifting units operate at FSNL between runs, when these runs are close together.[20] However as noted above, fuel costs incurred during FSNL operations are not covered under RT-GCG. Additionally, the unit will not incur some of its typical incremental start-up costs during an FSNL start. In these situations, the Panel would expect the submitted costs (i.e. incremental start-up and ramping costs) associated with all additional starts to be significantly lower than the submitted costs associated with the first start of the day. Nevertheless, when the Panel looked at situations when the second run occurred within three hours of the end of the first run it found that of the 76 total events, there were 26 instances when the submitted costs of the second run were equal to or higher than those of the first run. The frequency of this occurring is concerning as even if the units were not operating at FSNL the costs of the second starts with shorter times between runs would be expected to be significantly lower than those of a colder unit starting at the beginning of the day. It is expected that similar results would be observed for other situations in 2018.

Although the Panel and the IESO disagree about the need for RT-GCG, the Panel is of the view that if the IESO insists on retaining the program it should consider identifying mechanisms to achieve more cost effective outcomes. Ontario loads should not be paying for unnecessary costs of restarting units when their start-up costs have already been paid, in

[20] Operating at FSNL may lead to a shortened start-up period on the second start.

particular if those costs exceed the costs of retaining the unit at its MLP when the unit already qualified for the second RT-GCG run within a short timeframe. This is, in fact, consistent with the approach the IESO adopted when considering the interaction between RT-GCG and Day-Ahead Production Cost Guarantee Program (DA-PCG).[21] In situations where both the DA-PCG event and the RT-GCG event can be tied to the same generation unit start-up, and the incremental fuel costs for start-up and ramping to MLP with the related incremental O&M costs are eligible for inclusion in the DA-PCG settlement, these costs are not eligible in the assessment of the RT-GCG settlement. The Panel is mindful of the fact that in the RT-GCG/DA-PCG interaction the second event closely follows the first without the unit desynchronizing, however, the point to highlight is that in both scenarios the Market Participant can, based on their pre-dispatch schedules, anticipate being online (and potentially eligible for cost-recovery through either program) prior to the end of the (first) RT-GCG run.

The Panel believes that costs for electricity consumers would be lower by keeping these generating units at MLP for the period between dispatch runs for many situations. This would displace a marginal unit's output, resulting in a savings, with the net cost being the difference in marginal costs of the RT-GCG unit and the marginal unit. By applying this strategy when this difference is less than start-up costs, significant savings would result. However, the Panel understands that current RT-GCG rules and Dispatch Scheduling and Optimization (DSO) would not make this a simple exercise. As such, and until such time as when the IESO is able to account for all aforementioned costs in its scheduling decisions, the Panel believes, as recommended in previous Market Surveillance Panel (MSP) reports, that the IESO should not provide any start-up payment for an RT-GCG run that occurs within the same day. Overall, there appears to be little justification to provide guarantee payments for generators that have already been paid to come online. Alternatively, the payment for the second and subsequent

[21] See Market Manual 4: Market Operations, Part 4.6: Real-Time Generation Cost Guarantee Program, Section 6.3 - Interaction between RT-GCG and PCG. pages 27-31: http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-rtgcgprogram.pdf?la=en

cycles should not exceed the estimated payment the generation unit would have received had it remained online at its MLP. To ensure that the costs submitted by Market Participants have not been inflated, the Panel also recommends that the IESO conducts an audit of RT-GCG cost submissions in situations when a generation unit has had a second RT-GCG run within three hours of its first RT-GCG run and the submitted costs of the second run are equal to or higher than the submitted costs of the first run.

***Recommendation 2-1*: The IESO should eliminate the payment for start-up costs for second and subsequent RT-GCG runs in a day. Alternatively, when a generation unit has participated in the RT-GCG program once during a day, the IESO should consider ways to have the generation unit compensated on the basis of the lesser of the second and subsequent submitted start-up costs or the estimated cost of keeping the generation unit online between RT-GCG runs.**

***Recommendation 2-2*: The IESO should conduct an audit of RT-GCG cost submissions in situations when a generation unit has a second RT-GCG run within three hours of its first RT-GCG run and the submitted costs of the second run are equal to or higher than the submitted costs of the first run.**

2.3 Pickering Outages and SAR Price Distortions

2.3.1 Overview

The Pickering Nuclear Generating Station (PNGS) sits on the shores of Lake Ontario near Toronto, providing as much as 3,100 MW of capacity – or nearly 10% of all grid-connected capacity in the province. PNGS is owned and operated by a provincially-owned Crown corporation: Ontario Power Generation Inc. (OPG).

The PNGS contains eight individual reactor-generator combinations, referred to as units. The eight units were built in sets of four, with the first four – Pickering A – coming into service in the early 1970s. Two of the four reactors in Pickering A – Units 2 and 3 – are no longer in commercial operation after being permanently shut down in the late 1990s. The second set of four reactors – Pickering B – came into service in the mid-1980s and remains in full commercial operation.[22] While the PNGS is an active participant in the wholesale market, the Ontario Energy Board (OEB) sets the rate it receives for all output. The difference between PNGS' wholesale market revenues and its regulated rate is made up through the Global Adjustment (GA) charge.

In the summer of 2018, PNGS experienced two outages. The first occurred on July 22, 2018 and was a result of algae bloom in Lake Ontario. The algae bloom forced a sudden shutdown of the four Pickering B units, removing nearly 2,000 MW of energy (about 12% of all energy in Ontario when the outage occurred) in a matter of minutes. The outage resulted in a more than 18-fold increase in the Hourly Ontario Energy Price (HOEP), an urgent request for 1,000 MW of imports from neighbouring jurisdictions, a more than 20-fold increase in the price of Operating Reserve (OR) and multiple out-of-market activations (and payments) to generators. It also resulted in artificial suppression of the Market Clearing Price (MCP) when the Simultaneous Activation of Reserve was called on. The four units remained offline for more than two days.[23]

The second outage was to a Pickering A unit; it occurred on August 4, 2018 and was a result of high water temperature in Lake Ontario. Although this particular event did not have a significant impact on the IESO-Administered Markets, it is included in this report to note that such events have the potential to have a significant impact and may become a more frequent issue as a result of climate change.

[22] Pickering A's two active reactors are Unit 1 and 4. Pickering B's active reactors are Unit 5, 6, 7 and 8.

[23] Unit 5 was placed back in service on July 24, 2018 and Unit 7 on July 25, 2018. On July 27, 2018 the outage at Unit 6 was extended until August 4, 2018 and the outage at Unit 8 was extended until July 30, 2018.

2.3.2 PNGS Outage due to Algae Bloom in Lake Ontario

On July 21, 2018, OPG informed the IESO's Control Room that algae was clogging pumps at PNGS that take water from Lake Ontario to condense steam as part of the generating process. As a result of a few of the pumps being taken out of service, two of its generating units at Pickering B were de-rated.[24] The IESO requested OPG to update it on the risk of the algae bloom and the potential that more pumps would be compromised and, potentially, result in the shutdown of any one of the reactors.

On the following day, July 22, 2018, at approximately 9:00 A.M. OPG informed the IESO that it expected the algae issue to be resolved shortly, confirming that a number of water pumps would soon be back in service. Even with the de-rate from the previous day still in effect, many of the units continued to provide a significant amount of energy, with the hourly output at the four Pickering B units over the course of the morning averaging 1,860 MW – 13% higher than the average year-to-date hourly output of 1,640 MW.

About two hours after indicating that the algae issue was under control, OPG informed the IESO that it was removing one of the Pickering B units (Unit 7) from service immediately due to the algae problem. Within the next five minutes, the three remaining Pickering B units were also removed from service. Taken together, the loss of Pickering B amounted to 1,924 MW of capacity being removed from service in the span of five minutes.

The IESO reacted quickly to the sudden and significant loss of Pickering B, to fill the gap and address the change in the Area Control Error (ACE).[25] When there is a sudden outage to a large generator, ACE will be negative and the IESO will either activate OR or manually

[24] Meaning their maximum output was lowered.

[25] ACE is the difference between the scheduled flow and actual flow (mismatch of inflow and outflow schedules) on the interchange, along with an addition bias to maintain frequency, estimated in MW.

dispatch another resource(s) to come online in order to fill the gap.[26] By working to maintain ACE at zero, the IESO contributes to the reliability of the grid. In the minutes after the Pickering B units were taken out of service, the IESO activated nearly 1,100 MW of OR, manually dispatched a number of resources to come online and invoked what is known as Simultaneous Activation of Reserve (SAR).[27]

SAR is a program between a number of neighbouring electricity market system operators (New York Independent System Operator (NYISO), Independent System Operator-New England (ISO-NE), New Brunswick Power, PJM Interconnection and the IESO) to jointly activate reserves when one of the jurisdictions suffers a supply loss greater than or equal to 500 MW (300 MW in the case of New Brunswick). When SAR is activated, other participating jurisdictions will supply up to half of the lost generation as a “free” import for up to half an hour. SAR energy is treated as inadvertent flow[28] (in and out) and is “paid back” in kind through the normal balancing process when the IESO exchanges energy with other jurisdictions.[29] The full half hour of SAR was used in this event.

The sudden loss of nearly 2,000 MW of generation capacity resulted in a spike in the MCP which led to a substantial increase in the HOEP. The MCP spiked from approximately $4/MWh in the several five-minute intervals prior to the outage to $164/MWh in the interval when the first Pickering B unit was taken out of service. The MCP subsequently dropped from $164/MWh to around $28/MWh in the five-minute interval immediately following the Pickering B outages, for the reasons explained below.

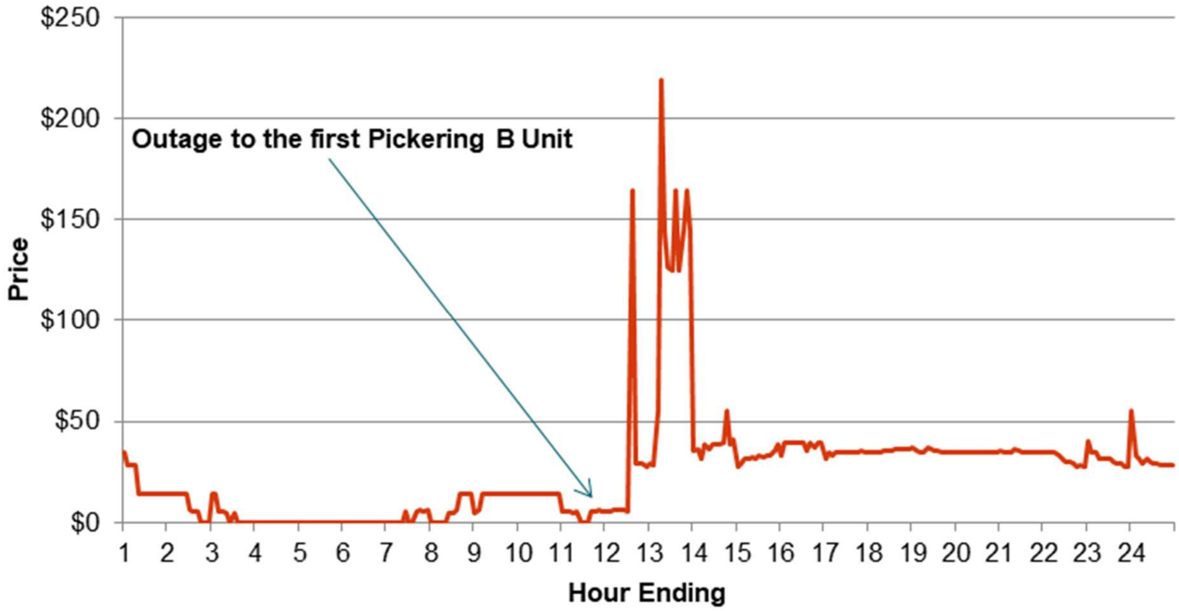
[26] If the resource is a dispatchable load, it would be dispatched to come offline.

[27] Referred to as Shared Activation Reserve in previous Panel reports based on accepted nomenclature.

[28] Inadvertent flow is the difference between the scheduled amount of energy interchange at one, or multiple interties, and actual metered flow.

[29] Ontario generators produce the energy to “pay back” other jurisdictions. That energy comes out of the market and is paid for by Ontario customers.

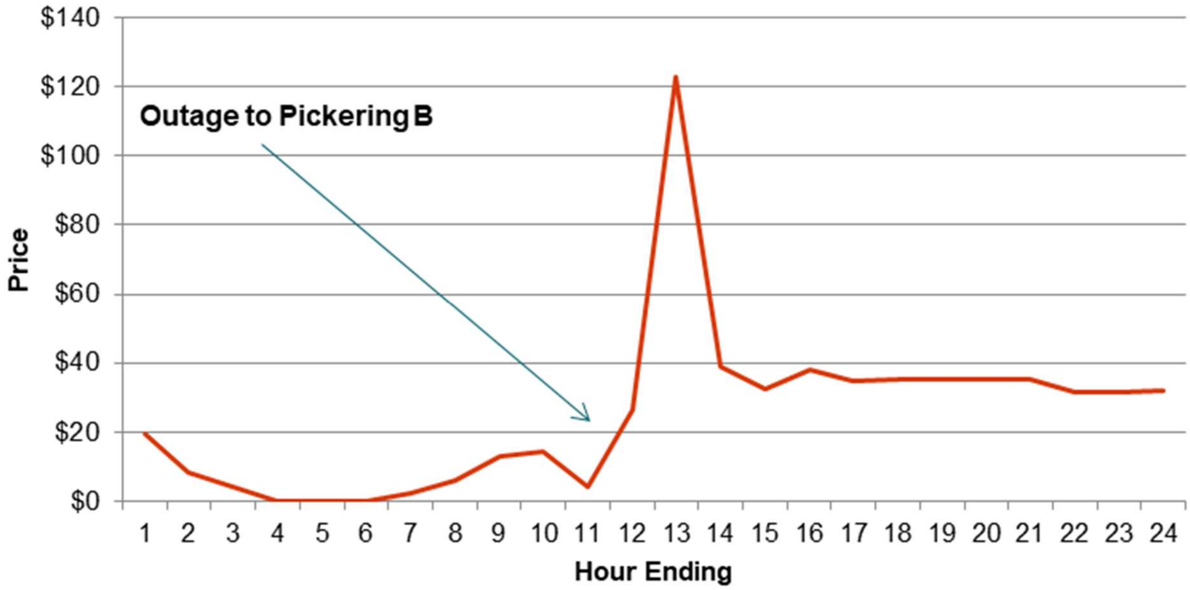
Figure 2-1: The MCP for July 22, 2018



The figure above shows the MCP for July 22, 2018.

The HOEP averaged $6.50/MWh in the hours prior to the outage at Pickering B; in the hour when the units were taken out of service, it jumped to $26/MWh and then to $122/MWh in the following hour.

Figure 2-2: The Hourly Ontario Energy Price (HOEP) for July 22, 2018



The figure above shows the HOEP for July 22, 2018.

<u>What is the Market Clearing Price (MCP) and the Hourly Ontario Energy Prices (HOEP)?</u>

The MCP is the price paid by large consumers and exporters to purchase energy and paid to generators and importers to supply energy. It is set every five minutes. The MCP marks the price where offers from generators to sell energy at a certain price intersects with consumer demand to buy energy at a certain price. The HOEP is the simple average of the MCP in any given hour.
The MCP is the basis of the wholesale energy market and is intended to send an economic signal to Market Participants. If the MCP is high, it will provide higher cost suppliers with an incentive to enter the wholesale market. At the same time, price-sensitive loads will curtail consumption when it is uneconomic to purchase additional energy. The MCP is the economically efficient point where marginal cost and marginal benefit intersect.

All non-dispatchable loads – such as electricity distributors that deliver power to consumers – are charged the HOEP for energy consumption. Dispatchable loads – predominantly large facilities directly connected to the grid which follow IESO's dispatch instructions – pay the MCP. Similarly, non-dispatchable generators receive the HOEP for their output, while dispatchable generators are paid the MCP.

The price spike could have been much higher but was mitigated by a couple of factors.

First, the outage took place on a Sunday when demand in Ontario is typically lower compared to demand on an average weekday. Peak demand for July 22, 2018 was 16,591 MW – approximately 6,000 MW less than the highest hour of demand in that month. Lower demand meant additional resources were available to be manually dispatched on – or were already online and capable of increasing output – to fill the generation gap left by the loss of Pickering B, helping to mitigate further price increases.

Second, by design the activation of SAR immediately brought the MCP down. As indicated above, the MCP hit $164/MWh in the interval when the first unit was taken offline, but immediately dropped to around $28/MWh in the subsequent interval when SAR was activated. It remained at that level for the next 30 minutes while SAR was in place. In the interval immediately following the end of SAR, the MCP spiked to nearly $200/MWh and remained above $124/MWh in the remaining intervals in that hour.[30]

[30] No material price changes were observed when the OR scheduling requirement was reduced to zero shortly after the activation of SAR, nor when it was ramped back to normal through increases late in hour ending (HE) 12 and at the start of HE 13. This suggests that OR co-optimization had minimal impact on the price changes that coincided with the activation and deactivation of SAR.

A SAR activation has a non-intuitive impact on the MCP – pushing prices down in times of scarcity when prices would be expected to increase.[31] This is a direct result of how energy from SAR is incorporated in the algorithm that determines the MCP. When the IESO activates SAR, all energy received through it is considered “out of market” by the algorithm and appears as a reduction in demand. As economic theory would suggest, any reduction of demand in a time of scarcity will have a dampening effect on the increased price of a good. The reduction in demand as a result of SAR activation and its subsequent impact on the MCP is clear in the following figure. Figure 2-3 shows the market demand and the MCP in the two hours during which the Pickering B reactors were taken out of service, including the 30 minutes when SAR was activated.

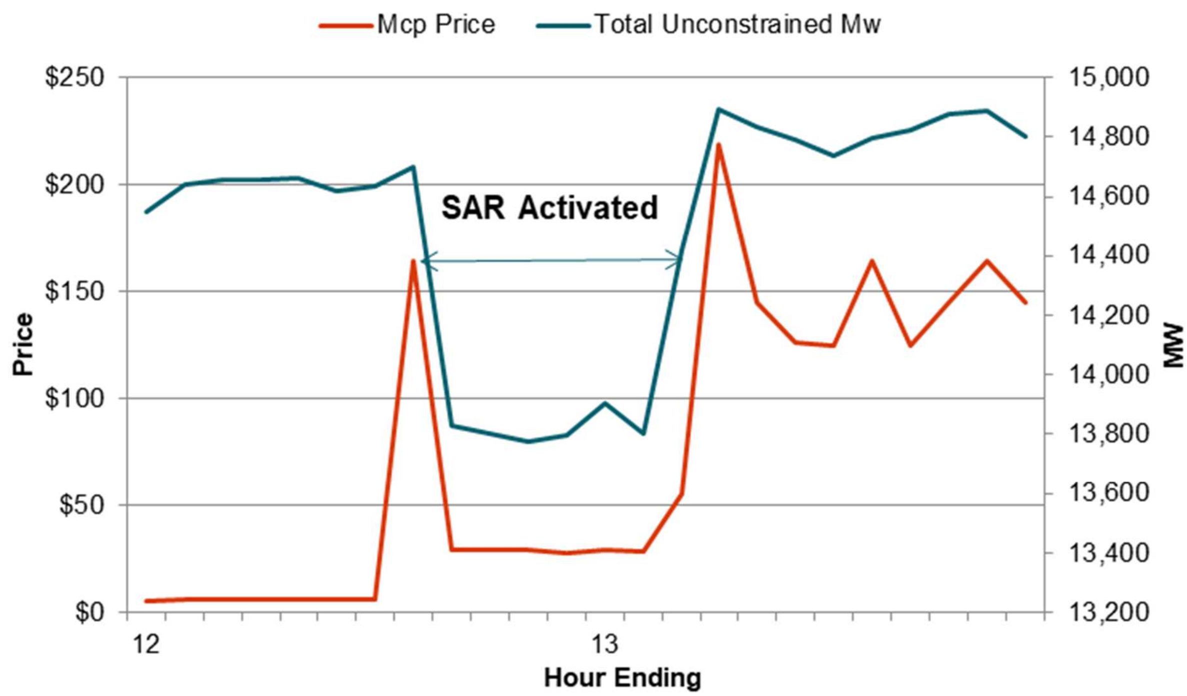
In the short-term, the price distortion caused by a SAR activation reduces the economic efficiency of the wholesale market, sending an artificially reduced price signal to loads and generators exposed to the MCP.[32] It also disturbs what is known as the economic merit order (“merit order”). The merit order stacks energy offers from lowest to highest and dispatches those units that are economic – i.e. their energy offer is at or below the MCP. In this case, some resources would have likely been scheduled had the MCP increased to a level reflective of the supply impact of a sudden outage to a major generator. These resources also would have likely provided energy at a lower cost than energy that was imported into Ontario from

[31] The IESO is aware of this non-intuitive price impact. In its “Guide to Operating Reserve” document, the IESO describes SAR’s impact on the MCP: “SAR has a non-intuitive price impact, as it is not captured in the offer stack used to determine price. When Ontario is receiving SAR energy, the hourly Ontario energy price (HOEP) is suppressed as zero-cost resources are being used to supply demand. There is corresponding upward pressure on the energy price when Ontario is supplying SAR to others.” For more information, see the IESO's "Guide to Operating Reserve", page 14: http://www.ieso.ca/-/media/Files/IESO/Document-Library/training/ORGuide.pdf?la=en

[32] Another common concern with price suppression is that it provides an incentive to remove offers by generators and importers who expect prevailing prices to be unprofitable, and/or discourages the submission of new offers for similar reasons, though this was unlikely to be at play in this case due to the short period for which SAR as activated.

neighbouring jurisdictions through SAR.[33] Depressing the wholesale price when conditions are tight undervalues generation when it is most valuable.

Figure 2-3: The MCP and Market Demand during SAR Activation



The figure above shows the MCP and the market demand for Hour Ending 12 and Hour Ending 13 on July 22, 2018.

