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
November 2011 – April 2012

January 2013

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Table of Contents

List of Tables

List of Figures

Executive Summary

This is the Market Surveillance Panel's (Panel) 20th semi-annual monitoring report on the IESO-administered markets. It covers the winter period November 2011 to April 2012, and also reports on market outcomes for the period May 2011 to April 2012.

This report first surveys market outcomes in the period spanning May 2011 to April 2012 (the 2011/12 Annual Period), with comparisons to the same period one year earlier as well as others where relevant (Chapter 1). It next focuses on high-price hours, low-price hours and other anomalous market outcomes in the period from November 2011 to April 2012 (the Winter 2012 Period) (Chapter 2). The report then discusses a number of matters affecting the wholesale markets, setting out recommendations where relevant to promote market objectives (Chapter 3). Finally, the report summarizes issues concerning the future development of the market and discusses the status of the implementation of Panel recommendations from the Panel's previous monitoring report (Chapter 4).

1. Overall Assessment

Ontario's IESO-administered wholesale electricity markets continued to operate reasonably well over the 2011/12 Annual Period, although there were occasions where the market design, actions by market participants or actions of the Independent Electricity System Operator (IESO) led to inefficient outcomes or potentially inefficient outcomes. The Panel has identified areas for improvement in the design, rules and operational procedures associated with the markets, in particular in respect of the Enhanced Day-Ahead Commitment Process and the transmission rights market.

During the Winter 2012 Period, the Panel released its reports on two gaming investigations. The Panel currently has six investigations under way, each relating to potential gaming conduct.

2. Demand and Supply Conditions

Total Ontario electricity consumption was 139.81 TWh in the 2011/12 Annual Period, down by 4.22 TWh (2.9%) from the period May 2010 to April 2011. Ontario demand was lower year-over-year in every month except September and October.

612 MW of new capacity was installed in the 2011/12 Annual Period, principally from large-scale wind projects and a new gas-fired facility. However, Ontario still experienced a net reduction in generating capacity due to the removal from service of two coal-fired generation units in January 2012, representing a loss of 975 MW of capacity.

3. Market Prices and the Global Adjustment

The average Hourly Ontario Energy Price (HOEP) across all hours in the 2011/12 Annual Period was $26.30/MWh, representing a 26.2% decrease from the $35.64/MWh average in the period from May 2010 to April 2011. The HOEP was lower year-over-year in every month.

This is the first monitoring report that covers an annual period during which the change in the allocation of the Global Adjustment (GA) was effective for the entire year. The GA for the 2011/12 Annual Period averaged $42.33/MWh for all Ontario customers, a 47.8% increase from the preceding annual period. During the 2011/12 Annual Period, the GA for Class A customers directly connected to the IESO-controlled grid averaged $22.92/MWh, and the GA for Class B customers and Class A customers not directly connected to the IESO-controlled grid averaged $44.69MWh.

The effective wholesale price (the sum of the HOEP, GA and uplift charges) averaged $72.64/MWh for all Ontario customers, $51.63/MWh for Class A customers directly connected to the IESO-controlled grid and $75.19/MWh for Class B customers and Class A customers not directly connected to the IESO-controlled grid.

4. Market Outcomes

The HOEP exceeded $200/MWh in three hours during the Winter 2012 Period. These high-price hours continue to be primarily attributable to the same factors as those identified in previous Panel monitoring reports.

During the Winter 2012 Period, the HOEP fell below $20/MWh in 1,690 hours, including 87 hours in which the HOEP was negative. This represents a significant increase in low- or negative-price hours relative to the November 2010 to April 2011 period. A sharp increase in the amount of fossil fuel-fired generation offered at less than $20/MWh and the amount of real-time self-scheduling and intermittent generation had a considerable effect on the frequency of low-price hours during the Winter 2012 Period.

The Panel's anomalous uplift screening criteria were met in one hour during the Winter 2012 Period. Over $500,000 in Congestion Management Settlement Credit (CMSC) payments were payable for that hour, the overwhelming majority of which were associated with exports on the Outaouais interface that had to be cut in real-time due to an internal transmission constraint.

5. Matters to Report in the Ontario Electricity Marketplace

Operation of the Phase Angle Regulators at the Michigan Interface

A Phase Angle Regulator (PAR) is a special transformer that controls the power flowing over a transmission line. The Panel has observed a significant reduction in Lake Erie Circulation (also known as "loop flow") since the five PARs came into operation on April 5, 2012.

Completion of Investigations Regarding Infeasible Import Transactions Offered by Two Market Participants

In October 2012, the Panel issued two reports in respect of its gaming investigations into CMSC payments made to TransAlta Energy Marketing Corp. and West Oaks NY/NE, LP for constrained-off imports at the Manitoba interface over a two-day period during which a transmission de-rating in Manitoba precluded transactions from flowing. The Panel concluded that neither market participant exploited the de-rating for the purpose of receiving CMSC payments, and that therefore neither market participant engaged in gaming in respect of the transactions at issue. However, the Panel identified enhancements that could be made to the procedures of the IESO that would serve to avoid such unwarranted CMSC payments and to inform market participants about intertie conditions in the future, and made two recommendations in that regard.

The Enhanced Day-Ahead Commitment Process and Production Cost Guarantee Payments

On October 12, 2011, the IESO's Enhanced Day-Ahead Commitment Process (Enhanced DACP) came into effect. With the Enhanced DACP, all "not quick start" generators (typically coal- and gas-fired units) are required to submit three-part offers covering their start-up, speed-no-load and incremental energy costs). While still a commitment process as opposed to a full day-ahead market, the Enhanced DACP is, in principle, a significant improvement over its predecessor. The Panel intends to undertake a more comprehensive study of the impact of the Enhanced DACP in a future report, once more data is available.

However, the Panel has identified one specific issue that has arisen thus far in the operation of the Enhanced DACP. Generators that are scheduled (committed) in the Enhanced DACP are guaranteed to receive, at a minimum, the total value of their day-ahead three-part offers. A top-up payment, called a Production Cost Guarantee (PCG), is made whenever a generator's real-time revenue is insufficient to cover the value associated with its day-ahead three-part offer over the committed period. The Panel has observed that large unwarranted PCG payments are being triggered on the first hour of a given dispatch day (Hour Ending (HE) 1). Of the approximately $6 million in unwarranted PCG payments made, the overwhelming majority was paid to a single market participant whose conduct in that regard is being investigated by the Panel. On December 21, 2012, a Market Rule amendment will come into effect that is expected to eliminate the potential for unwarranted HE 1 PCG payments under certain circumstances.

Transmission Rights

Transmission rights (TRs) are financial instruments established and auctioned by the IESO. TRs can be used by intertie traders to hedge the risks associated with congestion at an interface.

"Overselling" of TRs occurs where the quantity of TRs auctioned by the IESO in respect of an intertie exceeds the real-time transfer capability of the intertie. When this happens and if the intertie becomes congested, there will be a "congestion rent" shortfall (the congestion rent collected is less than the payouts to TR holders). It has been the practice of the IESO to use TR auction revenues to fund congestion rent shortfalls.

Issues associated with the TR market were noted by the Panel in its August 2010 Report, and the Panel recommended at that time that the IESO reassess the design of the TR market. In this report, the Panel notes that the overselling of TRs is of continuing concern, and reiterates its earlier recommendation. In the Panel's view, the use of TR auction revenues to fund congestion rent shortfalls also remains problematic, and the Panel therefore also reiterates its earlier recommendation that the number of TRs auctioned should be limited to a level where the congestion rent collected is approximately sufficient to cover the payouts to TR holders. The IESO had agreed with the Panel's recommendations at the time, but noted that efforts to implement them needed to be put on hold given other priorities.

The IESO maintains a TR Clearing Account for cash flows relating to congestion rent, TR auction revenues and TR payouts. In keeping with the Panel's view of the intention underlying the design of the TR market, the Panel is also recommending that the IESO regularly disburse any excess funds outstanding in the TR Clearing Account (i.e., above the reserve amount) and to reduce the transmission charges payable by loads by a corresponding amount.

As a matter of policy, the IESO currently sells only long-term TRs for single-circuit interfaces. As a result, fewer planned and unplanned outages are taken into account when determining the quantity of TRs to be sold at a given auction than would be the case if some of the TRs were made available as a short-term product. This can result in congestion rent shortfalls, as observed in relation to the Minnesota interface during the Winter 2012 Period. The Panel believes that the IESO should reserve a significant portion of available TRs for sale at short-term TR auctions, and is recommending that the IESO change its policy accordingly.

Finally, this report describes the circumstances that lead to a payment being made to a market participant under the IESO's day-ahead Intertie Offer Guarantee (IOG) program, which compensates importers for a drop in the intertie zonal price caused by congestion. The market participant's economic offers exceeded the intertie transfer capability of the Manitoba intertie, causing import congestion, a large drop in the intertie zonal price and a large IOG payment to all imports scheduled day-ahead. Upon further examination of the event, the Panel noted that the protection afforded by IOG payments overlaps with that afforded by TRs, and in effect that a market participant with a day-ahead commitment and TRs will be more than kept whole in the event of congestion. The Panel is therefore recommending that the IESO examine the interplay between the day-ahead IOG program and the TR market as part of the IESO's planned review of the Enhanced DACP.

6. Recommendations

In this Report, the Panel makes five recommendations: one 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 or transparency, although many of the Panel's recommendations have effects in more than one of the categories used to group its recommendations.

All of the recommendations contained in this report pertain to the TR market. Four of those recommendations speak to issues associated with the design and operation of that market, and are directed at restoring balance by bringing the TR Clearing Account back to the level where congestion rent collected is approximately equal to TR payouts. The fifth recommendation relates to the interplay between the TR market and the day-ahead IOG program.

Efficiency

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

Recommendation 3-1:

> ***The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.***

Uplift and Other Payments

The Panel examines uplift payments both as they contribute to the effective price paid by customers and as they impact the efficient operation of the market.

