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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2011 – October 2011

April 2012

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Ontario

April 25, 2012

Ms. Rosemarie T. Leclair
Chair
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Leclair:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Roger Ware and Bill Rupert, I am pleased to provide you with the Panel's 19th semi-annual Monitoring Report on the IESO-administered wholesale electricity markets.

This report, covering the period May to October 2011, is submitted pursuant to Article 7.1.1 of Ontario Energy Board By-law #3.

Best Regards,

Neil Campbell

Neil Campbell
Chair, Market Surveillance Panel

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Executive Summary

This semi-annual monitoring report covers the summer period (May to October) of 2011. As in recent Summer Reports, it focuses on monitoring of high-priced and low-priced hours as well as other potentially anomalous market outcomes (Chapter 2) and discusses significant updates as well as new matters affecting the wholesale markets (Chapter 3), making recommendations relevant to promote market objectives. The Panel also comments on issues related to the future development of the market and the implementation of Panel recommendations (Chapter 4).[1]

1. Overall Assessment

Ontario's IESO-administered wholesale electricity market has operated reasonably well having regard to its hybrid design over the summer of 2011, although there were occasions where actions by market participants or the IESO led to inefficient outcomes. In addition, the Panel continues to identify areas for improvement in the market design, rules or operational procedures. In particular, the Panel has observed numerous complications associated with the use of two schedules ("market" and "constrained") and related aspects of the market design that have undermined efficiency or increased costs to customers with little or no apparent benefit. To this end, the Panel is recommending that the IESO change some of its procedures or Market Rules related to congestion management settlement credits (CMSC) and transmission rights payments.

The Panel did not find an abuse of market power to have occurred in this period. The Panel currently has five investigations underway, all of which relate to possible gaming issues.

[1] The Summer Report no longer contains the detailed analysis of market outcomes historically published in Chapter 1 and the Statistical Appendix of the Panel's monitoring reports. A detailed Chapter 1 and a Statistical Appendix will be published in the comprehensive report for the period ending April 30, 2012.

2. Demand and Supply Conditions

Ontario demand totalled 70.2 TWh in the 2011 summer period, down by 1.3 TWh (1.8 percent) compared to the summer period of 2010. Demand was lighter from May through August and slightly heavier during September and October, compared to the same months in 2010. Relative to 2010, the largest monthly percentage decrease occurred in May where Ontario demand dropped by 5.2 percent; September experienced the largest increase at 0.7 percent.

The only major additions to the province's supply resources came from large scale wind projects. Between May and October 2011 approximately 315 MW of wind capacity was added to the supply mix. There were no significant reductions made to Ontario's generation supply during the reporting period.

3. Market Prices and the Global Adjustment

The average Hourly Ontario Energy Price (HOEP) was $30.68/MWh during the 2011 summer period, representing a decrease of 22.3 percent from $39.47/MWh in the summer of 2010. The lowest monthly average HOEP occurred in May 2011 at $24.42/MWh; the highest monthly average HOEP was experienced in July at $35.29/MWh. All months during the summer of 2011 experienced lower average HOEPs than their monthly counterparts in 2010.

This is the first Summer Report where all months of the reporting period were subject to the new Class A and Class B Global Adjustment (GA) allocation. From May to October 2011, the effective GA cost averaged $24.93/MWh for Class A customers and $39.62/MWh for Class B customers. Accordingly the effective total wholesale price (HOEP, plus GA, plus uplift charges) for electricity in the summer of 2011 was $57.34/MWh for Class A customers and $72.07/MWh for Class B customers, compared to $65.61/MWh in the summer of 2010 for all customers.

Over the reporting period Class A customers consumed about 16 percent of total electricity in Ontario and paid 11 percent of the total GA charges. Class B customers consumed about 84 percent of the power and paid 89 percent of the total GA charges.

4. Market Outcomes

There were six hours in the summer period in which the HOEP exceeded $200/MWh. All instances were consistent with normal supply/demand variation or explainable by the way in which the two-schedule market design operates.

There were 711 hours in which the HOEP was less than $20/MWh, including 96 hours where the HOEP was negative. The number of hours when the HOEP was less than $20/MWh or negative increased substantially in the summer of 2011 (compared to 2010 in which there were 361 hours with a HOEP less than $20/MWh and 19 hours with a negative HOEP). Surplus baseload generation (SBG) and other factors previously identified by the Panel continue to explain the low and negative prices. SBG is exacerbated by wind resources that are not dispatched off during such periods.

There were five hours where the Panel's anomalous uplift screening criteria were met. All five instances involved Operating Reserve (OR) payments greater than $100,000 in a given hour. There were no instances when Congestion Management Settlement Credit (CMSC) payments or Intertie Offer Guarantee (IOG) payments were greater than $500,000 in a single hour, or when CMSC payments at an intertie group exceeded $1 million for a day.

5. Matters to Report in the Ontario Electricity Marketplace

Overselling of Transmission Rights at the Outaouais Interface

In October 2011, the IESO oversold Transmission Rights (TRs) at the *Outaouais* interface, one of the main links between the Ontario grid and the Quebec grid. The IESO sold 1,094 MW of TRs when the actual transfer capability was only 675 MW due to one of two AC-DC converters being on a planned outage.

Although the TRs were significantly oversold, no individual TR holder owned TRs more than the available transfer capability. However, the interface could have been significantly congested had multiple TR holders collectively bid high to export (in order to benefit from their TR positions). As a result of the overselling the TR account was depleted by about $2.3 million before a key market participant changed its bidding behaviour early in the month. The TR account could have been depleted by much more than $2.3 million had traders fully exploited the overselling of TRs.

During the same month the Panel also observed significant transaction failures by market participants holding TRs at *Outaouais*, and also at other interfaces. Over the last year, these failures resulted in approximately $880,000 in TR payouts that were not offset through the collection of congestion rent.

The Panel makes two recommendations (see below) as a result of the October event at the *Outaouais* interface.

Implications of the New Global Adjustment Allocation Approach

Beginning in January 2011, the method of allocating the GA changed for large customers (i.e. “Class A” customers with average peak demand exceeding 5 MW). Significant demand reductions were observed during the highest demand days in the summer of 2011. This report also examines the impact of the GA allocation methodology for the two classes of customers (“Class A” and “Class B”), and estimates that participants who were compensated for curtailing or shifting under the DR3 and DR2 demand response programs avoided as much as $39 million of GA charges in the summer of 2011.

The Panel makes a recommendation (see below) related to the interface between the GA allocation methodology and existing demand response programs.

Self-Induced CMSC Payments to Generators

The Panel has previously recommended that CMSC payments to generators that raise their offer prices in order to shut down are unwarranted. After the IESO suspended work on proposed rule changes to address this issue, the Panel developed a Monitoring Document that indicates the evaluative criteria that the Panel will use in monitoring for gaming in relation to prices offered by generators in order to take their units offline.

Several generators reduced their shut down offer prices after the Monitoring Document was issued in August 2011. As a result, the Panel estimates that ramp down CMSC payments, which were running in the vicinity of $1 million per month, have been reduced by approximately 70%. Nevertheless, the Panel remains concerned about the continuing ramp down CMSC payments to generators of about $4 million per year (which are paid by wholesale customers as uplift charges) and makes a recommendation to the IESO (see below) to address this issue.

6. Future Development of the Market

Two recent reports, one by the Electricity Market Forum (EMF) and one by the Commission on the Reform of Ontario's Public Services, contain important discussions about the potential evolution of the Ontario electricity market. Both reports recognize some of the fundamental problems with the current two-schedule market design including prices which do not reflect supply and demand variations within the province. They make recommendations which are consistent with the Panel's long-standing position that the current market design has induced significant inefficiency in the marketplace and that significant changes need to be considered after almost 10 years of operation.

The Panel makes a recommendation (see below) regarding the importance of pursuing recommendations of the EMF that would improve the efficiency of the Ontario market.

7. Recommendations

In this Report, the Panel makes six recommendations: two related to efficiency and four related to uplift or other payments. Within each category, the recommendations are listed in order of priority. There are no recommendations in this report related to price fidelity[2] or transparency[3], although many of the Panel's recommendations have effects in more than one of the categories used to group its recommendations.

Efficiency

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market. The Panel is also concerned with other forms of productive as well as allocative and dynamic efficiencies.

a) The Panel believes that several of the recommendations made by the EMF could improve the efficiency of Ontario's wholesale electricity markets.

Recommendation 4-1:

The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.

b) The Panel is concerned that the suspension by the Northeast Power Coordinating Council (NPCC) of the regional sharing of operating reserves has resulted in as much as a $2.2 million dollar annualized efficiency loss as well as higher prices in the Ontario operating reserve market.

[2] The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market. While the Panel's recommendations in this report do not relate primarily to price fidelity, most of the efficiency and uplift or other payment recommendations would also contribute to greater price fidelity.
[3] The Panel believes that transparency (in respect of information that is not competitively sensitive) can improve decision-making by market participants and can contribute to greater price fidelity and market efficiency.

Recommendation 3-1:

The Panel recommends that the IESO continue to pursue the introduction by the Northeast Power Coordinating Council of a revised Regional Reserve Sharing Program and the negotiation of any necessary implementing agreements with neighbouring ISOs as expeditiously as possible.

Uplift and Other Payments

The Panel examines uplift and other payments both in respect of their contribution to the effective price paid by customers and also in respect of their impact on the efficient operation of the market.

a) There are several programs in the marketplace that are intended to induce demand response, and the new GA allocation methodology does so as well. The Panel believes that the GA methodology can create a windfall for those Class A customers who are already being paid to reduce output under OPA demand response contracts.

Recommendation 3-3:

The Panel recommends that the Government of Ontario and the OPA work together to ensure that Class A customers are not compensated by both the Global Adjustment allocation methodology and an OPA demand response contract for the same MW of load shedding or shifting.

b) After assessing the October events at the *Outaouais* interface, the Panel believes that the IESO must ensure that planned outage information is taken into account in order to avoid potentially large financial risks associated with the overselling of TRs.

Recommendation 3-4:

The Panel recommends that the IESO improve its internal controls and external processes to ensure that all information about outages and other relevant contingencies is taken into account when establishing the level of Transmission Rights to be auctioned.

c) The Panel continues to be concerned that unwarranted CMSC payments are being made to generators during self-induced ramp downs. The Panel believes that the most effective and efficient way to eliminate such payments is a market rule change.

Recommendation 3-2:

The Panel recommends that the IESO implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping-down generators.

d) The Panel believes that market participants are overcompensated by receiving TR payouts without being charged congestion rent when they schedule and then fail energy transactions.

Recommendation 3-5:

The IESO should ensure that, when a trader which owns Transmission Rights has failed its intertie transactions (at the same interface in the same direction), either the Transmission Right payout should not be paid or the Congestion Rent should be charged for the quantity of the failed transactions.

Chapter 1: Market Outcomes

1. Highlights of Market Indicators

This chapter provides a brief summary of the results for the IESO-administered markets over the period May 1, 2011 to October 31, 2011, with comparisons to the same period one year earlier. For ease of reference, the May to October period is referred to as the 'summer period'.[4]

1.1 Pricing

The average Hourly Ontario Energy Price (HOEP) was $30.68/MWh[5] during the 2011 summer period, representing a decrease of 22.3 percent from $39.47/MWh in the summer of 2010. The lowest monthly average HOEP occurred in May 2011 at $24.42/MWh; with the highest monthly average HOEP occurring in July at $35.29/MWh. All months during the summer of 2011 experienced lower average HOEPs than their monthly counterparts in 2010. Additionally, the average monthly HOEP varied considerably less in the summer of 2011, with the high month (July) averaging only $10.87/MWh more (44 percent) than the low month (May). In the summer of 2010 the high price month (July) had an average HOEP $21.44/MWh (73 percent) greater than the lowest month in that period (October).

This is the first summer report where all months of the reporting period were subject to the new Class A and Class B Global Adjustment (GA) allocation. From May to October 2011, the effective GA cost for Class A customers was $24.93/MWh, while Class B customers paid $39.62/MWh. Accordingly, the effective total wholesale price (HOEP, plus GA, plus Uplift) for electricity in the summer of 2011 was $57.34/MWh[6] for Class

[4] Beginning in 2009, the Panel adopted a streamlined format for its summer semi-annual report. More detailed analysis of market outcomes will be provided in the report for the period ending April 2012.
[5] Non-weighted average.
[6] Many Class A customers would have paid less than the average HOEP of $30.68/MWh, and therefore less than the average effective price of $57.34/MWh, due to relatively higher consumption during off-peak hours when prices tend to be lower.

A customers and $72.03/MWh for Class B customers. Over the reporting period Class A customers consumed about 16 percent of total electricity and paid 11 percent of the total GA charges, while Class B customers consumed about 84 percent of electricity and paid 89 percent of the total GA charges.

In order to examine price changes across the summer periods and account for the change in GA allocation, the GA and total effective price were also calculated on a per megawatt hour basis using the previous GA allocation method, with each customer paying an equal volumetric charge. Using the previous method, the effective GA per megawatt hour was calculated to be $37.29/MWh, with an effective total price of $69.70/MWh for all customers. This would have represented a $4.09/MWh increase (6.2 percent) over the effective total price experienced during the summer of 2010.

Table 1-1: Total Effective Electricity Price
May to October, 2010 & 2011
($ / MWh)

Customer Class	Average HOEP ($/MWh)	Average GA ($/MWh)	Average Uplift ($/MWh)	Effective Price ($/MWh)
Class A - 2011	30.68	24.93	1.73	57.34
Class B - 2011	30.68	39.62	1.73	72.03
Blended - 2011	30.68	37.29	1.73	69.70
Blended - 2010	39.45	24.53	1.63	65.61

1.2 Demand

Ontario demand totalled 70.2 TWh in the summer of 2011, down by 1.3 TWh (1.8 percent) when compared to the summer of 2010. In 2011, demand was lighter May through August and slightly heavier during September and October, compared to the same months in the preceding year. The largest monthly percentage decrease occurred in May where total demand dropped by 5.2 percent relative to 2010; September experienced the largest increase at 0.7 percent relative to 2010.

1.3 Supply

The only major additions to the province's supply resources came from large scale wind projects. Between May and October 2011 approximately 315 MW of wind capacity was added to the supply mix. There were no significant reductions made to Ontario's generation supply during the reporting period.

1.4 Imports and Exports

Net exports totalled 4.3 TWh in the summer of 2011, or 0.7 TWh (19.4 percent) higher than the prior summer.

Exports (excluding linked wheel transactions) declined by 0.7 TWh (9.5 percent) to 6.7 TWh relative to 2010. The largest monthly decline in exports occurred in September as exports fell by 0.86 TWh (50 percent) from the previous September. Exports in the month of May saw the largest jump, increasing by 1.03 TWh (188 percent) over the previous May. Approximately 38 percent of exports occurred at the Michigan intertie, followed by the New York and Quebec interties at 33 percent and 28 percent respectively. The summer of 2011 export shares changed considerably from the shares seen in the summer of 2010 where Quebec led the way at 40 percent with Michigan and New York registering 37 percent and 23 percent of total exports, respectively.

Imports (excluding linked wheel transactions) declined steeply from 3.7 TWh in the summer of 2010 to 2.4 TWh in the summer of 2011, a decrease of 1.3 TWh (35 percent). Off-peak hours accounted for 34 percent of the total import flows, down from 54 percent during the prior summer reporting period. The Quebec interties accounted for 49 percent of total import volumes over the summer 2011 period, with Manitoba being the other significant import source at 32 percent.

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Chapter 2: Analysis of Market Outcomes

1. Introduction

The Market Assessment Unit (MAU), under the direction of the Panel, monitors the IESO administered markets for anomalous events and behaviour. Anomalous behavior is action by market participants or the IESO that may lead to market outcomes that fall outside of the predicted patterns or norms.

The MAU monitors and reports to the Panel both high- and low-priced hours as well as other events that appear anomalous given the circumstances. The Panel believes that an explanation of these events provides transparency with respect to why certain outcomes occurred in the market, leading to learning by the IESO and all market participants. Where appropriate based on this monitoring, the Panel recommends changes to Market Rules or the tools and procedures that the IESO employs.

The MAU reviews the previous day's operation and market outcomes on a daily basis, not only to discern anomalous events but also to review:

- changes in offer and bid strategies – both price and volume;
- the impact of forced and extended planned outages;
- import/export arbitrage opportunities as well as the behaviour of traders;
- the appropriateness of uplift payments;
- the application of IESO procedures; and
- the relationship between market outcomes in Ontario and neighbouring markets.

The daily review process is an important part of market monitoring. Identification of anomalous events may lead to discussion with the relevant market participants and/or the IESO. Certain events may trigger more detailed examinations or formal investigations if, for example, the event pertains to the potential abuse of market power, gaming, or efficiency issues.

The Panel defines high-priced hours as all hours in which the HOEP is greater than $200/MWh and low-priced hours as all hours in which the HOEP is less than $20/MWh,[7] including negative-priced hours.

There were 6 hours during the May through October 2011 period where the HOEP was greater than $200/MWh. Section 2.1 of this Chapter summarizes these events and factors contributing to the relatively high HOEPs.

In the same period, there were 711 hours in which the HOEP was less than $20/MWh, including 96 hours where the HOEP was negative. Section 2.2 of this Chapter reviews the factors typically driving prices to low levels in these hours.

In its January 2009 Monitoring Report, the Panel refined the indicators of anomalous uplift as payments in excess of $500,000/hour for Congestion Management Settlement Credits (CMSC) or Intertie Offer Guarantees (IOG) and $100,000/hour for operating reserve (OR) payments. Daily payments of $1,000,000 for CMSC or IOG in the intertie zones are also considered anomalous.[8] As discussed in section 3 of this Chapter, there were five hours where the anomalous uplift criteria were met during the May to October 2011 period.

2. *Anomalous HOEP*

2.1 Analysis of High-Priced Hours

The MAU reviews all hours where the HOEP exceeds $200/MWh. The objective of this review is to understand the underlying causes that led to these high prices, and to signal whether further analysis of the design or operation of the market or of market participant conduct is warranted.

[7] Depending on fuel prices, $200/MWh is roughly an upper bound for the cost of a fossil generation unit while $20/MWh is an approximate lower bound for the cost of a fossil unit.
[8] See the Panel's January 2009 Monitoring Report, pp. 178-184.

Table 2-1 depicts the total number of hours per month where the HOEP exceeded $200/MWh over the last five summer periods.

Table 2-1: Number of Hours with a HOEP > $200/MWh
May to October, 2007 - 2011
(Number of Hours)

Month	Number of Hours with HOEP > $200/MWh				
	2007	2008	2009	2010	2011
May	0	0	0	0	2
June	2	4	0	1	3
July	1	3	0	4	0
August	0	2	4	0	1
September	0	5	0	1	0
October	1	3	2	1	0
Total	**4**	**17**	**6**	**7**	**6**

In previous reports, the Panel has noted that a HOEP greater than $200/MWh typically occurs during hours when at least one of the following occurs:

- real-time demand is much higher than the pre-dispatch forecast of demand;
- one or more imports fail in real-time;
- one or more generating units that appear to be available in pre-dispatch become unavailable in real-time as a result of a forced outage or derating; or
- there is a large increase in net exports in the unconstrained schedule from one hour to the next.

Each of the factors discussed above has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. Spikes in the HOEP above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[9]

[9] The Panel's March 2003 Monitoring Report, pp. 11-16, noted that a supply cushion lower than 10 percent was more likely to be associated with a price spike. The Panel began reporting a revised supply cushion calculation in its July 2007 Monitoring Report, pp. 79-81. It remains the case that when the supply cushion is below 10 percent, a price spike becomes increasingly likely.

The following analysis examines the circumstances surrounding four of the six high-priced hours during the summer 2011 reporting period. The other two high-priced hours are not discussed in this report because the market conditions surrounding these hours were similar to those surrounding the other four high-priced hours.

2.1.1 May 11, 2011 HE 16

On May 11, 2011 in HE 16, the HOEP reached $558.24/MWh. The spike was caused by numerous forced outages and a shortage in the operating reserve market. Changes in demand and sources of forecast inaccuracy had moderate effects on real-time prices, in some instances putting downward pressure on the HOEP relative to pre-dispatch prices.

Prices, Demand and Supply

Table 2-2 displays the real-time market clearing price (MCP), Ontario demand, and net exports for HE 15 and 16 on May 11, 2011.