The price of OR also spiked in the immediate hour after the outage. The price of ten minute spinning reserve averaged just higher than $1/MWh through the morning of July 22, 2018 but jumped to more than $3/MWh in the hour of the outage and nearly $23/MWh in the following hour. Once the outage at the first Pickering B unit occurred, the IESO activated 500 MW of

[33] Ontario ratepayers do not pay the direct cost of generation in other jurisdictions due to a SAR activation. Nonetheless, some of the energy that was delivered to Ontario likely came from higher cost resources.

OR, and subsequently activated the remaining 580 MW of OR once the other three reactors were taken out of service.

In the long-term, prices that diverge from the marginal cost of generation encourage inefficient investment and operational decisions by generators and consumers. This makes future electricity costs higher than they would otherwise be. While the price-distorting effect of SAR is unlikely to contribute in a major way to this phenomenon, given the infrequency with which SAR is activated and its short duration, there are ways the program's efficiency impacts may be reduced.[34]

The Panel has commented on this phenomenon in past Monitoring Reports, recommending that the IESO add demand back to the unconstrained schedule to counteract the non-intuitive price suppression when SAR is activated.[35,36,37] Implementing this recommendation would treat SAR in the same way that emergency imports are currently treated – in a manner that minimizes the market impact of the out-of-market action. The IESO last examined the issue in 2008 and concluded that the issue is of "low priority as the price effects of SAR has little impact on efficiency and reliability".[38] To date, no change has been made. The Panel is thus reiterating its concern with the impact of SAR activations on the MCP. Additionally, the type and amount of installed generating capacity in Ontario has changed significantly since the IESO last considered this issue. Fast-ramping coal plants capable of responding to outages, for example, have all been decommissioned and replaced with less flexible gas plants and

[34] SAR was used to import power into Ontario six times in 2017 and nine times in 2018.

[35] See the Panel's Monitoring Report 9 (May 06-Oct 06) published December 2006, pages 73-76: https://www.oeb.ca/documents/msp/msp_report_final_20061222.pdf

[36] See the Panel's Monitoring Report 13 (May 08-Oct 08) published January 2009, pages 126-128: https://www.oeb.ca/oeb/_Documents/MSP/msp_report_200901.pdf

[37] See the Panel's Monitoring Report 14 (Nov 08-Apr 09) published July 2009, pages 122-125: https://www.oeb.ca/oeb/_Documents/MSP/msp_report_200907.pdf

[38] See the IESO Shared Activation Reserve Presentation dated February 7, 2008: http://www.iemo.com/imoweb/pubs/consult/mep2/MP_WG-20080207-Shared-Activation-Reserve.pdf

variable generators. As such, the impact of SAR activations on the MCP and its impact on the economic efficiency of the wholesale market may be greater than it was a decade ago.

<u>Recommendation 2-3</u>: The IESO should treat SAR activations in much the same way as it treats emergency imports; namely, by adding demand back in to the unconstrained schedule.

2.3.3 High Water Temperature in Lake Ontario

The second event involving the PNGS occurred on the evening of August 4, 2018 when one of the reactors at Pickering A was forced out of service due to a high water temperature in Lake Ontario, which is used for cooling in the generation process.[39] This led to a loss of 375 MW of capacity just five minutes after the IESO was first notified of the issue. The grid recovered from the contingency within minutes after the activation of 600 MW of OR. The reason the IESO activated more OR than was lost – 600 MW of OR compared to a loss of 375 MW – was due to multiple thermal units scheduled to come offline at the same time.

There were no significant price impacts associated with this event, likely due to the smaller amount of lost capacity – the unit's capacity of 375 MW accounted for just 2% of all grid-connected generation in Ontario – and ample OR available to cover the loss. Out-of-market CMSC payments during the 20 minutes of OR activation totalled more than $10,000, as no resources were manually added to the grid. Despite the event's limited market impact, it is an example of possible environmental impacts on Ontario's nuclear fleet during periods of high temperatures.

Algae is a known risk to nuclear generation in Ontario. Algae in Lake Ontario resulted in forced outages, both at the PNGS and the Darlington Nuclear Generating Station in 2005, and again at the PNGS in 2007. The IESO control room highlighted in its daily reports the potential risk of another forced outage due to algae on July 26, 2018 – just four days after the forced outage

[39] Ontario Power Generation Inc. (OPG) estimated the increase in water temperature to be 4-5 degrees Celsius.

analyzed by the Panel in this report. Fortunately, the July 26, 2018 forced outage did not materialize. More persistent occurrences of high water temperatures in Lake Ontario – similar to those on August 4, 2018 – could heighten both the risk of algae blooms and the risk of algae-induced shutdowns at both the Darlington and Pickering nuclear plants. In addition, higher water temperatures reduce cooling efficiency and make it more difficult to meet regulatory and environmental standards – potentially leading to shutdowns or deratings.[40] For example, there were 25 nuclear outages in the U.S. due to high water temperatures between 2000 and 2015.[41] Given that electricity demand in Ontario is summer-peaking, market conditions during such outages tend to be especially tight, meaning nuclear shutdowns due to high water temperatures can occur when this capacity is needed most.[42]

In response to these risks, the North American Electric Reliability Corporation (NERC) has sponsored research on the reliability impacts of extreme weather and climate change, while the US Department of Energy has integrated climate change into its recent analysis of system

[40] For more information, see the Government of Canada's paper "From Impacts to Adaptation: Canada in a Changing Climate 2007" by Q. Chiotti and B. Lavender published in 2008, chapter 6 – Ontario (pages 227-274) and the 2016 case study presented to Natural Resources Canada by Ouranos, a Québec Consortium on Regional Climatology and Adaptation to Climate Change "Cooling for Thermal Generation in a Changing Climate": https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/earthsciences/pdf/assess/2007/pdf/ch6_e.pdf and https://www.ouranos.ca/publication-scientifique/Case-Study-8-AN-final.pdf

[41] See the National Renewable Energy Laboratory's report "Water-Related Power Plant Curtailments: An Overview of Incidents and Contributing Factors", published December 2016: https://www.nrel.gov/docs/fy17osti/67084.pdf

[42] See the Union of Concerned Scientists' report "Power Failure: How Climate Change Puts Our Electricity at Risk", published April 2014: https://www.ucsusa.org/global_warming/science_and_impacts/impacts/effects-of-climate-change-risks-on-our-electricity-system.html

reliability, security, and resilience from both supply and demand perspectives. [43,44] Over time these risks will come to be better understood, and may play a greater role in Ontario's supply and planning forecasts.

[43] See the Electric Power Research Institute's report "Joint Technical Summit on Reliability Impacts of Extreme Weather and Climate Change, " published December 2008: https://www.epri.com/research/products/000000000001016095

[44] See the U.S. Department of Energy's "Quadrennial Energy Review Second Installment: Transforming the Nation's Electricity System", published January 2017, specifically "Chapter IV: Ensuring Electricity System Reliability, Security, and Resilience": https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

Chapter 3: Revisiting Capacity Need Assumptions

3.1 Background

Ontario is moving towards a more market-based mechanism for procuring capacity. The Panel supports the goal of market-based investment decisions for electricity supply in Ontario, and the IESO's Market Renewal Program (MRP) more generally.

If it is to succeed, however, market-based capacity procurement requires clear information and a consistent and transparent process. Efficient markets depend on well-informed participants. If markets are going to lead to appropriate investment decisions, investors will need stability in the process and clarity from the IESO about its planning assessments. In this Chapter, the Panel reviews the IESO's current approach to procurement and planning, and offers recommendations for improvements to achieve greater consistency and transparency.

This Chapter reflects developments up to July, 2020. The Panel acknowledges that, since that time, the IESO has taken steps towards addressing some of the issues identified by the Panel in respect of the capacity planning and need assessment process.

3.1.1 The Road to Market-based Procurement

The *Energy Competition Act, 1998* was passed in Ontario in 1998, paving the way for the establishment of wholesale and retail electricity markets.[45] When the wholesale markets opened in May 2002, it was anticipated that the revenue from the competitive energy market would be sufficient to stimulate investments in generation as needed. However, when energy market prices rose dramatically soon after market opening, the government introduced rate

[45] See S.O. 1998, Chapter 15. The *Energy Competition Act, 1998* created, among other things, the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998.*

freezes and price ceilings later that same year,[46] which had a dampening effect on private investment in generation.

With little investment in merchant generation and supply shortages on the horizon, the government enacted the *Electricity Restructuring Act, 2004*.[47] The Ontario Power Authority (OPA) was created[48] and charged with long-term electricity planning and the procurement of new generation capacity, as well as a role in conservation. The OPA was tasked with preparing and regularly updating a long-term plan to achieve the government's goals relating to the adequacy and reliability of electricity supply and demand management, referred to as the Integrated Power System Plan (IPSP). The OPA was also tasked with developing procurement processes for managing electricity supply, capacity and demand in accordance with its approved IPSP. The IPSP and the OPA's procurement processes for managing electricity supply, capacity and demand were to be submitted to the Ontario Energy Board (OEB), where they were to be examined in a public hearing. Among other things, the OEB was to consider whether the IPSP was economically prudent and cost effective. The legislation also gave the Minister of Energy the authority to direct the OPA to assume any procurements of generation and conservation programs that had been issued before the OEB's first approval of the OPA's procurement process. This was intended to be transitional, pending the approval of the OPA's first IPSP by the OEB.

For various reasons, however, the process for the OEB's review of the OPA's IPSP and for the OEB's approval of the OPA's procurement processes was never completed, and government-directed procurement of generation endured, including a focus on the procurement of

[46] See *Electricity Pricing, Conservation and Supply Act, 2002*, S.O. 2002, Chapter 23.

[47] See S.O. 2004, Chapter 23. This *Act* consisted principally of amendments to the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998.*

[48] The OPA has since merged with the IESO.

renewable generation following the enactment of the now-repealed *Green Energy and Green Economy Act, 2009*.[49] Today, almost all generation is contracted or, in the case of most of Ontario Power Generation Inc.'s fleet, subject to rate regulation by the OEB.

Further legislative changes were made in 2016 to realign roles and responsibilities for energy planning, with the government assuming responsibility for preparing long-term energy plans with the technical support of the IESO, and with the IESO and the OEB being responsible for submitting plans respecting the implementation of the government's long-term energy plan.[50]

3.1.2 Capacity Auction Evolution[51]

In 2014, the IESO started to signal a new market-based approach to securing future incremental capacity, with the publication of a report outlining the expected benefits of a capacity auction.[52] The Capacity Auction stakeholder engagement initiated in 2014 was put on hold for a short period in 2015 while progress continued towards an auction.

In 2017, the IESO commissioned a report from external consultants that reviewed the potential benefits of a Capacity Auction, launching a broad stakeholder engagement.[53]

[49] See S.O. 2009, Chapter 12.

[50] See *Energy Statute Law Amendment Act, 2016,* S.O. 2016, Chapter 10.

[51] The IESO's capacity auction has variously been referred to as a Capacity Auction, an Incremental Capacity Auction, and a Transitional Capacity Auction. For convenience, the discussion below generally refers simply to Capacity Auction.

[52] See the IESO's report "Ontario Capacity Auction – Assessment of Expected Benefits", dated September 18, 2014: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ca-2014/capacity-20140918-Assessment_of_Expected_Benefits.pdf?la=en

[53] See the IESO's notice "Market Renewal - Incremental Capacity Auction Engagement" dated April 27, 2017: http://www.ieso.ca/Sector-Participants/IESO-News/2017/04/Market-Renewal---Incremental-Capacity-Auction-Engagement

In July 2019, the IESO cancelled its plans to move forward with the Capacity Auction, citing a limited need for new capacity based on updated planning assumptions.[54] The IESO stated that they intended to address the need with "existing and available resources such as Demand Response, imports, generators that are coming off long-term contract, uprates and energy efficiency" as they saw no "need for new baseload resources […] over the next ten years".[55]

Meanwhile, the IESO had introduced a Demand Response (DR) auction in 2015/2016, to shift DR resources – that were under contract – to a competitive market aligned with the long-term goal of a capacity auction. The plan was to transition the DR auction to a new version of the Capacity Auction – as the original Capacity Auction had been cancelled – by allowing additional resources to participate (initially generators coming off contract), starting in December 2019. However, the Market Rule amendments to evolve the DR auction were challenged before the OEB, and the December 2019 auction was run as a DR auction. The IESO then re-scheduled the first Capacity Auction to June 2020.

In April 2020, as a result of COVID-19, the IESO deferred the June 2020 Capacity Auction until the fourth quarter of 2020, while also suspending all work on "evolving" (IESO's term) the Capacity Auction.[56]

As of July 2020, the future evolution of the Capacity Auction remains uncertain.

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[54] See the IESO Engagement email to stakeholders "Market Renewal Update", dated July 16, 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ica/2019/MRP-20190716-Communication.pdf?la=en

[55] Ibid.

[56] See the IESO Engagement email to stakeholders "Capacity Auction", dated April 3, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ca/ca-20200403-communication.pdf?la=en

3.2 Planning Assumptions Impacting the Capacity Need

The IESO has emphasized the need for stable procurement processes and the availability of clear and transparent capacity needs forecasts.[57] The following sections examine certain elements of the IESO's capacity planning process with the aim of assessing how well they support the IESO's goal of providing clearer market signals to inform competitive procurements.

3.2.1 The IESO's Planning Publications and Resource Adequacy Assessments

The IESO assesses resource adequacy for several purposes, from near-term outage planning to long-term resource procurements. The IESO publishes the following planning and reliability reports:

- *Investment Planning:* The IESO has stated publicly that the Annual Planning Outlook (APO) is used to identify any capacity needs and guide any necessary procurements.[58] Evolved from the Ontario Planning Outlook, the APO satisfies the technical report requirement that supports the government's long-term energy planning exercise as set out in the *Electricity Act, 1998*. The APO does not account for economic imports or Emergency Operating Procedures (EOPs) in the analysis.
- *External Compliance*: The IESO reports to the Northeast Power Coordinating Council (NPCC) to ensure compliance with relevant planning criteria. The Ontario Comprehensive Review of Resource Adequacy (OCRRA) is a mandatory report submitted to NPCC to show compliance with the planning criterion of 0.1 days/year loss of load expectation (LOLE). As per NPCC's direction, economic imports and EOPs are

[57] See the IESO's presentation "Incremental Capacity Auction – Meeting #1", dated May 18, 2017, slide 10: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ica/ICA-20170518-Presentation.pdf?la=en

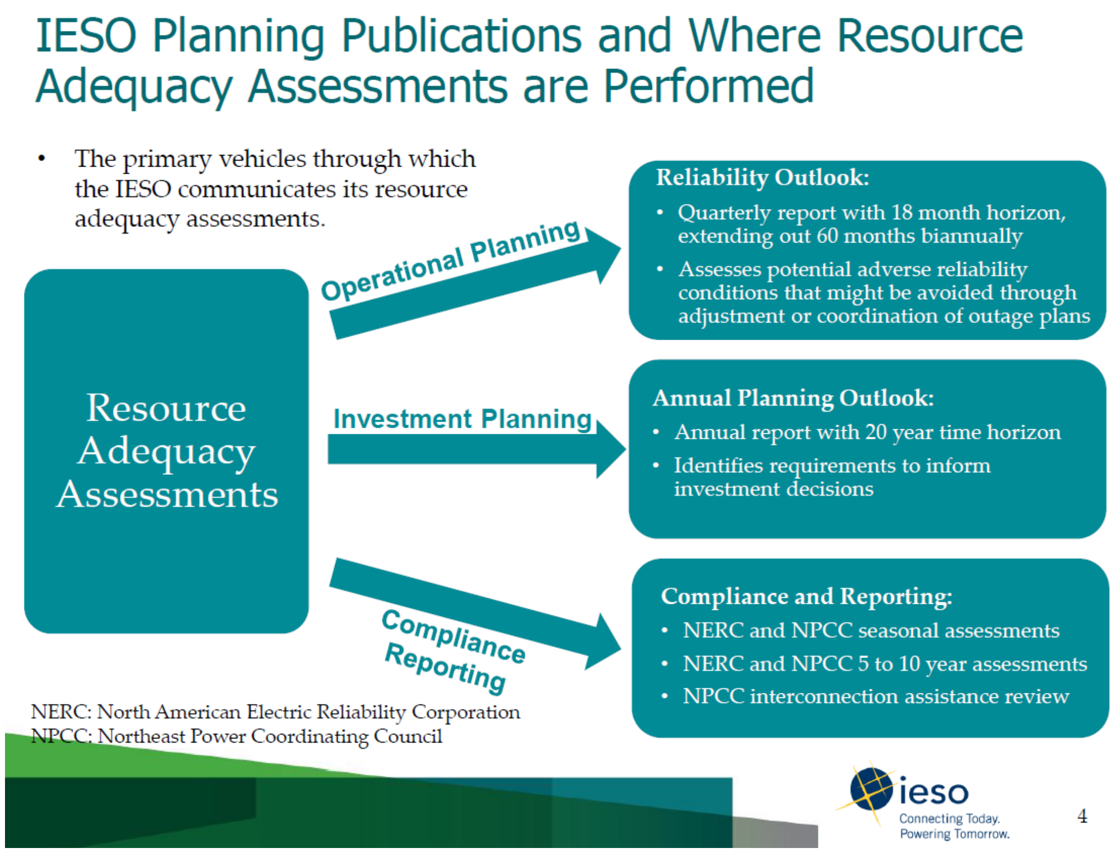
[58] See the IESO's presentation "Resource Adequacy and Transmission Key Insights" dated February 19, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/tech-conf/2020/TechnicalPlanningConference-Resource-Adequacy-Transmission-Key-Insights.pdf?la=en

considered. Comprehensive reviews are published every three years, with interim reviews published annually for intervening years.

- *Internal Compliance:* As required under the Ontario-specific planning criteria in the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO publishes annually the Ontario Resource Margin Requirements (ORMR), providing a forecast of the reserve margin requirement. Like the APO, the ORMR does not consider EOPs or economic imports in its analysis. As of January 2020, the APO has replaced the ORMR as the Internal Compliance Report.
- *Outage Planning:* The Reliability Outlook (RO) Report is used to plan outages, incorporating the scope of the previous "18-Month Outlook" Report. The report provides an 18-month outlook in Q1 and Q3, and a 5-year outlook in Q2 and Q4. It assumes the capability for up to 2,000 MW of economic imports under extreme weather conditions.

Figure 3-1 shows how these different publications are intended to be used.

Figure 3-1: IESO Planning Publications of Resource Adequacy Assessments



Source: IESO presentation, 2020 Technical Planning Conference.[59]

Although the APO is identified as the report to be used for investment planning, in May 2020 the IESO confirmed to the Panel that the Reliability Outlook (primarily an outage planning document) and the "Reliability Assurance" (for which no report or methodology has been made public) are also used in the investment planning exercise. As of July 2020, there has been no correction or update to any IESO planning documentation to inform stakeholders of this change in approach.

[59] See the IESO's presentation "Resource Adequacy and Transmission Key Insights" dated February 19, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/tech-conf/2020/TechnicalPlanningConference-Resource-Adequacy-Transmission-Key-Insights.pdf?la=en

3.2.2 Reliability Planning Standards in Ontario Related to Capacity

The IESO has responsibility for maintaining the reliability of the electricity grid in Ontario. Part of this responsibility involves assessing the adequacy of electricity resources to meet electricity demand, taking into consideration demand forecast uncertainty, generator availability and transmission constraints. The basic methods and criteria that the IESO uses in these assessments are outlined in the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) document, an Ontario-specific document that adopts the reliability adequacy planning standard set by the relevant standards authority.

In Ontario, two entities are recognized as "standards authorities" that approve standards or criteria applicable both in and outside Ontario: the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC).

NERC is recognized by jurisdictions in the U.S. and Canada as a reliability standards-setting organization with an oversight role in North America, relying on regional entities (like NPCC in the case of Ontario) to develop appropriate planning criteria related to resource adequacy. The main planning reliability standard relating to resource adequacy – as it applies to Ontario – is from NPCC. The ORTAC adopts the NPCC reliability adequacy planning standard for Ontario. The document states that the IESO adheres to this NPCC standard for resource adequacy planning for both the short- and long-term time horizons, although ORTAC also specifies that EOPs will not be considered for longer term planning.

The underlying NPCC standard for resource adequacy assessments states that "[…] the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 days per year".[60] This means there should be sufficient supply resources to meet demand for 99.97% of the days of the year, as calculated probabilistically.

[60] See the NPCC's "Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System", page 6, revised September 30, 2015: https://www.npcc.org/Standards/Directories/Directory1_Design%20and%20Oper_20200305.pdf

The NPCC standard further stipulates that as well as the forecast demand and supply, the assessments shall be carried out probabilistically with due allowance for the following:

- Demand uncertainty,
- Scheduled outages and de-ratings,
- Forced outages and de-ratings,
- Assistance over interconnections with neighbouring areas and regions,
- Transmission transfer capabilities, and
- Load relief from operating procedures.[61]

The parameters chosen for these elements can impact the magnitude of the capacity need.

Of particular interest is the reference to taking “assistance over interconnections with neighbouring areas and regions” – in other words, imports – into account. Economic (non-firm) imports, as used here, are defined as import transactions that occur based on economic forces when prices align, unlike firm imports which represent a contractual obligation to provide Ontario with a specific amount of import capacity. Economic (non-firm) imports can be included in capacity assessments based on what the Planning Coordinator (in Ontario, the IESO) has deemed probabilistically likely to be available from neighbouring jurisdictions, as well as how much risk the Planning Coordinator is willing to take since these imports are not guaranteed to be available.[62] As with the capacity assessment itself, probabilistic analysis would indicate the amount of economic imports that could be available at varying risk levels.

[61] Ibid, page 6. Typically in Ontario, adequacy assessments have included: demand uncertainty related to historical variations in weather, scheduled outages as identified by market participants explicitly in the short-term and through historical patterns in the longer term, forced outages based on actual market participant performance, transmission capability as a function of the system topography, load relief in the short-term including emergency actions, such as voltage reductions.