Recommendation 3-2:

> ***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 3-3:

> ***(A) The IESO Board of Directors should authorize the disbursement of the portion of the Transmission Rights Clearing Account balance that currently exceeds the Reserve Threshold to reduce the transmission charges payable by loads.***
>
> ***(B) In the future, the IESO Board of Directors should authorize disbursements of Transmission Rights Clearing Account balances in excess of the Reserve Threshold after each year end.***

Recommendation 3-4:

The IESO policy of selling only long-term transmission rights on single-circuit interfaces should be replaced by a policy of reserving a significant portion of the available transmission rights for sale at short-term transmission right auctions.

Recommendation 3-5:

As part of the IESO's planned review of the Enhanced Day-Ahead Commitment Process, the Panel recommends that the IESO examine the interplay between the day-ahead intertie offer guarantee program and the transmission rights market.

Chapter 1: Market Outcomes

This chapter reports on outcomes in the IESO-administered markets over the period May 2011 to April 2012, with comparisons to the same period one year earlier as well as others where relevant.[1] It focuses on market indicators related to electricity pricing, demand, supply, and import/export activity, and also briefly discusses outcomes in the market for operating reserve.

For convenience, the period May 2011 to April 2012 is referred to as the "2011/12 Annual Period" and the period May 2010 to April 2011 is referred to as the "2010/11 Annual Period". Except as otherwise noted, references to changes experienced in the 2011/12 Annual Period are expressed relative to the 2010/11 Annual Period.

1. Highlights of Market Indicators

1.1 Pricing

From May 2011 to April 2012, the average Hourly Ontario Energy Price (HOEP) was \$26.30/MWh, a 26.2% decrease from the 2010/11 Annual Period's average of \$35.64/MWh. However, the final cost of electricity to Ontario customers is higher than the wholesale price after the addition of delivery charges, regulatory charges (including uplift) and the Global Adjustment (GA).

The GA for the 2011/12 Annual Period averaged \$42.33/MWh for all Ontario customers (i.e., the total GA payment divided by the total Ontario demand). This is a \$13.69/MWh (or 47.8%) increase from the 2010/11 Annual Period.

[1] Market data from the IESO-administered markets and related reports for the period following the year covered in this report are available at http://ieso.ca/imoweb/marketdata/marketSummary.asp.

Effective January 1, 2011,[2] the manner of calculating the GA amount payable by a customer depends on whether the customer is a "Class A" (larger) customer or a "Class B" (smaller) customer.[3] Class A customers are those whose maximum hourly demand for electricity in a month exceeds an average of 5 MW for the applicable base period (for a given adjustment period (the 12 months commencing July 1), the 12-month period ending April 30 in the same calendar year in which the adjustment period commences). Class B customers are all other customers.[4] The GA payable by a Class A customer is determined based on the customer's "peak demand factor", which in turn is a function of the customer's electricity withdrawals during the 5 peak hours in the base period. The GA payable by a Class B customer is determined based on the customer's consumption in a month. Class A and Class B customers can both be either directly connected to the IESO-controlled grid or connected at the distribution level. While the majority of loads connected at the distribution level are Class B customers, some are Class A. Certain information pertaining to distribution-connected customers is not available from distributors. Unless otherwise noted, further discussion of the allocation of the GA to Class A customers in this report pertains only to Class A customers that are directly connected to the IESO-controlled grid (denoted as Direct Class A). "Class B plus Non-Direct Class A" are the nomenclature used to capture all Class B customers as well as Class A customers that are connected at the distribution level.

During the 2011/12 Annual Period, there were 64 Direct Class A customers, accounting for about 6% of total peak Ontario demand. The GA for Direct Class A customers for

[2] The methodology for calculating the GA is described at http://www.ieso.ca/imoweb/b100/ga_changes.asp. See also the discussion of the revised GA allocation methodology in the Panel's November 2011 Monitoring Report (at pp. 125-133), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf.

[3] Ontario Regulation 429/04 (Adjustments under section 25.33 of the Act) made under the *Electricity Act, 1998* sets out detailed rules pertaining to the determination of consumers as Class A and Class B, and to the determination of the GA payable by members of each class. The discussion set out here is by way of general summary only, based on Ontario Regulation 429/04 as it existed in the 2011/12 Annual Period. Except as otherwise noted, amendments to Ontario Regulation 429/04 that came into force after the end of the 2011/12 Annual Period are not reflected.

[4] A Class A customer can elect to be a Class B customer for the next billing period (from July of the current year to June of the next year). Initially a transitional provision, the ability to elect was made enduring by an amendment to Ontario Regulation 429/04 that came into force on June 1, 2012.

that Annual Period averaged $22.92/MWh, and the GA for Class B plus Non-Direct Class A customers averaged $44.69/MWh.

Given the magnitude of the GA and uplift charges, the Panel also reports the effective wholesale market price for electricity. The effective price is the "all-in" price to Ontario customers, consisting of the HOEP, the GA and uplift charges. Over the 2011/12 Annual Period, the effective price averaged $72.64/MWh for all Ontario customers, representing a 7.4% increase from the 2010/11 Annual Period. The effective price over the 2011/12 Annual Period averaged $51.63/MWh for Direct Class A customers and $75.19 for Class B plus Non-Direct Class A customers.[5]

1.2 Ontario Demand

Total Ontario electricity consumption was 139.81 TWh in the 2011/12 Annual Period, down by 4.22 TWh (2.9%) from the 144.03 TWh consumed in the 2010/11 Annual Period. Ontario demand declined in every month when compared to the 2010/11 Annual Period, except in September and October.

1.3 Ontario Supply

There were several significant changes in Ontario's electricity supply sources during the 2011/12 Annual Period. 612 MW of new capacity were added to the market; 464 MW from two gas-fired units (an increase of 6.5% in gas generation capacity) and 147.6 MW from two wind energy centres (an increase of 10.5% in wind generation capacity).

Two coal-fired units totalling 975 MW of generation capacity were taken out of service in 2011, in advance of the Ontario Government's requirement that coal-fired generation

[5] The effective price uses the load-weighted average HOEPs found in Table 1-2 instead of the average HOEP. This takes into account the fact that a greater percentage of large customers' consumption occurs during off-peak hours when the actual HOEP is lower than the average HOEP, and a greater percentage of small customers' consumption occurs during on-peak hours when the actual HOEP is higher than the average HOEP.

be phased out by the end of 2014.[6] This represented a 21.6% reduction from the 4,542 MW of coal-fired generating capacity available at the beginning of the 2011/12 Annual Period.

Overall, there was a 363 MW (1.0%) reduction in generation capacity in the wholesale market during the 2011/12 Annual Period.

1.4 Imports and Exports

Net exports decreased slightly by 0.24 TWh (2.6%) to 9.01 TWh during the 2011/12 Annual Period. An increase of 0.79 TWh in off-peak net exports was not enough to offset the 1.04 TWh decline in on-peak net exports.

Exports declined by 1.80 TWh (11.6%) and imports declined by 1.56 TWh (25.0%), resulting in the decrease in net exports noted above.

1.5 Operating Reserve

The average hourly operating reserve (OR) requirement in the 2011/12 Annual Period was 1,516 MW, which is 4 MW less than the 1,520 MW requirement in the 2010/11 Annual Period. The prices for all three categories of OR increased significantly in the 2011/12 Annual Period relative to the 2010/11 Annual Period, mainly due to high OR prices in May and June 2011.

[6] For details, see Ontario Regulation 496/07 (Cessation of Coal Use – Atikokan, Lambton, Nanticoke and Thunder Bay Generation Stations), available at http://www.e-laws.gov.on.ca/html/regs/english/elaws_regs_070496_e.htm.

2. Pricing

2.1 Hourly Ontario Energy Price

Table 1-1 presents the monthly average HOEP for the 2010/11 and 2011/12 Annual Periods. The average HOEP across all hours in the 2011/12 Annual Period was $26.30/MWh, a 26.2% decrease from the $35.64/MWh average in the 2010/11 Annual Period. The average on-peak and off-peak HOEPs decreased by 25.0% and 27.6%, respectively.

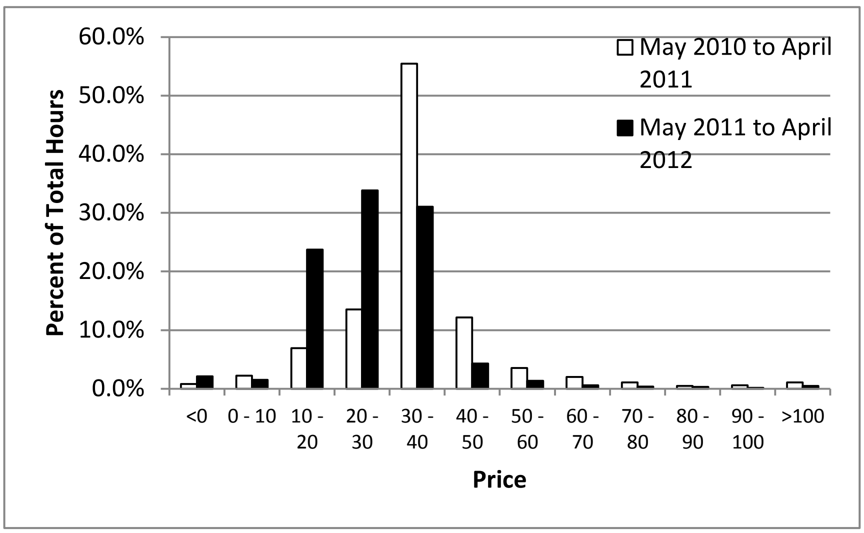
The average monthly HOEPs in the 2011/12 Annual Period were all lower than their monthly counterparts in the 2010/11 Annual Period. The month of March 2012 showed the largest year-to-year drop, from $31.23/MWh to $14.33/MWh (54.1%).