Table 2-2: Real-time MCP, Ontario Demand, and Net Exports May 11, 2011 HE 15 & 16 (MW & $/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Real-Time Ontario Demand (MW)	Real-Time Net Exports (MW)	Real-Time Ontario Demand plus Net Exports (MW)	Change in Ontario Demand plus Net Exports from Previous Interval (MW)	Change in Net Exports from Previous Hour (MW)
15	1	56.34	16,121	2,474	18,595	312	287
15	2	55.77	16,115	2,474	18,589	-6	287
15	3	59.23	16,151	2,474	18,625	36	287
15	4	59.23	16,191	2,474	18,665	40	287
15	5	53.09	16,146	2,474	18,620	-45	287
15	6	59.23	16,242	2,474	18,716	96	287
15	7	55.77	16,221	2,474	18,695	-21	287
15	8	43.00	16,129	2,474	18,603	-92	287
15	9	43.00	16,129	2,474	18,603	0	287
15	10	118.34	16,163	2,474	18,637	34	287
15	11	523.26	16,185	2,474	18,659	22	287
15	12	559.49	16,240	2,474	18,714	55	287
Average		**140.48**	**16,169**	**2,474**	**18,643**	**36**	**287**
16	1	498.00	16,270	2,187	18,457	-257	-287
16	2	355.23	16,246	2,187	18,433	-24	-287
16	3	305.23	16,228	2,187	18,415	-18	-287
16	4	1,999.50	16,234	2,187	18,421	6	-287
16	5	1,999.50	16,284	2,187	18,471	50	-287
16	6	296.67	16,240	2,187	18,427	-44	-287
16	7	228.20	16,154	2,187	18,341	-86	-287
16	8	228.20	16,174	2,187	18,361	20	-287
16	9	228.20	16,186	2,187	18,373	12	-287
16	10	248.13	16,221	2,187	18,408	35	-287
16	11	248.13	16,226	2,187	18,413	5	-287
16	12	63.90	15,855	2,187	18,042	-371	-287
Average		**558.24**	**16,193**	**2,187**	**18,380**	**-56**	**-287**

During the first 9 intervals of HE 15 the MCP remained within the range of $40-$60/MWh, fluctuating due in large part to changes in Ontario demand. For the remainder of HE 15 and during HE 16 interval-over-interval demand changes were modest, but the MCP fluctuated significantly, varying from $64/MWh to nearly $2,000/MWh.

Pre-dispatch Conditions

Table 2-3 displays pre-dispatch prices, as well as pre-dispatch Ontario demand and net exports. The pre-dispatch price was persistently around $41/MWh from five hours ahead to one hour ahead. Net exports were in the range of 2,240 MW to 2,319 MW during this time frame. In the final pre-dispatch run, 1,186 MW of imports and 3,427 MW of exports were scheduled, for 2,241 MW of net exports.

Table 2-3: Pre-dispatch Demand, Price, and Net Exports May 11, 2011 HE 16 (MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
5	40.06	16,142	512	2,752	2,240
4	40.44	16,170	527	2,846	2,319
3	40.19	16,098	547	2,866	2,319
2	41.16	16,107	1,186	3,427	2,241
1	41.16	16,199	1,186	3,427	2,241

Real-time Conditions

The real-time MCP jumped in interval 10 of HE 15 when all four units at one gas-fired generator were forced offline. The forced outage resulted in approximately 620 MW of lost generation and prompted the IESO to activate 680 MW in operating reserves.[10] The units remained unavailable for several hours, effectively removing a large supply of infra-marginal generation from the supply stack for the remainder of the afternoon peak.

In interval 4 of HE 16 the real-time MCP spiked again, with a dispatchable load setting the price at $1,999.50/MWh. The main causes of the spike were further shortfalls in expected supply from a gas-fired generator and operating reserve from a hydro generator. The gas-fired generator was scheduled to produce 30 MW but failed to start in interval 3. Concurrently, the hydro generator was experiencing a low forebay level, leading to a derating of 46 MW in interval 4. The derating caused the hydro generator’s operating reserve schedule to drop from 52 MW in interval 3, to only 6 MW in interval 4. The drop

[10] The activation of OR led to a reduction in the OR requirement, freeing up an additional 680 MW for the energy market, which put downward pressure on the energy price. The Panel has previously recommended that the IESO should replenish the OR requirement as soon as possible after each reduction in order to avoid this counterintuitive price impact. For details, see the Panel’s July 2007 Monitoring Report, pp. 86-90. For the IESO’s response, see: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20111215.pdf

in OR supply in turn caused a supply shortage in the OR market. When the IESO's dispatch tool optimized the OR and energy markets in interval 4, it pulled offered capacity at some generation units from the energy market into the OR market to satisfy OR requirements. This steepened the supply stack in the energy market and contributed to the jump in the real-time MCP.

With the exception of these generator shortfalls, all other sources of supply and demand forecast discrepancy had little effect on pre-dispatch to real-time price divergences. Table 2-4 lists all sources of pre-dispatch forecast discrepancy for HE 15 and 16 on May 11, 2011.

Table 2-4: Pre-dispatch and Real-time Demand & Supply Conditions May 11, 2011 HE 15 & 16 (MW)

HE	Interval	Ontario Demand (MW)			Self-Scheduler and Intermittent (MW)			PD Net Exports (MW)	RT Net Exports (MW)	Failed Net Exports (MW)	Total PD vs. RT Discrepancy (MW)
		PD	RT	PD - RT	PD	RT	RT - PD				
15	1	16,149	16,121	28	1,425	1,271	-154	2,435	2,474	-39	-165
15	2	16,149	16,115	34	1,425	1,261	-164	2,435	2,474	-39	-169
15	3	16,149	16,151	-2	1,425	1,259	-166	2,435	2,474	-39	-207
15	4	16,149	16,191	-42	1,425	1,274	-151	2,435	2,474	-39	-232
15	5	16,149	16,146	3	1,425	1,290	-135	2,435	2,474	-39	-171
15	6	16,149	16,242	-93	1,425	1,308	-117	2,435	2,474	-39	-249
15	7	16,149	16,221	-72	1,425	1,321	-104	2,435	2,474	-39	-215
15	8	16,149	16,129	20	1,425	1,329	-96	2,435	2,474	-39	-115
15	9	16,149	16,129	20	1,425	1,329	-96	2,435	2,474	-39	-115
15	10	16,149	16,163	-14	1,425	1,358	-67	2,435	2,474	-39	-120
15	11	16,149	16,185	-36	1,425	1,375	-50	2,435	2,474	-39	-125
15	12	16,149	16,240	-91	1,425	1,388	-37	2,435	2,474	-39	-167
Average		**16,149**	**16,169**	**-20**	**1,425**	**1,314**	**-111**	**2,435**	**2,474**	**-39**	**-171**
16	1	16,199	16,270	-71	1,408	1,404	-4	2,241	2,187	54	-21
16	2	16,199	16,246	-47	1,408	1,400	-8	2,241	2,187	54	-1
16	3	16,199	16,228	-29	1,408	1,398	-10	2,241	2,187	54	15
16	4	16,199	16,234	-35	1,408	1,413	5	2,241	2,187	54	24
16	5	16,199	16,284	-85	1,408	1,428	20	2,241	2,187	54	-11
16	6	16,199	16,240	-41	1,408	1,452	44	2,241	2,187	54	57
16	7	16,199	16,154	45	1,408	1,482	74	2,241	2,187	54	173
16	8	16,199	16,174	25	1,408	1,521	113	2,241	2,187	54	192
16	9	16,199	16,186	13	1,408	1,533	125	2,241	2,187	54	192
16	10	16,199	16,221	-22	1,408	1,524	116	2,241	2,187	54	148
16	11	16,199	16,226	-27	1,408	1,537	129	2,241	2,187	54	156
16	12	16,199	15,855	344	1,408	1,545	137	2,241	2,187	54	535
Average		**16,199**	**16,193**	**6**	**1,408**	**1,470**	**62**	**2,241**	**2,187**	**54**	**122**

Real-time demand in HE 16 stayed fairly close to the hourly pre-dispatch forecast of peak demand in the hour, with an under-forecasting of only 85 MW in interval 5.[11] Offsetting the under-forecast of demand was over-generation from intermittent and self-scheduling generators (an average of 62 MW) compared to their pre-dispatch forecast. Additionally, there was a net export failure of 54 MW in the hour.

Table 2-5 lists notable resource outages, the real-time MCP, and the marginal resource that set the price in each interval. In HE 16, peaking hydro resources set the MCP in most

[11] The IESO uses peak demand forecasts for HE 6 to 9 and HE 16 to 19 on weekdays, and average demand forecasts for all other hours.

intervals, with dispatchable loads setting two intervals, and gas-fired generators setting the remaining three intervals.

Table 2-5: Real-time MCP and Marginal Resource
May 11, 2011 HE 15 & 16
($/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
15	1	56.34	Gas	
15	2	55.77	Gas	
15	3	59.23	Gas	
15	4	59.23	Gas	
15	5	53.09	Gas	
15	6	59.23	Gas	
15	7	55.77	Gas	
15	8	43.00	Gas	
15	9	43.00	Gas	
15	10	118.34	Hydroelectric	A gas-fired generator forced offline, 620 MW generation loss, OR Activated
15	11	523.26	Hydroelectric	
15	12	559.49	Dispatchable Load	
Average		**140.48**		
16	1	498.00	Hydroelectric	
16	2	355.23	Hydroelectric	
16	3	305.23	Gas	A gas-fired generator failed to start (30 MW loss), a hydro unit was derated (46 MW loss)
16	4	1,999.50	Dispatchable Load	OR Shortage
16	5	1,999.50	Dispatchable Load	OR Shortage
16	6	296.67	Gas	
16	7	228.20	Hydroelectric	
16	8	228.20	Hydroelectric	
16	9	228.20	Hydroelectric	
16	10	248.13	Hydroelectric	
16	11	248.13	Hydroelectric	
16	12	63.90	Gas	
Average		**558.24**		

In summary, the high-priced hour was mainly caused by forced outages/deratings at several generating units.

2.1.2 June 7, 2011 HE 13

The HOEP was $278.13/MWh on June 7, 2011 in HE 13. The majority of this price spike was in the final two intervals of the hour where the MCP reached $476.65/MWh in interval 11 and $1,999.50/MWh in interval 12. The primary reasons for the price spike were a series of forced outages and deratings at a coal-fired generating station, as well as climbing demand over the hour.

Prices, Demand and Supply

Table 2-6 lists real-time MCP, Ontario demand, and net exports for HE 13 on June 7, 2011.

Table 2-6: Real-time MCP, Ontario Demand, and Net Exports June 7, 2011 HE 13 (MW & $/MWh)

Interval	Real-time MCP ($/MWh)	Real-Time Ontario Demand (MW)	Real-Time Net Exports (MW)	Real-Time Ontario Demand plus Net Exports (MW)	Change in Ontario Demand plus Net Exports from Previous Interval (MW)	Average Change in Net Exports from Previous Hour (MW)
1	40.20	19,217	1,371	20,588	-690	-550
2	42.53	19,237	1,371	20,608	20	-550
3	50.46	19,445	1,371	20,816	208	-550
4	50.46	19,440	1,371	20,811	-5	-550
5	51.88	19,501	1,371	20,872	61	-550
6	114.86	19,523	1,371	20,894	22	-550
7	113.46	19,510	1,371	20,881	-13	-550
8	115.37	19,552	1,371	20,923	42	-550
9	141.12	19,603	1,371	20,974	51	-550
10	141.11	19,612	1,371	20,983	9	-550
12	1,999.50	19,691	1,371	21,062	111	-550
Average	**278.13**	**19,493**	**1,371**	**20,864**	**-18**	**-550**

Real-time MCPs were modest for the first 5 intervals of HE 13, reflecting adequate supply and moderate demand conditions. In total, Ontario demand increased 474 MW over the course of the hour, peaking at 19,691 MW in interval 12.

Pre-dispatch Conditions

Table 2-7 displays pre-dispatch prices, Ontario demand, and net exports for the five pre-dispatch hours in advance of HE 13. The pre-dispatch MCP was in the range of $40-$50/MWh, except for the three hour ahead pre-dispatch MCP. The Ontario demand forecast was gradually revised downwards as real-time approached, and in the final three hours net exports declined.

Table 2-7: Pre-dispatch Demand, Price, and Net Exports
June 7, 2011 HE 13
(MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
5	41.34	19,962	583	1,947	1,364
4	45.23	19,686	593	2,402	1,809
3	70.89	19,238	663	2,162	1,499
2	45.00	19,196	1,392	2,877	1,485
1	46.97	19,272	1,466	2,877	1,411

Real-Time Conditions

As Table 2-6 shows, the real-time MCP experienced an initial jump to $114.86/MWh in interval 6. This increase was caused by a forced outage at a coal-fired unit, which resulted in the removal of 475 MW of infra-marginal generation from the supply stack. The MCP experienced a more pronounced spike in interval 11 when an additional coal-fired unit was derated by 195 MW, causing a large jump up a steep section of the supply stack.

The forced outage in interval 10 along with an increase of 111 MW of interval-over-interval demand in interval 12 led to an operating reserve shortage in real time. In this interval, scheduled operating reserves fell short of the OR requirement by 6 MW, causing the OR price to reach $1,999.50/MWh. During times of OR shortage the IESO's dispatch scheduling optimizer (DSO) will pull MW from the energy market and schedule them into the OR market. This steepens the supply stack in the energy market and can contribute to price spikes when coupled with increases in demand.

Prior to the forced outage of a coal-fired generator in interval 6, real-time MCPs were trending close to pre-dispatch prices. The final pre-dispatch price of $46.97/MWh provided a reasonable price signal of the prevailing market conditions in intervals 1 through 5, where the MCP averaged $47.11/MWh. In the back half of the hour demand continued to rise above forecasted levels, and when coupled with generator outages, led to the divergence between pre-dispatch and real-time prices.

Table 2-8 displays pre-dispatch versus real-time demand and supply conditions in HE 13 on June 7, 2011. In interval 12 of HE 13, real-time demand ran 419 MW heavier than the hourly average pre-dispatch demand forecast, representing a 2.2 percent increase over the forecast. On the supply side, self-scheduling and intermittent generators over-delivered during the early low-priced intervals, and under-delivered slightly during the high-priced intervals later in the hour.

Table 2-8: Pre-dispatch and Real-time Demand and Supply Conditions June 7, 2011 HE 13 (MW)

Interval	Ontario Demand (MW)			Self-Scheduler and Intermittent (MW)			PD Net Exports (MW)	RT Net Exports (MW)	Failed Net Exports (MW)	Total PD vs. RT Discrepancy (MW)
	PD	RT	PD - RT	PD	RT	RT - PD				
1	19,272	19,217	55	1,263	1,299	37	1,411	1,371	40	132
2	19,272	19,237	35	1,263	1,305	43	1,411	1,371	40	118
3	19,272	19,445	-173	1,263	1,301	39	1,411	1,371	40	-95
4	19,272	19,440	-168	1,263	1,296	34	1,411	1,371	40	-95
5	19,272	19,501	-229	1,263	1,280	18	1,411	1,371	40	-172
6	19,272	19,523	-251	1,263	1,273	11	1,411	1,371	40	-201
7	19,272	19,510	-238	1,263	1,259	-4	1,411	1,371	40	-202
8	19,272	19,552	-280	1,263	1,253	-10	1,411	1,371	40	-250
9	19,272	19,603	-331	1,263	1,251	-12	1,411	1,371	40	-303
10	19,272	19,612	-340	1,263	1,263	1	1,411	1,371	40	-300
11	19,272	19,580	-308	1,263	1,253	-10	1,411	1,371	40	-278
12	19,272	19,691	-419	1,263	1,256	-7	1,411	1,371	40	-386
Average	**19,272**	**19,493**	**-221**	**1,263**	**1,274**	**12**	**1,411**	**1,371**	**40**	**-169**

Table 2-9 displays real-time MCPs, the fuel type of the marginal resource, and any notable outage/derating events for each interval of HE 13. Gas-fired units were at the margin in the first seven intervals, followed by peaking hydro in intervals 8 through 11, and a dispatchable load in the last interval as the supply/demand balance became increasingly tight.

Table 2-9: Real-time MCP and Marginal Resource
June 7, 2011 HE 13
($/MWh)

Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
1	40.20	Gas	
2	42.53	Coal	
3	50.46	Gas	
4	50.46	Gas	
5	51.88	Gas	
6	114.86	Gas	A coal-fired unit forced out, loss of 475MW of supply
7	113.46	Gas	
8	115.37	Hydroelectric	
9	141.12	Hydroelectric	
10	141.11	Hydroelectric	A coal-fired unit derated by 195 MW
11	476.65	Hydroelectric	
12	1,999.50	Dispatchable Load	OR Shortage
Average	**278.13**		

In summary, the high-priced hour was mainly caused by forced outages/deratings at fossil-fired generating units as well as rising demand over the hour.

2.1.3 <u>June 28, 2011 HE 11 & 12</u>

On June 28, 2011 during HE 11 and 12, the HOEP reached $299.54/MWh and $288.33/MWh respectively. The persistent high prices in the two consecutive hours were primarily caused by forced outages/deratings at three coal-fired units, coupled with higher than forecasted demand.

Prices, Demand and Supply

Table 2-10 lists real-time MCP, Ontario demand, and net exports for HE 11 and 12 on June 28, 2011.

Table 2-10: Real-time MCP, Ontario Demand, and Net Exports June 28, 2011 HE 11 & 12 (MW & $/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Real-Time Ontario Demand (MW)	Real-Time Net Exports (MW)	Real-Time Ontario Demand plus Net Exports (MW)	Change in Ontario Demand plus Net Exports from Previous Interval (MW)	Average Change in Net Exports from Previous Hour (MW)
11	1	77.29	19,000	1,305	20,305	487	568
11	2	66.83	19,078	1,305	20,383	78	568
11	3	74.33	19,230	1,305	20,535	152	568
11	4	68.14	19,297	1,305	20,602	67	568
11	5	67.03	19,299	1,305	20,604	2	568
11	6	67.13	19,321	1,305	20,626	22	568
11	7	242.39	19,452	1,305	20,757	131	568
11	8	210.79	19,450	1,305	20,755	-2	568
11	9	228.20	19,473	1,305	20,778	23	568
11	10	248.53	19,573	1,305	20,878	100	568
11	11	245.79	19,591	1,305	20,896	18	568
11	12	1,998.00	19,633	1,305	20,938	42	568
Average		**299.54**	**19,366**	**1,305**	**20,671**	**93**	**568**
12	1	472.01	19,647	1,377	21,024	86	72
12	2	599.90	19,678	1,377	21,055	31	72
12	3	223.53	19,612	1,377	20,989	-66	72
12	4	101.24	19,439	1,377	20,816	-173	72
12	5	223.53	19,641	1,377	21,018	202	72
12	6	135.00	19,580	1,377	20,957	-61	72
12	7	219.40	19,657	1,377	21,034	77	72
12	8	223.08	19,721	1,377	21,098	64	72
12	9	220.78	19,727	1,377	21,104	6	72
12	10	218.55	19,680	1,377	21,057	-47	72
12	11	223.08	19,758	1,377	21,135	78	72
12	12	599.89	19,716	1,377	21,093	-42	72
Average		**288.33**	**19,655**	**1,377**	**21,032**	**13**	**72**

Interval-over-interval demand rose in all but four intervals, resulting in a cumulative increase of 716 MW (3.8 percent) from the beginning of HE 11 to the end of HE 12. Ontario was a net exporter with net exports of 1,305 MW and 1,377 MW in HE 11 and 12 respectively.

Pre-Dispatch Conditions

Tables 2-11 and 2-12 display pre-dispatch prices, as well as pre-dispatch Ontario demand and net exports, for HE 11 and HE 12 on June 28, 2011. The pre-dispatch prices in HE 11 were persistently projected at slightly above $30/MWh, even though net exports increased from 497 MW five hours ahead to 1,305 MW one hour ahead. The Ontario demand forecast increased by about 300 MW from five hours to one hour ahead.

Table 2-11: Pre-dispatch Demand, Price, and Net Exports June 28, 2011 HE 11 (MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
5	31.83	18,744	444	941	497
4	31.83	18,820	444	941	497
3	32.59	18,761	491	1,216	725
2	33.51	18,743	491	1,796	1,305
1	34.42	19,033	491	1,796	1,305

Similarly, the pre-dispatch prices in HE 12 were persistently projected in the range of $30/MWh to $40/MWh, with net exports increasing from 574 MW five hours ahead to 1,427 MW one hour ahead. The Ontario demand forecast increased by about 300 MW from five hours to one hour ahead.

Table 2-12: Pre-dispatch Demand, Price, and Net Exports June 28, 2011 HE 12 (MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
5	33.00	19,125	444	1,018	574
4	33.00	19,067	444	1,168	724
3	33.00	19,049	444	1,458	1,014
2	37.00	19,338	541	2,018	1,477
1	40.80	19,410	591	2,018	1,427

Real-Time Conditions

Table 2-13 below lists the pre-dispatch vs. real-time Ontario demand, self-scheduling and intermittent generation, and net exports in HE 11 and HE 12 on June 28, 2011. On average, Ontario demand was under forecast by 333 MW in HE 11 and by 245 MW in HE 12. Self-scheduling and intermittent generators as a group generally performed as projected, and failed net exports totaled only 50 MW in HE 12.