In the case of determining capacity need, the non-firm imports that could occur during system peak would be considered. As demand rises toward the Ontario system peak, increasingly costly resources will be dispatched, causing energy market prices in Ontario to rise. If other jurisdictions have spare generating resources and are not peaking at the same time, prices in these jurisdictions would be lower than in Ontario. This higher Ontario price can give market traders opportunities at the interties to make “economic import” transactions from neighbouring jurisdictions into Ontario. Under such conditions, it is reasonable to assume that some amount of economic non-firm imports will be available to meet peak demand, reducing the need to procure firm resources in Ontario.

Although the ORTAC does not preclude the consideration of economic imports, the IESO’s principal investment planning report – the APO – does not consider economic imports.

The IESO has identified economic imports as being under consideration in this year’s Annual Planning Outlook.

3.3 Treatment of Economic Imports

The IESO is inconsistent in its treatment of economic import assumptions in current planning reports, and has also been inconsistent historically, having previously included economic imports in its long-term planning assumptions to inform procurement decisions.

A study conducted by NPCC in 1999 (with participation from Ontario) determined that Ontario could increase economic imports beyond the 700 MW level that was being assumed at the time.[63] Less than a decade later, the IESO reduced the amount of economic imports assumed

[63] See NPCC’s “Review of Interconnection Assistance Reliability Benefits” dated May 12, 1999, page 17, “Ontario Hydro must consider increasing the amount of interconnection assistance used in its reliability studies”, available at:
https://www.npcc.org/Library/Interconnections%20Assistance%20Reliability%20Benefits/Review_of_Interconnection_Assistance_Reliability_Benefits.pdf

to 500 MW when providing input to the OPA as it was developing its inaugural IPSP.[64] In subsequent inputs to the long-term planning process, the IESO has reduced the amount of economic imports considered in their resource adequacy calculations to 0 MW.

The APO does not assume any economic imports. The only explanation provided as to why economic imports are not included in the APO assessment is "in order to model the system for a self-sufficient Ontario as per ORTAC requirements" (underlining added), a statement that does not appear in ORTAC and is only an interpretation of the criteria.[65,66] In fact, ORTAC – an IESO document – states clearly that the NPCC criterion should be the ultimate guide, criterion that explicitly states economic imports should be considered. NPCC periodically undertakes a study – the Review of Interconnection Assistance Reliability Benefits – to assess the amount of economic imports that could be available from the member jurisdictions.[67] The most recent NPCC study estimates the amount of non-firm imports potentially available to Ontario during the 2024 summer peak period varies between 3,663 MW to 3,789 MW, which is within the

[64] As referenced from the IESO's Ontario Reserve Requirements to Meet NPCC Criteria, Supporting Evidence – for Ontario Power Authority Integrated Power System Plan, dated September 28, 2007: "Support from Ontario's 5 interconnected neighbours was set to a maximum of 500 MW of imports in any hour where Ontario generator outages exceeded 500 MW. This is much less than the approximate 4,000 MW aggregate transfer capability of all of Ontario's interconnections. The 500 MW quantity is the maximum import quantity a generator can purchase to cover a planned outage under current market rules. Although NPCC criteria allow for a greater reliance on interconnections than considered in this study, OPA elected to adopt this particular planning approach since, currently, there are no firm power purchase contracts from outside of Ontario that are assumed in its supply mix scenarios." This document is not currently available online to the public but is accessible by the IESO's staff.

[65] See the IESO's Annual Planning Outlook report, dated January 2020, page 24: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Jan2020.pdf?la=en

[66] See the IESO's Ontario Resource Transmission Assessment Criteria (ORTAC): http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[67] Although the term "economic imports" is used throughout this report to imply non-firm imports, in this instance, assistance over the interconnections is referred to as only non-firm imports as the model used by NPCC is not an economic dispatch tool.

technical capability of the interties for Ontario of 5,910 MW.[68] While these levels of interconnection support may be somewhat higher than can be used for reliability purposes, this study demonstrates that significant support can be reasonably assumed.

The IESO stated an intention to investigate utilizing economic imports in 2015. In January 2020, the IESO announced at their Technical Planning Conference that a review would be undertaken of all resource adequacy-related reliability standards and their assumptions, including specifically economic imports. [69,70] The stakeholder engagement announced at the beginning of 2020 relating to this review has since been postponed. The Panel believes that the IESO should undertake a study to determine what level of economic imports should be included in the APO analysis of capacity needs. Assuming an estimated and appropriate level of economic imports could avoid unnecessary capacity acquisitions and reduce costs for ratepayers.

[68] NPCC has carried out studies to determine the amount of economic imports available for each of the interconnected jurisdictions in the northeast. For more information, see the NPCC's "Review of Interconnection Assistance Reliability Benefits" dated December 16, 2019, page 13: https://www.npcc.org/Library/Interconnections%20Assistance%20Reliability%20Benefits/RCC%20Approved%202019_December_16_Tie_Benefit_Report.pdf

Recommendation 3-1

The IESO should produce a report that probabilistically assesses the level of economic (i.e. non-firm) imports that would be appropriate to assume in their various resource adequacy studies for each year in the planning timeframe, with stakeholder input, using the Northeast Power Coordinating Council Review of Interconnection Assistance Reliability Benefits study as a reference.

While the APO does not assume any economic imports, other reports used by the IESO for planning purposes use economic imports as needed in some scenarios, citing the NPCC economic imports study to support the assumptions.[71]

Previous internal compliance reports published by the IESO discussed economic imports as an option to address any capacity needs. The 2018 internal compliance report (ORMR) stated that the calculated capacity shortfall in 2023 of approximately 1,300 MW is “well within the amounts the IESO can expect from its neighbours”, referencing an economic imports study (Review of Interconnection Assistance Reliability Benefits) by NPCC from 2015.[72]

The IESO assumes up to 501 MW of economic imports for 2023 when reporting directly to NPCC on its five-year External Compliance Report (Comprehensive Review of Resource

[71] See the NPCC’s “Review of Interconnection Assistance Reliability Benefits”, dated December 16, 2019:

https://www.npcc.org/Library/Interconnections%20Assistance%20Reliability%20Benefits/RCC%20Approved%202019_December_16_Tie_Benefit_Report.pdf

[72] 2018 was the final year that a complete Internal Compliance Report (ORMR) was published. A brief slide deck was published for 2019, and as noted above the APO will supersede the ORMR for 2020. See the IESO’s report “Ontario Reserve Margin Requirements From 2019 to 2023” dated December 21, 2018, page 14, “The implied capacity requirement is approximately 1,300 MW, without the use of emergency operating procedures. This amount is well within the amount of non-firm imports (tie benefit support) the IESO can expect from its neighbours", available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/Ontario-Reserve-Margin-Requirements-2019-2023.pdf?la=en

Adequacy) showing it has met the 0.1 days/year loss of load expectation criterion.[73] The IESO also includes up to 2,000 MW of economic imports in its Outage Planning document (Reliability Outlook).[74]

In a stakeholder comment, OPG pointed out the inconsistencies between the short-term (Reliability Outlook) and long-term (APO) reports, noting that the former references an extreme weather scenario whereas the latter uses normal weather.[75] The Panel notes that using extreme weather for the Reliability Outlook (RO) decreases the summer "reserve above requirement" by approximately 2,000 MW to 3,000 MW, but this is offset by the assumption of 2,000 MW of economic (non-firm) imports.[76]

The IESO should clearly explain why methodological differences exist between resource adequacy documents that are said to meet the same planning standard of 0.1 days per year loss of load expectation.

[73] For 2023, under a median scenario, up to 501 MW of economic imports are assumed and under a high demand growth scenario, up to 2,707 MW of economic imports are assumed. See the IESO's report "NPCC 2019 Ontario Interim Review of Resource Adequacy For the Period from 2020 to 2023", dated December 3, 2019, Page 6: https://www.npcc.org/Library/Resource%20Adequacy/IESO%202019%20Interim%20Review%20for%20RCC%20v3.0%20for%20posting%20(003).pdf

[74] See the IESO's Reliability Outlook report (January 2020 to December 2024), dated December 31, 2019, page 1: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2019Dec.pdf?la=en

[75] See Ontario Power Generation Inc.'s letter "re February 19, 2020 Technical Planning Conference Feedback" addressed to IESO Engagement, dated March 17, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/tech-conf/2020/technical-planning-conference-ontario-power-generation.pdf?la=en

[76] The IESO refers to the "Reserve Above Requirement" for justifying procurement where it refers to a capacity need, but also for outage planning where it is not referring to a capacity need. The "adequacy threshold" used for outage approval" is set at 2,000 MW below the Reserve Above Requirement, representing the assumed 2,000 MW of economic imports. For more information, see the IESO's Reliability Outlook report (April 2020 to September 2021), page 16, Figure 4-3: http://ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2020Mar.pdf?la=en

The Panel urges the IESO to reconcile, or at least explain, these apparent inconsistencies and improve transparency regarding such assumptions.

Recommendation 3-2

The IESO should better align the assumptions used in planning documents on an ongoing basis or explain in detail the reason for remaining differences, with quantities. This should address, at a minimum, differences in economic import assumptions and different weather scenarios that lead to different capacity need outcomes.

3.4 Transparency Concerns

The IESO has opened up the planning process to stakeholders, by introducing a Technical Planning Conference that accompanies the release of the APO. Feedback from the 2020 Technical Planning Conference includes stakeholder requests for more granular data, greater clarity on the methodology and increased transparency on assumptions relating to resource adequacy.[77]

3.4.1 Lack of Transparency on Capacity Need

The APO seeks to help Market Participants make informed investment decisions, yet the 2020 APO report does not clearly set out its role in addressing the stated needs. The document describes itself as a technical report which identifies needs without recommending specific resources or mechanisms to address them. However, certain capacity options are discussed at length and the executive summary concludes – without quantitative analysis – that capacity needs in the mid-2020s can be primarily met by existing and available resources. This statement could be interpreted as an observation, a recommendation, or an indication of the IESO's intentions. The vague language used within the 2020 APO report regarding capacity needs being addressed remains open to interpretation, an undesirable outcome for an annual planning document meant to inform the market on potential upcoming investment opportunities.

The need for clarity in messaging from the IESO extends beyond published reports – the term "existing and available resources" addressing capacity needs for the coming decade has been in use for some time and across many platforms, including speeches, stakeholder presentations, social media and podcasts.[78, 79, 80, 81] Despite the widespread use, the phrase is not clear, as is evident in the Ontario Energy Board's (OEB) interrogatory process when the IESO was asked to clarify what it meant in its 2019 rate Application.[82] The statement has also

[78] See the speech from the IESO's President and CEO Peter Gregg to the APPrO conference, dated November 21, 2019, "This need is initially limited to only a few hours a year and can be met cost-effectively by acquiring capacity from existing and available resources", available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/media/PGregg-APPrO-20191121.pdf?la=en

[79] See the IESO presentation to the Stakeholder Advisory Committee "Capacity Update", dated August 19, 2019, "over the next decade Ontario has a limited need for new-build capacity if existing Ontario resources are reacquired when their contracts expire", available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/sac/2019/sac-20190814-capacity-update.pdf?la=en

[80] See the IESO's Twitter account post dated January 22, 2020, "To wrap up: we are in a stable supply situation, with enough existing and available resources to meet our needs for next 10 years.", available at: https://twitter.com/IESO_Tweets/status/1220075146792374272

[81] See the IESO's podcast page "Power Tomorrow Podcast: Addressing the New Realities of Ontario's Electricity Supply System", dated January 27, 2020, "with enough existing and available resources to meet the province's needs for the next decade.", available at: http://www.ieso.ca/en/Powering-Tomorrow/Technology/Powering-Tomorrow-Podcast-Addressing-the-New-Realities-of-Ontarios-Electricity-System

[82] See the IESO's Application for Approval of 2019 Expenditures, Revenue Requirement, and Fees (EB-2019-0002), OEB Staff Supplementary Interrogatories, dated September 25, 2019, page 35, "Staff-42, Ref: Updated Evidence (August 26, 2019), C-2-2, Page 1, Exhibit C-2-2 Page 1 states:

'The revised approach reflects an update in the IESO's planning outlook which indicates that, over the next decade, there is enough energy to meet provincial demand and a limited need for additional *capacity if existing Ontario resources are reacquired when their contracts expire*. These limited capacity needs can be met through existing and available resources such as demand response, imports, generators coming off long-term contracts, uprates and energy efficiency.' [Emphasis added] been questioned in an article published by the Association of Power Producers of Ontario (APPrO) following the release of the 2020 APO report, that states “a number of consultants and Market Participants seem to interpret the situation differently, even though they are relying on the same basic data”.[83] Greater transparency relating to how the IESO will address the needs and how the APO informs these plans would improve the clarity of communication.

3.4.2 Lack of Transparency on Justifying Procurement Targets

As noted above, while the APO is identified as the investment planning document, the IESO also uses for that purpose the outage planning document (Reliability Outlook) as well as a new analysis that has not been published, referred to as the Reliability Assurance.

The Reliability Outlook, which is normally considered only for outage planning, has recently been added as a basis for justifying procurement. The IESO should be clear to stakeholders which sections of the report are being applied strictly for outage planning, and which sections are being applied to justify procurement.

The Reliability Assurance concept used to justify procurement is new, with no documented methodology and no analysis presented. Only the annual capacity amounts of Reliability Assurance – which underpinned the deferred Capacity Auction that was to take place in 2019

(a) Please further explain what is meant by the term ‘available resources’ in contrast to ‘existing resources’ in the excerpt above.

“RESPONSE: (a) existing resources refers to physical resources currently operating in Ontario. The IESO believes that there may be additional capacity available from demand response, imports, uprates, and energy efficiency.”, available at: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653629/File/document

[83] See the APPrO Magazine article “First Annual Planning Outlook released”, dated February 2020: https://magazine.appro.org/news/ontario-news/6194-1582419911-first-annual-planning-outlook-released.html

– are shown in a presentation to stakeholders.[84] One stakeholder pointed out that the IESO changed the target capacity for the auction "and there was no real mention as to why", leading the IESO to acknowledge that they did not "effectively communication (sic) the use of the [Reliability Assurance] value for the target capacity".[85]

The investor uncertainty that arises when the resource assessments in the APO and Reliability Outlook reports show differing capacity needs using different weather conditions and economic import assumptions is compounded by the introduction of a separate, non-transparent process to set procurement targets with Reliability Assurance.

3.4.3 Lack of Transparency Relating to Evolving Capacity Auctions

As noted in section 3.1.2, the progression towards a market-based mechanism to procure capacity has proceeded in fits and starts in recent years. Most recently, the IESO has stated that it was suspending work on efforts to evolve the Capacity Auction, addressing only the two auctions that would provide capacity until May 2023 – just prior to the stated summer peak capacity need.[86]

As of July 2020, it is unclear what the IESO is planning in terms of future procurements beyond 2020.

As generation contracts expire, there is a greater chance of generators exiting the market, possibly increasing the capacity need. It is paramount that the IESO send clear market signals

[84] See the IESO presentation "Transitional Capacity Auction – Draft Phase I Design" dated April 18, 2019, slides 10 to 13: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mocn/mocn-20190418-TCS-draft-phase1-design.pdf?la=en

[86] The IESO stated "We had expected to execute a second auction in March of 2021 for the one-year commitment period starting May 2022. We will continue to update stakeholders as results from the planning updates become available." in an IESO Engagement email to stakeholders "Capacity Auction", dated April 3, 2020, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ca/ca-20200403-communication.pdf?la=en

relating to capacity needs and subsequent procurements, providing sufficient information to stakeholders to make informed investment decisions. The lack of clarity on future auctions may lead to contract extensions as the capacity need becomes more imminent – the outcome that market-based procurements were meant to avoid.

Recommendation 3-3

The IESO should examine and report on potential improvements to its communications with stakeholders regarding the process(es) used to assess the need for and procure resources to meet future capacity needs. The IESO should also provide greater clarity regarding the documents used to inform those procurements and how any auction or procurement targets are set. In particular:

- ***the IESO should publish the analysis and methodology for the Reliability Assurance concept, which appears to be the basis for procuring capacity for the Capacity Auction scheduled for the winter of 2020/21; and***
- ***the IESO should explain the purpose of the Reliability Outlook, including a clear indication of which sections of that report may be used for outage planning, which sections (if any) may be used to inform procurements, and which sections have been included for informational purposes only.***

Recommendation 3-4

The IESO should periodically make available clear descriptions of the range of potential resources that may need to be procured, including the volume (MW), timelines, any required characteristics other than capacity (e.g. energy, ramp, etc.) and expected procurement mechanism (e.g. through capacity auctions, and/or alternative mechanisms) as part of its communication of future capacity needs in reports such as the Annual Planning Outlook.

<u>Recommendation 3-5</u>

The IESO should signal its confidence in different planning assumptions by publishing the uncertainty values associated with relevant assumptions and elements used to calculate the capacity need, including at a minimum a range of economic imports and a range of possible demand forecasts based on underlying economic drivers.

3.5 Oversight of Capacity Need Assessment and Procurements

The IESO currently makes provision for some limited involvement of stakeholders in respect of its resource adequacy processes. The IESO is therefore acting essentially as its own reviewing and approving body in terms of its resource adequacy assessment, with no independent, objective oversight of the assumptions and methodology used in the adequacy assessment analysis.[87] As discussed above, there are areas where the process is not sufficiently transparent. A stakeholder comment from APPrO expressed disappointment with the postponed resource adequacy stakeholder engagement, requested more transparency on assumptions relating to reserve margins, and requested increased dialogue on modelling assumptions while noting other jurisdictions have an objective review process.[88]

As noted above, for some period in the past there was to be oversight of resource planning and procurement through the OEB's review of the OPA's IPSP and procurement processes.

[87] The NPCC provides guidance on reliability criteria but does not assess the accuracy or dependability of the data provided by the jurisdictions.

[88] See APPrO's comments "re the Annual Planning Outlook and Technical Conference, Feb 19, 2020". http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/tech-conf/2020/technical-planning-conference-appro.pdf?la=en

In other jurisdictions, the reference margin levels are reviewed or approved by either a public utilities board, a public service commission, a reliability council, member utilities, or the Independent System Operator (ISO) board of directors.[89] A similar approach should be considered for Ontario as a means to improve transparency and clarity, which appear to be lacking today.

Greater stakeholder involvement in – and independent oversight of – the assumptions and methodologies underlying resource adequacy assessments could increase confidence and trust and enable Market Participants to make better- informed investment decisions. Investment decisions must be made well in advance of anticipated capacity needs, and lack of confidence and clarity in relation to the magnitude and timing of capacity needs may cause some investors to inflate their project costs. Were that to be the case, costs for ratepayers would also increase, with the burden falling primarily on Class B consumers that pay the lion's share of the Global Adjustment. With the current focus on cost reductions in electricity rates, planning for investments that will increase rates should be reviewed by an objective third party. The OEB would be well-placed to resume this role.

Recommendation 3-6

The IESO should examine and report on potential improvements to its stakeholder engagements regarding the methods and assumptions used to develop capacity needs. Specific consideration should be given to a periodic streamlined process to review the case for procuring existing or new resources that involves stakeholders and is overseen by an objective third party.

[89] See the North American Electricity Reliability Corporation (NERC) 2019 Long-Term Reliability Assessment, page 42: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

Appendix A: Market Outcomes for the Summer 2018 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Summer 2018 Period (May 1, 2018 to October 31, 2018), with comparisons to previous reporting periods as appropriate.

A.1 Pricing

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

Table A-1: Average Effective Price by Consumer Class and Period ($/MWh)

Customer Class	Average Weighted HOEP ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Effective Price ($/MWh)
Class A – Summer 2018	19.14	53.68	3.16	75.98
Class A – Winter 2017/18	19.23	47.52	2.89	69.65
Class A – Summer 2017	10.13	54.27	2.38	66.78
Class B – Summer 2018	24.59	95.98	3.71	124.27
Class B – Winter 2017/18	23.11	87.51	3.15	113.77
Class B – Summer 2017	12.72	110.17	2.77	125.66
All Consumers – Summer 2018	*N/A*	*N/A*	*N/A*	110.34
All Consumers – Winter 2017/18	*N/A*	*N/A*	*N/A*	101.79
All Consumers – Summer 2017	*N/A*	*N/A*	*N/A*	110.31

Table A-1 summarizes the average effective energy price in dollars per MWh by consumer class for the Summer 2018 Period (May 1, 2018 to October 31, 2018), Winter 2017/18 Period (November 1, 2017 to April 30, 2018) and the Summer 2017 Period (May 1, 2017 to October 31, 2017).

The effective price is the sum of the HOEP, the GA and the uplift charges paid by a given class of consumers (whose nominal sum equals total system cost), divided by the total quantity of energy consumed.[90] Accordingly, it captures the hourly market price, payments under IESO reliability and other programs, prices payable for contracted and regulated generation and the costs of conservation and Demand Response (DR) programs. It does not include all charges that appear on electricity bills, such as charges for transmission and distribution. Results are reported for three consumer groups: "Class A consumers", "Class B consumers" and "All Consumers".[91] The "All Consumers" group in Table A-1 represents what the effective electricity price would have been for all consumers if they all paid GA on a volumetric basis.[92]

Starting with the Panel's Monitoring Report 29 (May 2016-Oct 2016) published in March 2018, the Panel moved embedded Class A consumers from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table A-1.[93]

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

[91] Consumers are divided into two groups: Class A, being consumers with an average monthly peak demand less than 5 MW but greater than 1 MW (or 500 kW for some sectors) that have opted into the class as well as consumers with an average monthly peak demand greater than 5 MW that have not opted out of the class, and Class B, being all other consumers. For more information, see Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*: http://www.ontario.ca/laws/regulation/040429

[92] Since January 2011, the GA payable by Class A consumers has been based on 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. To the extent that Class A consumers reduce their demand during those hours, their share of GA is reduced. The remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel's Industrial Conservation Initiative Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[93] Following past practice, the Panel assumes that embedded Class A consumers have the same average load profile as directly-connected Class A consumers. Given the change in the Panel's definition of consumer groups (from "Direct Class A" to all "Class A" and from "Class B & Embedded Class A" to just "Class B"), there is no direct comparison to be made between effective prices reported in this report and those from reports issued before the Panel's Monitoring Report 29 (May 2016-Oct 2016) published March 2018. All references to effective price in the Panel's reports going forward – including all tables and figures – reflect the Panel's updated methodology.