Table 1-1: Average HOEP, On-peak and Off-peak May – April 2010/2011 & May – April 2011/2012 ($/MWh and % change)

Month	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change
May	38.77	24.42	(37.0)	44.87	31.21	(30.4)	34.16	18.83	(44.9)
June	40.36	32.09	(20.5)	45.49	42.49	(6.6)	35.44	22.15	(37.5)
July	50.83	35.29	(30.6)	65.84	41.76	(36.6)	38.46	30.41	(20.9)
August	44.41	32.62	(26.6)	52.39	39.25	(25.1)	37.84	26.66	(29.6)
September	32.91	31.18	(5.3)	37.88	34.05	(10.1)	28.56	28.68	0.4
October	29.39	28.53	(2.9)	34.12	32.14	(5.8)	25.82	25.81	0.0
November	31.89	27.97	(12.3)	34.97	32.52	(7.0)	28.94	23.61	(18.4)
December	33.83	25.18	(25.6)	36.98	28.78	(22.2)	31.23	22.46	(28.1)
January	31.92	24.83	(22.2)	37.27	28.35	(23.9)	27.88	21.92	(21.4)
February	33.29	22.09	(33.6)	34.84	22.67	(34.9)	32.01	21.59	(32.5)
March	31.23	14.33	(54.1)	33.29	17.46	(47.6)	29.20	11.53	(60.5)
April	28.37	16.94	(40.3)	35.71	18.71	(47.6)	23.01	15.64	(32.0)
Average	35.64	26.30	(26.2)	41.19	30.91	(25.0)	31.01	22.46	(27.6)

Figure 1-1 presents the frequency distribution of HOEP over the 2010/11 and 2011/12 Annual Periods. In the vast majority (89%) of hours in the 2011/12 Annual Period, the HOEP was in the $10-$20/MWh, $20-$30/MWh and $30-$40/MWh price ranges. The increased frequency of low (<$20/MWh) and negative HOEPs is examined in greater detail in Chapter 2 of this report.

Figure 1-1: Frequency Distribution of HOEP
May – April 2010/2011 & May – April 2011/2012
(% of total hours in $10/MWh price increments)



2.2 Load-weighted HOEP

Table 1-2 presents the load-weighted HOEP by load type for the 2010/11 and 2011/12 Annual Periods. The load-weighted HOEP provides a more accurate representation of the actual price paid by loads since it is weighted by hourly demand. As is the case for the un-weighted HOEP, there were significant decreases in the load-weighted HOEP for all load types in the 2011/12 Annual Period.

The average load-weighted HOEP was lowest for the dispatchable load category at $24.98/MWh ($2.53/MWh or 9.2% less than the load-weighted HOEP for all loads). Such customers tend to consume less during high-price hours and more during low-price hours. To some extent, the consumption of other wholesale loads follows a similar pattern; their average load-weighted HOEP was $26.39/MWh ($1.12/MWh or 4.1% less than the load-weighted HOEP for all loads). Consumption by loads connected at the distribution level,[7] some of which are directly exposed to the market price and others of which are not, had an average load-weighted HOEP of $27.77/MWh ($0.26/MWh or 0.9% more than the load-weighted HOEP for all loads). These customers generally use more electricity during high-price hours than they do during low-price hours.

Table 1–2 also shows the average load-weighted HOEP for Direct Class A and Class B plus Non-Direct Class A customers. Direct Class A customers have a lower weighted HOEP since they generally have a flatter or even opposite load profile than Class B plus Non-Direct Class A customers, who in turn tend to have higher consumption during the day (on-peak hours) and lower consumption at night (off-peak hours). The differential in load-weighted HOEP between Direct Class A and Class B plus Non-Direct Class A customers decreased from $2.10/MWh to $1.79/MWh between the two Annual Periods.

Table 1-2: Load-Weighted Average HOEP by Load Category
May – April 2010/2011 & May – April 2011/2012
($/MWh)

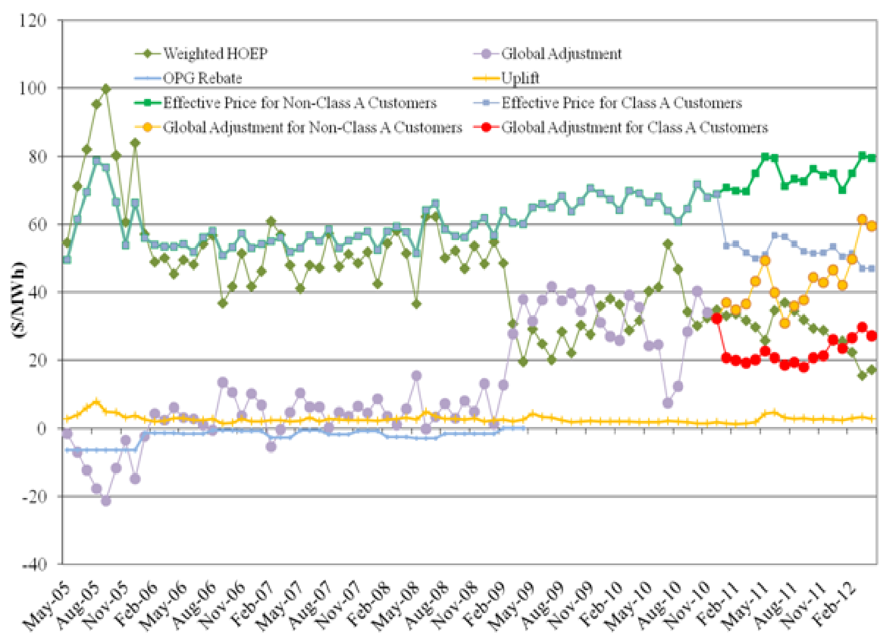
Year	Unweighted HOEP	Load-weighted HOEP					
		Dispatchable Loads	Other Wholesale Loads	Loads within Distributors	All Loads	Direct Class A	Class B plus Non-Direct Class A
2010/2011	35.64	34.70	35.65	37.43	37.11	35.24	37.34
2011/2012	26.29	24.98	26.39	27.77	27.51	25.90	27.69
Difference	(9.35)	(9.72)	(9.26)	(9.65)	(9.60)	(9.34)	(9.65)
% Change	(26.2)	(28.0)	(26.0)	(25.8)	(25.88)	(26.5)	(25.8)

[7] These are customers that are settled by the distributor to whose system they are connected. They include customers that are on the Ontario Energy Board's Regulated Price Plan and those who are charged by the distributor based on wholesale pricing.

2.3 Effective Price (including Global Adjustment and Uplift)

Figure 1-2 plots the monthly effective price of electricity, including the average weighted HOEP, uplift and the GA, between May 2005 and April 2012. While the HOEP has been declining since 2005, the GA continues to increase. At the aggregate level, the effective price of electricity continues to increase for Class B plus Non-Direct Class A customers. Due to the change in the GA allocation in 2011, however, Direct Class A customers have experienced a decline in their effective price compared to previous years.

Figure 1-2: Monthly Average Effective Price
May 2005 – April 2012
($/MWh)



The GA has been increasing since the beginning of 2009 mainly for two reasons. First, generators that have contracts with the Ontario Power Authority (OPA) are paid the contract price. When that price is higher than the HOEP, which is typically the case, the difference is included in the GA. Accordingly, there is a negative correlation between the HOEP and the GA. The substantial decline in average HOEP beginning in March 2009 triggered substantial increases in the GA as a result of the greater difference between the HOEP and the prices paid to generators under contract. Second, more OPA-contracted energy has come online. The prices paid under these more recent contracts (e.g., contracts with wind and solar power generators) also typically exceed the average HOEP by a significant margin.

The average effective price for all Ontario customers during the 2011/12 Annual Period was $72.64/MWh. On average, Direct Class A customers paid $17.45/MWh less than this price while Class B plus Non-Direct Class A customers on average paid $3.24/MWh more than this price. Table 1-3 compares the effective price for the periods January to April 2011 and January to April 2012, these dates being in keeping with the fact that the change in the GA allocation methodology became effective in January 2011. The effective price for Direct Class A customers was lower in 2012, but the effective price for Class B plus Non-Direct Class A customers was higher, which was mainly due to a substantial increase ($15.75/MWh) in the GA allocated to Class B plus Non-Direct Class A customers in 2012.

Table 1-3: Effective Electricity Price
January 2011 –April 2011 and January 2012 –April 2012
($/MWh)

Customer Class	Weighted HOEP		Global Adjustment		Average Uplift		Effective Price	
	2011	2012	2011	2012	2011	2012	2011	2012
Direct Class A	30.89	19.31	20.01	26.79	2.56	2.31	53.46	48.41
Class B plus Non-Direct Class A	31.97	20.43	40.22	55.97	2.56	2.31	74.75	78.71
Blended	32.03	20.31	35.85	49.87	2.56	2.31	70.44	72.49

2.3.1 Hourly Uplift and Components

Table 1-4 reports the monthly total hourly uplift charges for the 2010/11 and 2011/12 Annual Periods. The total hourly uplift charges in the 2011/12 Annual Period dropped from $239.1 million to $209.3 million, a 12.5% decrease. As discussed below, Congestion Management Settlement Credit (CMSC) payments and losses were the main drivers of this decline. Although OR and Intertie Offer Guarantee (IOG) payments increased, both were much smaller than CMSC payments and losses to begin with.

Table 1-4: Total Hourly Uplift Charge by Component and Month May – April 2010/2011 & May – April 2011/2012 ($ millions and %)

Month	IOG		CMSC*		Losses		Operating Reserve		Total Hourly Uplift	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0.5	0.4	9.6	13.0	9.5	7.2	0.4	12.2	19.9	32.8
June	0.1	0.8	11.2	18.4	8.8	9.8	1.1	4.7	21.3	33.7
July	0.5	0.4	13.7	9.6	14.5	11.3	1.5	1.5	30.1	22.7
August	0.3	0.4	10.3	7.0	12.6	7.8	2.1	2.4	25.3	17.5
September	0.5	1.1	8.4	6.6	8.3	7.3	3.3	0.7	20.5	15.7
October	0.3	0.4	5.5	5.6	7.1	6.7	1.3	0.5	14.1	13.1
November	0.1	0.5	6.6	9.1	7.0	4.8	1.1	0.6	14.8	15.0
December	0.4	0.7	8.5	3.5	10.4	6.9	3.7	1.2	23.0	12.3
January	0.5	0.8	5.9	2.7	10.1	6.3	2.2	1.3	18.7	11.1
February	0.4	1.2	5.0	3.8	7.5	4.9	1.3	0.6	14.2	10.5
March	0.4	1.5	7.1	6.2	8.4	4.0	1.1	4.0	17.0	15.6
April	0.4	0.4	7.7	3.5	7.3	4.2	4.7	1.2	20.2	9.3
Total	4.4	8.6	99.5	88.9	111.5	81.2	23.8	30.9	239.1	209.3
% of Total	1.6	3.6	41.6	42.5	41.1	33.6	8.8	12.8	100.0	100.0

*The CMSC figures include payments to all market participants.