Table 2-13: Pre-dispatch and Real-time Demand & Supply Conditions June 28, 2011 HE 11 & 12 (MW & $/MWh)

HE	Interval	Ontario Demand (MW)			Self-Scheduler and Intermittent (MW)			PD Net Exports (MW)	RT Net Exports (MW)	Failed Net Exports (MW)	Total PD vs. RT Discrepancy (MW)
		PD	RT	PD - RT	PD	RT	RT - PD				
11	**1**	19,033	19,000	33	1,531	1,452	-79	1,305	1,305	0	-46
11	**2**	19,033	19,078	-45	1,531	1,450	-81	1,305	1,305	0	-126
11	**3**	19,033	19,230	-197	1,531	1,445	-86	1,305	1,305	0	-283
11	**4**	19,033	19,297	-264	1,531	1,445	-86	1,305	1,305	0	-350
11	**5**	19,033	19,299	-266	1,531	1,450	-81	1,305	1,305	0	-347
11	**6**	19,033	19,321	-288	1,531	1,445	-86	1,305	1,305	0	-374
11	**7**	19,033	19,452	-419	1,531	1,445	-86	1,305	1,305	0	-505
11	**8**	19,033	19,450	-417	1,531	1,442	-89	1,305	1,305	0	-506
11	**9**	19,033	19,473	-440	1,531	1,436	-95	1,305	1,305	0	-535
11	**10**	19,033	19,573	-540	1,531	1,459	-72	1,305	1,305	0	-612
11	**11**	19,033	19,591	-558	1,531	1,483	-48	1,305	1,305	0	-606
11	**12**	19,033	19,633	-600	1,531	1,487	-44	1,305	1,305	0	-644
Average		**19,033**	**19,366**	**-333**	**1,531**	**1,453**	**-78**	**1,305**	**1,305**	**0**	**-412**
12	**1**	19,410	19,647	-237	1,589	1,515	-74	1,427	1,377	50	-261
12	**2**	19,410	19,678	-268	1,589	1,526	-63	1,427	1,377	50	-281
12	**3**	19,410	19,612	-202	1,589	1,543	-46	1,427	1,377	50	-198
12	**4**	19,410	19,439	-29	1,589	1,568	-21	1,427	1,377	50	0
12	**5**	19,410	19,641	-231	1,589	1,583	-6	1,427	1,377	50	-187
12	**6**	19,410	19,580	-170	1,589	1,635	46	1,427	1,377	50	-74
12	**7**	19,410	19,657	-247	1,589	1,637	48	1,427	1,377	50	-149
12	**8**	19,410	19,721	-311	1,589	1,671	82	1,427	1,377	50	-179
12	**9**	19,410	19,727	-317	1,589	1,689	100	1,427	1,377	50	-167
12	**10**	19,410	19,680	-270	1,589	1,684	95	1,427	1,377	50	-125
12	**11**	19,410	19,758	-348	1,589	1,699	110	1,427	1,377	50	-188
12	**12**	19,410	19,716	-306	1,589	1,654	65	1,427	1,377	50	-191
Average		**19,410**	**19,655**	**-245**	**1,589**	**1,617**	**28**	**1,427**	**1,377**	**50**	**-167**

Real-time demand climbed throughout HE 11, culminating in interval 12 with a peak demand of 19,633 MW, or 600 MW more than the average hourly demand forecast. This interval corresponded with the highest 5 minute MCP over the 2-hour period at $1,998/MWh. The pre-dispatch demand forecast increased in HE 12, but real-time demand continued to run heavier than predicted.

Additionally, real-time supply conditions were tight due to several forced outages at a coal-fired plant. The series of outages and derates put an upward pressure on the real-time energy price, as shown in Table 2-14. Peaking hydro units set the MCP in all intervals of both hours, except interval 4 of HE 12 in which a gas-fired unit was at the margin.

Table 2-14: Real-time MCP and Marginal Resource June 28, 2011 HE 11 & 12 ($/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
11	**1**	77.29	Hydroelectric	A coal-fired unit forced out, 265 MW loss in HE 10 Int 12
11	**2**	66.83	Hydroelectric	
11	**3**	74.33	Hydroelectric	A coal-fired unit derated to 125 MW, 330 MW loss
11	**4**	68.14	Hydroelectric	
11	**5**	67.03	Hydroelectric	
11	**6**	67.13	Hydroelectric	A coal-fired unit forced out, 125 MW loss
11	**7**	242.39	Hydroelectric	
11	**8**	210.79	Hydroelectric	
11	**9**	228.20	Hydroelectric	A coal-fired unit derated to 50 MW, 75 MW loss
11	**10**	248.53	Hydroelectric	
11	**11**	245.79	Hydroelectric	
11	**12**	1998.00	Hydroelectric	
Average		**299.54**		
12	**1**	472.01	Hydroelectric	
12	**2**	599.90	Hydroelectric	
12	**3**	223.53	Hydroelectric	
12	**4**	101.24	Gas	
12	**5**	223.53	Hydroelectric	
12	**6**	135.00	Hydroelectric	
12	**7**	219.40	Hydroelectric	
12	**8**	223.08	Hydroelectric	
12	**9**	220.78	Hydroelectric	
12	**10**	218.55	Hydroelectric	
12	**11**	223.08	Hydroelectric	A coal-fired unit derated to 260 MW, 130 MW loss
12	**12**	599.89	Hydroelectric	
Average		**288.33**		

In HE 11 the three coal-fired units offered a total of 1,250 MW of supply into the market at prices no higher than $48.52/MWh. However, due to deratings, outages, and operating reserve requirements these units were never scheduled to produce more than 845 MW in the market schedule, despite 5 minute MCPs as high as $1,998/MWh. In HE 12 one of the coal-fired units was removed from the market, while the other two offered a combined 900 MW at $48.52/MWh or cheaper, only 515 MW of which got scheduled in the energy market. This loss of low-priced supply in the energy market coupled with higher than anticipated demand drove up the MCPs and HOEP in each of these high-priced hours.

2.1.4 Overall Assessment of High-priced Hours

The Panel has reviewed all six of the high-priced hours that occurred during the reporting period, and commented on four of those hours above. Outages/deratings and/or demand forecast errors were the major contributing factors in all events. The Panel found no evidence of abuse of market power or gaming related to these high-priced hours.

2.2 Analysis of Low-priced Hours

Table 2-15 below presents the number of hours when the HOEP was less than $20/MWh (low HOEP) or negative by month over the last five May to October periods. The total number of hours with a low HOEP increased by 350 hours (96 percent) in the summer of 2011, relative to the summer of 2010. Although there was a significant increase in low-priced hours relative to 2010, the total number of low-priced hours in 2011 was similar to the levels observed in the 2008 summer period and less than half of the hours observed in the 2009 summer period.

The number of hours when the HOEP was negative also increased substantially in the summer of 2011. There were 96 negative-priced hours, up 77 hours (405 percent) from 19 hours in the summer of 2010. This was similar to the total from 2009. For only the second time in the past five years, there were negative-priced hours during all summer months.

Table 2-15: Number of Hours with Low and Negative HOEPs May to October, 2007 – 2011 (Number of Hours)

Month	Hours when HOEP<$20/MWh					Hours when HOEP<$0/MWh				
	2007	2008	2009	2010	2011	2007	2008	2009	2010	2011
May	115	193	210	22	266	0	6	24	0	31
June	67	87	295	8	122	0	0	42	0	23
July	57	144	393	20	46	0	16	14	0	4
August	11	126	236	19	85	0	4	11	0	17
September	45	90	297	143	66	1	0	25	9	6
October	36	84	188	149	126	0	2	5	10	15
Total	331	724	1,619	361	711	1	28	121	19	96

As outlined in previous Panel reports, the primary factors leading to a low (or negative) HOEP are:[12]

- Low market demand;
- Abundant low-priced supply (i.e. nuclear, baseload hydro, self-scheduling and intermittent generation, fossil generation up to minimum loading point, and hydro generation offering energy at prices less than $20/MWh);
- Demand deviation: the forecast demand that is used in pre-dispatch is typically different from, and often greater than, the average real-time demand that determines the HOEP; and
- Failed export transactions: these can place downward pressure on the HOEP as failures represent a reduction in demand in real-time relative to pre-dispatch.

Table 2-16 shows real-time schedules by resource type and unscheduled generation that offered at prices less than $20/MWh (called 'low-priced supply') for all low-priced hours in the summer of 2011. Generation categories are segmented into nuclear, baseload hydro[13], self-scheduling and intermittent resources, and other hydroelectric resources. Hydro units other than baseload hydro may want to operate even when market prices are low because of an abundant supply of water, with spilling being the only alternative.

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[12] These factors were first identified in the Panel's June 2004 Monitoring Report, pp. 84-85.
[13] For the purpose of the current analysis, the baseload hydro resources include the Beck, Saunders, and DeCew Falls stations. These are prescribed assets owned by Ontario Power Generation.

Average hourly scheduled imports, excluding linked wheels, during low-priced hours are also included in the low-priced supply table.

Table 2-16: Low-priced Supply During Low-priced Hours May to October, 2011 (MW)

Month	Low-priced Supply (MW)						Total Supply (MW)
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Other Unscheduled Generation (offered <$20)	Imports (excluding linked wheels)	
May	9,416	2,161	1,217	1,794	1,367	267	16,222
June	9,150	2,224	1,163	1,289	1,801	253	15,880
July	9,930	2,058	1,058	1,051	1,374	451	15,922
August	10,876	1,987	1,108	482	1,206	240	15,899
September	10,395	1,750	948	360	1,215	391	15,059
October	9,790	1,681	1,447	444	983	230	14,575
Average	**9,739**	**2,020**	**1,200**	**1,127**	**1,339**	**278**	**15,703**

*includes generation at the Beck, Saunders, and DeCew generation stations.

Summary statistics related to the demand conditions during the low-priced hours are presented in Table 2-17. The table includes monthly average Ontario demand, exports, and total market demand over the low-priced hours in the summer of 2011. Excess low-priced supply is presented in the final column of Table 2-17, and is calculated as the difference between low-priced supply (see Table 2-16) and market demand over all low-priced hours.

Table 2-17: Demand and Excess Low-priced Supply During Low-priced Hours May to October, 2011 (MW)

Month	Number of Low-priced Hours	Demand (MW)			Excess Low-Priced Supply (MW)
		Ontario Demand	Exports	Market Demand	
May	267	13,060	2,479	15,539	683
June	122	12,690	2,061	14,751	1,129
July	48	13,257	1,893	15,150	772
August	87	13,587	1,640	15,227	672
September	66	12,872	1,519	14,391	668
October	128	12,560	1,703	14,263	312
Average	**718**	**12,968**	**2,041**	**15,009**	**694**

On average, excess low-priced supply (including scheduled imports) was 694 MW higher than total market demand during the low-priced hours between May and October 2011, with a maximum monthly difference of 1,129 MW in June 2011. Excess low-priced supply was lowest in October 2011 at 312 MW.

Table 2-18 provides additional summary information by month for all low-priced hours including failed net exports, the difference between pre-dispatch demand and real-time average demand (referred to as 'Demand Discrepancy'), and average pre-dispatch and real-time prices. Demand Discrepancy can result from demand forecast errors or simply result from differences in peak and average demand within an hour. Pre-dispatch prices during the low-priced hours over the reporting period were on average $6.77/MWh higher compared to the real-time prices. Abundant low-priced supply relative to total demand (694 MW surplus on average) was the most important factor leading to the low HOEP over the reporting period, followed by demand deviation (72 MW), and finally by failed net exports (47 MW).

Table 2-18: Average Monthly Summary Data for Low-priced Hours May to October, 2011 (MW & $/MWh)

Month	Excess Supply	Failed Net Exports (MW)	RT Average Demand (MW)	PD Demand Forecast (MW)	PD to RT Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Difference (RT - PD) ($/MWh)
May	683	63	13,060	13,139	79	5.56	13.17	-7.61
June	1,129	45	12,690	12,808	118	-1.26	12.92	-14.18
July	772	54	13,257	13,532	275	9.15	16.37	-7.22
August	672	96	13,587	13,664	77	-3.79	10.14	-13.93
September	668	33	12,872	12,840	-32	11.69	18.39	-6.7
October	312	-14	12,560	12,548	-12	7.30	12.52	-5.22
Average	**694**	**47**	**12,968**	**13,040**	**72**	**4.38**	**13.34**	**-8.96**

The following analysis outlines the market conditions that led to five consecutive negative-priced hours spanning the night of August 28, 2011 to the early morning hours of August 29, 2011.

2.2.1 August 28, 2011 HE 23 to August 29, 2011 HE 3

On Sunday, August 28, 2011 in HE 23, the HOEP dropped to -$70.57/MWh, the first of five consecutive negative-priced hours. Two hours later, in HE 1, on August 29, 2011 the HOEP reached a reporting period low of -$128.64/MWh, the third lowest HOEP since market opening. Two hours after that, in HE 3, the HOEP experienced its final negative-priced hour of the day before returning to a positive price in HE 4. The prolonged dip in price was caused by low overnight demand, surplus baseload generation, and numerous exports being cut in real-time. Sources of supply and demand forecast discrepancy had moderate effects on pre-dispatch to real-time price differences.

Prices, Demand and Supply

Table 2-19 displays HOEP, real-time hourly average Ontario demand, and net exports for HE 22 on August 28, 2011 to HE 4 on August 29, 2011.

Table 2-19: HOEP, Ontario Demand, and Net Exports
August 28, 2011 HE 22 to August 29, 2011 HE 4
(MW & $/MWh)

Delivery Date	Delivery Hour	HOEP ($/MWh)	Average Real-Time Ontario Demand (MW)	Real-Time Net Exports (MW)	Average Real-Time Ontario Demand plus Net Exports (MW)	Change in Average Ontario Demand plus Net Exports from Previous Hour (MW)
8/28/2011	**22**	12.41	14,693	782	15,475	-
	23	-70.57	13,768	1,146	14,914	-561
	24	-122.58	13,128	1,121	14,249	-665
8/29/2011	**1**	-128.64	12,619	671	13,290	-959
	2	-116.25	12,347	867	13,214	-76
	3	-112.68	12,236	1,039	13,275	61
	4	11.62	12,257	1,524	13,781	506

Ontario demand started dropping off and the HOEP became negative as the market transitioned into the overnight period. Ontario demand fell consistently in these hours, hitting a low of 12,236 MW in HE 3 before picking back up for the Monday morning ramp up. Real-time net exports varied greatly across hours due to substantial cuts to real-time exports in some hours. Total market demand followed a similar arc to Ontario demand, but started its ramp up an hour earlier due to increased net exports in HE 3. Low demand and considerable baseload generation meant that the IESO was operating under surplus baseload generation (SBG) conditions. These conditions necessitated that the IESO ramp down or shut off four nuclear units between HE 23 and HE 2 to balance supply and demand in the province.

With SBG conditions throughout most of the night, the IESO changed wind generator offers in pre-dispatch from -$1/MWh to -$2,000/MWh for the latter hours of August 28, 2011 all the way through to the end of August 29.[14] This change eliminated a divergence between pre-dispatch and real-time merit order by ensuring that wind generators would not be dispatched-off in pre-dispatch before any dispatchable resources offering at prices less than -$1/MWh. Until this time, there was a difference between how wind resources are typically treated in pre-dispatch (dispatchable) versus real-time (non-dispatchable). A wind generator offering at -$1/MWh that fails to receive a pre-dispatch schedule, goes to the bottom of the real-time supply stack, receives a real-time schedule, and pushes out some more negatively priced generation. This difference in treatment causes a natural divergence between the pre-dispatch and real-time schedules and prices. By effectively switching wind generators into non-dispatchable units in the pre-dispatch schedule (*i.e.* by reducing their offer price to -$2,000/MWh) this natural divergence can be eliminated. While the offer change procedure is an improvement, it is still a sub-optimal solution when compared to making wind facilities fully dispatchable (*i.e.* using their actual offers, which are typically - $1/MWh, in both pre-dispatch and real-time), as suggested by the Panel in a previous report.[15]

Table 2-20 displays pre-dispatch prices, as well as pre-dispatch Ontario demand and net exports for the relevant intervals.

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[14] Switching wind generator offers from -$1/MWh to -$2,000/MWh is now standard procedure when the IESO observes negative shadow prices at wind generators in the Day-Ahead Commitment Process schedule.
[15] For more information regarding the efficiency gains of making wind dispatchable, see chapter 2 of the previous Market Surveillance Panel Report released on November 16, 2011, available at http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Market+Surveillance+Panel+Reports

Table 2-20: Pre-dispatch Demand, Price, and Net Exports August 28, 2011 HE 23 to August 29, 2011 HE 3 (MW & $/MWh)

Delivery Date	Delivery Hour	Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
8/28/2011	23	1	0.00	13,822	111	1,593	1,482
	24	1	-128.10	12,740	52	1,881	1,829
8/29/2011	1	1	14.20	12,777	200	1,900	1,700
	2	1	-128.20	12,566	415	1,786	1,371
	3	1	-128.20	12,341	415	2,091	1,676

Pre-dispatch prices were negative for three of the five consecutive hours that had negative HOEPs, providing a reasonable representation of real-time market conditions. Both HE 23 and HE 1 had non-negative pre-dispatch MCPs despite highly negative real-time HOEPs.

Table 2-21 below displays all sources of supply and demand forecast discrepancy to help explain why the prices collapsed from pre-dispatch to real-time.

Table 2-21: Pre-dispatch and Real-time Demand & Supply Conditions August 28, 2011 HE 23 to August 29, 2011 HE 3 (MW)

HE	Average Ontario Demand			Average Self-Scheduler and Intermittent (MW)			PD Net Exports	RT Net Exports	Failed Net Exports	Total Avg. Forecast Discrepancy
	PD	RT	PD - RT	PD	RT	RT - PD				
23	13,822	13,768	54	1,114	890	-224	1,482	1,146	336	166
24	12,740	13,128	-388	955	862	-93	1,829	1,121	708	227
1	12,777	12,619	158	888	848	-40	1,700	671	1,029	1,147
2	12,566	12,347	219	893	816	-77	1,371	867	504	646
3	12,341	12,236	105	907	791	-116	1,676	1,039	637	626

Real-time average hourly Ontario demand was over forecast in all but one of the hours. Additionally, export curtailments in all hours meant that total market demand was lower than forecasted. HE 1 was particularly affected by export curtailments when 1,229 MW of exports were curtailed by MISO, NYISO, and Hydro-Quebec due to excess generation in those jurisdictions. This reduced demand prompted the IESO to cut all imports (200 MW), all of which were scheduled from Manitoba. The net effect was 1,029 MW of net exports (demand) that failed to materialize in real-time, causing the price to collapse from $14.20/MWh in pre-dispatch to -$128.64/MWh in real-time.

Slightly off-setting the downward pressure on prices were self-scheduling and intermittent generators. These units undersupplied relative to forecasted levels, tightening real-time supply conditions.

SBG conditions in Ontario and neighbouring jurisdictions led to the five consecutive highly negative-priced hours. Even though the pre-dispatch price during two of the five hours was not negative, a more accurate pre-dispatch price would likely not have improved the excess supply conditions. A negative pre-dispatch price would have increased scheduled net exports during those hours, but it would not have improved the excess supply conditions because all additional exports would have been cut in real-time by other jurisdictions due to excess generation conditions in those areas.

3. Anomalous Uplift

During the May to October 2011 period there were five hours where the Panel's anomalous uplift criteria were met.[16] All five instances involved OR payments greater than $100,000 in a given hour. There were no instances where CMSC payments or IOG payments were greater than $500,000 in a single hour, or CMSC payments at an intertie group exceeded $1 million for a day.

Table 2-22 displays the number of hours over the past five summer reporting periods in which hourly OR payments exceeded $100,000.

[16] To see how the Panel determined the anomalous uplift criteria view the January 2009 Monitoring Report, pp. 178-184.

Table 2-22: Number of Hours with Total OR Payments > $100,000 May to October 2007-2011 (Number of Hours)

	Number of Hours with HOEP > $200/MWh				
	2007	**2008**	**2009**	**2010**	**2011**
May	0	0	0	0	1
June	1	0	0	0	3
July	0	0	0	0	0
August	0	0	4	0	1
September	0	0	0	0	0
October	0	1	0	0	0
Total	**1**	**1**	**4**	**0**	**5**

Table 2-23 displays operating reserve MCPs as well as the total payout for each class of reserve for all hours in which total OR payments exceeded $100,000.

Table 2-23: Operating Reserve Prices and Total Payments During Anomalous Uplift Hours - May to October, 2011 ($/MWh & $)

Delivery Date	Delivery Hour	10S Price ($/MWh)	10N Price ($/MWh)	30R Price ($/MWh)	10S Payments ($)	10N Payments ($)	30R Payments ($)	Total OR Payments ($)
5/11/2011	**16**	418.56	410.76	410.68	114,496	157,719	107,790	379,404
6/07/2011	**13**	250.31	248.37	238.91	129,452	72,866	11,024	315,342
6/07/2011	**14**	90.59	90.27	88.1	57,887	23,839	41,335	123,061
6/07/2011	**16**	136.89	135.94	135.84	54,202	27,611	38,742	120,555
8/08/2011	**16**	150.59	142.40	142.35	45,589	71,068	43,579	160,236

All five hours in which OR payments exceeded $100,000 were during, or shortly following a high-priced hour in the energy market. To better understand the underlying causes of high prices in the operating reserve market, view the analysis of the corresponding high-priced hour in section 2.1.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This Chapter summarizes notable changes and developments that impact the efficient operation of the IESO-administered markets, making recommendations where relevant to promote market objectives. Section 2 of this Chapter identifies material changes that have occurred in the market related to Panel activities and prior reports. In Section 3, the Panel discusses new matters: the overselling of Transmission Rights (TRs) and failed transactions on the Ontario-Quebec interface at Outaouais (PQAT) in October 2011.