The effective price for all consumers was essentially the same in the Summer 2018 Period compared to the Summer 2017 Period. A higher total demand for energy in the Summer 2018 Period compared to the Summer 2017 Period (see Figure A-20) caused the effective HOEP for both Class A and B consumers to increase in the Summer 2018 Period, while an increase in the frequency of Congestion Management Settlement Credit (CMSC) payments, transmission loss payments, Intertie Offer Guarantee (IOG) payments and cost guarantee payments (see Figure A-12) caused the effective uplift for both Class A and B consumers to increase. As explained in further detail below, HOEP and GA costs tend to move inversely to one another. When the HOEP increases, rate-regulated generators receive more market revenue for every MWh of energy that they produce, lowering the compensation through the GA required to meet the regulated rates that these generators receive for every MWh of energy that they produce, thus reducing the GA. The net effect was essentially no change in the average price for all consumers.

The effective price for Class B consumers remained significantly higher than the effective price for Class A consumers in the Summer 2018 Period as shown in Figure A-1. The Class A effective price increased substantially by $9.20/MWh to $75.98/MWh, and the Class B effective price decreased by $1.39/MWh to $124.27/MWh. The increase in the average effective price for Class A was far above the average increase in the Class A effective price over the last five years, which was less than $3/MWh per year. The decrease in the average effective price for Class B strayed away from the average increase in Class B effective prices over the last five years, which was just above $7/MWh per year.

The GA makes up a smaller portion of the effective price of Class A consumers compared to Class B consumers. Therefore, the absolute decrease in the average GA for Class A consumers was smaller than the increase in the average weighted HOEP for Class A consumers, causing the effective price for Class A consumers to increase in the Summer 2018 Period, when compared to the Summer 2017 Period. Conversely, the absolute decrease in the average GA for Class B consumers was higher than the increase in average weighted HOEP for Class B consumers, causing the Class B effective price to decrease in the Summer 2018 Period.

Figure A-1: Monthly Average Effective Electricity Price & System Cost

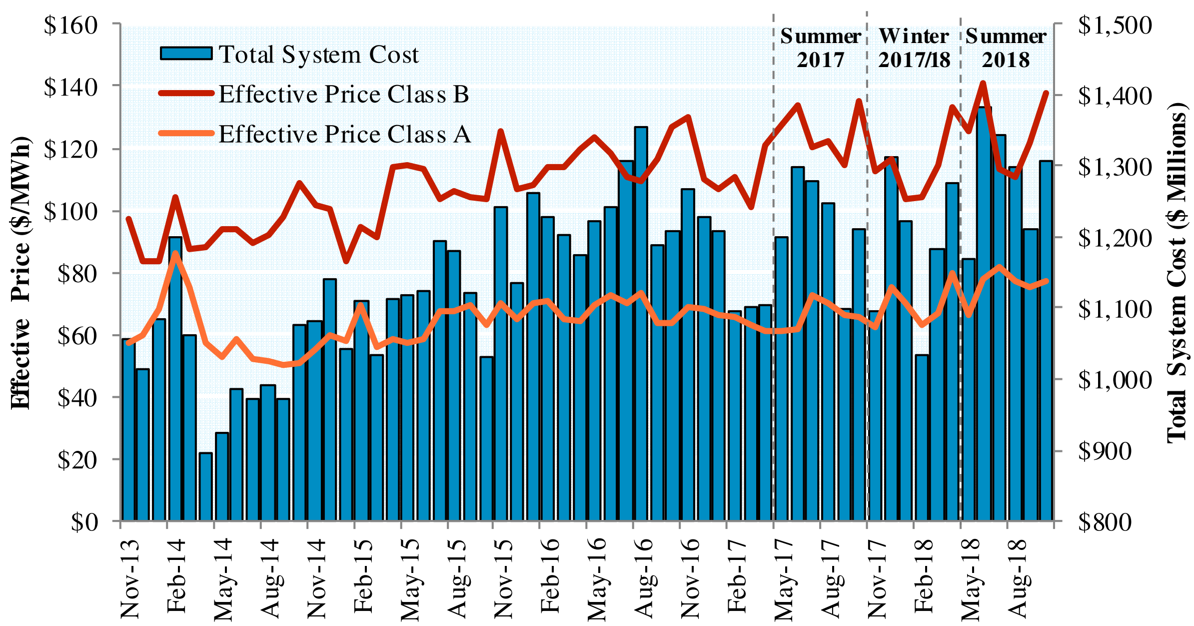

Figure A-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five years.

Total system costs borne by Ontario consumers in the Summer 2018 Period rose 5.1% compared to the Summer 2017 Period, and rose 8.2% from the Winter 2017/18 Period. This increase in system costs across summer reporting periods is slightly above average: over the last five years, total system costs have grown by about 4.4% per year. The increase in total system costs observed in the Summer 2018 Period compared to the Summer 2017 Period was caused by a similar rate of increase of total demand in the Summer 2018 compared to the Summer 2017 Period, resulting in a similar effective price between periods.

The Class A effective price increased significantly between May and June 2018, peaking in July 2018 and gradually declining in August and September 2018. The Class B effective price saw a similar increase in June 2018, but fell sharply in July 2018 before rising quickly again in September 2018 and October 2018. The average slope of the effective price curve for Class A consumers over the last three reporting periods appears steeper than over the preceding two years.

Figure A-2: Average Effective Price for Class A Consumers by Component

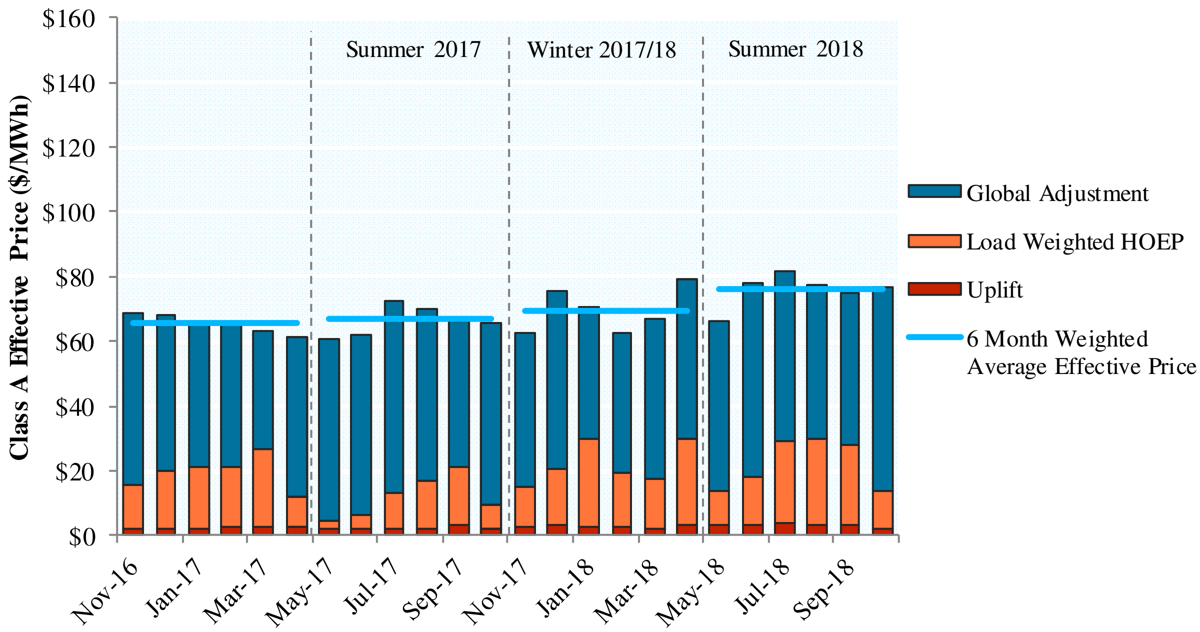

Figure A-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for the previous two years. They also show the total effective price averaged over each six-month period for each consumer class.[94]

[94] The GA is primarily composed of payments to rate-regulated and contracted generators to make up for the difference between the actual market revenues received by these generators (which are dependent on the HOEP, and thus are dependent on demand), and their regulated or contracted rates of revenue set by the OEB. The GA also includes costs associated with various IESO conservation programs. For more information regarding the GA, see the IESO's webpage "Guide to Wholesale Electricity Charges": http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges

The GA is the guaranteed revenue less HOEP and uplift payments. The GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases, but this is not necessarily a one-for-one relationship. A higher GA tends to increase the effective price more for Class B than Class A consumers because the current GA allocation methodology has the effect of allocating to Class A consumers a lower share of GA per MWh consumed than Class B consumers pay.

Figure A-3: Average Effective Price for Class B Consumers by Component

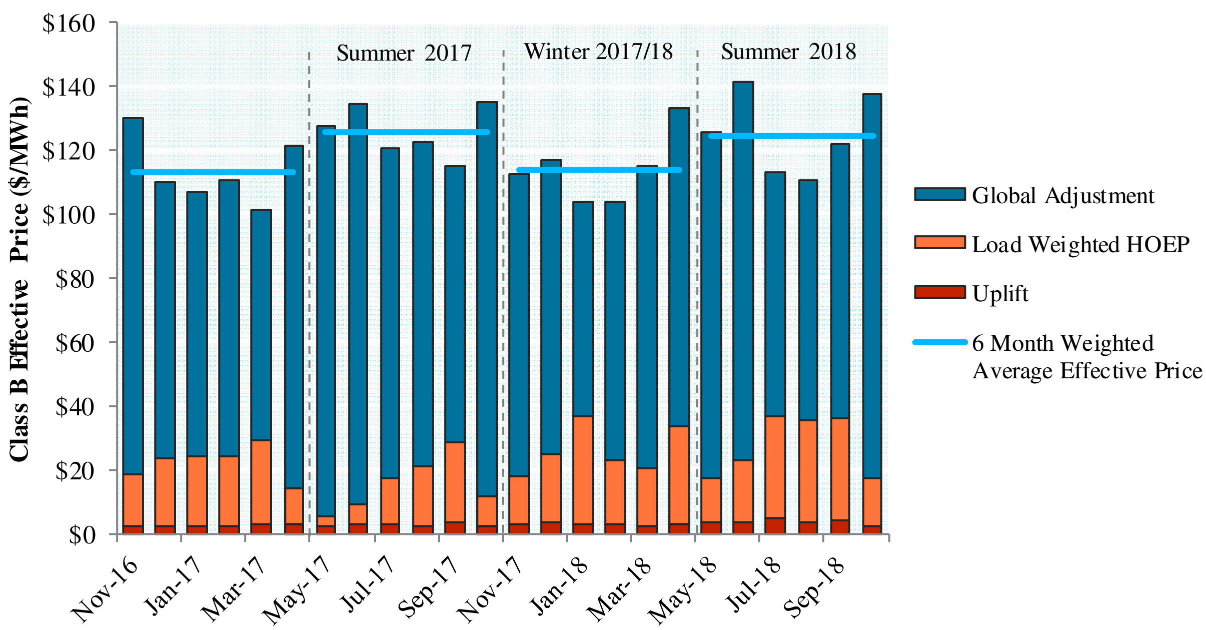

Figure A-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for the previous two years. They also show the total effective price averaged over each six-month period for each consumer class.

On average, Class A prices continued to be higher during months when the HOEP was high, and Class B prices continued to be higher during months when the GA was high. Class B had a particularly high effective price in June and October, when total system costs were above the average in the period, and the HOEP was lower than the average in the period. Conversely, the Class A effective price was highest between June and August, when the HOEP was highest during the Summer 2018 Period.

The Summer 2018 Period saw the six-month average HOEP almost double compared to the Summer 2017 Period, rising from $10.49/MWh in the Summer 2017 Period to $20.92/MWh in the Summer 2018 Period. This leap in average price was driven by the increase in demand for energy in the Summer 2018 Period compared to the Summer 2017 Period. The highest HOEPs in the Summer 2018 Period occurred in July, August and September – these months all had above average temperatures in 2018 compared to previous years, driven in particular by more frequent heatwaves.

Figure A-4: Monthly & 6 Month (Simple) Average HOEP

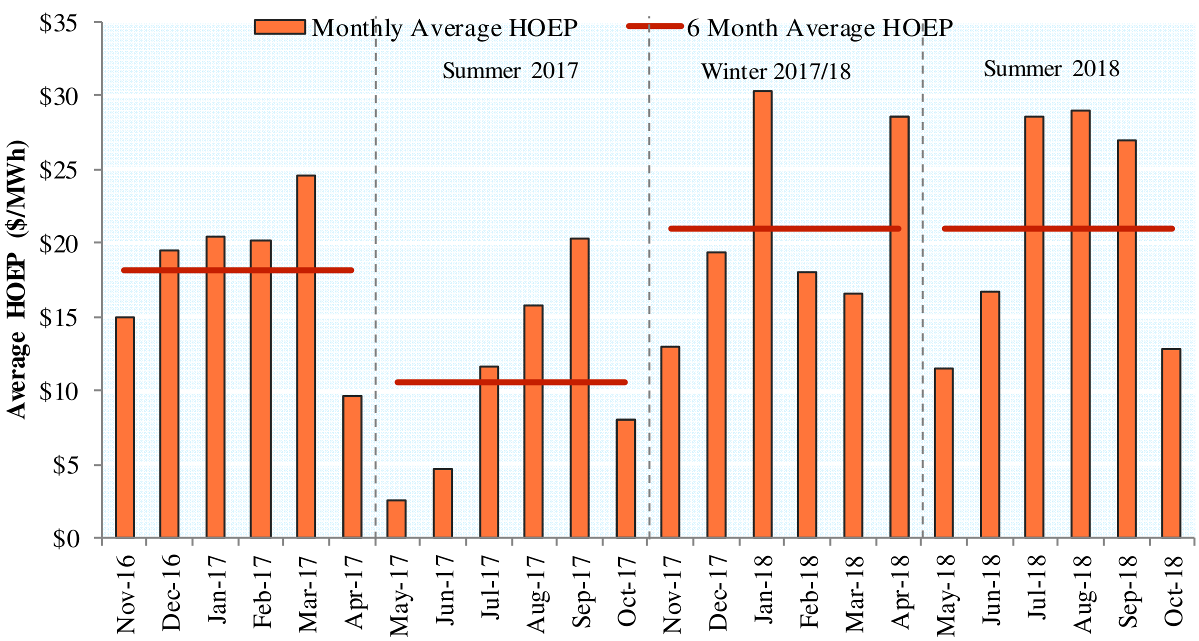

Figure A-4 displays the monthly average HOEP unweighted by the volume of energy consumed in any given interval (the "simple HOEP"), for each month between November 2016 and October 2018. Figure A-4 also displays the simple monthly average HOEP for each six-month period since November 2016. The HOEP is the unweighted average of the twelve Market Clearing Prices (MCPs) set every five minutes within an hour.

The average gas price during on-peak hours was $3.79/MMBtu in the Summer 2018 Period and $3.87/MMBtu in the Winter 2017/18 Period, compared to $3.78/MMBtu in the Summer 2017 Period and $4.31/MMBtu in the Winter 2016/17 Period.

Figure A-5: Natural Gas Price & HOEP during Peak Hours

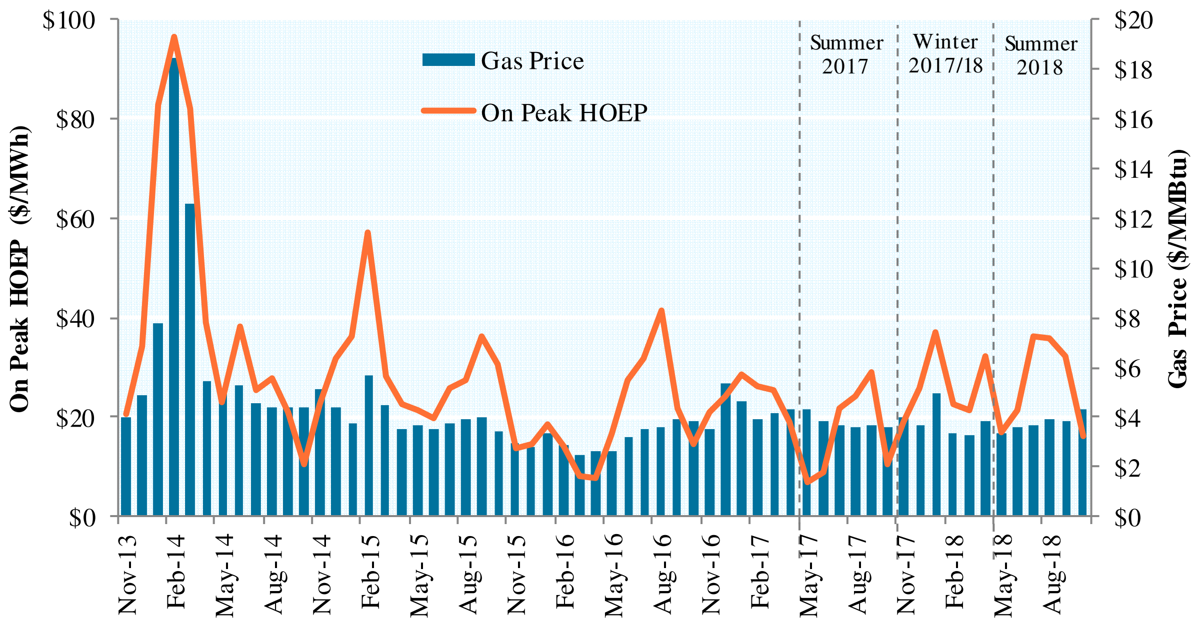

Figure A-5 plots the average monthly HOEP during on-peak hours and the monthly average of Dawn Hub day-ahead natural gas prices for days with on-peak hours for the previous five years.[95] Natural gas prices are compared to the HOEP for on-peak hours as gas-fired facilities frequently set the price during these hours. Gas-fired facilities typically purchase gas day-ahead.

[95] On-peak hours here are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays) to capture all hours when gas generators are likely to be running. Off-peak hours are all other hours.

Figure A-6: Frequency Distribution of HOEP

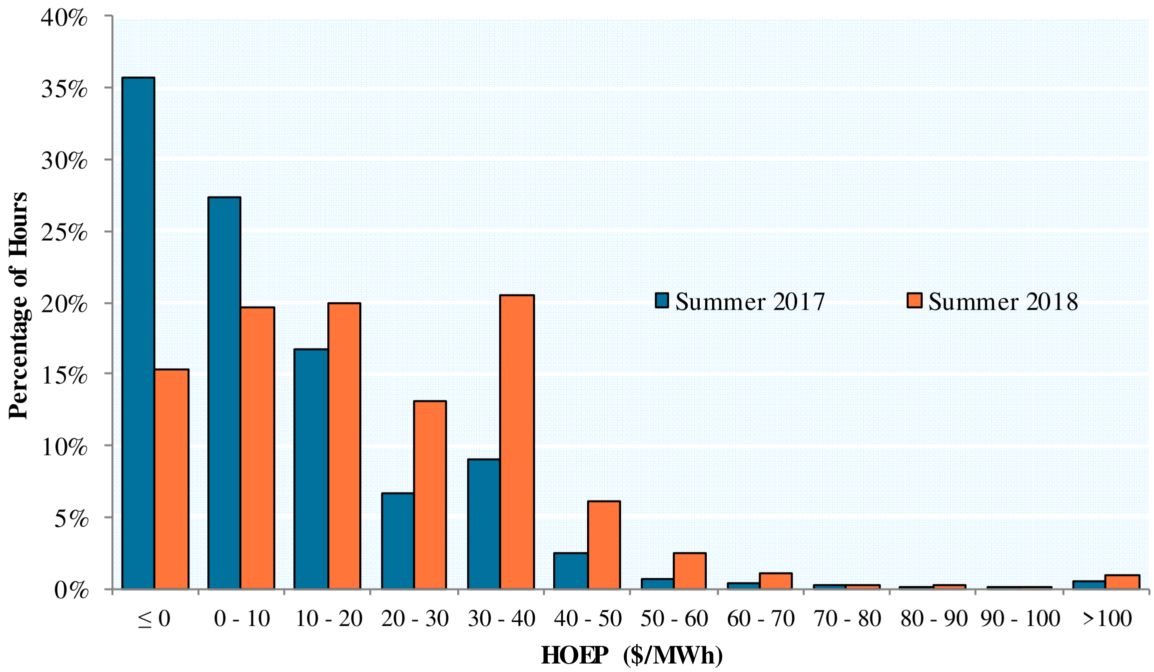

Figure A-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Summer 2018 and Summer 2017 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh values.

A correlation coefficient of 0.08 was observed between average daily natural gas prices and daily averages of on-peak HOEP values during the Summer 2018 Period, which is much lower than in the Winter 2017/18 Period, but higher than that observed in the summer reporting periods over the last two years. A higher correlation between natural gas prices and the HOEP would be expected, as natural gas resources frequently set the Market Clearing Price (MCP) during the months when the HOEP was highest in the Summer 2018 Period (see Figure A-7).[96] Therefore, it is likely that the frequent setting of the MCP by natural gas generators during high-priced hours was primarily influenced by the effects of supply and demand with the price of natural gas having little impact.