Major factors contributing to the changes in uplift are summarized below:

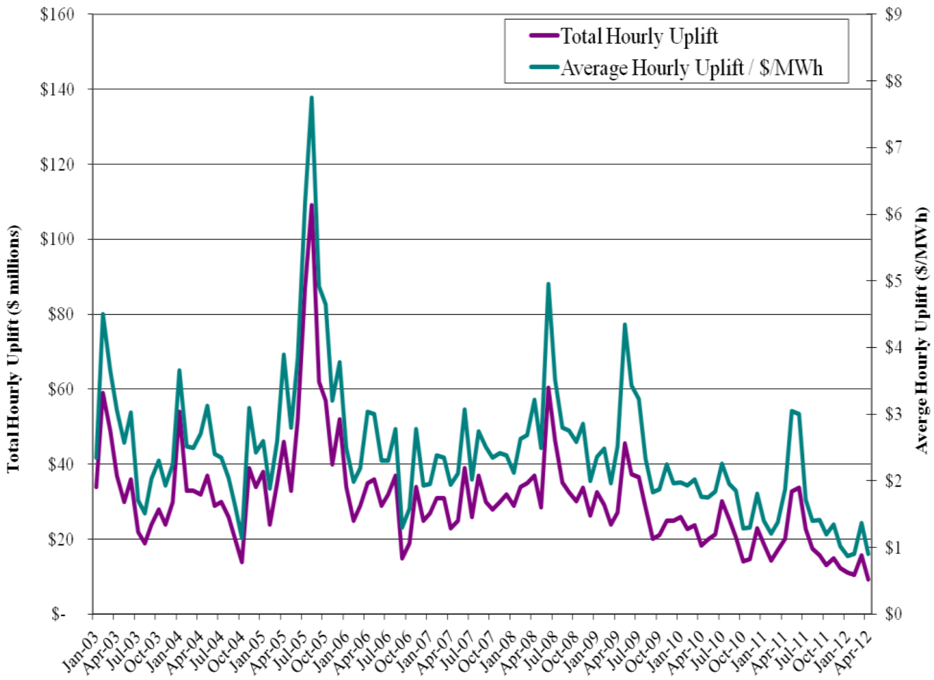
- Total IOG payments almost doubled (95.5% increase) from $4.4 million to $8.6 million. IOG payments for transactions over the Manitoba and Minnesota interfaces were particularly high because many imports from Manitoba and Minnesota were committed under the enhanced day-ahead commitment process (Enhanced DACP) and received compensation when the real-time price turned out to be lower. (Chapter 2 and 3 discuss the hour in which the largest IOG payment occurred, and Chapter 3 also contains an analysis of the significant increase in IOG payments in respect of transactions over the Minnesota interface.)

- Total CMSC payments decreased by $10.6 million (10.7%), but continued to represent a similar percentage of the total hourly uplift payments. During the 2011/12 Annual Period, June 2011 had the highest total CMSC payments ($18.4 million).
- Total payments due to losses decreased by $30.3 million (27.2%). The percentage decrease is very similar to the decrease in the HOEP - the drop in the losses category primarily reflects the decrease in the value of the lost electrical energy (i.e., the decrease in the HOEP) rather than a decrease in the amount of lost electrical energy.
- Total OR payments increased substantially from $23.8 million to $30.9 million (a $7.1 million or 29.8% increase). May 2011 had very large OR payments of $12.2 million, which was much higher than any other month since market opening in 2002. Many of the hydro facilities that typically offer low-priced OR laminations did not offer into the OR market at all due to abundant supplies of water which would have had to have been spilled if not used for energy production.[8]

[8] To provide OR, a hydro-electric resource must have both capacity and water available in case of OR activation. When there is abundant water that cannot be stored, providing OR would force the facility to spill water that is more profitably used by providing energy.

Figure 1-3 plots hourly uplift charges in millions of dollars and $/MWh between January 2003 and April 2012. The hourly uplift charges have generally been decreasing since early 2008, and they set record lows in April 2012.

Figure 1-3: Total and Average Hourly Uplift Charges
January 2003 – April 2012
($ millions and $/MWh)



2.3.1.1 Constrained-off Payments for Operating Reserve

As is the case with energy, operating reserve can be constrained on or off. OR can be constrained on when an OR offer is not economic in the unconstrained schedule but is required in the constrained schedule. Conversely, OR can be constrained off when OR is economic in the unconstrained schedule but does not receive a corresponding dispatch in the constrained schedule.[9]

[9] Being constrained on in the OR market does not mean that the resource supplies power (or reduces the consumption of electricity); it is merely on standby to do so if an activation occurs.

Table 1-5 below provides the total constrained-off CMSC payments in the OR market in the period May 2009 to April 2012 by region. Annual constrained-off CMSC payments for OR ranged from $6.2 million to $15.6 million, with most of it paid to generators located in the Northeast and Northwest regions (the same areas where generators, importers and dispatchable loads have already been receiving the vast majority of constrained-off CMSC payments for energy). However, dispatchable loads in the Northwest also receive a large amount of CMSC payments in respect of the OR market.

Table 1-5: Constrained-off CMSC Paid to Suppliers of Operating Reserve, by Region
May 2009 to April 2012
($ 000s)

Area (Zone)	Resource Type	May 2009 - April 2010	May 2010 - April 2011	May 2011 - April 2012	Total	% of Total
Bruce	Generators	0	0	0	0	0
East	Generators	818	233	522	1,572	5
ESSA	Generators	122	7	12	141	0
Northeast	Generators	12,060	3,934	5,706	21,701	70
	Dispatchable Loads	169	56	142	367	1
Niagara	Generators	266	183	155	604	2
Northwest	Generators	1,022	1,153	1,364	3,538	11
	Dispatchable Loads	597	434	688	1,719	6
Ottawa	Generators	0	0	0	0	0
Southwest	Generators	282	47	50	378	1
	Dispatchable Loads	19	1	7	26	0
Toronto	Generators	11	35	111	157	1
	Dispatchable Loads	2	7	21	29	0
Western	Generators	280	132	284	697	2
Total		15,648	6,222	9,062	30.9	100

Constrained-on CMSC payments for OR have totalled about $9 million in the period covered by Table 1-5, or an average of $3 million per year. Most of the constrained-on payments were paid to generators or dispatchable loads in Southern Ontario where major loads are located.

2.3.2 Monthly Uplift and Components

The monthly uplift consists of charges that are not allocated to a specific hour. These include payments to generators under the generation cost guarantee programs (including both the day-ahead commitment program or DACP (the Enhanced DACP after October 13, 2011) and the real-time spare generation online (SGOL) program), and the recovery of costs associated with regulation (previously referred to as automatic generation control or AGC), voltage support, and black start capability. Table 1-6 below reports the monthly uplift for the 2010/11 and 2011/12 Annual Periods. The total monthly uplift was higher in the 2011/12 Annual Period, but the percentage breakdown by monthly uplift component was relatively similar over the two Annual Periods.

Table 1-6: Total Monthly Uplift Charges, by Component
May – April, 2010/2011 & May – April 2011/2012
($ millions and %)

Month	Generator Cost Guarantees		Regulation		All Others		Total Monthly Uplift	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	8.1	8.2	1.9	2.2	0.6	0.6	10.6	10.9
June	12.3	10.0	2.0	3.5	0.6	0.6	14.9	14.0
July	13.9	12.3	2.0	2.3	0.1	0.6	16.0	15.3
August	12.3	13.4	2.3	1.8	(0.3)	(0.2)	14.2	15.0
September	12.8	15.1	2.2	2.0	0.8	0.9	15.8	18.0
October	9.3	12.8	2.3	1.5	(0.1)	0.0	11.5	14.3
November	10.9	12.8	2.0	1.4	0.6	0.8	13.6	15.0
December	11.4	12.8	1.7	5.2	0.1	0.6	13.2	18.5
January	12.0	9.4	2.3	4.0	0.8	(0.1)	15.0	13.7
February	13.5	13.2	1.9	2.5	0.5	1.4	15.8	17.6
March	11.6	13.2	1.8	1.5	0.0	0.8	13.4	15.7
April	7.1	10.2	1.9	2.4	0.1	0.2	9.1	13.1
Total	135.2	143.4	24.2	30.2	3.8	6.2	163.2	189.6
% of Total	82.8	79.8	14.8	16.8	2.3	3.4	100.0	100.0

2.4 Price Setters (Marginal Resources)

During the 2011/12 Annual Period, gas-fired units and hydro-electric units have more frequently replaced coal-fired generators as the marginal resource. Based on pre-dispatch prices, there was a decrease in the share of hours in which imports were marginal, corresponding to a rise in the share of hours in which exports and domestic resources were marginal.

2.4.1 Real-time Marginal Resources

Table 1-7 presents the share of real-time intervals in which particular resource types were the marginal resource (and therefore set the Market Clearing Price or MCP) for each of the 2010/11 and 2011/12 Annual Periods. The table shows that the average share by resource type shifted significantly towards hydro-electric units. The share of coal-fired units declined by 12.9%, while gas-fired units and hydro-electric units gained 2.9% and 9.9%, respectively. This is not unexpected given the gradual phasing out of coal-fired generation capacity within the province. During the 2011/12 Annual Period, nuclear units were the marginal resource in 968 intervals, which is significantly higher than the 297 intervals in the 2010/11 Annual Period. In all of these intervals, the HOEP was negative and Ontario was experiencing surplus baseload generation (SBG) conditions, market conditions that are discussed in greater detail in Chapter 2 of this report.