2. Changes Related to Panel Activities and Previous Reports

This section covers five issues:

- Changes to the Day-Ahead Commitment Process;
- Suspension of the Regional Reserve Sharing program;
- A Market Rule limiting constrained off CMSC payments to dispatchable loads;
- The Panel's Monitoring Document on Generators' Offer Prices Used to Signal an Intention to Come Offline; and
- Changes to the allocation of Global Adjustment.

2.1 Changes to the Day-Ahead Commitment Process

Unlike many neighbouring markets, Ontario does not have a day-ahead market. A day-ahead market commits internal generators (and intertie transactions) on the day prior to when transactions are scheduled to flow. This provides greater certainty to the system operator in maintaining real-time reliability, as well as operational and revenue certainty for market participants. The Panel continues to support a full day-ahead market and believes it would improve price fidelity. [17]

After nearly two years of stakeholder consultations,[18] the IESO decided in 2005 not to proceed with a full day-ahead market given the complexity of the two schedule design, substantial implementation cost and lack of stakeholder support.[19] Instead, the IESO implemented a Day-Ahead Commitment Process (DACP) in the summer of 2006 in light of the extremely tight supply situation in the summer of 2005. The DACP was a cost guarantee program that guaranteed non-quick start generators[20] their start-up costs as well as fuel and operating and maintenance (O&M) costs at their minimum loading point (MLP) for their minimum run time (MRT) when they were scheduled day-ahead and where revenue from the real-time market was insufficient to cover those costs. The DACP also guaranteed importers their offer price when they were scheduled day-ahead and the HOEP was less than their offer price.

Because the DACP scheduled generators based on the offer price, but allowed generators to submit costs after-the-fact, the offer price used to schedule a generation facility in the DACP could be significantly lower than the actual cost, leading to significant dispatch inefficiency. In its August 2007 Report, the Panel recommended that the IESO review the DACP in order to reduce the costs and improve effectiveness of the generator cost guarantee. It also noted that a three-part bid (including start-up cost, speed-no-load cost, and incremental cost) with 24 hour optimization may be an appropriate approach.[21]

When the Panel made its recommendation, the IESO was in the process of considering new options for the existing DACP program and possible evolution of the day-ahead market design. The process was initiated shortly after the DACP was implemented and

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[17] See the Panel's October 2002 Monitoring Report, p. 141; March 2003 Monitoring Report, pp. 89 and 95; and December 2005 Monitoring Report, p. 95.
[18] For details of the stakeholdering process, see: http://www.ieso.ca/imoweb/consult/mep_dam_WG.asp.
19 For details, see "Technical Panel's Comments on Comprehensive DAM - Dec 2004"m available at: http://www.ieso.ca/imoweb/pubs/consult/dayAhead/da_2005jul15_tp-comments.pdf.
[20] These generators include all nuclear generators and most dispatchable fossil-fired generators.
[21] For details, see the Panel's August 2007 Monitoring Report, pp. 114–121. See also the Panel's January 2009 Monitoring Report, pp. 217-221.

included several options to improve or even replace the existing DACP.[22] After years of stakeholdering followed by project development and testing, the IESO implemented enhancements to the DACP on October 12, 2011.

The new DACP is still a commitment process rather than a fully functioning day-ahead market. It optimizes the day-ahead schedules based on generators' three-part offers within a 24-hour horizon and then guarantees the scheduled generators their submitted costs if the revenue in the real-time market is insufficient. In other words, the IESO's dispatch algorithm minimizes the system-wide costs by taking into account the submitted generation costs. This is in principle a significant improvement on the prior DACP program, which did not incorporate such costs when making the dispatch decision.[23] The IESO estimated that the new DACP program would improve market efficiency by $13 to $19 million per year.[24]

There was not sufficient data on the operation of the new DACP in the May to October 2011 period for the Panel to conduct a meaningful analysis of its impact on the market. The Panel has instructed the MAU to continue to monitor the program and a more detailed study will be presented in a future report.

2.2 Suspension of the Regional Reserve Sharing Program

On June 1, 2005, the Northeast Power Coordinating Council (NPCC)[25] approved the voluntary implementation of an NPCC Regional Reserve Sharing (RRS) program that allowed for the sharing of ten-minute non-synchronized (10N) operating reserve among

[22] See the IESO's "Day Ahead Market Evolution (SE – 21)", available at: http://www.ieso.ca/imoweb/consult/consult_se21.asp.

[23] Under the old DACP, the start-up costs are submitted after-the-fact. The Panel has previously reviewed IESO cost guarantee programs (the old DACP and the real-time generation cost guarantee program) in its July 2009 Monitoring Report (pp. 197–202) and concluded that the after-the-fact cost submission could lead to more than cost recovery, depending on how the cost is allocated among resources at the same plant. The new DACP requires generators who want the cost guarantee to submit their start-up cost before the dispatch tool makes the dispatch decision, which should significantly mitigate generators' ability to take advantage of the after-the-fact cost submission.

[24] For a study of various options and anticipated benefits, see the IESO's "Day Ahead Market Evolution Preliminary Assessment" (dated May 6, 2008), available at: http://www.ieso.ca/imoweb/pubs/corp2/EB-2008-3040-IESO-B-4-1-Appendix-A-DAM.pdf.

[25] NPCC, following the rules and standards of the North American Electric Reliability Corporation (NERC), is responsible for promoting and improving the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC includes New York state, the six New England states, Ontario, Quebec, and the Maritime provinces that operate within the region. The IESO is a registered member of NPCC.

participating control areas. Under the RRS program, each participating control area could, subject to availability and deliverability, share 100 MW of 10N operating reserve and count 50 MW towards its 10N reserve requirement.[26]

The IESO implemented the RRS program on January 4, 2006. In doing so it lowered its total operating reserve requirement by 50 MW, from a normal level of 1,418 MW to 1,368 MW.[27]

On April 27, 2007, NPCC approved changes to the RRS program.[28] The changes allowed participating areas to reduce their synchronized (10S) and/or 10N ten-minute operating reserve requirement by a total of 100 MW, subject to availability and deliverability (i.e. a further 50 MW reduction in OR requirements). On May 17, 2007, the IESO implemented this second tranche of 50 MW of regionally shared reserve. As a result, it lowered its normal total operating reserve requirements further to 1,318 MW.[29]

The Panel reviewed these changes in its previous reports and estimated the price and efficiency impact of the reduction in the OR requirement. [30] The Panel welcomed these developments because the RRS allowed the IESO to maintain the overall reserve level at a lower cost.

On December 2, 2010 NPCC Directory #5 came into effect. Directory #5 replaces the existing rules relating to operating reserve as well as a number of guidelines and procedures established by NPCC. Significantly, Directory #5 removed certain provisions that had enabled RRS programs. In eliminating the RRS provisions through Directory #5, NPCC proposed a separate set of rules unique to RRS and to be covered by a new

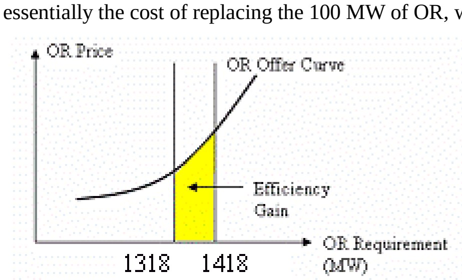
[26] NPCC Document C-38, "Procedure for Operating Reserve Assistance", which was retired in 2010.
[27] See Market Rule Amendment MR 00299, available at: http://www.ieso.ca/imoweb/pubs/mr/MR_00299-Q00.pdf.
[28] For more information see the IESO's "Rule Amendment MR-00332", available at http://www.ieso.ca/imoweb/pubs/mr2007/MR-00332-Q00-AS.pdf
[29] See: the IESO's May 10 2007 Participant News, available at https://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3455.
[30] See the Panel's June 2006 Monitoring Report, pp. 102-104; and December 2007 Monitoring Report, pp. 159-161.

Directory #6.[31] The IESO had opposed the changes in Directory #5 that eliminated the RRS provisions, but the majority of NPCC members voted in support of the changes. Since Directory #5 came into force before Directory #6 was adopted, the implementation of Directory #5 effectively terminated the RRS program.[32] In order to comply with Directory #5 the IESO eliminated its RRS arrangements on December 2, 2010.

NPCC posted its initial draft of Directory #6 for comment on September 8, 2011.[33] The IESO submitted its comments on the draft of Directory #6 on December 19, 2011, generally supporting the proposal with a few recommendations.[34] The Panel understands that efforts to bring back the RRS program through Directory #6 are still in process.

Table 3-1 below estimates the price impact and efficiency loss in Ontario resulting from the suspension of the RRS between December 2010 and October 2011. The efficiency and price impacts have been estimated by the MAU through simulation of the unconstrained (market) schedule. This enables the calculation of the total cost savings in both the energy and OR markets had the OR requirement been reduced by 100 MW. The efficiency loss comes from a higher OR requirement, leading to a higher cost in the OR market as well as more expensive generation capacity being used in the energy market (that is not being used for operating reserves).[35] The efficiency loss is estimated at $2

[31] See NPCC web site at: https://www.npcc.org/Standards/commRegStand/default.aspx.
[32] For details, see the IESO Weekly Bulletin, November 11, 2010, available at: http://www.ieso.ca/imoweb/news/bulletinItem.asp?bulletinID=5467.
[33] For details, see: Directory #6, Reserve Sharing Group, https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=109.
[34] See "IESO Comments on Directory #6 Reserve Sharing Group", available at: https://www.npcc.org/_Layouts/ViewDocument.aspx?documentId=136889.
[35] The simulation mimics the unconstrained schedule and ignores all constraints that exist in the constrained schedule. As a result, the estimated efficiency loss may understate the actual efficiency impact in the constrained schedule. The estimated efficiency loss is essentially the cost of replacing the 100 MW of OR, which is the shaded (yellow) area in the following graph.



Due to the joint optimization of the Dispatch Scheduling Optimizer, there may be efficiency gains in the energy market as well even though there is no change in energy demand (although the gains are usually very small). The efficiency gains reported in Table 3-1 are the total cost savings in both the energy and OR markets, as derived from the reported total costs in the simulations.

million in the 11 month period. The lower OR requirements could also have resulted in a lower average HOEP (a $0.30/MWh, or 1 percent, reduction) and lower average OR prices (roughly $1/MWh for all categories).[36]

Table 3-1: Estimated Price Impact and Efficiency Loss Resulting from Suspension of the Regional Reserve Sharing Program December 2010 to October 2011 ($/MWh and $ thousand)

Month	10 minutes spinning (10-S) "Actual" ($/MWh)	10 minutes spinning (10-S) Simulated ($/MWh)	10 minutes non-spinning (10-N) "Actual" ($/MWh)	10 minutes non-spinning (10-N) Simulated ($/MWh)	30 minutes reserve (30-R) "Actual" ($/MWh)	30 minutes reserve (30-R) Simulated ($/MWh)	MCP "Actual" ($/MWh)	MCP Simulated ($/MWh)	Total Efficiency Gain ($1 000) ($/MWh)
Dec-10	3.57	2.54	3.48	2.47	3.37	2.44	33.35	33.01	186
Jan-11	2.33	2.09	2.21	1.83	2.30	2.08	31.81	31.71	133
Feb-11	1.46	1.05	1.56	1.14	1.43	1.04	33.19	33.08	75
Mar-11	1.04	0.75	1.13	0.87	1.00	0.73	30.86	30.78	65
Apr-11	4.36	2.95	4.78	3.47	4.77	3.26	25.83	25.38	235
May-11	14.09	9.53	13.91	9.55	10.13	7.08	23.15	22.59	760
Jun-11	5.20	3.40	5.33	3.57	4.14	2.79	29.86	29.29	274
Jul-11	2.04	1.65	1.94	1.74	1.96	1.61	34.86	34.53	101
Aug-11	2.98	1.80	2.56	1.72	2.87	1.78	31.80	31.22	143
Sep-11	0.83	0.54	0.88	0.64	0.77	0.53	30.70	30.57	38
Oct-11	0.51	0.36	0.45	0.49	0.40	0.36	27.85	27.81	26
Average/ Total	3.50	2.43	3.48	2.50	3.01	2.16	30.29	29.99	2,036

"Actual" is a simulated actual. Because the MAU simulation tool does not have exactly the same input data as the IESO's Dispatch Scheduling Optimizer, the simulated outcome at times may be slightly different from actual market outcomes.

In view of the potential efficiency and price impacts from Regional Reserve Sharing, the Panel believes that the Ontario OR and energy markets would benefit from the re-introduction of this program and encourages the IESO to continue its efforts in this regard.

[36] In its June 2006 Report, the Panel estimated that the energy price was $0.36/MWh lower due to the 50 MW reduction in the OR requirement for the period January to April 2006 (see pp. 102-104). In its December 2007 Report, the Panel estimated an efficiency gain of $119,000 due to the implementation of the additional 50 MW of RRS and the price was estimated to be $0.07/MWh lower for energy and $0.14 to 0.17/MWh lower for OR in the period May to October 2007 (see pp. 123-125).

Recommendation 3-1

The Panel recommends that the IESO continue to pursue the introduction by the Northeast Power Coordinating Council of a revised Regional Reserve Sharing Program and the negotiation of any necessary implementing agreements with neighbouring ISOs as expeditiously as possible.

2.3 A Market Rule Limiting Constrained-off CMSC Payments to Dispatchable Loads

In its August 2010 Report, the Panel reported that for the period February to June 2010 two dispatchable load facilities[37] earned approximately $18 million in net CMSC payments for energy.[38] Despite accounting for only 0.5% of the dispatchable capacity in the province[39] these two facilities received 43% of all CMSC payments for energy over the corresponding period.[40] The Panel concluded that the majority of the CMSC payments to the two dispatchable load facilities were self-induced, meaning that the payments arose either as a result of actions taken by the facilities or as a result of conditions specific to those facilities, as opposed to conditions on the IESO-controlled grid. As part of its August 2010 Report, the Panel made three recommendations that related to CMSC payments to dispatchable loads.[41] Most notably, the Panel recommended that "[t]he IESO should immediately eliminate self-induced CMSC paid to dispatchable loads resulting from either a voluntary change in consumption or a consumption deviation."[42]

On August 27, 2010 the IESO implemented a temporary urgent Market Rule amendment to address the self-induced CMSC payments to dispatchable loads. The urgent rule amendment temporarily suspended all energy-related CMSC for constrained-off

[37] A dispatchable load is a large, price-responsive consumer that bids into the market.
[38] See the Panel's August 2010 Monitoring Report, pp. 112–128.
[39] There is approximately 35,000 MW of dispatchable capacity in the province, mostly from generation.
[40] Dispatchable facilities can receive CMSC in either the energy market or the operating reserve market.
[41] The Panel also commenced a formal investigation into the behaviour of the dispatchable load facilities, which investigation remains ongoing.
[42] See the Panel's August 2010 Monitoring Report, p. 123.

dispatchable load facilities.[43] On December 3, 2010 the IESO reintroduced constrained-off CMSC payments to dispatchable loads, replacing the temporary urgent rule amendment with a rule that aimed to more narrowly target self-induced, constrained-off, ramping CMSC.[44] During the reporting period May to October 2011, Ontario's dispatchable loads received approximately $5.8 million in constrained-off CMSC payments for energy. In addition, dispatchable loads received approximately $800,000 in constrained-off CMSC in the operating reserve market. A further assessment of these CMSC payments and the December 3, 2010 Market Rule amendment will be provided in a future report.

2.4 The Panel's Monitoring Document on Generators' Offer Prices Used to Signal an Intention to Come Offline

2.4.1 Introduction

In Ontario's market, generators raise their offer prices to signal to the IESO's dispatch algorithm their desire to come offline. In order to be dispatched off, the generator must submit an offer price that exceeds the shadow price at its connection node.[45]

Because of the two-schedule design in the Ontario market, a high offer price normally leads to a faster ramping down in the unconstrained schedule.[46] The difference between the unconstrained and constrained schedules results in the generator being "constrained-on" (i.e. its constrained schedule is greater than its unconstrained schedule). The generator is effectively paid its offer price during the ramp-down period (i.e. the real-time MCP plus a constrained-on payment to cover the difference between the offer price and the MCP). A higher offer price results in higher constrained-on CMSC payments.

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[43] See: http://ieso.ca/imoweb/pubs/mr2010/MR_00373-R00.pdf .
[44] See: http://www.ieso.ca/imoweb/pubs/mr2010/MR-00374-R00-BA.pdf. Ramping refers to a change in the level of consumption (production) by a dispatchable load (generation) facility. Specifically the Market Rule amendment proposal states that "dispatchable loads will not be entitled to constrained off CMSC payments related to ramping, where such payments are caused by conditions and/or actions at the load facility, and not by conditions on the IESO-controlled grid."
[45] The IESO's dispatch tool uses shadow (or "nodal") prices to set the constrained schedule. These shadow or nodal prices take into account transmission constraints on the system, whereas the unconstrained price that is used to settle the market does not.
[46] The unconstrained schedule uses a fictitious three times ramp rate multiplier compared to the actual ramp rate in the constrained schedule.

2.4.2 History of Panel Recommendations

In its January 2009 Report, the Panel recommended that the IESO take "action to limit CMSC payments where the CMSC payments are induced by the generator strategically raising its offer price to signal the ramping down of its generation." [47] The IESO responded by initiating Stakeholder Engagement – 84 (SE-84), which was to address, among other things, CMSC associated with high offer prices used by generators to signal an intention to take their facilities offline.[48]

In its January 2010 Report, the Panel indicated that it remained concerned about self-induced CMSC paid to ramping-down generators. However, it did not make a further recommendation on the basis that the IESO was addressing the matter through SE-84.[49]

In July 2010, the IESO temporarily suspended SE-84 to address other priority issues.[50] In its August 2010 Report, the Panel observed that CMSC payments to generators shutting down were contributing approximately $1 million per month to the uplift paid by loads (which, based on an annual market demand of approximately 155 TWh, translated into an uplift charge for all wholesale market customers of $0.08/MWh). As a result, the Panel urged "the IESO to expedite its efforts to implement a market rule amendment limiting CMSC paid to generators that are shutting down".[51]

In March 2011, the Panel reiterated its finding from the August 2010 Report that CMSC payments to generators shutting down were contributing approximately $1 million per month to the uplift paid by loads. The Panel concluded with a formal recommendation that "the IESO should resume work on Stakeholder Engagement 84 regarding elimination of self-induced CMSC payments for ramping-down generators".[52]

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[47] See the Panel's January 2009 Monitoring Report, pp. 216-217.
[48] For details on the IESO's Stakeholder Engagement (SE) – 84, see: http://ieso.ca/imoweb/consult/consult_se84.asp.
[49] See the Panel's January 2010 Monitoring Report, pp. 112-113.
[50] See the IESO stakeholdering status update available at http://www.ieso.ca/imoweb/consult/consult_se84.asp.
[51] See the Panel's August 2010 Monitoring Report, pp. 270-273.
[52] See the Panel's March 2011 Monitoring Report, pp. 93-94 and 96.

2.4.3 Monitoring Document: Generator Offer Prices Used to Signal an Intention to Come Offline

In light of the lack of the progress on the IESO's stakeholdering process over a 2½ year period, in June 2011 the Panel published a proposed monitoring document which would provide guidance to market participants regarding the level of offer prices that would not normally trigger a gaming investigation.[53] Five submissions were received from interested parties.[54] The final version of the document was published on August 19, 2011.[55]

In brief, the Monitoring Document indicates that, where there are *bona fide* business reasons for a generator to come offline, the Panel will normally not consider a gaming investigation to be warranted if the generator utilizes an offer price that is not higher than the greater of (i) 130% of the generator's 3-hour ahead constrained schedule pre-dispatch nodal (or shadow) price, or (ii) the generator's marginal (or other incremental or opportunity) costs.[56]

An unexpected outcome of the adoption of the Monitoring Document is that the IESO used its publication as the basis for postponing its efforts to pursue a permanent rule-based solution to address the issue of self-induced ramping CMSC payments to generators.[57] Following the publication of the Monitoring Document the IESO responded to the Panel's March 2011 recommendation by stating that it would "continue to assess the impact of the MSP monitoring document providing guidance to generators regarding

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[53] For text of the proposed document, see http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Proposed_Monitoring_Document.pdf. The MSP By-law #3, Article 4, authorizes the Panel to issue monitoring documents which set out the evaluative criteria that will be used in its market monitoring activities.
[54] The submissions are available online at http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance/Monitoring+Document+-+Generator+Offers.
[55] Market Surveillance Panel, "Monitoring Document: Generator Offer Prices Used to Signal an Intention to Come Offline", August 19, 2011, available online at http://www.oeb.gov.on.ca/OEB/_Documents/MSP/MSP_Proposed_Monitoring_Document.pdf (the "Monitoring Document").
[56] *ibid*
[57] See: http://www.ieso.ca/imoweb/pubs/icms/tp/2011/08/IESOTP_252_5a_MR_00252_cover_memo.pdf.

offer prices for signaling an intention to come offline – which the IESO believes to be the most effective action to address this matter".[58]

2.4.4 Impact of the Monitoring Document

Since the publication of the Monitoring Document, almost all generators have reduced their offer price on ramp down, although some offers remain above the 130% of three-hour-ahead shadow price branch of the threshold set out in the Monitoring Document. In the coming months, the Panel will determine what, if any, actions should be taken with respect to the generators that continue to offer above this level during ramp down.