The Summer 2018 Period saw a large decrease in the frequency of hours when HOEP was negative or zero, and an increase in the frequency of hours with a more expensive HOEP. Only 15% of hours in the Summer 2018 Period had a negative HOEP, compared to 36% in the Summer 2017 Period, while 45% of hours had HOEPs of at least $20/MWh in the Summer 2018, up from 20% in the Summer 2017 Period. This is likely because demand was higher on average in the Summer 2018 Period than it was in the Summer 2017 Period, causing MCPs to be higher on average. Available supply may have also been a factor; the Summer 2018 Period had more resources on outage than the Summer 2017 Period on average. In particular, more hydro resources were on outage in every month of the Summer 2018 Period compared to the Summer 2017 Period – this would have given gas resources more opportunity to set the MCP (as shown in Figure A-7), which offer energy at higher prices, contributing to the higher frequency of high-priced hours in the Summer 2018 Period.

The percentage of hours that natural gas resources set the real-time MCP increased from 15% in the Winter 2016/17 Period to 38% in the Summer 2018 Period, while the percentage of hours that wind and nuclear resources set the real-time MCP decreased from 32% to 21% and from 11% to 1.6%, respectively. This likely occurred because demand was higher in the Summer 2018 Period than in the Summer 2017 Period, resulting in higher energy market prices and thus more frequent use of natural gas to meet peak demand. Hydroelectric

[96] This outcome assumes that changes in Ontario natural gas prices affect the fuel costs of natural gas generators. Increasing the marginal cost of energy provided by these generators should give these generators the incentive to increase their offer prices, which would cause an increase in energy prices if natural gas generators are setting the real-time MCP. This should result in a positive correlation between natural gas prices and the HOEP.

resources set the real-time MCP during 39% of intervals in the Summer 2018 Period – continuing the trend of setting the real-time MCP more frequently than any other resource.

Figure A-7: Share of Resource Type Setting the Real-Time MCP

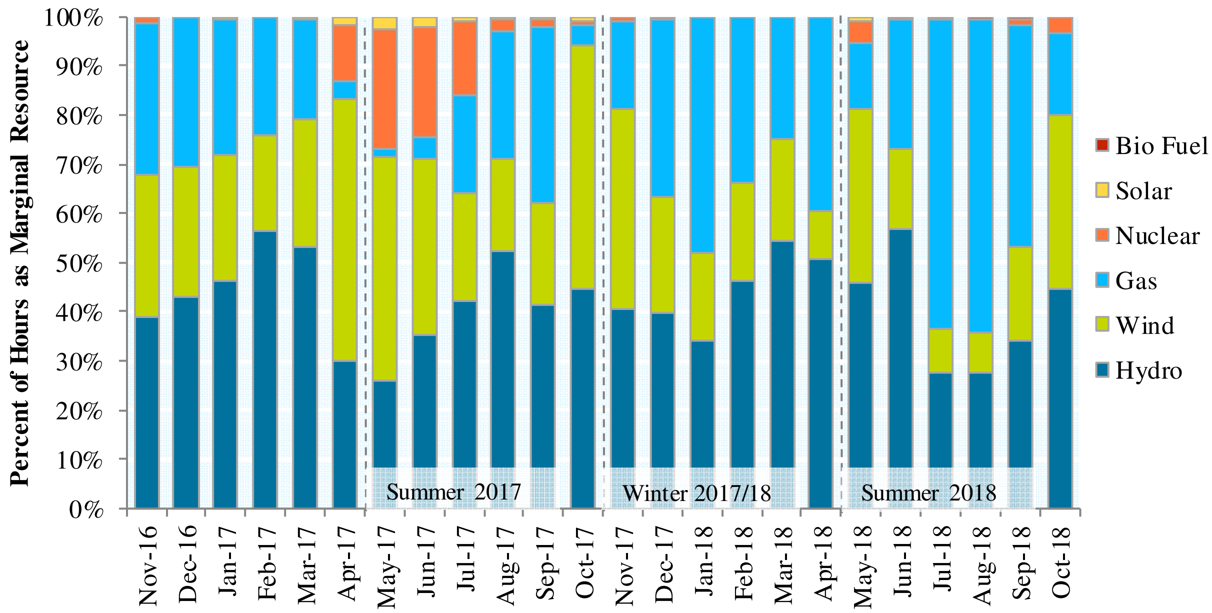

Figure A-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the previous two years. The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

The frequency with which imports and exports set the pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[97] 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.

[97] Due to scheduling protocols, imports and exports are scheduled hour-ahead. In real-time imports and exports are fixed for any given hour and their offer and bid prices adjusted to -$2,000 and $2,000/MWh, respectively. Accordingly, imports and exports are treated as non-dispatchable in real-time and scheduled to flow for the entire hour regardless of the price, though their schedules may be curtailed within an hour to maintain reliability.

Figure A-8: Share of Resource Type Setting the One-Hour Ahead Pre-Dispatch MCP

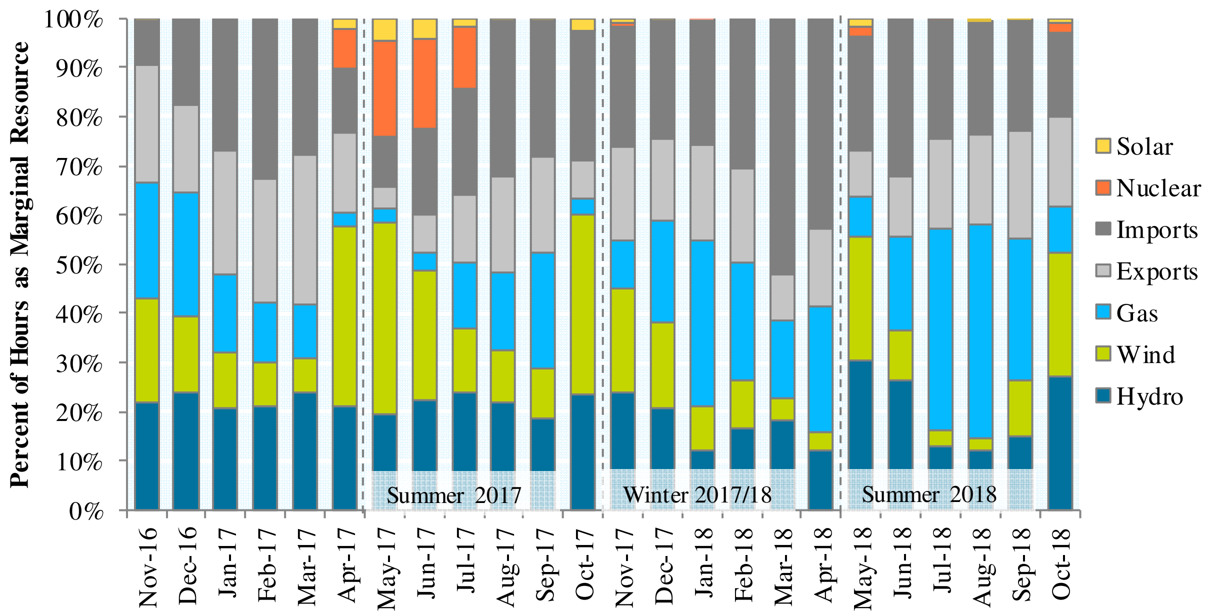

Figure A-8 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP in each month of the previous two years. When compared with Figure A-7, Figure A-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

The mix of resources setting the PD-1 MCP in the Summer 2018 Period saw an increase in natural gas, decreases in wind and nuclear, and a slight decrease in hydro. Gas resources set the PD-1 MCP in 25% of hours in the Summer 2018 Period, compared to 10% in the Summer 2017 Period. The increase in the frequency of natural gas setting the PD-1 MCP in the Summer 2018 Period compared to the Summer 2017 Period was caused by the expectation that demand would be higher in the Summer 2018 Period, resulting in the scheduling of more expensive marginal resources. Wind and nuclear resources saw reductions from 23% and 8% of hours in the Summer 2017 Period to 13% and 1% of hours in the Summer 2018 Period. Hydro saw a reduction from 22% of hours in the Summer 2017 Period to 21% of hours in the Summer 2018 Period.

The proportion of intervals that imports and exports set the PD-1 MCP remained relatively constant between the Summer 2017 and Summer 2018 Periods. Imports set the PD-1 MCP in 23% of hours in the Summer 2018 Period, compared to 22% of hours in the Summer 2017 Period. Exports set the PD-1 MCP in 16% of hours in the Summer 2018 Period, compared to 12% of hours in the Summer 2017 Period.

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.

In the Summer 2018 Period, there was a variation of less than $10/MWh between PD-1 and real-time prices for 78% of hours, down from 85% in the Summer 2017 Period. The average absolute deviation between PD-1 and real-time prices in the Summer 2018 Period of $8.11/MWh was also above the Summer 2017 Period average deviation of $5.63/MWh. Higher demand for energy and greater use of wind generation in the Summer 2018 Period may have contributed to more variability between pre-dispatch and real-time prices.

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time.[98] Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as they enter offers and bids into the market.

[98] 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**: i) Self-scheduling and intermittent generation forecast deviation (other than wind), ii) wind generation forecast deviation, iii) generator outages and iv) import failures/curtailments. **Demand**: v) Pre-dispatch to real-time demand forecast deviation and vi) export failures/curtailments. Imports or exports setting the PD-1 MCP can also result in price divergences as these transactions cannot set the price in real-time.

Figure A-9: Difference between HOEP & PD-1 MCP

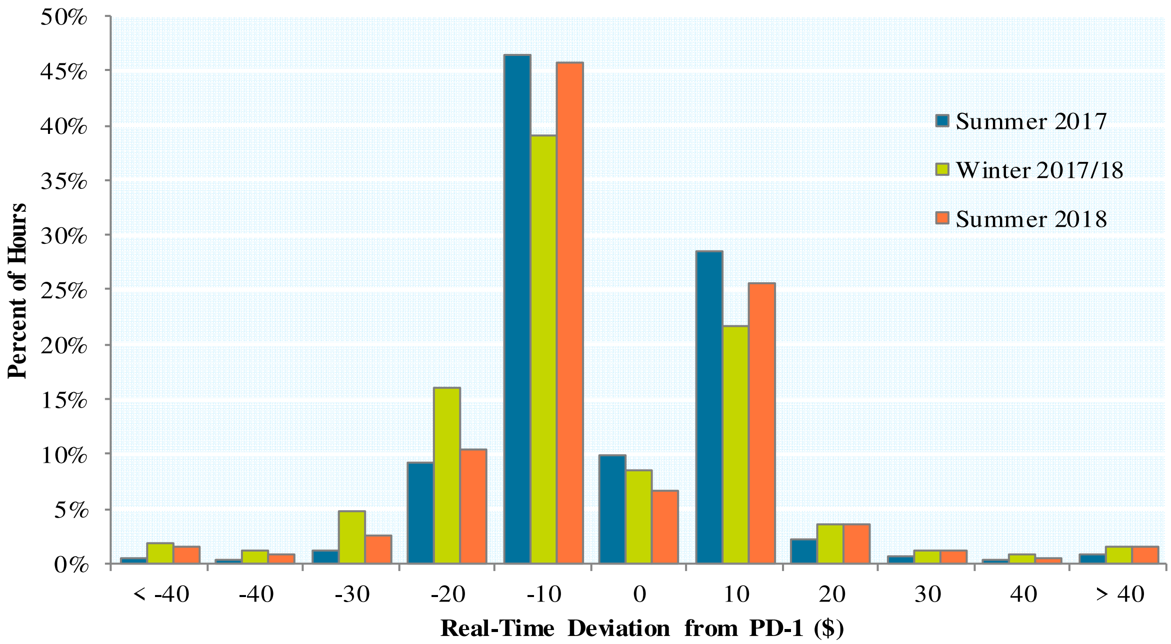

Figure A-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Summer 2018, Winter 2017/18 and Summer 2017 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP, as well as the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$40/MWh. Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease.

Average demand forecast deviation, the most significant source of deviation between PD-1 MCP and HOEP, worsened somewhat in the Summer 2018 Period relative to the Summer 2017 Period. The next most significant source of deviation, wind forecasts, remained relatively constant between the Summer 2017 and Summer 2018 Periods. Total wind output in the Summer 2018 increased compared to the Summer 2017 Period, causing the absolute average deviation of the wind forecast to increase. However, the increase in average energy demand between the Summer 2017 and Summer 2018 Periods resulted in the amount of wind forecast deviation relative to demand for energy to remain about the same between periods. Self-scheduling and intermittent forecast deviation, as well as net export curtailments, also remained relatively constant between the Summer 2017 and Summer 2018 Periods.

Table A-2: Factors Contributing to Differences between PD-1 MCP & HOEP

Factor	Summer 2018: Average Absolute Difference		Winter 2017/18: Average Absolute Difference		Summer 2017: Average Absolute Difference	
	MW	% of Ontario Demand	MW	% of Ontario Demand	MW	% of Ontario Demand
Ontario Average Demand	15,547		15,869		14,629	
Forecast Deviation	250	1.61%	225	1.42%	221	1.51%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	14	0.09%	14	0.09%	14	0.10%
Wind Forecast Deviation	142	0.91%	131	0.83%	131	0.90%
Net Export Failures/Curtailments	63	0.41%	61	0.38%	63	0.43%

Table A-2 displays the average absolute difference between PD-1 and real-time for all of the above-noted factors, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

The three-hour ahead pre-dispatch (PD-3) MCP is the last price signal seen by the market prior to the closing of the offer and bid window. Changes in price between PD-3 and HOEP are particularly relevant to non-quick start facilities and energy limited resources, both of which rely on pre-dispatch prices to make operational decisions.[99] Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

Figure A-10: Difference between HOEP & PD-3 MCP

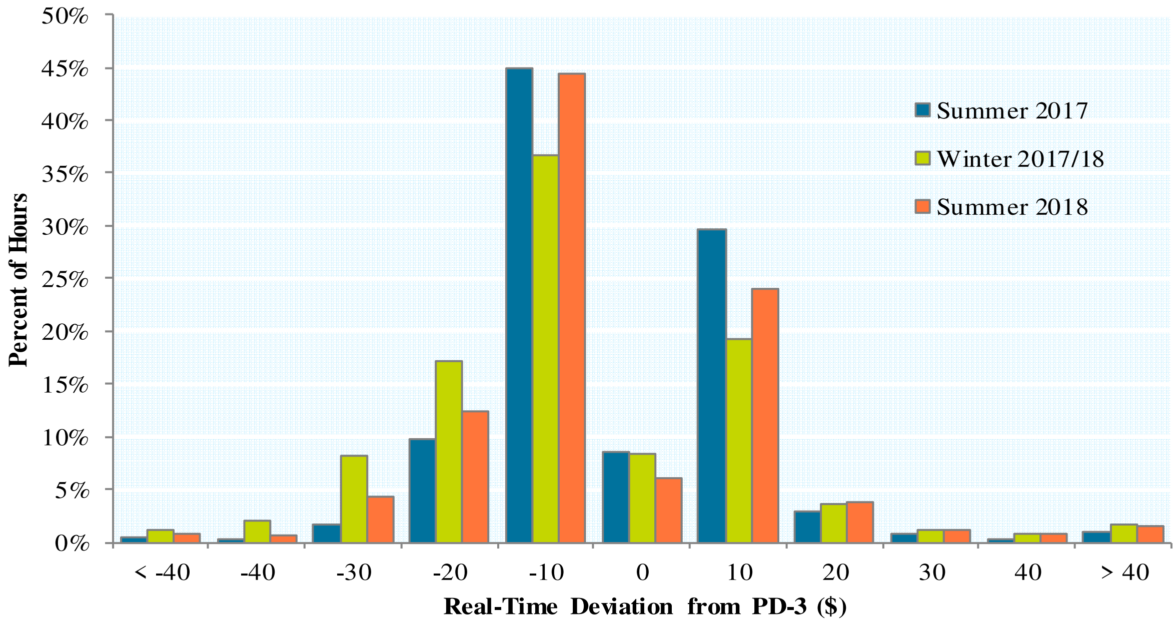

Figure A-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Summer 2018, Winter 2017/18 and Summer 2017 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP, as well as the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$40/MWh. 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.

PD-3 prices were within $10/MWh of the real-time MCP in 75% of hours in the Summer 2018 Period, down from 83% of hours in the Summer 2017 Period. The average absolute deviation between PD-3 and real-time MCPs was also higher in the Summer 2018 Period ($8.32/MWh)

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

compared to the Summer 2017 Period ($5.99/MWh). These trends are closely aligned with the deviations observed in relation to PD-1 prices.

Figure A-11: Monthly GA by Component

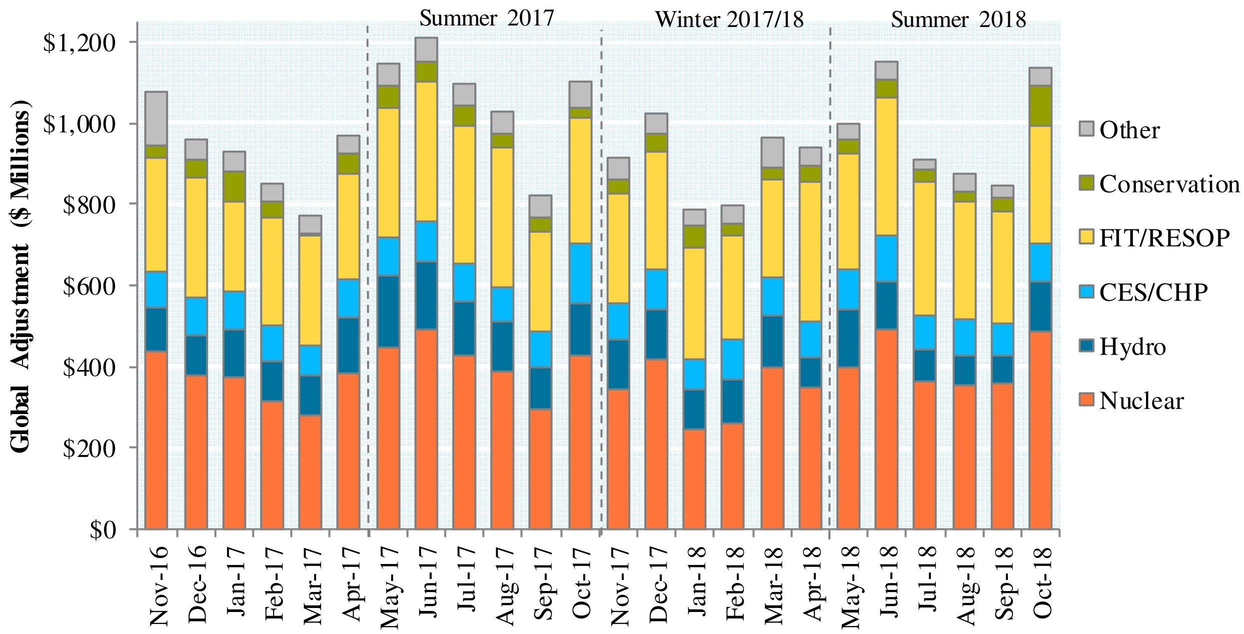

Figure A-11 plots the payments to various resources and recovered through the GA each month by component for the previous two years.

We divide the total Global Adjustment (GA) into six components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station and Ontario Power Generation Inc.'s (OPG) nuclear assets);
- Payments to holders of Clean Energy Supply (CES) and Combined Heat and Power (CHP) contracts;
- Payments to regulated or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff, including microFIT (collectively FIT), and the Renewable Energy Standard Offer Program (RESOP));

- Payments related to the IESO's conservation programs; and
- Payments to others (including to holders of Non-Utility Generator (NUG) contracts and OPG's Lennox Generating Station).

The total GA throughout the Summer 2018 Period was about 7.5% less than the total GA during the Summer 2017 Period, falling from $6.4 billion to $5.9 billion. The increase in demand between the Summer 2017 and Summer 2018 Periods caused the market revenues of nuclear and hydro generators under revenue regulation to increase, resulting in lower payments to meet the requirements of these generators through GA charges. As such, GA payments towards regulated hydro generation fell by about 27% compared to the Summer 2017 Period.

In March 2018, the Ontario Energy Board (OEB) issued a Payments Amount Order in response to OPG's approved request to increase the regulated revenue that OPG earns from its nuclear generation.[100] This increase in total revenue received likely offset the decrease in nuclear GA payments that would have occurred otherwise under higher prices, as observed in the Summer 2018 Period – GA payments towards regulated nuclear generators fell by less than 1% compared to the Summer 2017 Period. Other than payments towards hydro generators, which fell from 13% to 10% of total GA payments in the Summer 2018 Period, the relative contribution of each component to the GA remained largely unchanged.

Hourly uplift components are charged to wholesale consumers (including distributors) based on their share of total hourly demand, while monthly uplift components are charged to

[100] See OPG's Payment Amounts Order dated March 29, 2018 (EB-2016-0152): http://www.rds.oeb.ca/HPECMWebDrawer/Record/603940/File/document

wholesale consumers (including distributors) based on their share of total daily or monthly demand.[101]

Total uplift increased in the Summer 2018 Period compared to the previous three reporting periods. Total uplift in the Summer 2018 Period was $266 million, while Winter 2017/18 Period was $241 million, Summer 2017 Period was $191 million and Winter 2016/17 Period was $199 million. The increase in total hourly uplift was primarily driven by an increase in Congestion Management Settlement (CMSC) payments, transmission losses and Intertie Offer Guarantee (IOG) payments. The increase in total monthly uplift was primarily driven by an increase in cost guarantee payments. Compared to the Summer 2017 Period, total CMSC, transmission loss, IOG and cost guarantee payments rose by $17.8 million, $19.3 million, $23.1 million and $12.1 million (or by 47%, 126%, 182% and 43%), respectively.

The increase in CMSC and transmission loss payments in the Summer 2018 Period can be explained at least in part by the increase in the demand compared to the Summer 2017 Period, as these payments are typically higher when prices are high. Indeed, transmission losses are directly proportional to market prices. A majority of the increase in IOG payments in the Summer 2018 Period can be attributed to a series of events in which the intertie scheduling limit over a Quebec intertie was reduced after a large volume of Day-Ahead Commitment Process imports was scheduled. The day-ahead import offers were reduced to -$2,000/MWh, creating an extremely low Intertie Zonal Price, leading to high IOG payments. These events are described in Chapter 2 of this report. The increase in cost guarantee payments was driven by increases in both RT-GCG payments and Production Cost Guarantee (PCG) payments in the Summer 2018 Period relative to the Summer 2017 Period.