Table 1-7: Share of Marginal Resource Setting Real-Time MCP May – April 2010/2011 & May – April 2011/2012 (% of intervals)

Fuel Type	2010/2011[10]	2011/2012	Change
Coal	34.5	21.6	(12.9)
Gas	39.6	42.5	2.9
Hydro	22.7	32.6	9.9
Nuclear	0.3	0.9	0.6
Dispatchable Load[11]	3.0	2.4	(0.6)
Total	100.0	100.0	-

[10] In past reports, the Beck pumping storage load was not considered as a load. However, given its treatment as a load in this report (when it withdraws energy from the grid), the values for 2010-2011 have been updated in this report relative to those set out in the Panel's November 2011 Monitoring Report (available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf) to facilitate comparison. The 2010-2011 values in Table 1-8 have also been updated for the same reason and in the same way.
[11] *Ibid.*

2.4.2 Pre-dispatch Marginal Resources

The final one-hour ahead pre-dispatch sequence schedules imports and exports for the upcoming delivery hour and provides advisory schedules for generators and dispatchable loads, based on forecast Ontario demand. That final pre-dispatch sequence also generates a pre-dispatch price, which is considered a predictor of the HOEP. Imports and exports are scheduled based on their offers and bids, respectively, in the final pre-dispatch sequence, and could be marginal. Table 1-8 presents the percentage of hours that a specific resource or transaction type was marginal in the one-hour ahead pre-dispatch schedule for the 2010/11 and 2011/12 Annual Periods. During the 2011/12 Annual Period, both domestic generation and exports increased the share of hours in which they set the final pre-dispatch price by 1.6% and 1.8%, respectively. This was taken from the share of hours in which imports were marginal in pre-dispatch.

Table 1-8: Marginal Resources Setting Final Pre-dispatch Price
May – April 2010/2011 & May – April 2011/2012
(% of intervals)

Fuel Type/ Intertie Trade	2010/2011	2011/2012	Change
Coal	25.9%	17.4%	-8.4%
Gas	7.5%	15.8%	8.3%
Hydro	32.2%	33.9%	1.7%
Nuclear	0.0%	0.1%	0.1%
Import	14.6%	11.2%	-3.4%
Export	17.8%	19.6%	1.8%
Dispatchable Load	2.0%	2.0%	0.0%
Total	100.0	100.0	-

2.5 Pre-dispatch Prices and HOEP

An accurate pre-dispatch price signal can contribute to real-time dispatch efficiencies. Production and consumption decisions are improved when market participants can use pre-dispatch prices as an informative signal. Given that a market participant can only submit offers or bids no later than two hours before the delivery hour, the three-hour ahead pre-dispatch price is the last signal available to market participants as a basis for submitting or adjusting their final offers/bids. The Panel monitors the three-hour ahead pre-dispatch price relative to both the real-time and the one-hour ahead pre-dispatch price to assess their accuracy as signals.

2.5.1 Three-Hour Ahead Pre-dispatch Price

Table 1-9 below presents the differences between the three-hour ahead pre-dispatch price and the average HOEP for the 2010/11 and 2011/12 Annual Periods. In the 2011/12 Annual Period, the three-hour ahead pre-dispatch price on average was less than the real-time price by \$1.71/MWh. This represents a decrease of \$0.96/MWh (36%) relative to the 2010/11 Annual Period. The average absolute difference between the real-time price and the three-hour ahead pre-dispatch price was \$6.74/MWh in the 2011/12 Annual Period, a slight increase from the 2010/11 Annual Period.

Table 1-9: Measures of Differences between Three-Hour Ahead Pre-Dispatch Prices and HOEP May – April 2010/2011 & May – April 2011/2012 ($/MWh and %)

Month	Average Difference (PD-RT)*		Average Absolute Difference		Standard Deviation		Average Difference as a % of Average HOEP[12]	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	(2.36)	(3.45)	4.87	10.41	9.65	28.23	(6.09)	(14.13)
June	(3.51)	(1.62)	5.35	11.71	14.01	28.11	(8.70)	(5.05)
July	(7.23)	(3.17)	10.01	6.14	27.11	14.57	(14.22)	(8.98)
August	(4.60)	(4.76)	6.52	10.25	12.25	23.47	(10.36)	(14.59)
September	(4.37)	(2.45)	7.92	5.11	18.46	8.79	(13.28)	(7.86)
October	(4.09)	(4.67)	7.00	8.00	21.25	16.80	(13.92)	(16.37)
November	(1.53)	(0.46)	4.07	6.38	7.71	14.44	(4.80)	(1.64)
December	(1.54)	(1.08)	7.44	6.49	19.10	14.62	(4.55)	(4.29)
January	2.49	(0.02)	4.87	4.52	12.61	11.94	7.80	(0.08)
February	0.19	(0.39)	4.26	2.13	8.76	10.97	0.57	(1.77)
March	(1.91)	1.74	5.78	7.38	10.39	26.12	(6.12)	12.14
April	(3.57)	(0.23)	12.18	2.33	27.32	5.69	(12.58)	(1.36)
Average	(2.67)	(1.71)	6.69	6.74	15.72	16.98	(7.19)	(5.33)

* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.

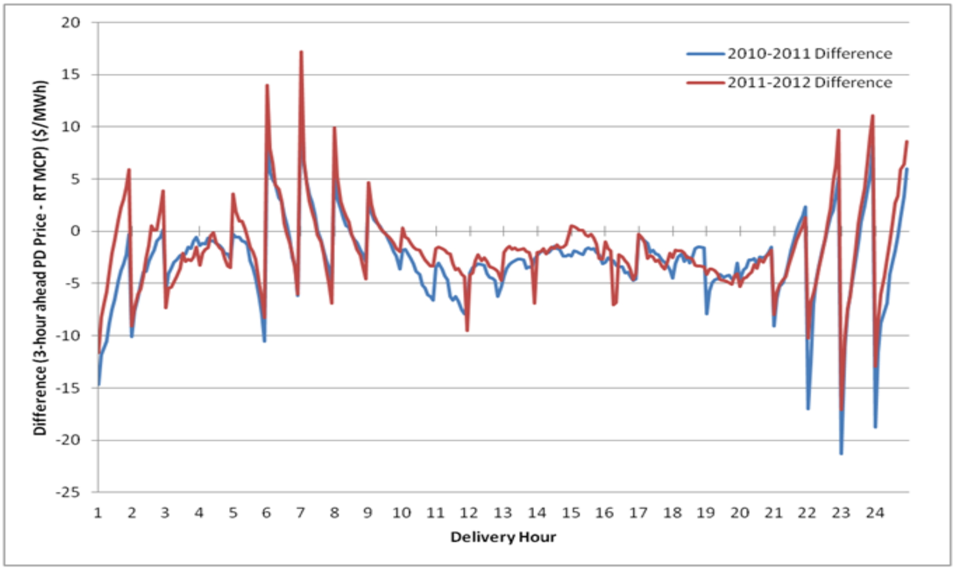
Figure 1-4 illustrates the average difference between the three-hour ahead pre-dispatch price and the real-time MCP for every delivery hour in each of the 2010/11 and 2011/12 Annual Periods. The average difference between the three-hour ahead pre-dispatch price and the real-time MCP in the 2011/12 Annual Period followed the same pattern as in the 2010/11 Annual Period, but the differences in the 2011/12 Annual Period were marginally higher.

The pre-dispatch sequence projects an hourly price based on the peak interval demand during ramp-up and ramp-down hours. When demand is steadily increasing or decreasing, which is typically reflected by a price increase or decrease (respectively), there may be a significant difference in both demand and price between the beginning

[12] This calculation expresses the average price difference (from the first and second data columns) as a percentage of the average HOEP in each month (the denominator being the monthly average HOEP reported in Table 1-1).

and end of the hour. On average over the hour, the three-hour ahead pre-dispatch price generally overestimates the MCP in ramp-up and ramp-down hours.

Figure 1-4: Average Difference Between Three-Hour Ahead Pre-Dispatch Price and Real-Time MCP, by Delivery Hour May – April 2010/2011 & May – April 2011/2012 ($/MWh)



* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.

2.5.2 One-hour Ahead Pre-dispatch Price

Table 1-10 below presents the differences between the one-hour ahead pre-dispatch price and the average HOEP for the 2010/11 and 2011/12 Annual Period. On average, one-hour ahead pre-dispatch prices were greater than the average HOEP during the 2011/12 Annual Period, whereas the opposite was true in the 2010/11 Annual Period. The average difference changed from -$1.06/MWh to $0.09/MWh, which reflects nearly equal magnitudes of positive and negative differences. The average difference as a percentage of the average HOEP shifted from -2.48% to 1.4%. The absolute average difference increased from $5.49/MWh to $5.97/MWh (an 8.0% increase), indicating less accurate one-hour ahead pre-dispatch prices as a predictor of HOEP in the 2011/12

Annual Period. Particularly large average differences between the one-hour ahead pre-dispatch price and the average HOEP occurred in January and March 2012 (although May, June and August 2011 also had higher absolute average differences than their counterparts in the 2010/11 Annual Period). January 2012 also had an unusually high standard deviation, indicating large prediction errors in certain hours.