Table 3-2 below lists the average CMSC payment per shutdown by generator and the estimated CMSC savings resulting from reduction of their ramp down offer prices. Only the five participants with the most significant CMSC payments (i.e. frequent shutdowns that yield significant CMSC amounts) are reported in this table.[59] The "pre-Document" period is from June 1, 2011 to August 19, 2011 (approximately three months) and the "post-Document" period runs from August 20, 2011 to November 21, 2011 (approximately three months). The total savings in CMSC uplift charges to loads in the 13 weeks after issuance of the Monitoring Document is estimated to be $1.8 million, which translates into about $7 million per year if the three month results reflect a typical seasonal pattern. Most of the savings were from two market participants who had the majority of shutdowns during the period August 20, 2011 to November 21, 2011 and who had significantly reduced their offer prices used to signal ramp down.

[58] All of the IESO's responses to the Panel's recommendations are available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20111215.pdf.
[59] Collectively, these five generators accounted for approximately 97% of ramp down CMSC payments in the period from June 1, 2011 to August 19, 2011.

Table 3-2: CMSC Savings After Issuance of the Panel's Monitoring Document on Ramp-Down Offer Prices by Participant
June 1, 2011 to November 21, 2011
($/MWh & $ thousands)

	Pre-Document		Post-Document					
Generator	**Typical Shutdown Offer Price ($/MWh)**	**CMSC per Unit per Shutdown ($1 000)**	**Typical Shutdown Offer Price ($/MWh)**	**No of Unit-Shutdowns**	**CMSC per Unit per Shutdown ($1 000)**	**CMSC Savings per Shutdown ($1 000)**	**Percent of CMSC Reduction**	**Total Estimated CMSC Savings ($1 000)**
Participant 1	149	5,000	99	160	2,100	2,900	58%	484
Participant 2	240	3,900	49	277	600	3,300	85%	1,184
Participant 3	200	1,300	55	64	700	600	46%	34
Participant 4	150	4,100	51	41	800	3,300	80%	137
Participant 5	60	900	60	194	900	0	0%	0
Total								1,839

2.4.5 Continuing Need for Amendment of Market Rules

As noted above, as a result of the publication of the Monitoring Document, the IESO ceased efforts to implement changes through SE-84. Instead the IESO has committed to monitor the impact of the MSP's Monitoring Document on self-induced CMSC payments during ramp-down.[60]

On a monthly basis, the Panel estimates that self-induced CMSC for generator ramp-downs has been reduced from an average of approximately $1 million per month to about $310,000 per month (average for September 2011 to February 2012). While a 70 percent saving is substantial, the Panel continues to believe that CMSC payments for self-induced ramp-downs are unwarranted, and that neither the Monitoring Document nor resource-intensive gaming investigations will be able to fully eliminate the associated unnecessary uplift charges. The Panel therefore continues to believe that a permanent rule-based solution is needed.[61]

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[60] See "IESO Responses to Market Surveillance Panel Report Recommendations", at: http://ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20110811.pdf.

[61] As discussed above, on December 3, 2010 the IESO implemented a rule change that aimed to eliminate self-induced ramping CMSC payments to dispatchable loads. Pursuant to that rule change dispatchable loads are no longer entitled to constrained off CMSC payments where there is a price-quantity change in the energy bid associated with the dispatchable load and where that bid

Recommendation 3-2

The Panel recommends that the IESO implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping-down generators.

2.5 Allocation of Global Adjustment

2.5.1 Introduction

The Global Adjustment (GA) was established in 2005 by the Government of Ontario. The GA is a charge collected from Ontario (but not export) customers that is mainly used to recover any shortfall in the costs of generation contracts or regulated rates not covered by wholesale market revenues.[62] Conservation and demand response program costs are also included in the GA.

Since 2005 the Ontario Power Authority (OPA) and the Ontario Electricity Financial Corporation (OEFC) have awarded numerous contracts such that the majority of Ontario's generation is now subject to a generation contract or is otherwise subject to a regulated price. Because the regulated rates and the prices paid under these contracts on average have exceeded the average HOEP, the GA has grown considerably. In 2011, the GA represented a charge of just over $5.3 billion. Over the last several years the GA has represented approximately half of the commodity cost of electricity, with the market price for energy representing the other half.[63] In the next few years, more resources are expected to come online with contract prices greater than HOEP.

change results in: (i) a change in the quantity scheduled in the market schedule; and (ii) the ramping up or down of the dispatchable load. A corollary rule change for generators would eliminate constrained on CMSC payments where there has been a price quantity change in the energy offer and where the offer change resulted in: (i) a change in the quantity scheduled in the market schedule; and (ii) the ramping up or down of the generator.

[62] For example, if a generator has a contract to which guarantees a price of $65/MWh, but the energy price or HOEP is only $35/MWh, a GA charge of $30/MWh is required in order to pay the generator the amount stipulated in its contract.

[63] See the Panel's November 2011 Monitoring Report at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf, Figure 1-2, p. 7.

In its previous report, the Panel described the significant change to the manner in which the GA is allocated among customer groups.[64] At the time of that report there was insufficient data to conduct a comprehensive assessment of the new allocation methodology and the Panel deferred further analysis to a future Report.[65] This section will deal with the following:

- Components of the Global Adjustment;
- Historical Global Adjustment charges;
- Changes to the Global Adjustment allocation methodology;
- Impact of the new Global Adjustment allocation on peak demand;
- Shifting of Global Adjustment charges from Class A to Class B customers;
- Efficiency considerations associated with Global Adjustment allocation; and
- Interface with demand response programs.

2.5.2 Components of the Global Adjustment

The OPA is responsible for procuring long-term supply contracts with new and existing generators, and with promoting conservation and demand response in an effort to ensure the long-term adequacy of supply in Ontario. To the extent that the costs associated with these contracts and programs are not recovered through market revenues they are recovered through the Global Adjustment (GA) charge. In addition, the output from some of Ontario Power Generation's (OPG) assets is subject to a regulated price. To the extent that wholesale market revenues are lower than the regulated price, the difference is recovered through the GA. The subsections below describe the components of the GA.

[64] See the Panel's November 2011 Monitoring Report at: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf, pp 128-133.
[65] As described later in this section, the Panel has made progress in further analysing the impact of the new GA allocation methodology but at this stage it has yet to reach a firm conclusion.

2.5.2.1 Supply Contracts

All recently built generation facilities, and some legacy generation facilities, have long-term contracts with the OPA. The major contracts entered into by the OPA include:[66]

- Bruce Power contracts: fixed-price contracts for generating unit A (at $63/MWh in 2005[67]), and floor price contracts for unit B (a floor price of $50.18/MWh in 2011[68]). All payments are based on actual output or, in the event of SBG conditions, foregone output.
- Clean Energy Supply (CES) contracts with new gas-fired generators: these contracts were given to the first group of generators that were planned and built following the creation of the OPA in 2005. They include Greater Toronto Airport Authority (GTAA), Greenfield, Goreway, Portlands, Halton Hills and St. Clair, among others. The CES contracts are designed to mitigate generators' exposure to the financial risk of low market prices while preserving their incentive to produce energy in response to market prices when it is efficient to do so.[69] The gas-fired generators with CES contracts are essentially guaranteed a rate of return on their long-term investment.
- "Early-mover contracts" with two gas-fired generators: TransAlta's Sarnia facility and Coral's Brighton Beach facility were built or planned prior to market opening and in anticipation of a traditional electricity market. Accordingly, when built they did not have a contract. These "early movers" subsequently obtained contracts from the OPA similar to the CES contracts.

[66] For a more detailed discussion of various types of generation contracts and the extent to which they incentivize efficient production decisions, see the Panel's December 2007 Monitoring Report, pp. 169-186.
[67] The OPA's web site indicates Bruce Power's A units earned approximately $64/MWh in 2010. See: http://www.powerauthority.on.ca/bruce-power-contract-amendment-february-2011.
[68] The OPA originally signed a contract with Bruce Power in 2005 with a floor price of $45/MHh for Unit B. See: http://archive.powerauthority.on.ca/Storage/56/5149_Bruce_Power_Refurbishment_Implementation_Agreement.pdf. The contract contains an adjustment factor for inflation. Cameco Corp., a part-owner of Bruce Power, reported that the floor price in 2011 was $50.18/MWh. See: http://www.cameco.com/fuel_and_power/bruce_power/operations/.
[69] The CES contracts link the generator's revenue with the wholesale pre-dispatch and real-time price through the contract "strike heat rate". The concept of "deemed dispatch" is used to calculate the "deemed" revenue from the wholesale market. The deemed revenue is in turn used to reduce the monthly contract payments by OPA to the generator. For details, see the Panel's December 2007 Monitoring Report, pp. 172-174.

- Renewable Energy Supply contracts: these contracts were given to an initial group of approximately 20 wind power suppliers and typically guaranteed a fixed price of around $80/MWh for actual output produced.[70]
- Feed-In-Tariff (FIT) contracts with renewable energy providers: in 2009 the Ontario Government passed the *Green Energy and Green Economy Act, 2009* (GEA)[71] in order to expand Ontario's production of renewable energy, to encourage energy conservation and to promote the creation of clean-energy green jobs.[72] The OPA was subsequently directed to develop the FIT program to procure renewable energy supply. The vast majority of the FIT contracts to date are with wind power suppliers, who are guaranteed a fixed price of $135/MWh, and with solar power suppliers who are guaranteed fixed prices varying between approximately $400/MWh to $800/MWh, for actual output produced.[73]
- Non-utility generator (NUG) contracts: these are generators who have contracts that pre-date the opening of the market in 2002 and which are held by the OEFC rather than the OPA. In November 2010, the OPA was directed by the Ministry of Energy to renew contracts with NUG generators on the expiry of their existing contracts.[74]

All of these contracts generally provide higher compensation than the revenue that the generators can receive from the wholesale market alone.

[70] See Ontario Energy Board, Regulated Price Plan Price Report May 1, 2011 to April 30, 2012, April 19, 2012, p. 14, available at: http://www.ontla.on.ca/library/repository/ser/251139//201105-201204.pdf .
[71] Green Energy and Green Economy Act, 2009 S.O. 2009, c. 12, available at http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&BillID=2145.
[72] See Ontario's Ministry of the Environment web page at: http://www.ene.gov.on.ca/environment/en/legislation/green_energy_act/index.htm.
[73] See the OPA's FIT program price schedule, available at http://fit.powerauthority.on.ca/fit-price-schedule.
[74] See Directives to OPA from Minister of Energy, available at: http://www.powerauthority.ca/about-us/directives-opa-minister-energy-and-infrastructure .

2.5.2.2 Conservation and Demand Response

As one of its statutory objects the OPA is to promote conservation and demand response.[75] The OPA has initiated various types of rebate programs to promote the adoption of energy-saving furnaces, water heaters, lighting and other devices. The OPA has also introduced three demand response programs[76] and it implemented an industrial accelerator program in June 2010.[77] The costs associated with conservation and demand response programs are recovered through the GA.

2.5.2.3 OPG's Assets

Under the *Electricity Restructuring Act, 2004*, the following of OPG's assets were classified as "prescribed" assets: all of the nuclear units operated by OPG and OPG's baseload hydroelectric units (Beck, Saunders, and Decew Falls). Effective April 1, 2005, the prices paid for the output of these prescribed assets were set by regulation. Responsibility for setting these payment amounts shifted to the Ontario Energy Board (OEB) effective April 1, 2008. The payment mechanism set by the OEB for the baseload hydroelectric facilities is designed to induce price responsiveness and efficient operation.[78]

In 2009, in light of the Government's directive to OPG to reduce power production at its main coal-fired plants (Nanticoke and Lambton), the OEFC signed a contingency agreement which allows OPG to recover the operational costs incurred when running

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[75] For details about the OPA's objects and powers, see the Electricity Restructuring Act 2004, Part II.1, available at http://www.search.e-laws.gov.on.ca/en/isysquery/08d3ab1e-a206-42ad-a8c3-2c992241ef55/1/doc/?search=browseStatutes&context=#BK34.

[76] The Panel has discussed the Demand Response Program 1 (DR1) in the Panel's December 2006 Monitoring Report, pp. 135-138; and Demand Response Program 3 (DR3) in the Panel's July 2009 Monitoring Report, pp. 191-196. For further information about these OPA programs, see Demand Response Programs at the OPA website, available at: http://archive.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=147.

[77] The program is a five-year program that provides attractive financial incentives to speed up investment in electricity-saving projects. For more information, see: http://www.powerauthority.on.ca/news/energy-efficiency-program-launched-ontarios-industrial-sector.

[78] The non-prescribed assets were regulated through a rebate mechanism, under which OPG was required to pay back Ontario customers 85 percent of its revenue above $47/MWh at these non-prescribed assets (in 2006 dollars). Roughly speaking, when the market price was greater than $47/MWh, there was a rebate from OPG. In contrast, when the market price was less than $47/MWh, there was a charge to Ontario loads. For details, see: Independent Electricity System Operator Licence, EI-2003-0088, July 31, 2008, available at http://ieso.ca/imoweb/pubs/corp/EI-2003-0088_IESO-Licence.pdf.

these units. Payments made pursuant to this contract are also recovered through the GA charge.

2.5.3 Historical Global Adjustment Charges

Table 3-3 below lists the annual GA from 2005 to 2011. In 2005, the GA was a net credit to Ontario customers of $1.2 billion.[79] However, since 2006 it has been a charge to customers, rising to $5.3 billion in 2011. The GA is expected to increase in 2012 and beyond as a large number of wind and solar resources that have been awarded FIT contracts come online.[80] These contracts pay a fixed price per MWh that has significantly exceeded the average HOEP in recent years.

Table 3-3: Total Global Adjustment Charge (Credit) by Year 2005 to 2011 ($ millions, TWh & $/MWh)

Year	Total Global Adjustment ($ Millions)	Ontario Demand (TWh)	$/MWh*
2005	-1,153.0	157.3	-7.3
2006	654.0	151.4	4.3
2007	597.0	152.5	3.9
2008	900.7	148.8	6.1
2009	4,219.5	139.5	30.2
2010	3,847.7	142.6	27.0
2011	5,309.8	141.8	37.4

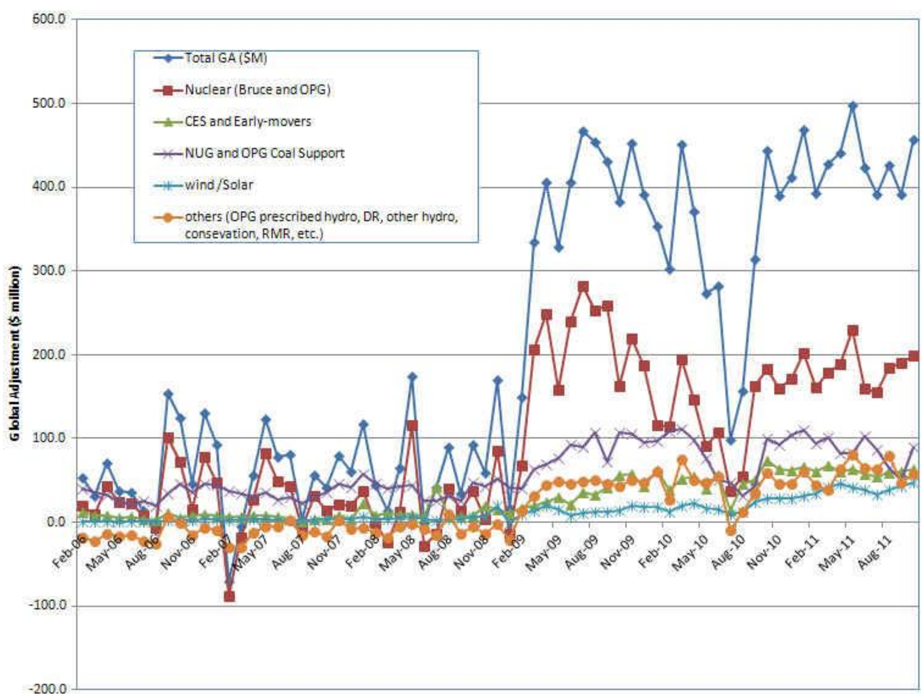
*This is a simple division of total GA by total Ontario demand. It does not take into account the fact that payments for OPG's prescribed assets started in April 2005 and customers were separated into two classes for GA allocation purposes in 2011.

[79] In 2005 the average HOEP received by regulated and contracted generators exceeded the regulated/contracted rate they were to have been paid. Accordingly, this excess revenue was returned to consumers.

[80] The Association of Major Power Consumers in Ontario (AMPCO) has estimated that the GA due to Renewable Energy Supply (RES) and FIT contracts would amount to $3 billion a year by 2020. For details, see AMPCO, Global Adjustment, available at http://www.ampco.org/index.cfm?pagepath=&id=36560. The Ontario Auditor General expects $8.1 billion of GA in 2014. For details, see the Auditor General's 2011 Annual Report, Chapter 3, Section 3.03, Electricity Sector – Renewable Energy Initiatives, December 5, 2011, available at http://www.auditor.on.ca/en/reports_en/en11/303en11.pdf.

Figure 3-1 below depicts the monthly GA charges by source from February 2006 until October 2011.[81] The sources are divided into to five groups: nuclear (including Bruce and OPG nuclear assets): CES and early-mover gas-fired generation contracts; the OEFC's NUG contracts and contingency support to OPG's coal-fired units; contracts for wind and solar power (RES and FIT); and others (including, but not limited to, OPG's prescribed baseload hydroelectric facilities, OPA's demand response programs, conservation programs, and the contract with OPG's Lennox generating station). The GA increased significantly in March 2009 and has generally averaged between $300 and $500 million per month since then.

Figure 3-1: Monthly Global Adjustment by Source
February 2006 to October 2011
($ millions)



Since February 2006 the sources of GA have been approximately as follows:

- 45 percent is attributable to the Bruce Power and OPG nuclear units. The major factors that led to the increase in 2009 were a significant decrease in the

[81] Before February 2006 the GA was not separated by source in the IESO's database.

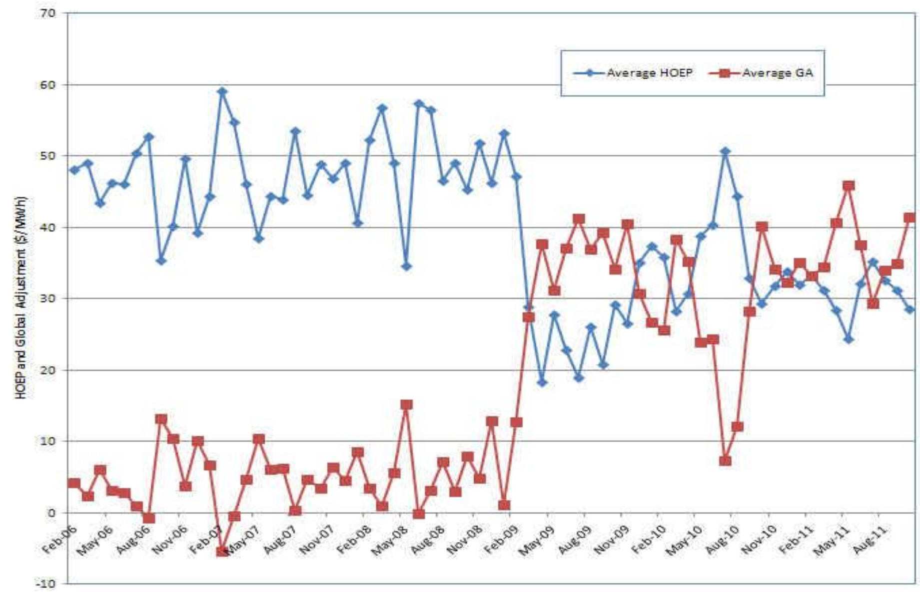
wholesale electricity price and a higher regulated price paid to OPG, both of which increased the spread between the contract prices and the HOEP.