[101] This applies to all monthly and daily uplifts with the exception of costs associated with DR. The costs of DR are allocated with the same methodology as the GA, where Class A consumers pay the fraction of costs corresponding to their fraction of Ontario demand during the 5 highest demand peaks of the year, and Class B consumers are billed the remaining sum volumetrically.

Figure A-12: Total Uplift Charge by Component on a Monthly Basis

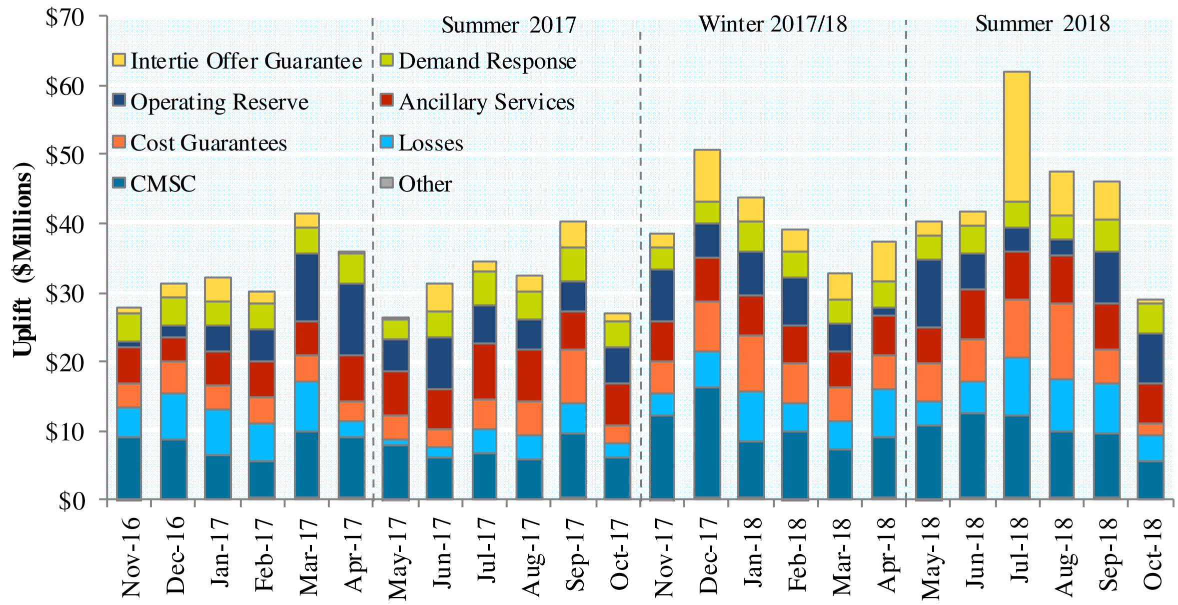

Figure A-12 presents the total uplift charges by component on a monthly basis for the previous two years. This includes both hourly and monthly uplift, which were displayed in separate figures in previous Panel reports.[102] In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while Production Cost Guarantee (PCG) and Real-Time Generation Cost Guarantee Program (RT-GCG) payments are combined as Cost Guarantees.

Average 10S and 30R OR prices increased in the Summer 2018 Period compared to the Summer 2017 Period, from $7.84/MW and $2.26/MW to $8.10/MW and $3.69/MW, respectively. In contrast, 10N prices decreased slightly, from an average of $6.10/MW in the Summer 2017 Period to $5.65/MW in the Summer 2018 Period. The average weighted offer

[102] **Hourly uplift components include**: Congestion Management Settlement Credit (CMSC) payments; Intertie Offer Guarantee (IOG) payments; Operating Reserve (OR) payments; Voltage support payments; and Transmission losses. **Monthly uplift components include**: Payments for ancillary services; Guarantee payments to generators under the Day-Ahead Production Cost Guarantee (PCG) and RT-GCG programs; Payments for the IESO's DR capacity, such as capacity procured through the DR auction; and Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.

prices associated with the offers of the 10S and 30R classes of OR were higher in the Summer 2018 Period than they were in the Summer 2017 Period, and the average weighted offer price of 10N OR was slightly lower in the Summer 2018 Period than it was in the Summer 2017 Period. Fewer offers and higher offer prices in the OR markets are typically associated with higher (Market Clearing Prices) MCPs in the OR markets, as reflected in the increase in the prices of 10S and 30R OR between the Summer 2017 and Summer 2018 Periods.

Figure A-13: Average Monthly OR Prices by Category

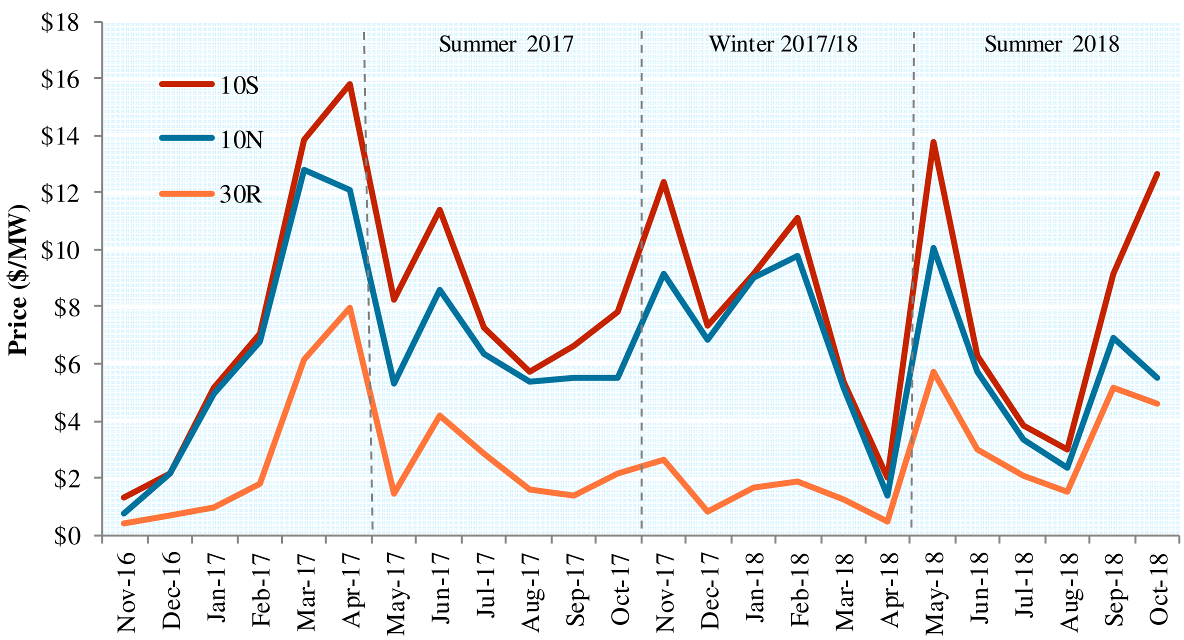

Figure A-13 plots the monthly average OR price for the previous two years for the three OR markets: 10--minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).

The three OR markets are co-optimized with the energy market, so prices in these markets tend to be subject to similar dynamics. The OR demand is non-discretionary because of reliability standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The IESO must schedule sufficient OR to allow the grid to recover from the single largest contingency (such as loss of the largest generator) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes.

The average prices of all three classes of OR followed a similar trend throughout the Summer 2018 Period, with the exception of 10S OR in October 2018, which increased sharply. This was possibly caused by the low quantity of 10S OR scheduled from hydro resources during October 2018. The average hourly scheduled 10S OR from hydro resources fell from 157 MW in September 2018 to only 114 MW in October 2018.

Nodal prices approximate the marginal cost of electricity in each region and reflect Ontario’s internal transmission constraints. High average nodal prices are generally caused by expensive or limited supply while low average nodal prices are generally caused by cheaper or abundant supply.

In general, monthly average nodal prices outside the two northern zones are similar and move together. Most of the time, the nodal prices in the Northwest and Northeast zones are significantly lower than in the rest of the province because there is more low-cost generation than there is demand in these zones, as well as insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

In addition, some hydroelectric facilities operate under must-run conditions, generating 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.

Figure A-14: Average Internal Nodal Prices by Zone

Zone	Summer 2018	Winter 2017/18	Summer 2017
Bruce	$16.26	$15.28	$11.54
East	$15.13	$12.15	$12.13
Essa	$16.99	$16.56	$12.68
Niagara	$15.50	$15.71	$11.88
Northeast	$14.39	$15.14	-$19.11
Northwest	$14.85	$17.98	-$155.06
Ottawa	$17.36	$16.14	$12.46
Southwest	$17.29	$15.96	$11.98
Toronto	$16.87	$16.06	$12.25
West	$18.62	$13.49	$4.26

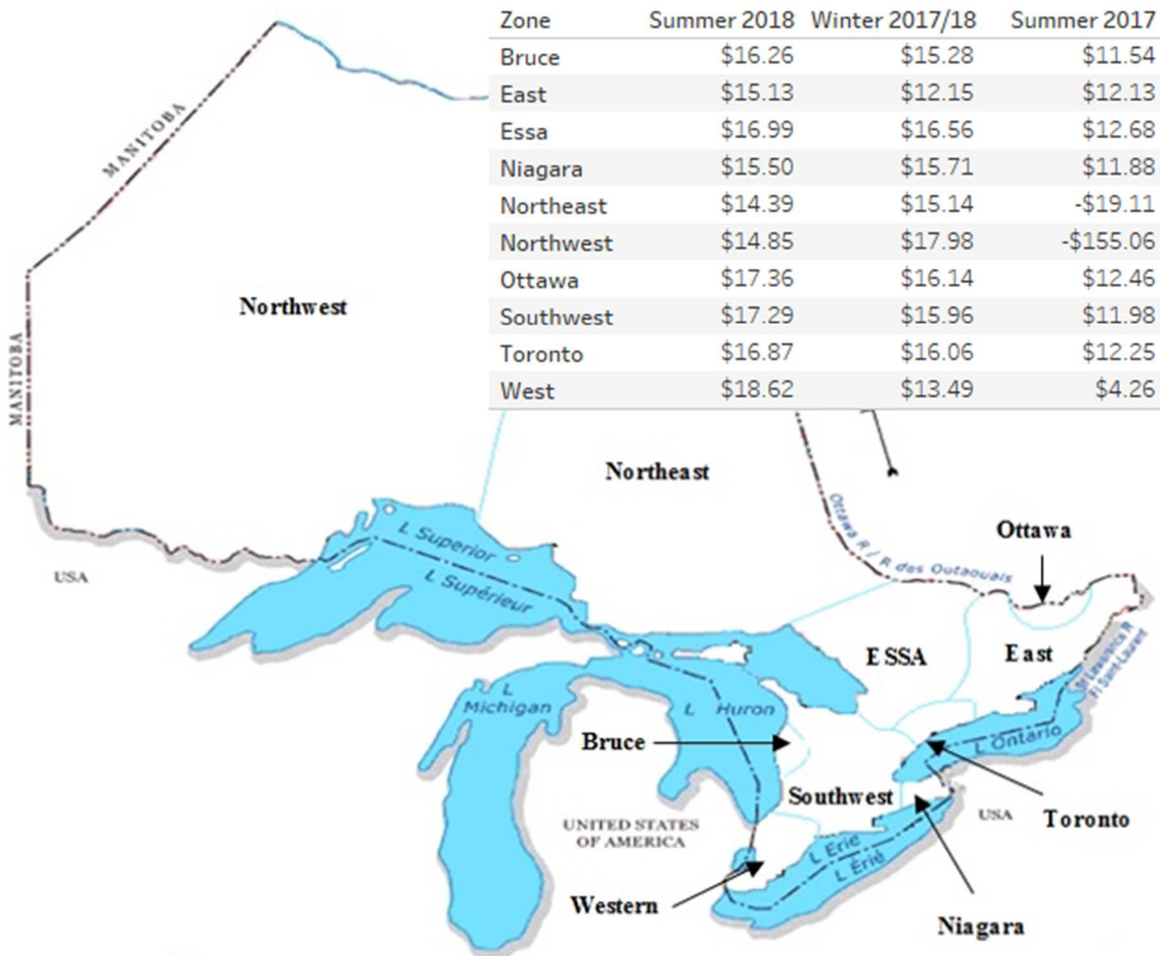

Figure A-14 illustrates the average nodal prices of Ontario's ten internal zones for the Summer 2018, Winter 2017/18 and Summer 2017 Periods.[103]

Nodal prices in all zones were higher in the Summer 2018 Period compared to the Summer 2017 Period, which is to be expected during a period of higher demand. Notably, only 0.3% of

103 Each zone has a series of nodes, with each node having its own shadow price. The average price for each zone in the Summer 2018 Period is calculated by taking the simple average of the nodes within that zone over every hour in the monitoring Period, and then taking a simple average of the price calculated for each hour in the monitoring Period associated with that particular zone.

all nodal prices in the Summer 2018 Period were -$2,000/MWh, compared to 4.3% of all nodal prices in the Summer 2017 Period. The nodal price in the Northwest zone increased dramatically as compared to the Summer 2017 Period, becoming positive rather than deeply negative. This is likely explained at least in part by the large increase in demand within the Northwest region, which rose by about 7.9% on average between the Summer 2017 and Summer 2018 Periods.

Figure A-15: Import Congestion by Intertie

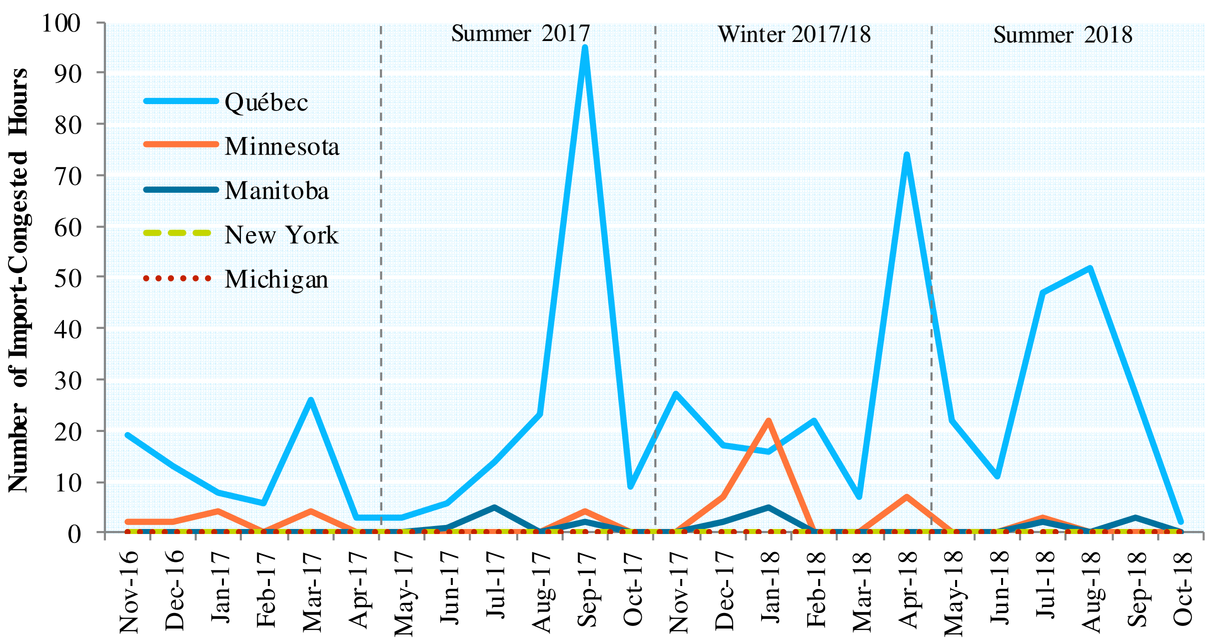

Figure A-15 reports the number of hours per month of import congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

When an intertie has a greater amount of economic net import offers (or economic net export bids) than its Pre-Dispatch (PD-1) transfer capability, the intertie will be import (or export) congested.

For a given intertie, importers are paid the intertie zonal price (IZP), while exporters pay the IZP. The difference between the IZP and the (Market Clearing Price) MCP is called the Intertie

Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 when there are more economic transactions than the intertie transmission lines can accommodate. The ICP is positive when there is export congestion and negative when there is import congestion.

Only the Québec, Minnesota, and Manitoba interties experienced import congestion during the Summer 2018 Period. The Québec interties saw a slight increase in the number of import-congested hours from 150 hours in the Summer 2017 Period to 163 hours in the Summer 2018 Period. Congestion on the Québec interties was highest in July and August, reaching 47 hours and 52 hours of congestion, respectively. As expected, these months of congestion occurred when imports from Québec were highest in the Summer 2018 Period (see Figure A-26), when there were many economic import offers and thus greater opportunities for congestion.

Figure A-16: Export Congestion by Intertie

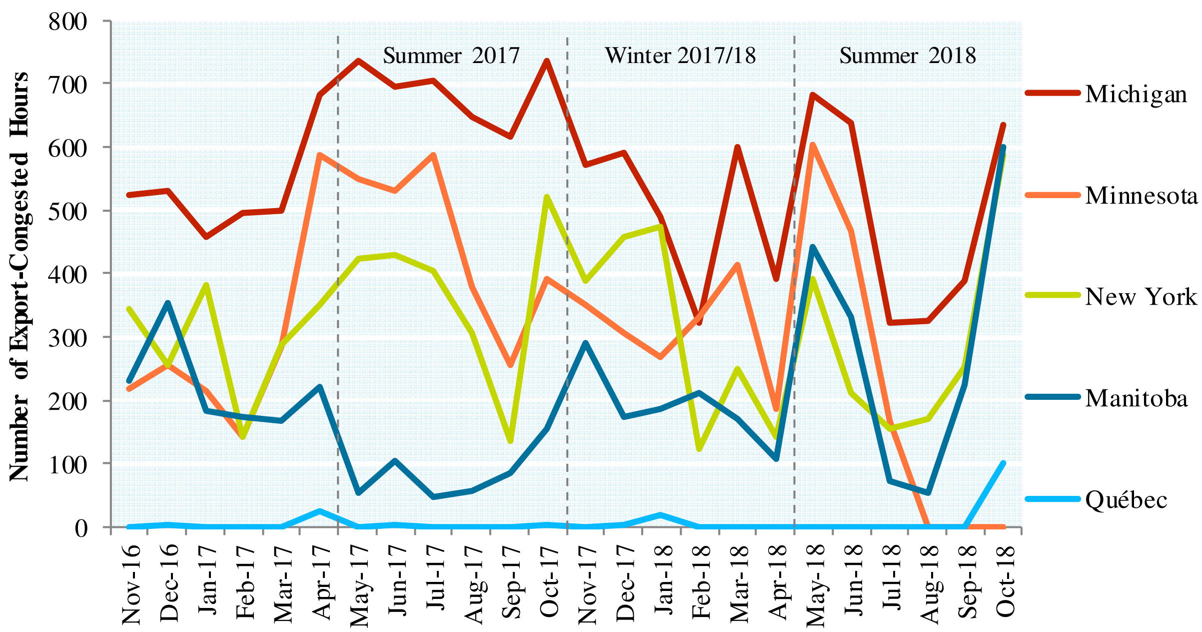

Figure A-16 reports the number of hours per month of export congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

Total export congestion decreased greatly in the Summer 2018 Period relative to the Summer 2017 Period. Compared to the Summer 2017 Period, export congestion fell in Michigan, Minnesota and New York by 1,145, 1,452 and 449 hours (or by 28%, 54% and 20%), respectively. This is because the Summer 2018 Period had higher Ontario prices than the Summer 2017 Period, giving Ontario less opportunity to export energy to other jurisdictions, reducing the probability of export congestion. Manitoba had greater export congestion in the Summer 2018 Period compared to the Summer 2017 Period, having high export congestion in September and October of 2018. This congestion was likely driven by higher prices in Manitoba, giving Manitoba greater incentive to import energy from Ontario.

Table A-3: Monthly Electricity Spot Prices – Ontario & Surrounding Jurisdictions

Date	Ontario (HOEP) ($/MWh)	Manitoba ($/MWh)	Michigan (MISO) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO) ($/MWh)	PJM ($/MWh)
May 2018	11.54	33.10	44.78	35.00	24.75	36.48
Jun 2018	16.73	30.79	35.42	32.12	24.18	34.15
Jul 2018	28.60	30.57	39.65	33.35	36.06	39.44
Aug 2018	28.92	34.11	41.22	35.94	39.12	40.84
Sep 2018	26.93	34.72	43.72	36.67	39.07	38.72
Oct 2018	12.78	36.89	36.14	37.30	34.49	39.23

Table A-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 Global Adjustment (GA) or uplift. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table A-3. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs.

Absent congestion at an intertie, importers receive, and exporters pay, the Hourly Ontario Energy Price (HOEP) when transacting in Ontario. If there is congestion, however, importers and exporters in Ontario receive or pay the IZP rather than the HOEP.

The external prices reported are the real-time locational-marginal prices that correspond with the node on the other side of Ontario's intertie with each jurisdiction.

As it has been for several years, the average HOEP was lower than the market price in all of Ontario's neighbouring jurisdictions in every month in the Summer 2018 Period. This is due in part to the capacity surplus in Ontario, and in part to characteristics in the Ontario market that depress prices. Accordingly, Ontario remained a net exporter for every month in the Summer 2018 Period.