Table 1-10: Measures of Differences between One-Hour Ahead Pre-Dispatch Prices and HOEP May – April 2010/2011 & May – April 2011/2012 ($/MWh and %)

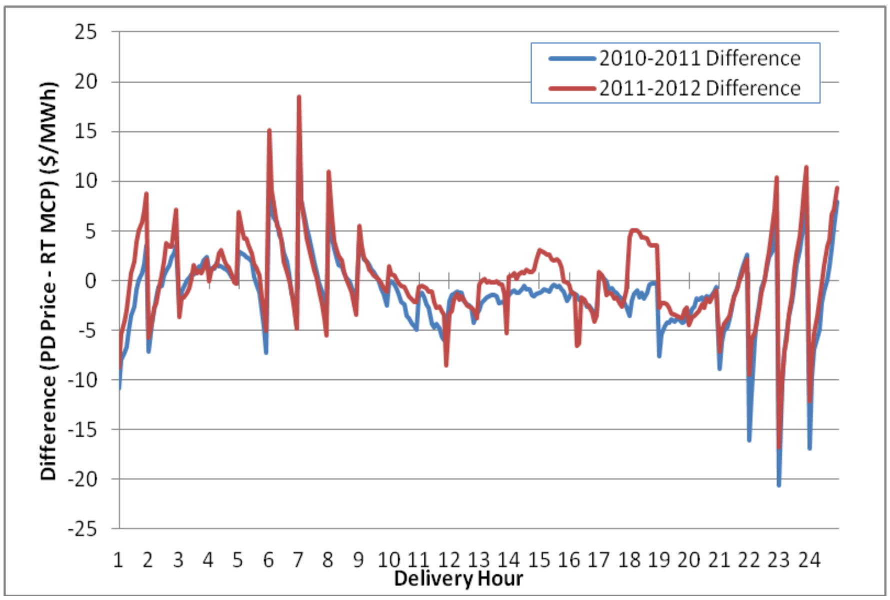
Month	Average Difference (PD-RT)*		Average Absolute Difference		Standard Deviation		Average Difference as a % of Average HOEP[13]	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	(1.34)	(0.63)	3.82	8.64	7.81	25.90	(3.5)	(2.6)
June	(1.74)	0.11	3.96	11.35	13.09	34.79	(4.3)	0.3
July	(5.39)	(1.30)	8.80	5.08	25.99	12.08	(10.6)	(3.7)
August	(3.23)	(2.58)	5.64	8.33	11.47	20.49	(7.3)	(7.9)
September	(2.33)	(1.30)	6.81	4.30	16.84	8.01	(7.1)	(4.2)
October	(2.23)	(1.93)	5.41	5.96	20.19	12.49	(7.6)	(6.8)
November	(0.99)	0.94	3.33	6.00	6.46	14.42	(3.1)	3.4
December	0.99	0.87	6.80	4.86	24.67	11.67	2.9	3.5
January	2.46	4.30	4.42	6.45	12.69	70.14	7.7	17.3
February	1.02	0.05	2.94	1.73	5.61	10.64	3.1	0.2
March	0.69	2.32	3.80	6.91	7.95	25.49	2.2	16.2
April	(0.59)	0.17	10.17	1.97	25.81	5.35	(2.1)	1.0
Average	(1.06)	0.09	5.49	5.97	14.88	20.96	(2.48)	1.40

* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.

[13] This calculation expresses the average price difference (from the first and second data columns) as a percentage of the average HOEP in each month (the denominator being the monthly average HOEP reported in Table 1-1).

Figure 1-5 depicts the average difference between the one-hour ahead pre-dispatch price and the real-time MCP by delivery hour in the 2010/11 and 2011/12 Annual Periods. The trends and magnitudes are similar to those shown in Figure 1-4. However, the one-hour ahead pre-dispatch prices are marginally closer to the HOEP for non-ramping hours and to the hourly peak MCP for ramping hours than are the three-hour ahead pre-dispatch prices. This is to be expected, as the one-hour ahead pre-dispatch price should be a more accurate predictor of the real-time price.

Figure 1-5: Average Difference Between One-Hour Ahead Pre-Dispatch Price and Real-Time MCP, by Delivery Hour
May – April 2010/2011 & May – April 2011/2012
($/MWh)



* A positive number indicates that pre-dispatch prices were on average higher than real-time prices, while a negative number indicates that pre-dispatch prices were on average lower than the real-time prices.

2.5.3 Reasons for Differences in Pre-dispatch Prices and Real-Time MCP

The Panel has identified four main factors that contribute to differences between final (one-hour ahead) pre-dispatch and real-time prices:[14]

- pre-dispatch to real-time demand forecast deviations (the deviations include forecast error and differences due to the profile of real-time demand)[15];
- production forecast errors of self-scheduling and intermittent (primarily wind) generators;
- failures of scheduled imports and exports; and
- the frequency with which imports or exports set the pre-dispatch price (these are re-priced in real-time at the bottom of the supply stack for imports and at the top of the demand stack for exports).

Except for intertie transaction failure, all other factors also contribute to differences between three-hour ahead pre-dispatch and real-time prices.

While the price impact of these factors cannot be measured directly, Table 1-11 presents the absolute average differences in MW for each of the first three factors listed above for the 2010/11 and 2011/12 Annual Periods.[16] Monthly absolute averages provide some indication as to which of the factors are the most important contributors to differences between pre-dispatch and real-time prices. However, any one of these factors can lead to significant price discrepancies in a given hour.

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[14] Pre-dispatch and real-time scheduling also differ in the magnitude of control action operating reserve (CAOR) incorporated, although this tends primarily to affect operating reserve price differences, with an indirect and smaller influence on energy prices (through joint optimization). Until September 2008, there were 400 MW of CAOR available in pre-dispatch and 800 MW of CAOR available in real-time. Subsequently, the 400 MW in pre-dispatch was dropped due to the continued failure of exports that were used to back the scheduled CAOR. For details, see the Panel's January 2009 Monitoring Report (at pp. 191-193), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf.

[15] In particular, when forecast demand is for the peak interval in the hour, the pre-dispatch to real-time price difference can be induced by either forecast error or the profile of real-time demand (i.e., demand in all other intervals will be lower than the peak demand in the hour even though the peak demand is accurately forecast). See the Panel's November 2011 Monitoring Report (at pp. 22-23), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf.

[16] The table does not report the frequency with which imports (or exports) set the pre-dispatch price, since the metric to measure that frequency (percentage of hours) does not translate into an hourly quantity (MW) statistic that can be compared with the three other factors.

Table 1-11: Factors Contributing to Differences Between One-Hour Ahead Pre-dispatch and Real-Time Prices May - April 2010/2011 & May- April 2011/ 2012 (MW per hour and % of Ontario demand)

Factor	2010/2011		2011/2012	
	Absolute Average Difference (MW)	Absolute Average Difference as % of Ontario Demand*	Absolute Average Difference (MW)	Absolute Average Difference as % of Ontario Demand*
Pre-dispatch to Real-time Demand Forecast Deviation	188	1.2	195	1.2
Differences due to Real-time Demand Profile	22	0.1	10	0.1
Pre-dispatch to Real-time Average Demand Forecast Deviation (sum of two above rows)	210	1.3	205	1.3
Self-Scheduling and Intermittent Forecast Deviation	100	0.6	121	0.8
Net Export Failures	173	1.1	134	0.8

*Average hourly Ontario demand (denominator) was 16,441 MW for the 2010/11 Annual Period and 15,916 MW for the 2011/12 Annual Period

Overall, the largest absolute average differences result from pre-dispatch to real-time demand forecast deviations (which as noted above include demand forecast error and differences induced by the profile of real-time demand).

The difference between pre-dispatch schedule and real-time demand induced by the real-time demand profile is extremely small, and fell by more than half in the 2011/12 Annual Period relative to the 2010/11 Annual Period. Self-scheduling and intermittent generation forecast deviation increased its contribution to the average differences by 21 MW in the 2011/12 Annual Period, and increased its contribution as a percentage of Ontario demand by 0.2%. The contribution of net export failures decreased by 39 MW, or by 0.3%, as a percentage of Ontario demand. In the aggregate, there was very little change in the contribution of these three factors in terms of percentage of Ontario demand from the 2010/11 Annual Period (3.0%) to the 2011/12 Annual Period (2.9%).

The following sections set out data pertaining to each of the four factors that have been identified by the Panel as contributing to differences between pre-dispatch and real-time prices.

2.5.3.1 Pre-dispatch to Real-time Average Demand Forecast Deviation

The difference between the pre-dispatch demand forecast and real-time average demand can lead to discrepancies between pre-dispatch prices and the HOEP. To improve market efficiency and address increased SBG incidents, the IESO implemented a new procedure in December 2009 whereby it uses average instead of peak demand as the forecast in pre-dispatch for non ramp-up hours.[17] This was expected to reduce demand forecast deviations in the non ramp-up hours, and has done so. Figure 1-6 below indicates that the deviation for non ramp-up hours is quite small. This is in contrast to the average demand forecast deviation during ramp-up hours, which continues to be significant.

[17] More precisely, average demand is applied to non ramp-up hours, including hour ending 1 to 5, 10 to 15 and 20 to 24 every day. For details, see http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4973. The IESO may also use the average forecast for the ramp-up hours when SBG conditions are credibly foreseeable.

Figure 1-6: Average Demand Forecast Deviation
May 2009 – April 2012
(one-hour ahead pre-dispatch forecast minus real-time actual, MW)

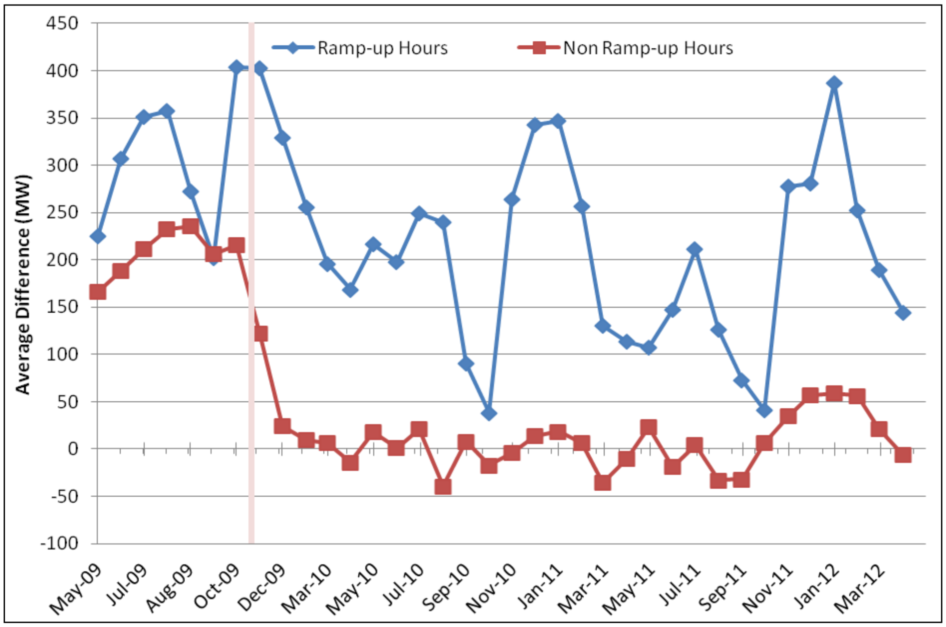


Table 1-12 presents the average demand forecast deviation by month between pre-dispatch (both one-hour ahead and three-hour ahead) and real-time for the 2010/11 and 2011/12 Annual Periods.[18] The one-hour ahead deviation measure remained the same over the two Annual Periods, while the three-hour ahead deviation increased slightly in the 2011/12 Annual Period, moving from 1.60% to 1.62%. For the months of May through August, both three-hour ahead and one-hour ahead average demand forecast deviations were lower in the 2011/12 Annual Period, with the opposite being true for all remaining months.