- 28 percent is attributable to OEFC's NUG contracts and contingency financial support for OPG's coal-fired generation in light of the Government's directive of coal-emission reduction.[82] Two factors led to the increase: the lower wholesale electricity price and the inclusion of OPG's coal-fired generation support.
- 13 percent is attributable to CES and early-mover gas-fired generation contracts.
- 6 percent is attributable to renewable assets, primarily wind and solar resources. The share associated with renewables has been increasing significantly and is expected to continue to do so.
- 8 percent is attributable to other sources such as demand response and payments for the output of OPG's prescribed hydroelectric assets.

Since the GA is largely used to hold generators whole to a regulated or contract price, a higher HOEP will result in a lower GA. Figure 3-2 below depicts the monthly average GA (i.e. total GA divided by total Ontario demand) and average HOEP since February 2006 and provides a visual demonstration of the strong inverse relationship between the GA and the average HOEP.

[82] Because the coal-fired generators were required to produce less but maintain the ability to operate reliably when needed, OPG would not be able to recover all the costs of such facilities from the market. As a result, OEFC signed a contingency support contract with OPG.

Figure 3-2: Monthly Average Global Adjustment and HOEP
February 2006 to October 2011
($/MWh)



2.5.4 Changes to the Global Adjustment Allocation Methodology

Until the end of 2010 the GA was recovered uniformly from all Ontario customers on a volumetric basis. Each month the IESO totaled the invoices received from the OPA and the OEFC as well as the payment amounts related to OPG's prescribed assets and divided that sum by the total number of MWhs consumed in the month. The resulting dollar per MWh GA charge was applied to all consumption. For example if the total GA in a month was $250,000 and the total Ontario consumption was 25,000 MWh, then the GA charge would be $10/MWh to all Ontario customers.

Effective January 1, 2011 the Government of Ontario amended Ontario Regulation 429/04[83] to change the way in which the GA is allocated to customers.[84] Customers are now split into two classes – Class A customers (those customers that have an average

[83] Ontario Regulation 429/04, as amended, available at: http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_040429_e.htm.
[84] For details, see: http://www.e-laws.gov.on.ca/html/source/regs/english/2010/elaws_src_regs_r10398_e.htm.

peak demand of more than 5 MW for a defined base period[85]) and Class B customers (all other customers).[86] Each month the total GA is now allocated between Class A and Class B customers based on their relative contribution to hourly Ontario demand during the five coincident peak hours in the preceding period (the Base Period).[87] Once the GA is divided between the two groups, it is allocated to the individual wholesale market customers within each group as follows:

- Each Class A customer pays its share based on its own consumption during the five coincident peak hours in the Base Period. For example, a Class A facility responsible for 1 percent of the total Ontario demand during these hours will pay 1 percent of the total GA amount in the following 12-month GA billing period.

- After the GA charged to Class A customers is subtracted from the total monthly GA, the remainder is allocated to Class B customers as a whole. Each member of this group is charged based on its actual energy consumption during the month (i.e., the same volumetric allocation method that had been used before 2011 to allocate GA to all customers).

There is a very important distinction between how Class A and Class B customers are treated. If a Class A customer can completely avoid consuming energy during the five coincident peak hours, it will avoid paying any GA during the following billing period. Conversely, if a Class B customer completely avoids consuming energy during the five coincident peak hours, it cannot avoid paying the GA during the following billing period. For Class B customers, the benefit of reduced GA charges associated with the reduction in consumption by an individual Class B customer accrues to all Class B customers. With Class A customers, the benefit accrues directly and solely to the Class A customer

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[85] Given the significant demand threshold, Class A customers tend to be large industrial or natural resource entities (such as mining and pulp and paper companies). The average peak demand is calculated as the average of maximum hourly demand for electricity in a month for the applicable base period.

[86] A market participant that would fall into Class A based on the demand threshold can elect to be a Class B customer until June 2012 (i.e. the Adjustment Period of January 2011 to June 2011 and/or the Adjustment Period of July 2011 to June 2012). During the first year of this transitional period, a few customers with average peak demand in excess of 5 MW have chosen to be Class B customers.

[87] The coincident peak hours are the five hours (occurring on five different days) in which the greatest number of megawatts of electricity was used in Ontario (excluding exports). For an IESO description of changes to the allocation of the global adjustment, see the IESO's Changes to the Global Adjustment Recovery: Backgrounder for Eligible Loads, available at http://www.ieso.ca/imoweb/pubs/ga/Backgrounder_Changes_to_the_GA.pdf.

that reduced consumption. Because of this design difference the new allocation methodology creates a powerful incentive for each Class A customer to reduce consumption during hours which may become one of the five coincident peaks, while creating virtually no incentive for individual Class B customers to reduce consumption.

Table 3-4 below shows the Base Periods to be used by the IESO for the purposes of the new GA allocation and the related GA billing periods. The table also lists the first set of coincident peak hours as well as the probable coincident peaks for the Base Period May 2011 to April 2012. [88]

Table 3-4: Global Adjustment Allocation Base Periods, Coincident Peak Hours and Billing Periods

Base (Peak-setting) Period	Five Coincident Peak Hours	Peak Demand** (MW)	Adjustment (Billing) Period
May 1, 2010 to October 31, 2010	*Actual:* July 6, 2010, HE 16 July 7, 2010, HE16 July 8, 2010, HE 15 August 31, 2010, HE 16 September 1, 2010, HE 16	 24,211 24,724 24,691 24,320 24,167	January 1, 2011 to June 30, 2011
May 1, 2010 to April 30, 2011	Same hours as initial Base Period		July 1, 2011 to June 30, 2012
May 1, 2011 to April 30, 2012	*Probable peak hours:** July 18, 2011, HE 16 July 19, 2011, HE 17 July 20, 2011, HE 17 July 21, 2011, HE 16 July 22, 2011, HE 12	 23,154 22,517 23,720 24,707 22,401	July 1, 2012 to June 30, 2013
May 1, (Year X) to April 30, (Year X+1)	To be determined		July 1, (Year X+1) to June 30, (Year X+2)

Given that Ontario consistently had demand peaks during the summer months in the past years, it is highly likely that the five highest demand hours for the period May 2011 to April 2012 will be the listed five hours.
** Source: IESO, available at: http://www.ieso.ca/imoweb/b100/ga_changes.asp, and http://www.ieso.ca/imoweb/peaktracker/.

[88] Source: The IESO's Changes to the Global Adjustment, available at http://www.ieso.ca/imoweb/b100/ga_changes.asp.

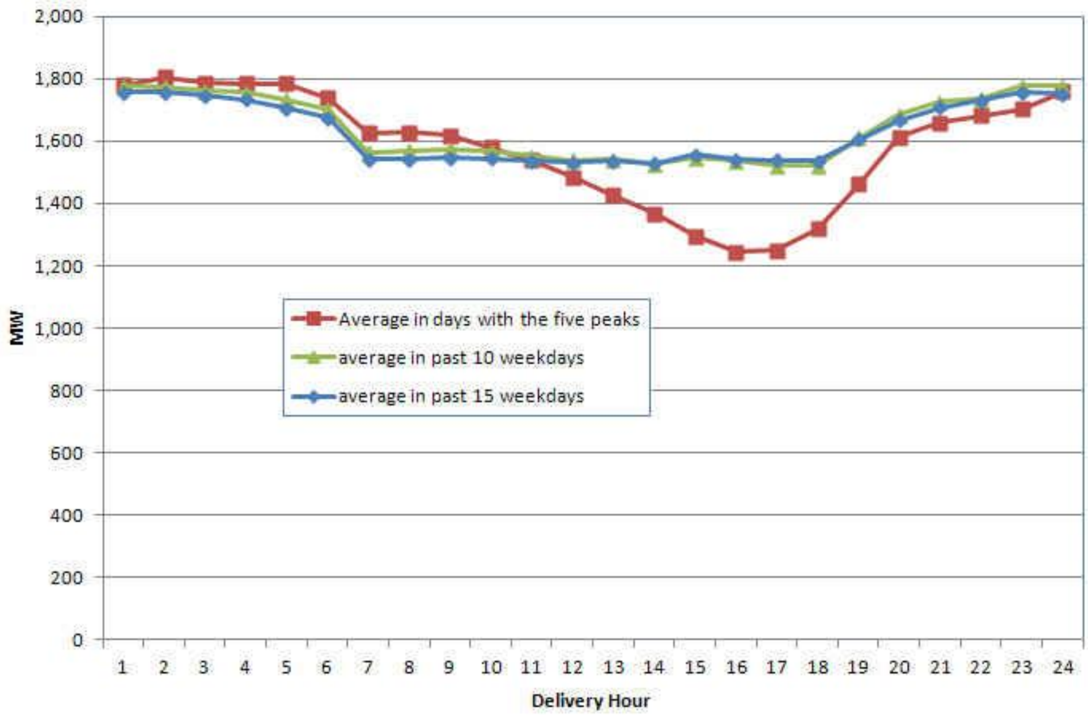
2.5.5 Impact of the New Global Adjustment Allocation on Peak Demand

The demand for electricity in HE 16 on July 21, 2011 turned out to be the highest demand hour for all of 2011. The high demand on July 21 was not difficult to predict given that on July 20 the humidity-adjusted temperature forecast for July 21 was expected to reach a high of 50°C and given that Ontario is a summer-peaking jurisdiction. Indeed, as Ontario was subject to a heat wave during the week of July 18-22, 2011, it was reasonable to predict that there would be a high probability that some, if not all, of the coincident peaks for the May 2011 to April 2012 Base Period would occur during that week. Practically speaking, the only factor that would prevent these days from becoming the coincident peaks would have been a more extreme heat wave later in the summer.

As demonstrated by Figure 3-3 below, Class A customers that were directly-connected to the IESO-controlled grid[89] were able to reduce their consumption significantly during these five coincident peak hours (and therefore will have significantly reduced their GA charges for the next GA billing period of July 2012 to June 2013). When compared to the 10 or 15 weekdays prior to the heat wave, directly-connected Class A customers reduced their consumption between July 18-22, 2011, by an average of approximately 300 MW (17 percent of their total load and 1 percent of total Ontario demand) in HE 16 and 17 as well as smaller but non-trivial amounts during HE 13-15 and HE 18 and 19.

[89] The Panel only has access to data for directly-connected Class A customers. It does not have access to data for Class A customers that are embedded within local distribution companies (LDCs).

Figure 3-3: Directly-Connected Class A Customer Average Consumption in the Five Days with Highest Demand and Preceding Weekdays July 18-22, 2011 and Three Weeks' Prior (MW)



It is worth noting that the peak demand in summer 2011 appears in retrospect to have been relatively easy to predict because of the significant and prolonged heat wave (particularly the day of July 21, 2011 when the temperature reached 50°C with humidity) that was publicised well in advance. The Panel expects that the ability to predict peak demand in future years may not be as easy as it was in 2011. For example in 2010 three of the coincident peak days occurred on consecutive days during a three-day heat wave, but the other two days did not occur until several weeks later during a separate heat wave.[90] It is also possible that if Class A customers attempt to avoid or reduce consumption during what they collectively anticipate will become a coincident peak hour

[90] For information on historical heat alerts and extreme heat alerts in Toronto (Ontario's load centre), see: http://app.toronto.ca/tpha/heatStats.html. For a list of Ontario's all-time top 20 coincident peaks see the IESO's web site at: http://www.ieso.ca/imoweb/media/md_peaks.asp For a list of hourly Ontario demand since market opening, see the IESO web site at: http://www.ieso.ca/imoweb/marketdata/marketSummary.asp

their collective reduction in consumption will cause the coincident peak to shift to a different hour in the same day or to a different hour in a different day.[91]

2.5.6 Shifting of Global Adjustment Charges from Class A to Class B Customers

This section summarizes the shifting of some GA charges from Class A to Class B customers as a result of the change to the GA allocation methodology. Table 3-5 below shows the estimated GA avoided by Class A customers during the period January to October 2011. The table reports the actual Class A and Class B consumption as well as the GA allocations for Class A and Class B on a monthly basis. The right hand column of the table calculates the differential between the GA charges to Class A under the new methodology compared with the prior volumetric method that was based on shares of monthly consumption.

[91] For example, on July 22, 2011 the peak was set in HE 12, whereas daily peaks are typically set later in the afternoon. Figure 3-3 shows the average reduction in Class A consumption during HE 12 was muted, with significant reductions coming in HE 14 through HE 18.

Table 3-5: Estimated Impact
of the New Global Adjustment Allocation on Class A and B Customers
January to October 2011
(TWh, $ millions & %)

Month	Consumption (TWh & %)			Global Adjustment ($ millions & %)			
	Class A	Class B	Total	Class A*	Class B	Total	Estimated GA Avoided by Class A Customers
January 2011	2.0	11.3	13.3	51.1	418.0	469.1	19.0
	14.9%	85.1%	100%	10.9%	89.1%	100%	
February 2011	1.8	10.0	11.8	42.8	350.6	393.5	18.0
	15.4%	84.6%	100%	10.9%	89.1%	100%	
March 2011	2.0	10.3	12.3	46.6	381.1	427.7	22.7
	16.2%	83.8%	100%	10.9%	89.1%	100%	
April 2011	1.9	9.0	10.9	48.0	392.5	440.4	29.6
	17.4%	82.6%	100%	10.9%	89.1%	100%	
May 2011	1.9	8.9	10.8	54.2	444.0	498.2	33.5
	17.6%	82.4%	100.0%	10.9%	89.1%	100%	
June 2011	1.8	9.3	11.1	46.0	377.1	423.1	22.5
	16.2%	83.8%	100.0%	10.9%	89.1%	100%	
July 2011	1.9	11.3	13.1	39.0	352.7	391.7	16.7
	14.2%	85.8%	100.0%	10.0%	90.0%	100%	
August 2011	1.9	10.5	12.4	42.4	383.7	426.2	24.3
	15.6%	84.4%	100.0%	10.0%	90.0%	100%	
September 2011	1.9	9.1	11.0	39.0	352.5	391.5	28.2
	17.2%	82.8%	100.0%	10.0%	90.0%	100%	
October 2011	1.9	9.1	11.0	45.5	411.4	456.9	34.2
	17.4%	82.6%	100.0%	10.0%	90.0%	100%	
Total	19.0	98.7	117.7	454.7	3,863.6	4,318.2	243.6
	16.2%	83.8%	100.0%	10.5%	89.5%	100%	

*In July 2011 the share of Class A customers' consumption and their share of GA dropped because some customers that had been classified as Class A for the GA billing period January 1, 2011 to June 30, 2011 elected to be treated as Class B customers for the GA billing period July 1, 2011 to June 30, 2012. The ability to elect out of being classified as a Class A customer will no longer be possible in the GA billing period beginning July 1, 2012 and beyond.

As Table 3-5 shows, Class A customers paid 10.5 percent of total GA during the first 10 months of 2011, although their share of Ontario domestic energy consumption was 16.2 percent. The estimated savings in GA charges for Class A customers associated with the change from the old volumetric allocation methodology to the five coincident peak hours allocation methodology (assuming GA charges were not affected by the allocation methodology[92]) was approximately $243.6 million, or $12.79/MWh for the energy consumed by Class A customers. That portion of GA charges was effectively transferred to Class B customers, which increased Class B customer costs by $243.6 million or $2.47/MWh for the energy consumed by Class B customers. This represents an approximate 4 percent increase in their effective price.

2.5.7 Efficiency Considerations Associated with Global Adjustment Allocation

The IESO has argued that a uniform GA allocation approach could lead to potential short-term market inefficiency and that if the former volumetric GA allocation approach could be replaced with a new well-designed approach, both short-term and long-term efficiency gains could potentially be achieved.

As noted in the Panel's last report, one of the Government's principal objectives for adopting the new GA allocation method was to reduce inefficient price signals in non-peak periods.[93] The Panel has pointed out in past Monitoring Reports that growth in the GA has increasingly undermined the fidelity of the price signal.[94] Allocative efficiency is achieved when consumers respond to prices that are accurate reflections of the marginal costs of production of goods and services. Each consumer will purchase a good and service to the point where his or her marginal benefit equals the prices of that good or service. When this occurs, in broad terms, overall allocative efficiency is maximized.

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[92] These estimates are based on a comparison of allocation rates between the new and old methodologies. They assume no behavioural changes by market participants (in the coincident peak hours in 2010 and all hours in 2011) and no subsequent impact on market prices (which in turn would affect the total GA charges). Effectively, they assume that the new GA allocation methodology resulted in load shedding by Class A customers during the five coincident peaks but did not lead these customers to materially increase their level of average consumption during all other hours of the year. If the consumption did increase during all other hours of the year and the new GA allocation methodology was a variable contributing to the increase in consumption, this could have the effect of increasing HOEP during all other hours of the year and decreasing the GA. By the same token, reduced on-peak consumption by Class A customers could have led to a lower HOEP on-peak, and thus a greater GA. The net effect on the total GA and the share of GA between Class A and Class B customers has not been estimated by the Panel.

[93] See the Panel's November 2011 Monitoring Report, p. 132.
The IESO also estimated an efficiency gain from the use of a coincident peak methodology: see: IESO's presentation to the Stakeholder Advisory Committee, March 31, 2010, available at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20100331-Allocation-of-Global-Adjustment.pdf.

[94] The Panel's January 2008 Monitoring Report, pp. 8-10 and pp. 198-202, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20080115.pdf . (Note: this Report was posted in January 2008, but was submitted by the Panel to the OEB on December 31, 2007.)

It is apparent from Figure 3-3 above that the new allocation methodology did lead to reduced consumption during the July 18-22, 2011heat wave by Class A customers. What is less clear is whether the new allocation methodology also contributed to an increase in consumption during other hours of the year. The Panel is developing a model to measure the impact of the GA allocation methodology on peak and non-peak hour consumption, but additional refinements are required before the Panel will be in a position to reach any robust conclusions from this analysis.

Another main objective for adopting the new GA allocation method was to reduce consumption at critical times so as to "avoid costly investments in new peaking generation resources."[95] The analysis of potential long-term efficiencies is complex and the Panel has not yet reached any conclusion on the long-term efficiency implications of the new GA allocation method. The Panel will continue to examine these issues and will report on its assessment of efficiency in a future report.

2.5.8 Interface with Demand Response Programs

This section assesses the interaction of the OPA's demand response (DR) programs and the new GA allocation approach. Because the DR programs and the new GA allocation are assessed independently but share the purpose of reducing peak demand,[96] there may be redundancy built into these programs.

There are currently three demand response programs operated by OPA. Each program pays participants to reduce or shift their peak consumption. The DR1 program is a voluntary curtailment program in which participants are paid the strike price for every MW that they have curtailed.[97] DR2 is a consumption shifting program in which participants are contracted to shift their consumption from on-peak periods. DR3 is a

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[95] Ministry of Energy, Regulation Proposal Notice 011-0973, August 27, 2010, p. 2. In its March 31, 2010 presentation to the IESO's Stakeholder Advisory Committee, the IESO argued that changing the GA allocation methodology to a coincident peak pricing model would reduce peak consumption by an estimated 450 to 500 MW and could potentially avoid capital cost investments of $420 to $460 million. See http://ieso.ca/imoweb/pubs/consult/sac/sac-20100331 – Allocation of Global Adjustment.pdf, p. 6.

[96] For stated objectives of the new GA allocation, see Global Adjustment Qs and As, February 2011, available at: http://www.ieso.ca/imoweb/pubs/ga/Global_Adjustment-QAs.pdf.

[97] See the Panel's December 2006 Monitoring Report, pp.135-138.

contractual curtailment program in which participants are required to off-peak to follow curtailment instructions when issued by the IESO.[98]

After the new GA allocation was introduced in 2011, any curtailment or shifting during a coincident peak hour that was already contracted for under a DR program is further rewarded if the participant is a Class A customer. Table 3-6 below shows the actual DR3 curtailment and contracted DR2 shifting that occurred during the five summer peaks in 2011.[99] These five peaks are likely to set the coincident peaks for the July 1, 2012 to June 30, 2013 GA billing period. Table 3-6 also provides an estimate of GA that will be avoided in the next billing period and that was associated with demand reduction that was otherwise procured under the DR2 or DR3 program.

Table 3-6: Estimated Avoided Global Adjustment by Demand Response Resources July 2012 to June 2013 (MWh)

Date	Delivery Hour	Total Ontario Consumption (MWh)	Demand Response Program (MWh)	
			DR3	DR2
21-Jul-11	16	24,707	328	119
20-Jul-11	17	23,720	0	119
18-Jul-11	16	23,154	0	119
19-Jul-11	17	22,517	0	119
22-Jul-11	12	22,401	0[100]	119
Total		116,499	328	595
Avoided GA Share (%)			0.2793	0.5055
Estimated Global Adjustment Charges Avoided ($ millions)			14	25

Since all DR2 resources are Class A customers, they have a strong incentive to reduce consumption during the five coincident peaks. This would be true independent of their participation in the DR2 program. Similarly, any DR3 resource that is a Class A

[98] The Panel examined the operation of DR3 during 2008. See the Panel's January 2009 Monitoring Report, pp 197-212.