Figure A-17: Import Congestion Rent & Transmission Rights (TR) Payouts by Intertie

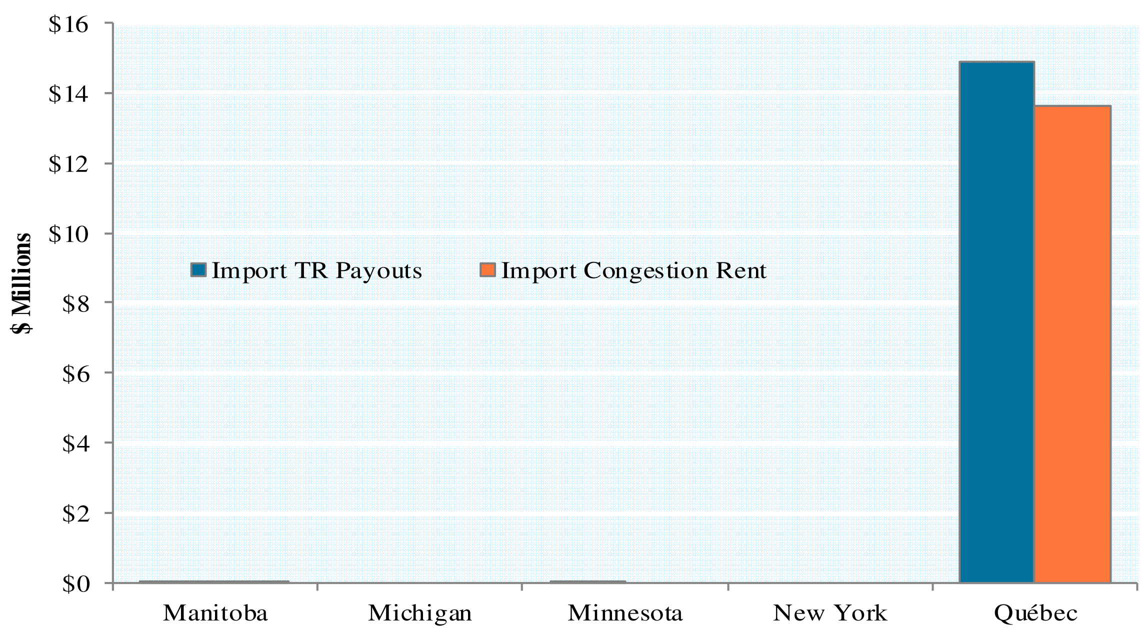

Figure A-17 compares the total import congestion rent collected to total TR payouts by intertie for the Summer 2018 Period.

An IZP is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 MCP and the PD-1 IZP. While the importer is paid the lower IZP, 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 in such a case is import “congestion rent”. Congestion rent accrues to the IESO’s Transmission Rights Clearing Account (TRCA).

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or “payout”) equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. Any shortfalls are covered primarily by TR auction revenues, which are the proceeds from selling TRs (a payment into the TRCA).

Interties with a high frequency of import congestion hours (see Figure A-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.

Total import TR payouts in the Summer 2018 Period were $14.9 million, while total import congestion rent was $13.7 million, creating a congestion rent shortfall of $1.2 million. This shortfall was almost entirely composed of the congestion rent shortfall on the Québec intertie – the Minnesota intertie had a congestion rent shortfall of less than $2,000, and the Manitoba intertie had a congestion rent surplus of less than $10,000. Québec’s congestion rent shortfall was largely due to there being more megawatts of TRs for the Québec intertie than there were megawatts being transacted over the intertie during hours of extreme import congestion in the Summer 2018 Period, causing TR payments to outweigh the congestion rent collected during these hours.

Export TR payouts in the Summer 2018 Period totalled $71.4 million, while export congestion rent totalled $83.2 million. This $11.8 million surplus of congestion rent is primarily due to the $10.9 million imbalance between congestion rent and TR Payouts on the Michigan intertie, as well as the $4.3 million imbalance between congestion rent and TR payouts on the New York intertie. These surpluses in congestion rent in the Summer 2018 Period were counterbalanced in part by the congestion rent shortfalls in Manitoba and Minnesota, of $2.3 million and $1.1 million, respectively. Québec had a congestion rent shortfall of only $46,000, so it was very close to being balanced.

Figure A-18: Export Congestion Rent & TR Payouts by Intertie

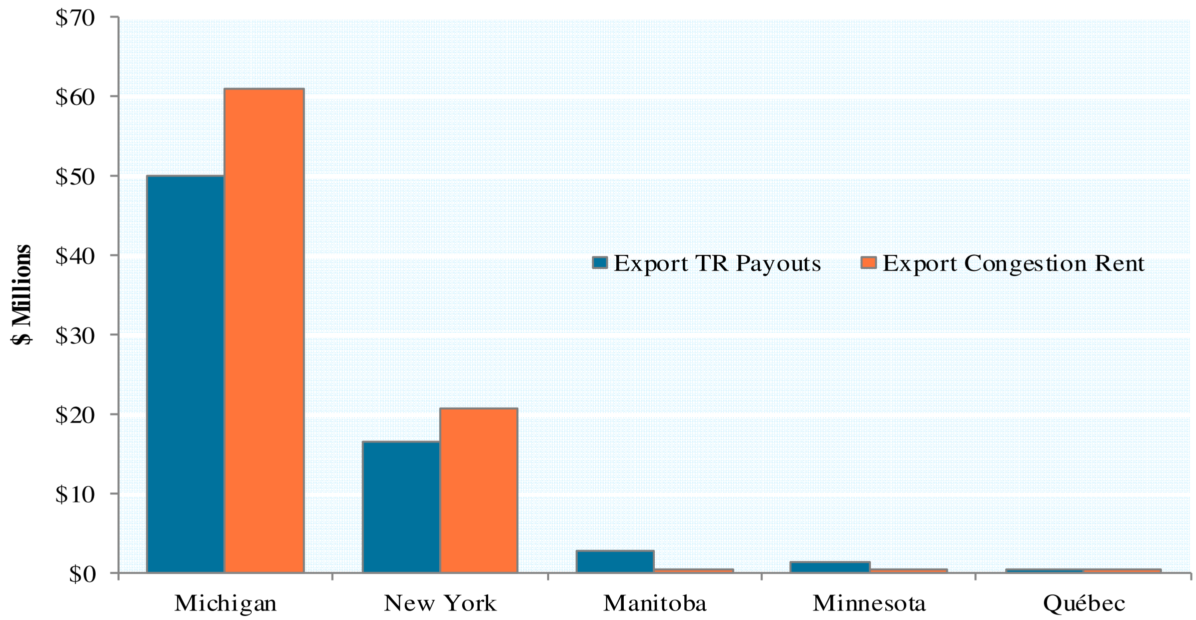

Figure A-18 compares the total export congestion rent collected to total TR payouts by intertie for the Summer 2018 Period.

Compared to the November 2017 and May 2018 auctions, long-term export TR prices fell modestly across all jurisdictions during the February 2018 auction. Export TR prices continued to rise for Manitoba and Québec during the May 2018 auction, while decreasing for Michigan. Long-term import TR prices increased across all jurisdictions except for Michigan when compared to the November 2017 auction, indicating that traders expected import congestion to decrease in late 2018 and early 2019. No long-term TRs were auctioned for either direction along the Minnesota intertie for the Period between October 2018 and September 2019.

Table A-4: Average 12-Month TR Auction Prices by Intertie & Direction

Direction	Auction Date	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	Nov-17	Jan-18 to Dec-18	340	223	1,638	59	4,908
	Feb-18	Apr-18 to Mar-19	925	140	2,580	85	6,332
	May-18	Jul-18 to Jun-19	1,179	193	2,996	150	6,462
	Aug-18	Oct-18 to Sep-19	1,449	218	-	208	8,700
Export	Nov-17	Jan-18 to Dec-18	33,106	139,460	63,117	57,141	2,896
	Feb-18	Apr-18 to Mar-19	26,374	128,674	54,443	52,440	2,206
	May-18	Jul-18 to Jun-19	36,721	140,168	60,773	57,154	2,707
	Aug-18	Oct-18 to Sep-19	38,632	123,458	-	52,185	3,068

Table A-4 lists the average auction prices for 1 MW of long-term (12-month) TRs for each intertie in either direction for each auction since November 2017. These are the TRs that would have been valid during the Summer 2018 Period. If an auction is efficient, the price paid for 1 MW of TRs should reflect the expected payout from owning that TR for the period. Prices signal Market Participant expectations of intertie congestion conditions for the forward period.

Compared to the November 2017 and May 2018 auctions, long-term export TR prices fell modestly across all jurisdictions during the February 2018 auction. Export TR prices continued to rise for Manitoba and Québec during the May 2018 auction, while decreasing for Michigan. Long-term import TR prices increased across all jurisdictions except for Michigan when compared to the November 2017 auction, indicating that traders expected import congestion to increase in late 2018 and early 2019. No long-term TRs were auctioned for either direction along the Minnesota intertie for the period between October 2018 and September 2019.

Table A-5: Average One-Month TR Auction Prices by Intertie & Direction

Direction	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	Nov-17	50	2	55	8	252
	Dec-17	20	2	64	13	260
	Jan-18	44	11	222	21	260
	Feb-18	54	0	420	22	235
	Mar-18	60	1	185	10	260
	Apr-18	11	4	245	15	252
	May-18	15	0	89	1	260
	Jun-18	18	1	158	11	400
	Jul-18	20	7	202	37	455
	Aug-18	28	13	222	37	744
	Sep-18	-	7	-	7	255
	Oct-18	65	3	-	10	760
Export	Nov-17	1,836	11,543	-	5,076	10
	Dec-17	2,835	7,415	5,260	2,900	111
	Jan-18	3,006	7,821	4,546	5,555	117
	Feb-18	2,964	12,036	5,416	7,778	650
	Mar-18	3,147	8,411	4,288	4,918	164
	Apr-18	3,725	13,615	5,053	5,472	5
	May-18	1,250	11,822	4,523	4,836	5
	Jun-18	3,622	12,161	6,120	5,076	9
	Jul-18	2,686	11,664	-	3,758	10
	Aug-18	2,322	8,555	-	3,921	12
	Sep-18	-	8,752	-	3,276	14
	Oct-18	3,413	12,671	-	5,246	10

Table A-5 lists the auction prices for 1 MW of short-term (one-month) TRs for each intertie in either direction for each auction during the Summer 2018 and Winter 2017/18 Periods. Auction prices signal Market Participant expectations of intertie congestion conditions for the forward period.

Short-term import TR prices remained relatively constant through the Summer 2018 Period. However, short-term import TR prices did decrease for Manitoba in the Summer 2018 Period compared to the Summer 2017 Period. The August 2018 import Québec short-term TR price spiked in August, reaching $744 – imports over the Québec intertie were high between July and September, leading to the expectation of import congestion and thus causing this spike in price.

Short-term export TR prices were more volatile, especially for the Michigan and New York interties, in which prices frequently fluctuated by more than $1,000 between months. In several months during the Summer 2018 Period, the Minnesota and Manitoba interties had little to no capacity due to outages, preventing TRs from being sold.

The balance of the Transmission Rights Clearing Account (TRCA) decreased to $126.1 million at the end of the Summer 2018 Period, down from $145.3 million at the end of the Summer 2017 Period. The October 2018 balance was $106.1 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:

1. *$167.4 million in revenue, specifically:*
   - $96.8 million in congestion rent
   - $69.3 million in auction revenues
   - $1.3 million in interest
2. *$186.7 million in debits, specifically:*
   - $86.3 million in TR payouts
   - $100.4 million in disbursements to Ontario consumers and exporters.

Compared to the Winter 2017/18 Period, there was a large decrease in credits and a small decrease in debits during the Summer 2018 Period. This decrease to the TRCA balance was largely due to the increase in the TRCA disbursement awarded in May 2018, which was more than $16 million higher than the disbursement awarded in the Winter 2017/18 Period.

Figure A-19: Transmission Rights Clearing Account

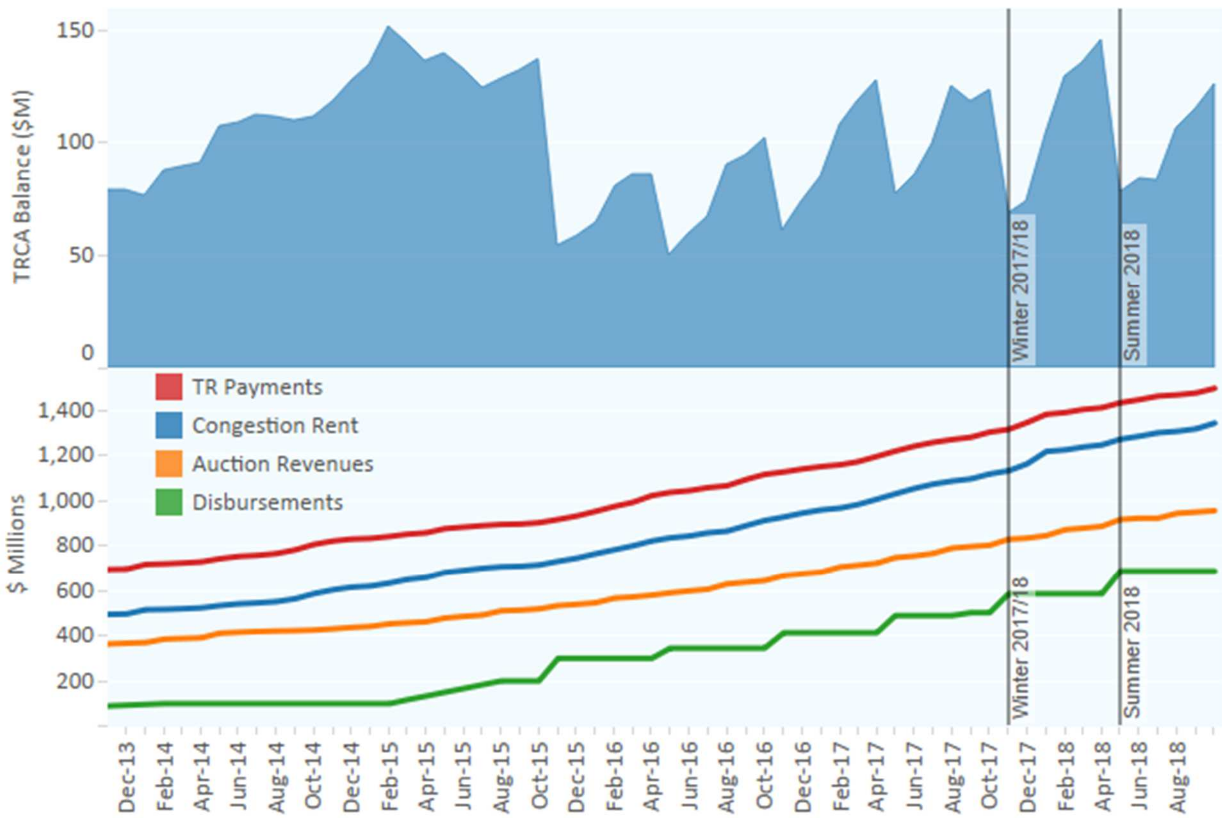

Figure A-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account.

A.2 Demand

Figure A-20: Monthly Ontario Energy Demand by Class A & Class B Consumers

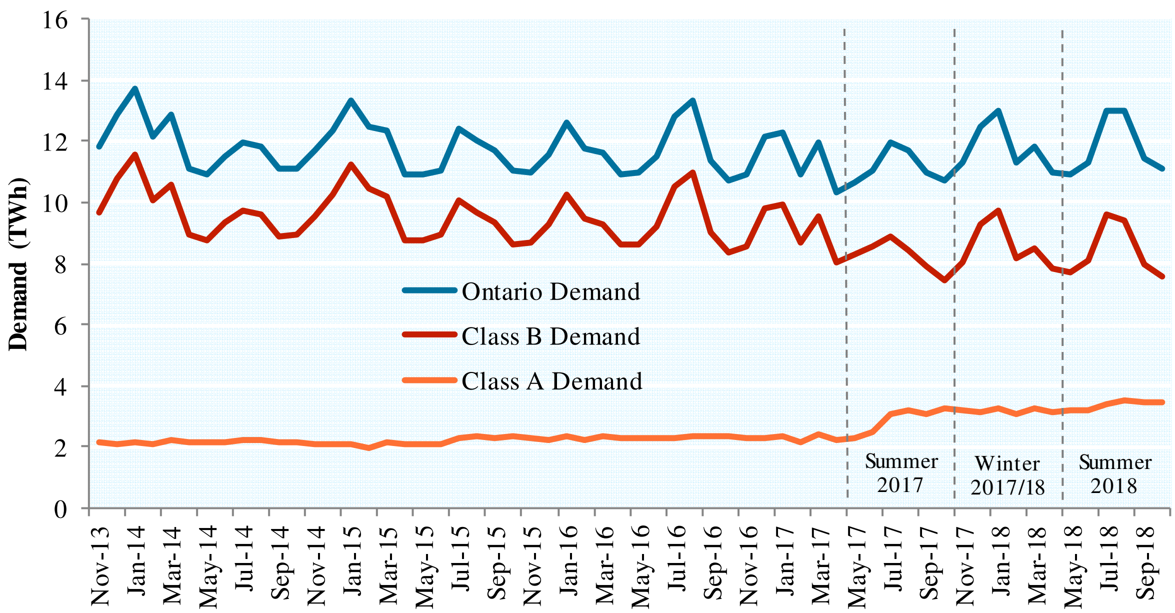

Figure A-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand–not grid-connected demand–in that it includes demand satisfied by embedded generators.[104]

Total demand in the Summer 2018 Period was 70.7 TWh – 5.6% higher than the total demand of 67.0 TWh in the Summer 2017 Period. This increase in demand in the Summer 2018 Period was caused primarily by the weather, which was warmer on average than the Summer 2017 Period, especially during July and August, increasing air conditioning load in the province. Total demand and average temperatures in the Summer 2018 Period were very similar to the

[104] Class A demand may be understated as the Panel does not have access to behind-the-meter generation data, which serves to offset demand from the grid. For more information, see the Panel's Monitoring Report 24 (Nov 2013-Apr 2014) published April 2015, pages 105-109, and the Panel's Industrial Conservation Initiative Report published December 2018: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf and https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

Summer 2016 Period – in contrast, the Summer 2017 Period had more moderate temperatures.

Compared to the Summer 2017 Period, Class A demand grew significantly, whereas Class B only increased slightly. This is because in July 2017, the threshold for participation in Class A was lowered from 1 MW to 500 kW for certain industrial sectors, causing Market Participants in industry to move from Class B into Class A. As a result, Class A demand during the months in the Summer 2017 Period (May and June 2017) was much lower than the same months in 2018. The increase in Class A demand was exacerbated by the increase in temperature from the Summer 2017 to the Summer 2018 Periods. The increase in Class B demand was a result of the warmer temperatures in the Summer 2018 Period more than offsetting the shift of Market Participants from Class B to Class A. Demand of Class A was 2.9 TWh higher in the Summer 2018 Period than the Summer 2017 Period, and Class B demand was 0.9 TWh higher in the Summer 2018 Period than the Summer 2017 Period.

A.3 Supply

This section presents data on generating capacity, actual generation, and OR supply for the Summer 2018 Period relative to previous years.

Table A-6: Changes in Generating Capacity

Generation Type	Grid-connected		Distribution-level ("Embedded")	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	-	13,009	-	-
Natural Gas	-	10,277	-	-
Hydro	-	8,473	1	278
Wind	99	4,412	-	591
Solar	-	380	56	2,113
Biofuel	-	495	1	110
Gas-Fired and Combined Heat and Power	-	-	-	271
Energy from Waste	-	-	-	24
Total	99	37,046	58	3,387

Table A-6 lists the quantity of nameplate generating capacity that completed commissioning and was added to the IESO-controlled grid's total capacity during the second and third quarter of 2018, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[105] Total capacity of each type at the end of the Summer 2018 Period is also shown.

Little new capacity was added to the Ontario generation fleet at either the IESO-controlled grid or the distribution level. The capacity added was mostly variable generation that generally offers into the wholesale spot market at low prices, potentially contributing to the continuation of low wholesale spot prices in Ontario.

[105] Grid-connected and embedded capacity totals were obtained from the quarterly Ontario Energy Report, available at: http://www.ontarioenergyreport.ca/index.php

Figure A-21: Resources Scheduled in the Real-Time Market (Unconstrained)

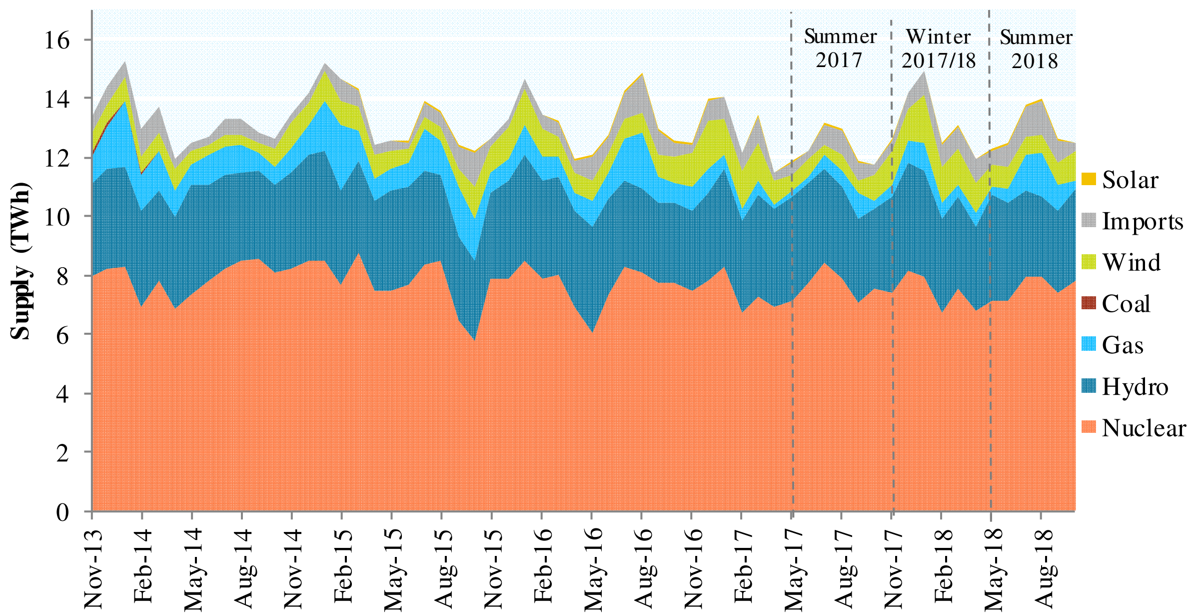

Figure A-21 displays the real-time unconstrained production schedules from November 2013 to October 2018 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear and imports.[106] Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand or seasonal fuel variations (for example, during the spring snowmelt or freshet when hydroelectric plants have an abundant supply of water).