[18] Pre-dispatch forecast to real-time average demand discrepancy is calculated as the absolute value of pre-dispatch minus real-time average demand divided by real-time average demand in each hour.

Table 1-12: Pre-dispatch to Real-Time Average Demand Forecast Deviation Three-Hour and One-Hour Ahead May – April 2010/2011 & May – April 2011/2012 (% of real-time average demand)

Month	Three-Hour Ahead		One-Hour Ahead	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	1.86	1.34	1.48	1.16
June	1.79	1.78	1.36	1.35
July	2.00	1.91	1.52	1.43
August	1.93	1.90	1.49	1.39
September	1.36	1.48	1.05	1.11
October	1.14	1.19	0.92	0.97
November	1.53	1.57	1.30	1.34
December	1.57	1.60	1.34	1.36
January	1.61	1.75	1.33	1.44
February	1.45	1.64	1.13	1.27
March	1.50	1.62	1.20	1.26
April	1.50	1.67	1.23	1.33
Average	1.60	1.62	1.28	1.28

2.5.3.2 Pre-dispatch to Real-time Demand Forecast Error

This section focuses on the forecast error (i.e., how well the IESO's demand forecast has performed).

Table 1-13 reports the one-hour and three-hour ahead average absolute demand forecast errors on a monthly basis for the 2010/11 and 2011/12 Annual Periods. On an annual basis, both the one-hour ahead and three-hour ahead average absolute demand forecast errors, expressed as a percentage of real-time demand, increased by 0.05% in the 2011/12 Annual Period relative to the 2010/11 Annual Period. The demand forecast error in the three-hour ahead forecast remained 0.25% higher than in the one-hour ahead forecast.

Table 1-13: Pre-dispatch to Real-time Demand Forecast Error Three-Hour and One-Hour Ahead May – April 2010/2011 & May – April 2011/2012 (% of real-time demand)

Month	Average Absolute Forecast Error*			
	Three-Hour Ahead		One-Hour Ahead	
	2010/2011	2011/2012	2010/2011	2011/2012
May	2.06	1.66	1.68	1.55
June	1.99	2.20	1.71	1.87
July	2.22	2.16	1.77	1.79
August	2.25	2.37	1.89	1.96
September	1.86	2.22	1.70	1.89
October	1.80	1.86	1.72	1.79
November	1.68	1.61	1.49	1.49
December	1.50	1.62	1.35	1.43
January	1.67	1.64	1.38	1.37
February	1.51	1.70	1.29	1.38
March	1.79	1.77	1.55	1.52
April	1.83	2.00	1.72	1.75
Average	1.85	1.90	1.60	1.65

*Absolute difference between pre-dispatch and real-time demand divided by real-time demand

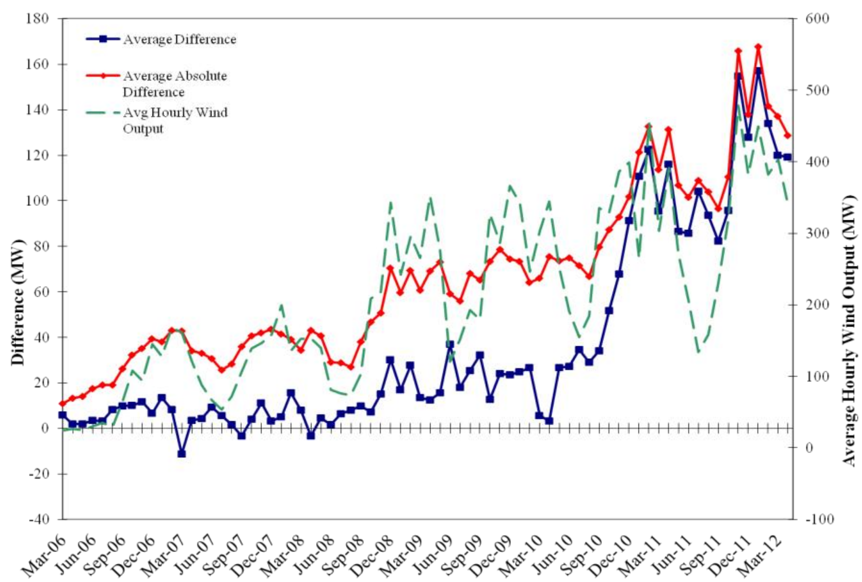
2.5.3.3 Wind Generation Forecast Errors

The amount of wind generation has increased steadily since the first wind facility was connected to the IESO-controlled grid in early 2006.[19] As of April 2012, there was a combined name-plate capacity of 1,561 MW of wind generation connected to the IESO-controlled grid (approximately 4.5% of total Ontario installed generating capacity).[20] This capacity is now greater than the total capacity of all other self-scheduling and intermittent generation connected to the IESO-controlled grid.[21]

[19] For details on wind projects that are currently operational and those under development, see the OPA's wind contracts webpage at http://www.powerauthority.on.ca/current-electricity-contracts/wind-power.
[20] Wind generation (among others) can also be connected at the distribution level. Generation that is not directly connected to the IESO-controlled grid is not included in the data contained in this report.
[21] For details regarding new capacity that came online in the 2011/12 Annual Period, see section 4.1 of this chapter.

Before October 1, 2012, wind generators forecast their own output on an hourly basis.[22] Figure 1-7 below presents the average and absolute average difference between wind generators' one-hour ahead forecast output and delivered energy. Average hourly wind output is also plotted.[23]

Figure 1-7: Average and Absolute Average Differences between Wind Generator Forecast and Delivered Energy, and Relationship to Average Hourly Wind Output March 2006 – April 2012 (MW)



Both the average and absolute average wind forecast error has been increasing since 2006, as installed wind capacity and output has increased. The average error is an

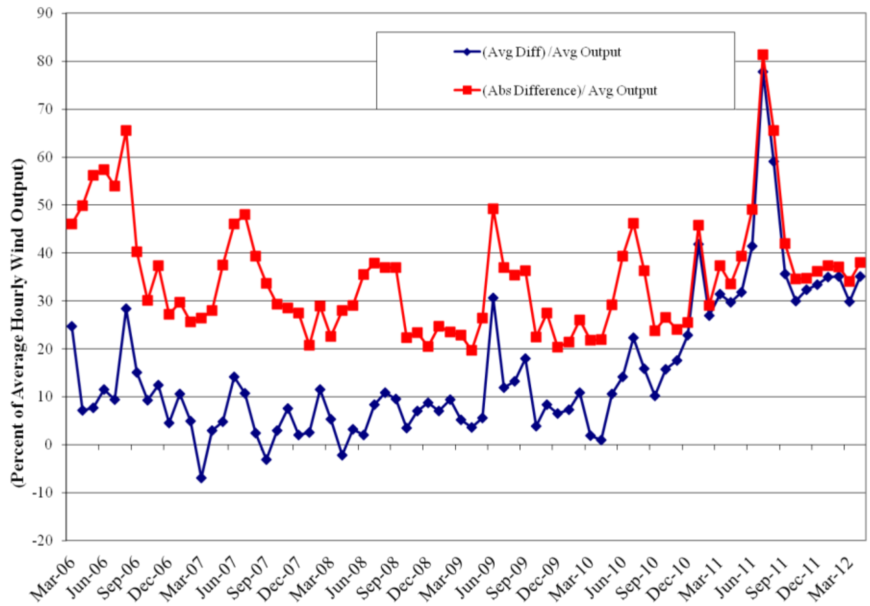
[22] The Panel recommended centralized wind forecasting in its January 2009 Monitoring Report (at pp. 253-256), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf). A centralized forecast program for wind developed by the IESO was implemented on October 1, 2012. A day-ahead forecast has been incorporated into the Enhanced DACP and a pre-dispatch forecast into the pre-dispatch sequence. For details, see: http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=6184 and http://ieso.ca/imoweb/news/bulletinItem.asp?bulletinID=5736. However, the IESO is still working on making wind resources dispatchable in real-time. For details, see: http://www.ieso.ca/imoweb/consult/consult_se91.asp.

[23] In previous Panel reports, nameplate capacity was plotted to show the amount of wind available in a given month. However, using average hourly wind output provides a better measure of actual wind generation performance in a given month since outages and other factors constraining wind generation at specific facilities are reflected in actual output levels but not in the nameplate capacity value. Average hourly wind output is also used to determine the percentage average and absolute average error in Figure 1-8.

indication of whether supply tends to be over- or under- forecast, while the absolute error is an indication of how far the forecast deviates from the actual production. The overall average of the absolute forecast error was 125.6 MW during the 2011/12 Annual Period, up 31.4% from 95.6 MW in the 2010/11 Annual Period. With wind generation capacity expected to increase significantly, the magnitude of the forecast error will likely also grow. The IESO's implementation of a centralized wind forecasting program in October 2012 is expected to alleviate some of the anticipated growth in wind forecast error.

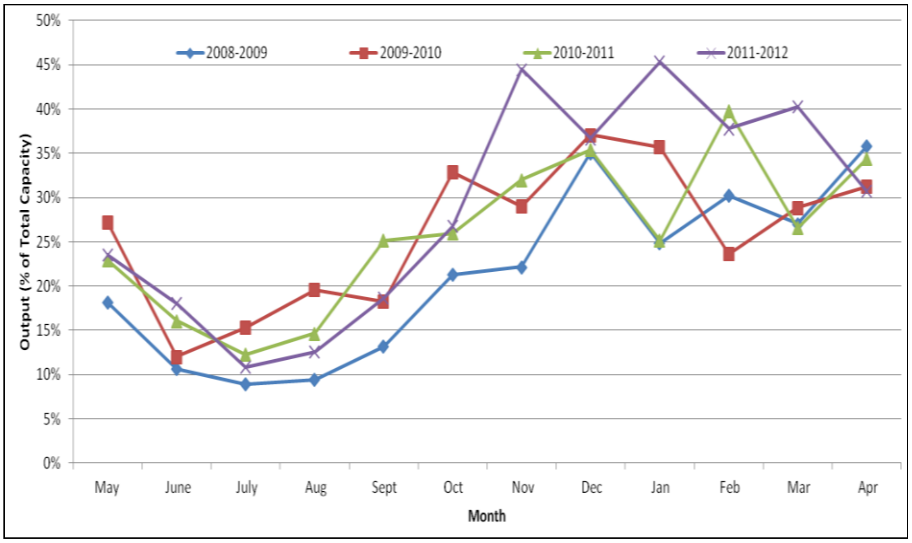
Although the average wind production forecast error has been increasing as new wind generators come online, the percentage error (absolute average forecast error relative to total wind power output) has been relatively stable. Figure 1-8 plots the average and absolute average difference between wind generators' forecast and actual production in each month since March 2006, normalized against average hourly wind output for the month. Normalized average absolute difference as a percentage of hourly wind output typically fluctuated between 20-40%. During the 2011/12 Annual Period, the average differences (absolute and actual) were consistently in the 30% and 40% range. The peaks in the summer are the result of lower hourly output of wind in the summer, which causes the fraction of average difference over average output to become large; the average differences were not anomalous in those months.