[100] DR3 was activated on July 22, 2011 but not until HE 14.

participant would have a strong incentive to reduce consumption during the five coincident peaks independent of their participation in the DR3 program. Assuming that all DR3 resources are Class A customers[101] and that the GA in the next Billing Period (July 2012 to June 2013) remains in the $5 billion vicinity, then the avoided GA charges associated with MWs of demand reduction already procured under a DR program is $14 million for DR3 customers and $25 million for DR2 customers. In addition to avoiding future GA charges, in 2011 DR3 customers received $36 million and DR2 customers received nearly $23 million in compensation from the OPA for their participation in the programs.

Given that DR programs and the new GA allocation approach are both generally aimed at reducing demand during periods that coincide with peak system demand,[102] the Panel encourages the Government of Ontario and the OPA to work together to ensure that Class A customers are not compensated by both the new GA allocation methodology and an OPA Demand Response contract for the same MW of load shedding or shifting.

Recommendation 3-3:

The Panel recommends that the Government of Ontario and the OPA work together to ensure that Class A customers are not compensated by both the Global Adjustment allocation methodology and an OPA Demand Response contract for the same MW of load shedding or shifting.

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[101] The majority of DR3 resources are aggregators who administer the DR3 program on behalf of customers. The Panel does not have information on how many participants are Class A customers in a given aggregator. However, it is reasonable to assume that many of these customers are relatively large in order to make any curtailment material.

[102] Under the DR2 program participants typically are contracted to reduce consumption by a set amount during for a set period of time (i.e. 50 MW reduction from 7 am to 7pm, Monday through Friday). While this reduction in consumption covers far more than just the peak hours of the year, it will also cover the five coincident peak hours in the year, which typically occur in HE 15 to HE 17 on a weekday. If a load would otherwise have reduced its consumption during the five coincident peaks as a result of a DR contract, then the new GA allocation methodology cannot have induced the same reduction in consumption. Accordingly, any GA avoided under the new GA allocation methodology appears to double-compensate the load where the MW of reduction that reduced the GA payable by the Class A customer had already been procured under a DR program.

3. New Matters

3.1 Overselling of Transmission Rights and Transaction Failures on the Outaouais Interface in October 2011

3.1.1 Introduction

The Outaouais (PQAT) interface, located in the Ottawa area, is a Direct Current (DC) interface linking the Ontario power grid with the Quebec grid. There are two circuits with two independent converters which transfer the alternating current (AC) in one grid into DC and then back into AC in the other. The converters are located in Quebec and are owned and operated by Hydro-Quebec TransEnergie (HQTE), Hydro-Quebec's transmission arm. The total transfer capacity is 1,250 MW with both converters in service and 675 MW with only one converter in service. When both converters are out of service, no power can flow at the interface. HQTE and the IESO have in place an interconnection agreement that provides a coordination framework between the two entities in their roles as Reliability Coordinator and Balancing Area Authority.

In October 2011 HQTE took a planned outage on one of the converters. This planned outage was not accounted for at the time the IESO held its short-term Transmission Rights (TR) auction in mid-September 2011 for October 2011 TRs. As a result TRs were oversold by 419 MW in October.

3.1.2 Transmission Rights

The Ontario market is currently divided into 15 zones, 14 of which are referred to as "external zones" and one of which is referred to as the Ontario zone. External zones represent the major transmission lines that link Ontario with external markets or jurisdictions, and the "intertie congestion prices" at these zones reflect the congestion at the lines. In contrast, the Ontario zone covers all domestic generation and loads and the price (i.e. the HOEP) is calculated based on domestic supply and demand as well as imports and exports scheduled in the unconstrained (or market) schedule.

In Ontario exporters pay the uniform price (HOEP) whenever the interface on which they are transacting is uncongested (i.e. the total MWs bidding to flow over the interface is less than the capacity of the interface). When the interface is congested (i.e. collectively traders bid to flow more MWs than the interface is capable of accommodating), the trader pays a higher intertie congestion price (ICP) in addition to the HOEP. For example, assume the HOEP is $50/MWh and a trader bids to export 700 MW over an interface with 675 MW of capacity at a price of $100/MWh. Because, collectively, the MWs bid for export exceeds the interface's capacity, it is congested. The trader will be scheduled to flow 675 MW and will be charged $100 /MWh, composed of the $50/MWh HOEP and a $50/MWh ICP. The $50/MWh ICP (or "congestion rent") is collected by the IESO and held in a Transmission Rights (TR) account.

In order to provide traders with an opportunity to hedge against high ICPs, the IESO sells TRs.[103] In the event of congestion owners of TRs receive a payout from the TR account equal to the ICP. In the example above, if the trader holds 675 MW of TRs, it is charged $100 /MWh to export the power but also receives $50 for each MW of TRs that it owns. In effect, the trader is perfectly hedged against exposure to the ICP with its only exposure being to the HOEP. In order to ensure that their export transactions are prioritized over the transactions of other traders, perfectly hedged traders will sometimes bid at extreme prices that do not reflect the underlying value they place on a MWh of electricity. For example, a perfectly hedged trader may bid $2,000/MWh to export from Ontario. In the highly unlikely outcome that the trader sets the clearing price on the intertie at $2,000/MWh, the trader knows that its effective exposure is limited to the HOEP because the ICP charge ($1,950/MWh) will be offset by a TR payout ($1,950/MWh).

The amount of TRs for sale is determined based on a "simultaneous feasibility test" in order to "ensure that the congestion rent collected by the IESO … shall, under most circumstances, be sufficient to cover any payment obligations owing by the IESO to TR holders".[104] One of the important factors that the simultaneous feasibility test normally considers when determining the transmission transfer capability is the outage information

[103] TRs may also be purchased as speculative investments.
[104] Market Rules, Chapter 8, s. 4.6.1.

at the interfaces.[105] When a transmission line is on planned outage or the IESO believes it will be on prolonged forced outage during the period when TRs will be valid, the IESO would normally reduce the quantity of TRs that are sold. The reason for doing so is that, if the IESO were to sell more TRs than the capacity of the interface, it would create a greater obligation for TR payouts than the congestion rent it can expect to collect. For example, assume an interface had a transfer capacity of 675 MW and the IESO sold 1,000 TRs. If the ICP in a given hour were $50/MWh, the IESO would collect 675 MW * $50/MWh in congestion rent but would have an obligation to pay out 1,000 MW * $50/MWh in TR payouts. To the extent that TR payouts are not covered by auction revenues and the collection of congestion rent, the TR obligation would be funded by Ontario consumers through an uplift charge.[106] If TRs were significantly oversold for an extended period of time TR payout obligations could quickly overwhelm the ability of the TR account to fund the obligation.[107]

3.1.3 Overselling of Transmission Rights on the Outaouais Interface in October 2011

As noted above, when the IESO auctioned off the short-term TRs for the month of October on September 14, 2011 it did not take into account the October planned outage at the Outaouais interface. As a result, 475 MW of short-term export TRs for the interface were sold for October. When added to the 619 MW of long-term TRs that had been sold in earlier months (specifically, in January, April and July 2011), there were 1,094 MW of TRs outstanding for October.[108] With the actual transfer capacity reduced to 675 MW because of the planned converter outage, the TRs were oversold by 419 MW for the month.

In late September 2011, HQTE advised the IESO Market Forecasts and Integration business unit (which is responsible for selling TRs) that it would be taking one converter

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[105] Market Rules, Chapter 8, s. 4.7.3.

[106] The TR account has never been in a deficit position and in fact typically carries a surplus as the TR account includes TR auction revenues in addition to the congestion rent and the TR payouts.

[107] In the event the IESO TR account is depleted, the IESO is to fulfill its TR payout obligations by borrowing money. If the shortfall is not made up the IESO is to recover the shortfall from market participants on a pro rata basis across all quantities of actual energy withdrawn. See Chapter 9, s. 6.14.5 of the Market Rules.

[108] A similar amount of import TRs were sold. These are not discussed further because there was no import congestion and thus no import TR payout during October 2011.

out of service for a planned outage for the month of October. (It also advised the IESO that, at the end of October, after bringing the converter back into service, it would take the second converter out of service for a planned outage for the month of November.) Unfortunately, by the time the notice was provided the IESO had already sold the incremental short-term TRs for October. Although HQTE provided the IESO member on the Interconnection Committee with planned outages for the year in early 2011, that information did not constitute a formal outage notification pursuant to the Interconnection Agreement.

During the course of daily market monitoring, the MAU noticed that the interface was more frequently congested in the first few days of October, although the magnitude of congestion was generally small. The MAU also noticed a large CMSC payment and high ICPs in the late evening on October 3, 2011 and early morning on October 4, 2011. The overselling of TRs led to $2.3 million more TR payouts than congestion rent collected ("shortfall") on the *Outaouais* interface for exports during October. More than half of the total occurred on October 4 as can be seen from Table 3-7 below. On October 4, one trader with a major TR position advised the IESO that it would voluntarily reduce its bid prices on the interface. If traders, including the trader with the major TR position, had fully exploited the overselling of TRs the depletion of the TR account could have been much greater than $2.3 million.

Table 3-7: Daily Transmission Right Payouts, Congestion Rent and Shortfall for Exports on the Outaouais Interface October 1 – 31, 2011 ($ thousands)

Date	TR Payout	Congestion Rent	Shortfall
October 1	763	462	-301
October 2	225	137	-88
October 3	713	349	-364
October 4	2,597	1,188	-1,409
October 5	3	2	-1
October 6	20,	12	-7
October 7	35	18	-17
October 8	41	23	-18
October 9	35	20	-15
October 11	13	7	-6
October 12	22	12	-10
October 14	11	6	-50
October 15	20	12	-7
October 16	63	38	-25
October 22	23	14	-8
October 23	16	10	-6
October 30	11	7	-4
October 31	33	21	-12
Total	4,643	2,339	-2,304

The October events at Outaouais have highlighted not only the importance of proper and timely internal and external communications at the IESO but also the need for proper controls. This is a separate issue from the concern that the Panel raised in a previous Report relating to the systemic overselling of TRs by the IESO.[109] Due to the potentially large financial risks to the TR account if outages are not taken into account, the Panel believes that it is important for the IESO to ensure that transmission capability is properly accounted for at the time TR auctions are held.

[109] See the Panel's August 2010 Monitoring Report, p. 164. In the August 2010 Report the Panel recommended that "the IESO should limit the number of transmission rights auctioned to a level where the congestion rent collected is approximately sufficient to cover the payouts to transmission right holders".

Recommendation 3-4:

The Panel recommends that the IESO improve its internal controls and external processes to ensure that all information about outages and other relevant contingencies is taken into account when establishing the level of Transmission Rights to be auctioned.

3.1.4 Assessment of Export Congestion at Outaouais

In this section, the Panel analyzes participant-specific behaviour on the Outaouais interface in October 2011.

As noted above, TRs are financial instruments which provide the holder with a contractual right to receive payouts during the hours when an intertie is congested. They are not a guarantee that physical transactions will flow.[110] A participant who wants to schedule a transaction between Ontario and Quebec must offer or bid at a level that result in its import or export being scheduled in the Ontario market. If the transaction is scheduled, transmission at the intertie and within Ontario is provided unless real-time system conditions prevent such a transaction from flowing. The participant must separately arrange transmission service within Quebec.

Table 3-8 below reports TRs held by individual market participants at the *Outaouais* interface in October. Two of the nine TR holders are active traders: one regularly trades in both directions, while the other typically exports from Ontario to New England and on rare occasions imports from New England. Other TR holders either hold positions for speculative purposes (i.e. they do not trade on the interface) or rarely schedule transactions.

[110] See generally the Panel's August 2010 Monitoring Report, pp. 140-267.

Table 3-8: Transmission Rights and Exports by Market Participant at the Outaouais Interface October 2011 (MW & MWh)

Participants	Export TRs Owned (MW)	Total Exports Scheduled			
		Unconstrained Schedule		Constrained Schedule	
		MWh	% of TR Position	MWh	% of TR Position
Participant 1	465	206,700	59.7	202,404	58.5
Participant 2	168	0	0	0	0
Participant 3	161	0	0	0	0
Participant 4	110	116,344	142.2	115,594	141.2
Participant 5	65	292	0.6	320	0.7
Participant 6	52	117	0.3	25	0.1
Participant 7	50	0	0	0	0
Participant 8	20	988	6.6	251	1.7
Participant 9	3	0	0	0	0
Participant 10	0	0	n/a	0	n/a
Participant 11	0	249	n/a	249	n/a
Total	1,094	324,690	39.9	318,843	39.2

Participant 1 is the participant noted earlier as having the major TR position. Its strategy prior to October 4 was to bid to export 465 MW at a very high price. Given its TR position, the full amount of 465 MW was hedged against congestion and the trader was effectively a price taker purchasing at the HOEP (subject to any CMSC payments). As noted above, Participant 1 voluntarily reduced its bid price on October 4.

Participant 4 purchased 110 MW of TRs and was also bidding 110 MW of exports at a very high price throughout October. These were fully hedged transactions which effectively resulted in it being a price-taker of the HOEP (subject to any CMSC payments). It also bid a further 75-120 MW in many hours at a relatively low price, apparently looking for opportunities to arbitrage price differences between Ontario and external markets.

Given the TR positions and high bid price strategies of Participants 1 (465 MW) and 4 (110 MW), there was effectively 100 MW of capacity for other traders to bid for hourly before the interface capacity of 675 MW became congested.

When one or two additional traders bid at a high price to export 100 MW or more, the interface became congested. All TR holders with a net long position (i.e. those with TRs greater than scheduled export transactions) benefited from the congestion because they received more TR payouts than the congestion rent that they paid.

Because Participants 1 and 4 are the only physical traders with more than 100 MW of TRs, other traders individually had little or no incentive to congest the interface. The reason is that if a trader with less than 100 MW of TRs exported more than 100 MW, it was in a short position and the quantity of exports that exceeds its TR quantity would have been exposed to the ICP.

Between October 1 and October 3, HE 23 the interface was significantly congested in four hours (with an ICP above $50/MWh). In one hour, the ICP of about $129/MWh was induced by a very low (about -$128/MWh) pre-dispatch MCP in Ontario compared to a $1/MWh MCP at the interface. The persistent and high congestion from Oct 3 HE 24 to Oct 4 HE 6 was induced in part by internal congestion at the Flow-In-Ottawa (or FIO) flowgate. One of the major transmission lines (X522A) that link the Lennox transformer station (in Kingston) with the Hawthorne transformer station (in Ottawa) was on planned outage from October 3 to October 19. When the Saunders station (east of the Ottawa area) is operated under Segregated Mode of Operation (SMO), the FIO limit is reduced to 1,300 MW (from a normal level of 2,900 MW). Even with the significantly reduced FIO limit, the FIO interface was only congested in the period Oct 3 HE 24 to Oct 4 HE 6. The congestion (in the constrained, not the unconstrained schedule) in these hours resulted in very high locational shadow prices, varying from $200/MWh to $1,000/MWh, in the Ottawa area and at the nearby interfaces with the Quebec grid.[111]

Although it would seem counter-intuitive, the high shadow prices appeared to attract an increase in export bids. In other words, high prices appeared to increase the incentive for exporters to purchase power. Practically speaking, however, if an exporter were able to bid at price that was below the shadow price it would be constrained-off and attract a constrained-off CMSC payment based on the difference between its bid price and the

[111] All interfaces beside the Outaouais interface in the Ottawa area are import-only interfaces.

HOEP. For example, when the final pre-dispatch (PD) unconstrained price and HOEP were $50/MWh and the pre-dispatch shadow price was $1,000/MWh, an exporter could bid up to $999/MWh to export but would be constrained-off and receive a constrained-off CMSC payment of $949/MWh (i.e. the difference between its bid price and the HOEP).[112]

Table 3-9 reports CMSC payments related to export and import transactions on the Outaouais interface by market participant and constraint type in October 2011.[113] The total CMSC payments were about $300,000. Most of these CMSC payments were paid to constrained-off exports which occurred during hours in which the intertie was congested between October 3 HE 24 to October 4 HE 6.[114]

Table 3-9: Congestion Management Settlement Credits by Participant and Type at the Outaouais Interface October 2011 ($)

	Congestion Hours			Non-congestion Hours				Total
	Import	Export		Import		Export		
Participant	CONSTRAINED ON	CONSTRAINED ON	CONSTRAINED OFF	CONSTRAINED ON	CONSTRAINED OFF	CONSTRAINED ON	CONSTRAINED OFF	
Participant 8			173,924		490		4,837	**179,251**
Participant 1		15	49,541	-669		1,865	65,777	**116,529**
Participant 10	-1,443			-428	3,189			**1,318**
Participant 5			-21			1,553		**1,532**
Participant 11					154			**154**
Participant 6			47					**47**
Participant 4		-1	4,109			1,056	-6,738	**-1,574**
Total	**-1,443**	**14**	**227,600**	**-1,097**	**3,833**	**4,474**	**63,876**	**297,257**

112 An importer could have offered up to $999/MWh to import and receive the offer price. However, its profit could be considerably less than $949/MWh after paying the purchase cost in the external market and transmission charges.

113 Congestion hours are hours with export congestion. 'Constrained-on' means that a transaction is scheduled in the constrained schedule but not in the unconstrained schedule. In contrast, 'constrained-off' means that a transaction is scheduled in the unconstrained schedule but not in the constrained schedule.

114 Although the Outaouais interface was congested in many of the hours, the other Quebec interfaces were never congested (even though some are in the same area or zone). These interfaces are for import only. There were little to no CMSC payments paid at these interfaces.

The incidents described above further highlight the inefficient behaviours and outcomes that can be induced by the two-sequence design. A high ICP at an interface should normally imply a low profit or even a loss for exporters and accordingly should discourage exports and encourage imports. However, the existence of constrained-off CMSC payments can encourage an increase in exporter participation, with exporters bidding at a high price (but just under the expected zonal shadow price) in order to be constrained-off. Absent the two-schedule design one would not expect the counter-intuitive behavior of increased exporter participation in the event of rising prices.

3.1.5 Transactions Failed by Market Participants

During the congestion hours in October, some market participants whose transactions were fully or largely hedged through TRs failed a significant amount of their exports.[115] Transaction failures have a negative impact on the TR account. TR payouts are determined based on the pre-dispatch schedule, whereas congestion rent is collected based on real-time power flows.[116] Thus a failed real-time transaction will contribute to a congestion rent shortfall and will have the effect of depleting the TR account. For example, if a line with 675 MW of capacity is congested in pre-dispatch it will result in a TR payout of 675 MW * ICP. If, however, 100 MW of the scheduled transactions fail in real-time, the IESO will only collect 575 MW * ICP in congestion rent.

As indicated in Table 3-10 below, Participant 5 was the trader with the largest export failure, with 943 MWh failed (because of either not purchasing transmission service or not inputting valid NERC E-tags). It had only 320 MWh of exports (to New England), with a failure rate of 75 percent. Participant 6 had the second largest failure, with 204 MWh failed (invalid E-tags). It had only 25 MWh of exports (to New England), with a failure rate of 89 percent. Participant 8 failed 62 MWh (invalid E-tag) and had no exports which flowed, with a resulting failure rate of 100%. The high failure rates by

[115] When a trader has failed its transaction for reasons under its control, it is not eligible for CMSC payments. But under the current market rules, the participant is still eligible for TR payout if it owns TRs.
[116] While the ICP is provisionally set in pre-dispatch it can be adjusted based on the real-time price. The combined value of the ICP and the real-time MCP is always bounded by the maximum market clearing price (MMCP) of $2,000/MWh. For example if the pre-dispatch ICP is $1950/MWh and the real-time MCP is $60/MWh for a given interval, then the ICP for that interval will be reduced to $1940/MWh, as will the TR payout.

these three participants suggest that they had little interest in flowing the transactions. IP Market participants that fail intertie transactions may be penalized through the Intertie Failure Charge (IFC) based on the extent to which the failure contributed to a discrepancy between the HOEP and the pre-dispatch price.[117] While failing a transaction in real-time may attract an export failure charge, this charge is typically small relative to the amount of the congestion rent. As a result, where a participant holds TRs it may have an incentive to deliberately fail a transaction to attract a TR payout, even if it is also subject to an export failure charge.

Collectively, intertie transaction failures at Outaouais in October 2011 contributed to nearly $54,000 in TR payouts to TR holders that had failed their transactions. The payouts were not offset by the approximately $9,000 in transaction failure charges. In addition, by failing these transactions the traders avoided approximately $90,000 in congestion charges, with a corresponding shortage in congestion rent collected relative to TR payouts.

[117] For details on how the difference (Bias Factor) is calculated by the IESO, see Market Manual Part 5.5: Physical Markets Settlement Statements, Appendix D: Price Bias Adjustment Factors Calculation Method for Real-Time Import and Exports failure Charge, available at: http://www.ieso.ca/imoweb/pubs/settlements/se_RTEStatements.pdf. For the calculated Bias Factor by the IESO for each month/season, see: http://www.ieso.ca/imoweb/settlement/se-itf.asp.