Compared to the Summer 2017 Period, the Summer 2018 Period showed a considerable increase in the output of gas-fired generators, wind generators, and imports: gas generator output increased from 2.5 TWh to 4.7 TWh, wind generator output increased from 3.4 TWh to 4.3 TWh, and imports increased from 3.0 TWh to 4.4 TWh. Increases in supply from gas-fired generators and imports can be attributed to the increase in demand between the Summer

[106] Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time. Ontario has significant solar and wind generation connected at the distribution level that is not included in this figure. These embedded resources are not scheduled in Ontario Market. Average output from these embedded generators was approximately 0.5 TWh per month; due to data constraints, this quantity cannot be broken down by type of generation.

2017 and Summer 2018 Periods, when resources with lower marginal costs are fully utilized. Use of nuclear and hydro capacity remained largely unchanged.

Figure A-22: Average Hourly OR Scheduled by Resource Type

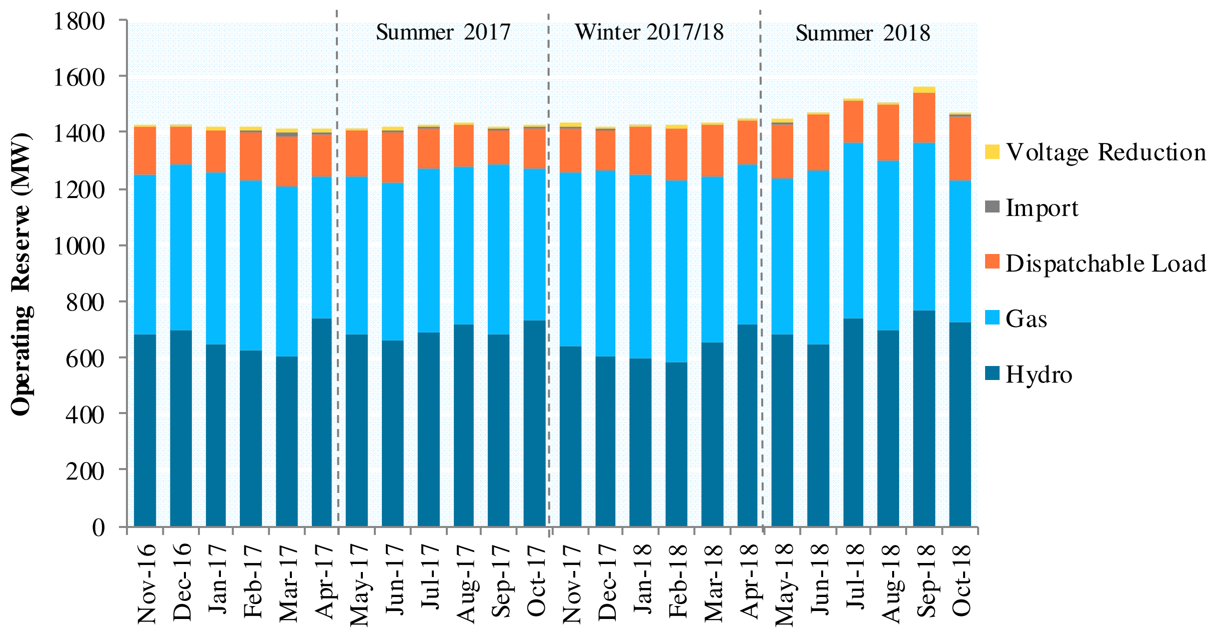

Figure A-22 displays the real-time unconstrained OR schedules from November 2016 to October 2018 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads, and voltage reduction (taken as a control action by the IESO).[107] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

The average quantity of OR that is scheduled increased modestly compared to the Summer 2017 Period. On average, 1,497 MW of OR was scheduled during the Summer 2018 Period, compared to 1,435 MW and 1,427 MW in the Winter 2017/18 and Summer 2017 Periods,

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

respectively. Gas generators were scheduled for OR a little less frequently in the Summer 2018 Period than the Summer 2017 Period. 39.0% of OR scheduled came from gas generators in the Summer 2018 Period, compared to 39.6% in the Summer 2017 Period. Hydroelectric generators were scheduled slightly less, with hydro making up 47.4% of scheduled OR in the Summer 2018 Period compared to 48.8% in the Summer 2017 Period. Dispatchable loads were scheduled more frequently for OR, with loads making up 12.7% of scheduled OR in the Summer 2018 Period, compared to 10.5% in the Summer 2017 Period.

The Summer 2018 Period had, on average, 11.7 GW of unavailable capacity, which is 8% more than the average of 10.9 GW of capacity that was unavailable in the Summer 2017 Period. This difference was primarily driven by more outages of wind, nuclear and hydro capacity in the Summer 2018 Period. Minimum and maximum available capacity were lower in the Summer 2018 by 0.84 GW and 1.0 GW on average compared the Summer 2017 Period, respectively.

Figure A-23: Unavailable Generation Relative to Installed Capacity

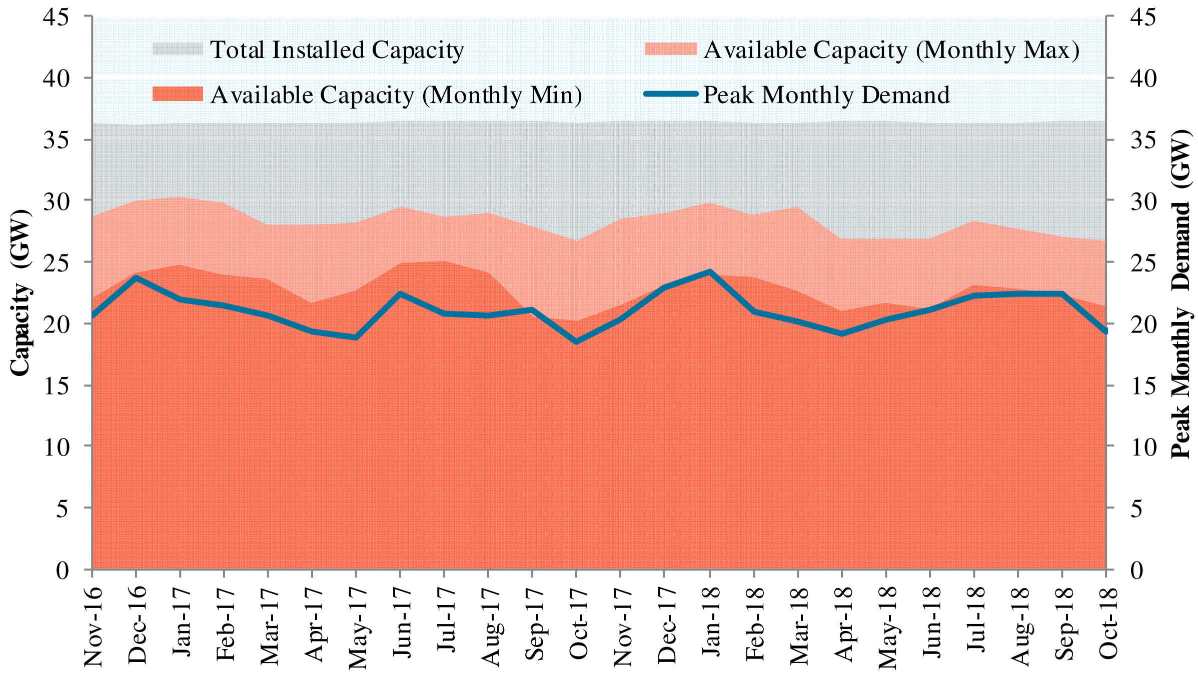

Figure A-23 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from November 2016 to October 2018. The maximum and minimum megawatts on outage during a given month can be observed by comparing the total installed capacity to the monthly minimum and maximum available capacity, respectively. For reference, the figure also includes the monthly peak market demand, excluding demand served by imports.[108]

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

A.4 Imports, Exports and Net Exports

This section examines import and exports transactions in the unconstrained sequence, as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[109]

Figure A-24: Monthly Imports and Exports, and Average Net Exports (Unconstrained)

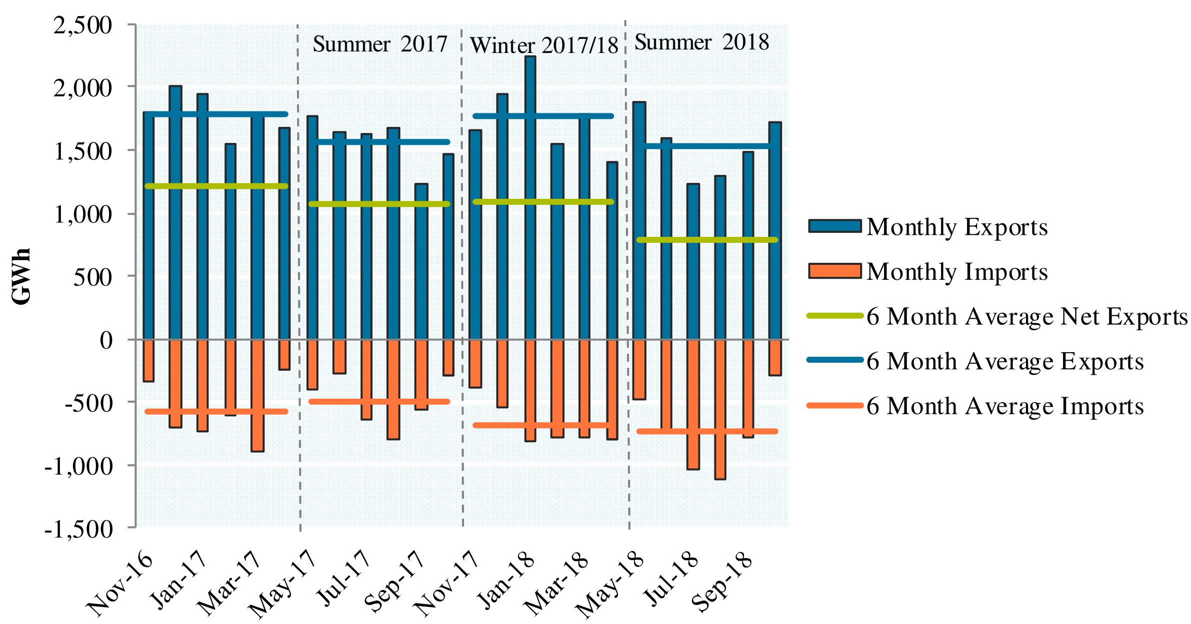

Figure A-24 plots total monthly imports and exports from November 2016 to October 2018, as well as the average monthly imports, exports and net exports calculated over each six-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Ontario remained a net exporter in the Summer 2018 Period, with net exports of 4.76 TWh, down from 6.45 TWh in the Summer 2017 Period. Compared to the Summer 2017 Period, exports fell by 0.21 TWh, and imports rose by 1.48 TWh. The decrease in net exports over the

[109] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not impact Intertie Congestion Prices (ICPs) or the Ontario uniform price.

Summer 2018 Period was primarily driven by a large decrease in exports to New York and the large increase in imports from Québec, compared to the Summer 2017 Period.

Figure A-25: Exports by Intertie

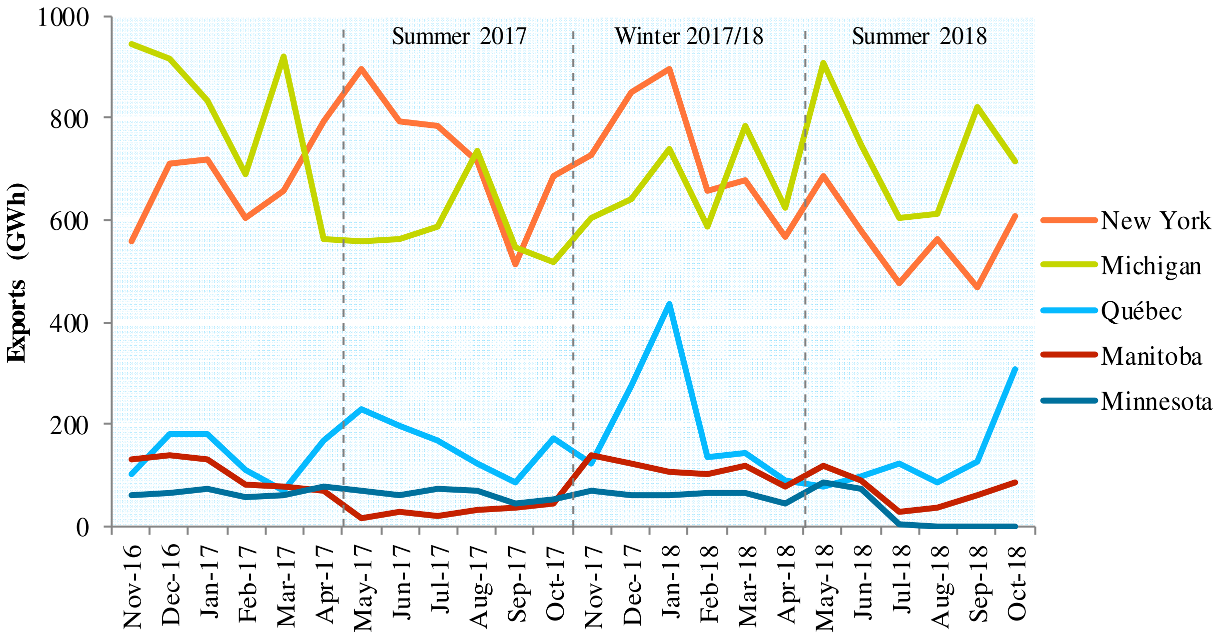

Figure A-25 presents a breakdown of exports from November 2016 to October 2018 to and from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average constrained monthly export quantities over the Summer 2018 and Winter 2017/18 Periods are given for each intertie in Table A-7.

Figure A-26: Imports by Intertie

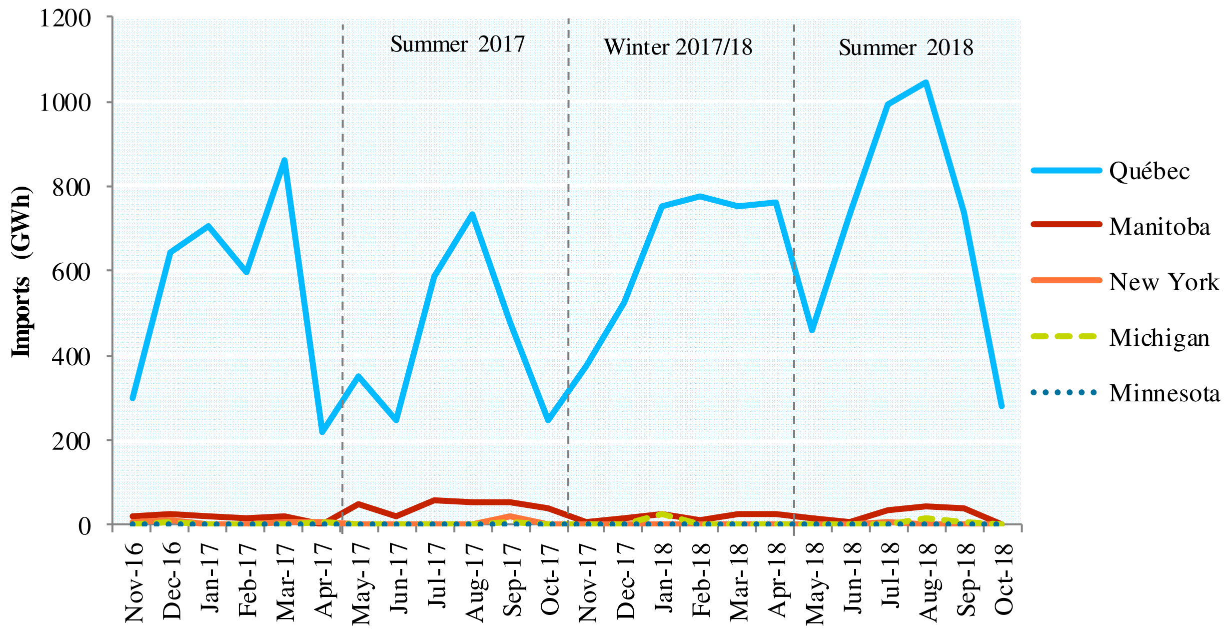

Figure A-26 presents a breakdown of imports from November 2016 to October 2018 to and from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average constrained monthly import quantities over the Summer 2018 and Winter 2017/18 Periods are given for each intertie in Table A-8.

Exports to Michigan increased considerably in the Summer 2018 Period compared to the Summer 2017 Period, increasing by 151 GWh per month on average. In contrast, exports to New York fell considerably in the Summer 2018 Period compared to the Summer 2017 Period, decreasing by 166 GWh per month on average. New York energy prices in May 2018 and June 2018 were low compared to Michigan, when Ontario had greater incentive to export during the Summer 2018 Period, as the Hourly Ontario Energy Price (HOEP) was also low compared to later months in the period. Exports to New York and Michigan in the Summer 2018 Period were lowest in July and August, when Ontario faced high domestic demand compared to the Summer 2017 Period. Prices increased in Michigan in September, giving Ontario incentive to export more energy to Michigan that month. Lower prices in Ontario in October 2018 led to greater exports to New York compared to the previous months. In the

Summer 2018 Period, exports to Manitoba increased, while exports to Minnesota and Québec decreased compared to the Summer 2017 Period. Cumulatively, exports to external jurisdictions decreased in the Summer 2018 Period compared to the Summer 2017 Period, as mentioned in the commentary of Figure A-24.

Imports from Québec greatly increased in the Summer 2018 Period compared to the Summer 2017 Period, rising from an average of 441 GWh per month to an average of 707 GWh per month. This increased was primarily caused by the increase in energy demand between the Summer 2017 and Summer 2018 Periods, which was satisfied in part by imports. Imports from Michigan, Manitoba, Minnesota and New York all remained under 60 GWh per month throughout the Summer 2018 Period, as they did in the Summer 2017 Period.

Failed or curtailed exports reduce demand between Pre-dispatch (PD-1) and real-time. The Market Participant percentage failure rate of exports on the Manitoba intertie, which has consistently been above that of the other interties in previous periods, increased significantly, due to both an increase in the amount of exports curtailed by Market Participants compared to the Winter 2017/18 Period, and a decrease in volume of average exports to Manitoba per month compared to the Winter 2017/18 Period. This increase is at least partly seasonal: exports to Manitoba have been higher in the winter in past years compared to the summer.

The Québec intertie experienced a decrease in total Independent System Operator (ISO)-curtailed exports in the Summer 2018 Period, causing their rate of ISO-related curtailments to fall to 2.1% in the Summer 2018 Period. The Minnesota intertie saw a large decrease in average exports from Ontario compared to the Winter 2017/18 Period, while total ISO-related curtailments stayed relatively constant, causing the rate of ISO-related curtailments for exports along the Minnesota intertie to increase.

Table A-7: Average Monthly Export Failures by Intertie and Cause

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		Market Participant (MP) Failure		ISO Curtailment		Market Participant (MP) Failure	
	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18
New York	570	708	3.0	2.0	8.1	8.0	0.5%	0.3%	1.4%	1.1%
Michigan	629	562	1.8	3.2	7.1	5.2	0.3%	0.6%	1.1%	1.0%
Manitoba	70	107	2.4	1.6	19.2	12.1	3.4%	1.5%	27.3%	11.2%
Minnesota	8	33	0.7	0.6	0.2	0.7	8.8%	1.7%	2.1%	2.0%
Québec	134	201	2.9	8.3	1.2	3.3	2.1%	4.2%	0.9%	1.7%

Table A-7 reports average monthly export curtailments and failures over the Summer 2018 Period and the Winter 2017/18 Period by intertie and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each intertie, excluding linked wheel transactions.[110] Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure) refers to a transaction that fails for reasons within the control of the Market Participant such as a failure to obtain transmission service.

Failed or curtailed imports reduce supply between the PD-1 and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for Market Participant (MP) Failures and ISO Curtailments.

The percentage rate of ISO Curtailments for imports increased in the Summer 2018 Period compared to the Winter 2017/18 Period for the New York, Manitoba and Minnesota interties,

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

due to a decrease in import volume, an increase in the average monthly volume of curtailments, or both. The rate of Market Participant failures in Michigan dropped dramatically due to a decrease in the total amount of Market Participant failures of imports from Michigan in the Summer 2018 Period. The Minnesota intertie saw a large decrease in average imports from Ontario compared to the Winter 2017/18 Period, causing the rate of Market Participant failures for imports along the Minnesota intertie to increase.

Table A-8: Average Monthly Import Failures by Intertie and Cause

Intertie	Average Monthly Imports GWh		Average Monthly Import Failure and Curtailment GWh				Import Failure and Curtailment Rate			
			ISO Curtailment		Market Participant (MP) Failure		ISO Curtailment		Market Participant (MP) Failure	
	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18	Summer 2018	Winter 2017/18
New York	4	8	0.1	0.1	0.2	0.2	2.7%	0.9%	4.6%	2.2%
Michigan	9	9	0.2	0.5	1.5	3.0	1.9%	4.8%	17.7%	31.9%
Manitoba	48	69	4.4	1.2	1.2	0.2	9.1%	1.8%	2.4%	0.3%
Minnesota	7	23	0.5	0.6	1.1	1.7	6.9%	2.5%	15.3%	7.4%
Québec	556	514	4.4	5.0	0.5	0.1	0.8%	1.0%	0.1%	0.0%

Table A-8 reports average monthly import failures and curtailments the Summer 2018 Period and the Winter 2017/18 Period by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.