Table 3-10: IntertieTransaction Failures by Transmission Rights Holder When the Outaouais Interface was Export Congested October 2011 ($/MWh, MW & $)

Participant	Delivery		Intertie Congestion Price (ICP) ($/MWh)	Export Quantity		Bid Price ($/MWh)	Reasons	Failure Charge ($)	TR Payout ($)	Congestion Rent Avoided ($)[118]
	Date	Hour		PD (MW)	RT (MW)					
	Oct 1	12	153.38	100	0	208	NBTS*	4,094	9,969	15,338
	Oct 1	15	346.82	150	0	380	NBTS*	2,842	22,543	52,023
	Oct 2	10	7.2	100	0	284	NBTS*	1,118	468	720
	Oct 2	15	14.51	100	0	321	NBTS*	0	943	1,451
	Oct 7	24	18.48	65	0	195	E-tag	0	1,201	1,201
	Oct 8	11	9.26	50	0	324	E-tag	0	601	463
	Oct 8	18	14.01	65	0	418	E-tag	17	910	911
	Oct 9	12	19.37	65	0	521	E-tag	7	1,259	1,259
	Oct 11	4	12	65	0	364	E-tag	284	780	780
	Oct 12	4	20	65	0	52	E-tag	19	1,300	1,300
	Oct 14	2	10.41	65	0	88	E-tag	0	676	677
Participant 5	Oct 16	3	14.91	53	0	345	E-tag	0	969	790
	Subtotal			943	0			8,382	41,619	76,913
	Oct 4	1	520.47	7	0	690	E-tag	0	3,643	3,643
			218.49	10	0	979	E-tag	5	2,184	2,185
	Oct 4	5	218.49	11	0	989	E-tag	5	2,403	2,403
				11	0	186	E-tag	65	114	115
				6	0	189	E-tag	35	62	62
				11	0	183	E-tag	65	114	115
Participant 8	Oct 7	23	10.41	6	0	192	E-tag	35	62	62
	Subtotal			62	0			210	8,582	8,586
	Oct 4	2	427	4	0	639	E-tag	0	1,708	1,708
	Oct 7	23	10.41	100	0	150	E-tag	588	541	1,041
Participant 6	Oct 7	24	18.48	100	0	150	E-tag	0	960	1,848
	Subtotal			204	0			588	3,209	4,597
	Oct 1	12	153.38	110	109	2,000	E-tag	41	153	153
Participant 4	Oct 2	24	5.16	54	53	21	E-tag	0	5	5
	Subtotal			164	162			41	158	158
Total				1,373	162			9,221	53,568	90,254

* NTBS = Not Buying Transmission Service

[118] To the extent that TR payouts and congestion rent avoided are not the same, it is as a result of a discrepancy between the amount of MW the trader bid relative to the number of TRs it held.

The Panel believes that when a TR holder has failed its physical transactions, it should not be able to profit by receiving the TR payout for the quantity it has failed. When a TR holder has a physical transaction scheduled at an interface, its financial risk due to congestion is effectively hedged through ownership of the TRs. Failing a physical transaction in which the congestion risk has effectively been hedged should not be encouraged. Furthermore, providing the TR payout to TR holders even though they have failed their physical transactions may provide incentives to the TR holders to congest the interface and then to not flow their transactions. On a province-wide basis, the estimated TR payout reduction had TR holders not received TR payouts for the quantities where they had physical transactions that failed would have been approximately $880,000 for the period November 2010 to October 2011.

There may be multiple options for addressing this problem. Two possible solutions are: not paying the TR payout for the portion of the transaction that the trader has failed, or charging the congestion rent for the whole failed transaction. Depending on the relative magnitude of a trader's TR position and the MW that it has failed, the consequences and implications can be different, with charging congestion rent for the full failure potentially imposing a greater penalty.[119] Because the current study focuses on the interactions between transaction failures and transmission rights, the Panel has not yet fully investigated the consequences and implications of charging congestion rent for the full amount of failed transaction but it encourages the IESO to assess both options.

<u>Recommendation 3-5:</u>

The IESO should ensure that, when a trader which owns Transmission Rights has failed its intertie transactions (at the same interface in the same direction), either the Transmission Right payout should not be paid or the Congestion Rent should be charged for the quantity of the failed transactions.

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[119] Assume that a trader has 100 MW of export TRs at an interface and has been scheduled for 200 MW in the final pre-dispatch run. Two scenarios could result:

1. The trader has failed less than or up to 100 MW of the scheduled export. Not paying the TR payout would result in the same result as charging congestion rent for the failed MW.
2. The trader has failed more than 100 MW. Not paying the TR payout to the 100 MW of TRs will lead to a smaller amount of reduction in the trader's revenue than charging the congestion rent for the failed MW. Charging congestion rent for the full amount of failure is effectively a penalty for the transaction failure.

3.1.6 Lack of Import Response

Under normal situations, a very high shadow price should attract more imports because importers are guaranteed at least the offer price if they are scheduled. On the *Outaouais* interface, an importer would have had a guaranteed price as high as $1,000/MWh during the hours between October 3 HE 24 and October 4 HE 6. However, no imports showed up during this period. The Panel plans to conduct further analysis regarding the lack of import response on the Quebec interfaces.

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Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is the Panel's 19th semi-annual Monitoring Report on the IESO-administered markets. It covers the summer period May to November 2011. As in previous reports, the Panel has concluded that the market has operated reasonably well having regard to its hybrid design, although there were occasions where the market design, actions by market participants, or actions taken by the IESO led to inefficient or potentially inefficient outcomes.

The Panel has five investigations in progress related to potential gaming activity. Each will be released as a separate report when completed.

2. Future Development of the Wholesale Market

2.1 The Report on "Public Services for Ontarians: A Path to Sustainability and Excellence"

On February 15, 2012, a commission established by the Government of Ontario and led by economist Dr. Don Drummond issued a report on how to run public services more efficiently and how to make these services more affordable.[120] Included in the report was a section on the electricity sector, which contained 13 recommendations. Among these recommendations, 11 are fully or partially linked to the wholesale electricity market and two are related to the Government's relationship with or operation of OPG and Hydro One.

The most important wholesale electricity market recommendation, in the Panel's view, is Recommendation 12-17: "*making wholesale electricity prices inclusive of transmission costs such as capacity limitations and congestion as part of a comprehensive restructuring of the wholesale electricity market*".[121] The following comment is added, which makes it clear that the recommendation is advocating locational pricing: *"[c]onsumers located nearer to generation*

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[120] For the full report, see Commission on the Reform of Ontario's Public Service, *Public Service for Ontarians: A path to Sustainability and Excellence*, February 2012, available at: http://www.fin.gov.on.ca/en/reformcommission/chapters/report.pdf.
[121] *Ibid*, p. 332.

stations should be able to benefit from lower electricity prices. Sending more efficient price signals to the marketplace should encourage more optimal levels of investment in electricity infrastructure — generation, transmission and distribution."[122] This recommendation is consistent with the Panel's frequently reiterated position that the existing two-schedule market design should be replaced by an electricity market with some form of locational pricing.[123]

2.2 Electricity Market Forum

The Electricity Market Forum (EMF) was established by the IESO in March 2011 to identify and explore possible changes that might improve a number of aspects of the market, including the ability of the market to efficiently deliver reliable and sustainable electricity. A series of meetings were held over the course of 2011 among members and observers from across the electricity sector. The Panel made a presentation regarding key market development issues at the introductory meeting and a member of the Market Assessment Unit (MAU) attended the EMF meetings as an observer on behalf of the Panel. In December 2011 the EMF published its final report.[124]

The EMF report investigated three broad categories of issues: (1) how to integrate the changing supply mix; (2) how to engage and empower consumers; and (3) how to improve market efficiency. It provided 12 recommendations, most of which were directed to the IESO, with some being directed to the OEB, the OPA or a combination of the IESO, OEB and OPA. The report also suggested a roadmap regarding the sequence and timing for implementation of recommendations.

Many of the EMF recommendations involved areas that the Panel has addressed in prior monitoring reports and recommendations. In particular:

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[122] *Ibid*, p. 332.
[123] See the Panel's June 2004 Monitoring Report, p. 107; and more recently the Panel's January 2010 Monitoring Report, pp. 89-105. This is also consistent with the recommendation of the Market Design Committee (MDC), which developed the existing market. See Market Design Committee – Final Report, Volume 1, pp. 1-9, available at: http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/Q4Report.asp.
[124] For the full report, see: Electricity Market Forum, Reconnecting Supply and Demand, December 2011, available at http://www.ieso.ca/imoweb/pubs/consult/Market_Forum_Report.pdf.

- The EMF recommended that the IESO review how its current programs, products, and mechanisms impact the structure of the HOEP, with the specific purpose of identifying whether the HOEP includes components that unnecessarily dampen real-time price signals (Recommendation 1). It particularly noted the importance of re-examining generator cost guarantees, Control Action Operating Reserve (CAOR) and the Enhanced Day Ahead Commitment Process. In previous reports the Panel has commented on how the HOEP is artificially dampened by the IESO's generation cost guarantee program[125] as well as by the use of a ramp rate multiplier.[126] The Panel has also previously recommended the development of a full day ahead market in Ontario[127] and has frequently commented on price fidelity and efficiency issues arising from the two-schedule market design system and its corresponding CMSC side payments.
- The EMF recommended that the IESO should review the Global Adjustment mechanism to allow greater responsiveness from customers including potential unbundling into capacity and energy components which might be allocated differently (Recommendation 2). The Panel has previously expressed concern about the size of the GA and its adverse impact on the real-time price signal.[128] In the current report, the Panel has provided a high-level comparison on the old and new Global Adjustment allocation approaches, and it has further analysis in progress regarding the implications for market efficiency.
- The EMF recommended that the OPA's procurement process should seek to better ensure that new and existing contracts contain strong market-based incentives (Recommendation 6). The Panel has undertaken assessments of the incentives and efficiency implications of various OPA contracts and demand

[125] For example, see the Panel's August 2010 Monitoring Report, pp. 128-140. Specifically, the Panel concluded (at p. 139) that the "GCG program, which permits after the fact costs submissions, led to inefficient dispatch, a depressed market clearing price, and an inflated global adjustment."

[126] For example, see the Panel's December 2003 Monitoring Report, pp. 112-113. Specifically, "The embodiment of [a ramp rate multiplier] assumption in the determination of the MCP has muted if not eliminated the price signals needed to induce the types of competitive responses outlined above ... [and] essentially pretends that capacity can enter or leave the market faster than it can. This prevents spikes in the MCP. But it has also reduced the incentive for the type of market responses that could also have prevented spikes in the MCP."

[127] See the Panel's December 2005 Monitoring Report, p. 100.

[128] The Panel has been reporting on the HOEP, GA and OPG rebate components of the effective price for many years, and documented the inverse relationship between the GA and the HOEP. For details, see, for example, the Panel's November 2011 Monitoring Report, pp. 6-7.

response programs in past reports and concluded that many of the contracts and programs could be improved.[129]

- The EMF recommended that the OEB should review its approach to determining payments to OPG's prescribed assets (Recommendation 7). The Panel in past reports expressed concerns about lack of price responsiveness at these generation facilities especially during times when the HOEP is negative.[130]
- The EMF recommended that the IESO consider improving, amending, or replacing the two-schedule design (Recommendation 11). This is also the Panel's long-standing position.[131]
- The EMF recommended that the IESO review whether there are barriers to maximizing potential benefits from greater alignment with regional markets through intertie transactions (Recommendation 12). The Panel in the past has recommended a more frequent intertie scheduling with neighbouring markets[132] and bringing the Michigan interface Phase Angle Regulators (PARs) into service in order to mitigate inadvertent power flow around Lake Erie.[133]

At its March 21, 2012 Stakeholder Advisory Committee meeting the IESO provided its response to the nine recommendations directed to the IESO, breaking down its responses according to the EMF's three broad categories of investigation: [134]

<u>Integrating the Changing Supply Mix</u>:
The need to adapt the market to address Ontario's changing supply mix was a key theme in the Forum discussions. The associated recommendations address several matters: the OEB's review of the treatment of OPG's prescribed assets; identifying the need for new or modified ancillary services; enhanced market rule co-ordination with the OPA's procurement practices; and working

[129] For example, see the Panel's December 2009 Monitoring Report, pp. 197-213 (DR3 program).
[130] See the Panel's August 2010 Monitoring Report, pp. 101-110.
[131] Most recently, see the Panel's February 2011 Monitoring Report, pp. 108-110.
[132] Most recently, see the Panel's November 2011 Monitoring Report, pp. 96-100.
[133] See the Panel's January 2010 Monitoring Report, pp. 69-89.
[134] See the IESO's web site at: http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20120321-Item2_Market_Forum_Report.pdf .

with the OPA to provide strong market based incentives to new and existing procurement contracts. These activities will be included in IESO plans for 2012. The review of ancillary services will follow and build on the energy modeling capability the IESO is developing and expects to have available by year end.

Engaging and Empowering the Consumer:
Consistent with our new vision statement, the need to engage the consumer was highlighted in the Forum's final report. Stakeholders will be engaged to identify barriers to increased demand-side participation in the wholesale markets, and how best to overcome those barriers.

The IESO has already initiated a consultation process to address the Forum's recommendation to review the accessibility, relevance and timeliness of information and data made available to market participants, policy makers and others.

The IESO is also working to provide input to the OPA's demand response review and the OEB's review of the Regulated Price Plan.

Improving Efficiency
Recommendations in this area were given high priority by the Forum. The IESO was asked to carry out a pricing and cost review of the HOEP and Global Adjustment in addition to a review of the two schedule system and intertie trading practices. To assist with these efforts the IESO expects to launch a request for proposals (RFP) process in Q2 with work getting underway in Q3.

The EMF report recommends important improvements to the electricity market including replacement of the existing two-schedule design. The Panel recognizes that the challenges of evolving towards a more efficient wholesale electricity market are complex and that some of the conceptual or directional recommendations will require more detailed analysis and development. The Panel encourages the IESO to address the EMF recommendations as a high priority.

Recommendation 4-1

The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.

3. Implementation of Panel Recommendations from Previous Reports

The IESO formally reports on the status of actions it has taken in response to the Panel's recommendations. Following each of the Panel's Monitoring Reports the IESO posts the recommendations and its responses to those recommendations on its public web site.[135] The IESO also provides the Stakeholder Advisory Committee (SAC) with its responses to the Panel's recommendations.

3.1 Recommendations to the IESO from the Winter 2011 Report

The Panel's November 2011 report contained four recommendations, all of which were directed at the IESO. The IESO responses are summarized in Table 4-1 below.[136]

[135] All responses are available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20111215.pdf.
[136] See IESO Response to MSP Recommendations, available at: http://ieso.ca/imoweb/marketSurveil/surveil.asp.

Table 4-1: IESO Responses to Recommendations in the Panel's November 2011 Monitoring Report

Recommendation	IESO Response
Recommendation 2-1 *The Panel recommends that the IESO publish the most current aggregate wind generation forecast information that is available. The published information should be updated on an hourly basis and should cover all future hours for which wind generation forecasts are available.*	"IESO staff intend to discuss this recommendation with the MSP, as publishing the sometimes highly inaccurate aggregate of output forecasts submitted by wind generators may present a misleading picture of upcoming operations. Meanwhile, the IESO is in the final stages of contracting for central wind and solar forecasting services that extend to all wind and solar facilities directly connected to the IESO controlled grid and all distribution connected facilities over 5 MW. We anticipate that this service will be calibrated to the point where quality forecasts are available to us by mid-2012. While integrating these forecasts fully into our automated tool sets is expected to take another year, we anticipate that publication of that data over several forecast timeframes could commence as early as Q3 2012. Updates will be available through stakeholder engagement SE-91."
Recommendation 2-2 *The Panel recommends that the IESO and the Electricity Market Forum investigate increasing the frequency with which interties are scheduled in order to improve market efficiency and price fidelity. In conjunction with any such increase, the IESO should explore parallel increases in the frequency of the forecasts of demand and the output from wind and other intermittent generation, as well as pre-dispatch schedules.*	"This recommendation contemplates a significant change to current market design. The IESO will consider this recommendation together with the broader market evolution investigations, and associated timetable, envisaged by the Electricity Market Forum."[137]
Recommendation 2-3 *The Panel recommends that the IESO accelerate its efforts under Stakeholder Engagement (SE-91) to make wind generators dispatchable.*	"The IESO continues stakeholder discussions through SE-91: Dispatch Technical Working Group (DTWG) to develop an enduring solution for the dispatch of variable generation resources. DTWG meetings are expected to be held between November 2011 and May 2012. The target is to fully integrate 5-minute dispatch for wind and solar directly connected to the transmission grid into our automated dispatch tool sets by late 2013. Meanwhile the IESO and the OPA have worked together to develop interim hourly dispatch proposals, and are awaiting guidance on certain associated policy questions identified in that regard."

[137] As reported above, the EMF recommended (Recommendation 12) that the IESO examine whether there are barriers to maximising potential benefits to Ontario from greater alignment with regional markets through intertie transactions.

Recommendation	IESO Response
Recommendation 3-1 *The Panel recommends that for the purposes of calculating constrained-on CMSC payments made to dispatchable loads that have bid at a negative price, the IESO should set a new replacement bid price that does not take into account any global adjustment charges. This new price would be higher than the current replacement price of -$50/MWh.*	"The IESO agrees with this recommendation and has previously initiated this change, with a proposed target of completing the revision for the IESO's March 2012 baseline."[138]

4. Summary of Recommendations

In this Report, the Panel makes six recommendations: two related to efficiency and four related to uplift or other payments. Within each category, the recommendations are listed in order of priority. There are no recommendations in this report related to price fidelity[139] or transparency,[140] although many of the Panel's recommendations have effects in more than one of the categories used to group its recommendations.

4.1 Efficiency

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market. The Panel is also concerned with other forms of productive as well as allocative and dynamic efficiencies.

a) The Panel believes that several of the recommendations made by the EMF could improve the efficiency of Ontario's wholesale electricity markets.

Recommendation 4-1:

The Panel recommends that the IESO proceed with development work on those recommendations of the Electricity Market Forum that are directed at improving market efficiency, including the consideration of options to replace the two-schedule structure of the current market design.

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[138] The IESO implemented a change on March 7, 2012, replacing the -$50/MWh replacement bid with -$15/MWh for CMSC calculation purposes. For details, see: "Limiting CMSC for Dispatchable Loads – Change to Replacement Bid Price", available at: http://www.ieso.ca/imowebpub/201201/Limiting_CMSC_for_DLs_20120111.pdf.

[139] The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market. While the Panel's recommendations in this report do not relate primarily to price fidelity, most of the efficiency and uplift or other payment recommendations would also contribute to greater price fidelity.

[140] The Panel believes that transparency (in respect of information that is not competitively sensitive) can improve decision-making by market participants and can contribute to greater price fidelity and market efficiency.

b) The Panel is concerned that the suspension by the Northeast Power Coordinating Council (NPCC) of the regional sharing of operating reserves has resulted in as much as a $2.2 million dollar annualized efficiency loss as well as higher prices in the Ontario operating reserve market.

Recommendation 3-1:

The Panel recommends that the IESO continue to pursue the introduction by the Northeast Power Coordinating Council of a revised Regional Reserve Sharing Program and the negotiation of any necessary implementing agreements with neighbouring ISOs as expeditiously as possible.

4.2 Uplift and Other Payments

The Panel examines uplift and other payments both in respect of their contribution to the effective price paid by customers and also in respect of their impact on the efficient operation of the market.

a) There are several programs in the marketplace that are intended to induce demand response, and the new GA allocation methodology does so as well. The Panel believes that the GA methodology can create a windfall for those Class A customers who are already being paid to curtail or shift consumption under OPA demand response programs.

Recommendation 3-3:

The Panel recommends that the Government of Ontario and the OPA work together to ensure that Class A customers are not compensated by both the Global Adjustment allocation methodology and an OPA demand response contract for the same MW of load shedding or shifting.

b) After assessing the October events at the *Outaouais* interface, the Panel believes that the IESO must ensure that planned outage information is taken into account in order to avoid potentially large financial risks associated with the overselling of TRs.

Recommendation 3-4:

The Panel recommends that the IESO improve its internal controls and external processes to ensure that all information about outages and other relevant contingencies is taken into account when establishing the level of Transmission Rights to be auctioned.

c) The Panel continues to be concerned that unwarranted CMSC payments are being made to generators during self-induced ramp downs. The Panel believes that the most effective and efficient way to eliminate such payments is a market rule change.

Recommendation 3-2:

The Panel recommends that the IESO implement a permanent, rule-based solution to eliminate self-induced CMSC payments to ramping-down generators.

d) The Panel believes that market participants are overcompensated by receiving TR payouts without being charged congestion rent when they schedule and then fail energy transactions.

Recommendation 3-5:

The IESO should ensure that, when a trader which owns Transmission Rights has failed its intertie transactions (at the same interface in the same direction), either the Transmission Right payout should not be paid or the Congestion Rent should be charged for the quantity of the failed transactions.