Figure 1-8: Normalized Average and Absolute Average Differences between Wind Generators' Forecasted and Delivered Energy March 2006 – April 2012 (% of average hourly wind output for the month)



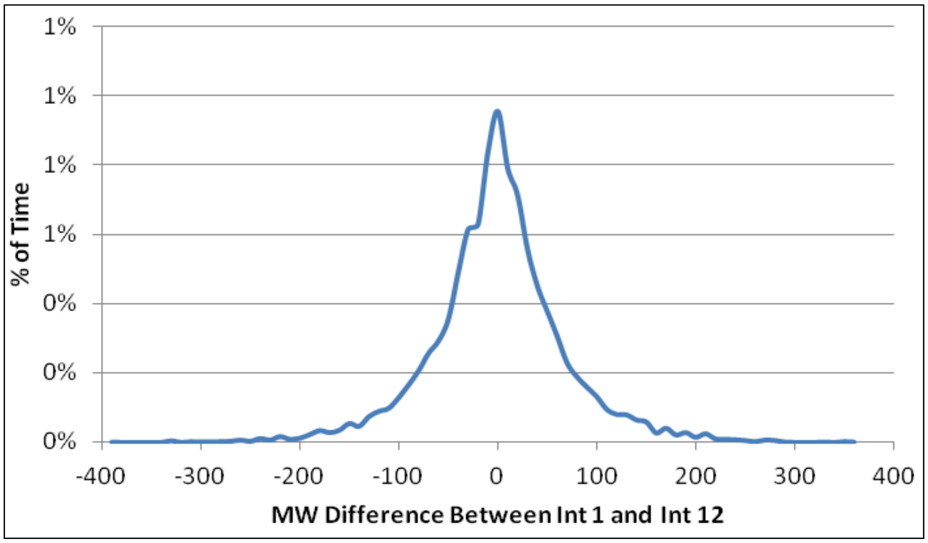
Output from wind generation facilities has seasonal trends. As illustrated in Figure 1-9, wind generation tends be higher during the winter months, peaking in or around December and falling to a summer trough in or around July.

Figure 1-9: Monthly Average Wind Output Relative to Installed Capacity May – April 2008/2009 to May – April 2011/2012 (% of total wind capacity)



Wind output tends to be relatively stable hour-to-hour, but can change quite rapidly. Figure 1-10 depicts the distribution curve of the change in intra-hour wind output (i.e., the difference of output at interval 1 and interval 12 in the same hour) during the 2011/12 Annual Period. It can be seen that with approximately 1,500 MW of installed wind capacity, in 87.4% of the hours wind output only increased or decreased by 100 MW or less from the beginning of the hour to the end of hour.

Figure 1-10: Distribution Curve of Intra-Hour Change in Wind Power Production May 2011 – April 2012 (MW and %)



2.5.3.4 Forecast Errors of Other Self-Scheduling and Intermittent Generation

Non-wind self-scheduling and intermittent generators include small gas-fuelled, biomass and hydro-electric plants.[24] Any generators that are commissioning are also self-scheduling.

Figure 1-11 plots the average and absolute average monthly difference between the energy that all non-wind self-scheduling and intermittent generators forecasted and the quantity of energy they actually delivered in real-time since May 2005. Both the average and the absolute average error have been relatively stable in the past seven years.

[24] As of the end of April 2012, no solar resources have been directly connected to the IESO-controlled grid.

Figure 1-11: Average and Absolute Average Production Forecast Errors of Non-Wind Self-Scheduling and Intermittent Generators
May 2005 – April 2012
(forecast - delivered energy, MWh)

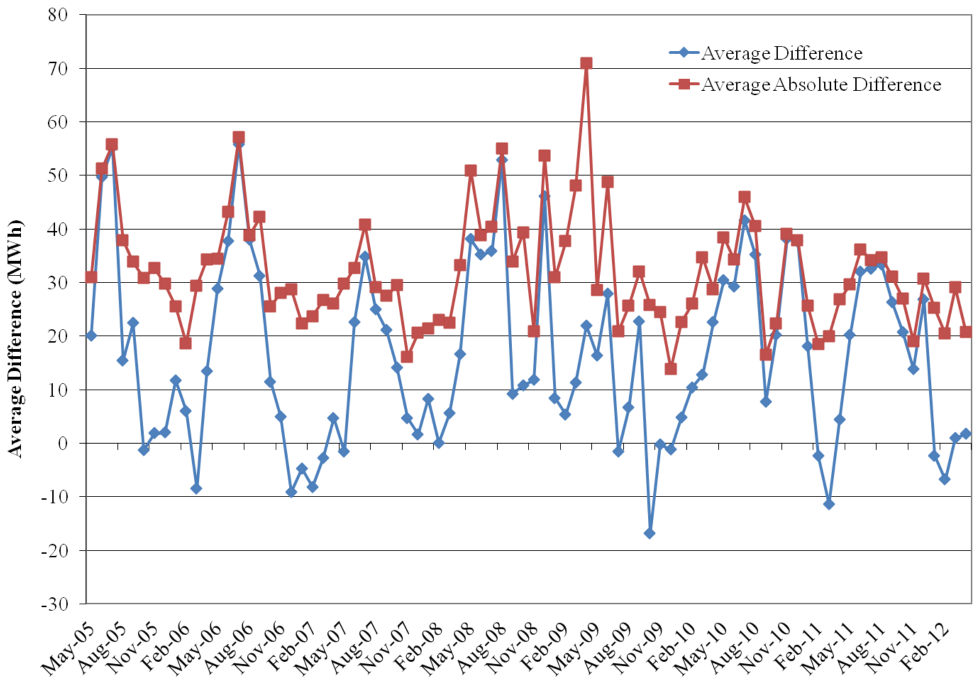
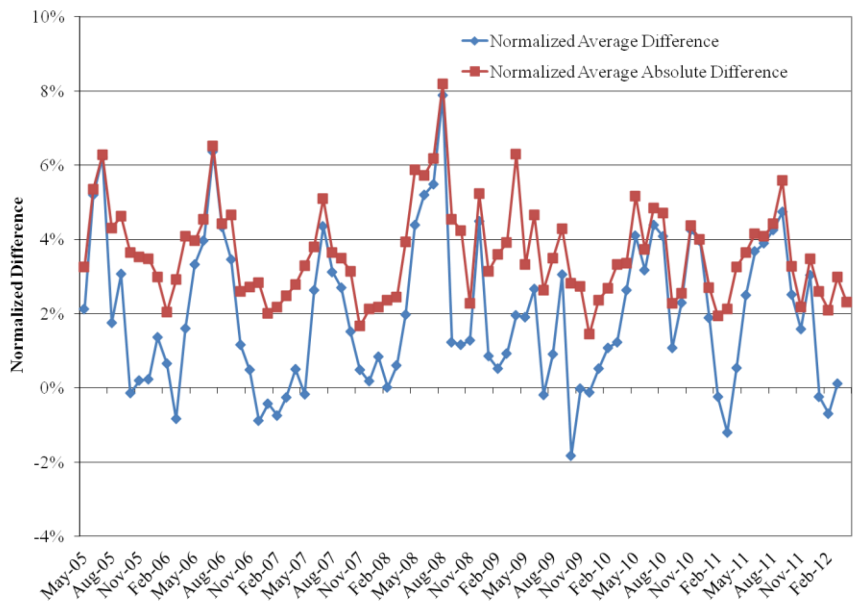


Figure 1-12 normalizes the production forecast error in a month against the average hourly output for the month since May 2005. As commissioning units are considered self-scheduling, this normalization helps to eliminate some of the impact of fluctuations in capacity arising when units become and cease to be commissioning. The normalized errors have also been relatively stable despite short-term fluctuations.

Figure 1-12: Normalized Average and Absolute Average Production Forecast Errors of Non-Wind Self-Scheduling and Intermittent Generators by Average Hourly Output May 2005 – April 2012 (% of average hourly output for the month)



2.5.3.5 Real-Time Failed Intertie Transactions

Imports and exports that are scheduled in the final pre-dispatch can fail before or in real-time. An intertie transaction can fail because it is not scheduled in the other market (including because of an inability to obtain transmission service or a ramping limitation), because of an incorrect North American Electric Reliability Corporation (NERC) tag,[25] or because it is curtailed by the IESO or external system operators for reliability reasons. Import failures represent a loss of supply while export failures represent a decline in demand, both of which can result in discrepancies between pre-dispatch and real-time prices.

[25] All intertie transactions require an associated NERC tag in order to be scheduled by corresponding system operators.

Export Failures

Table 1-14 provides summary statistics on the frequency and magnitude of failed export transactions over the 2010/11 and 2011/12 Annual Periods. The number of hours with failed exports decreased by 268 hours (5.2%), from 5,122 hours to 4,854 hours. Along with a decreased frequency of export failures, the average magnitude of export failures per hour decreased by 26 MW. The average amount of hourly failed exports was lower in six of the twelve months in the 2011/12 Annual Period when compared to the same months in the 2010/11 Annual Period. The failure rate decreased from an average of 6% to an average of 5.2%.

Table 1-14: Frequency, Magnitude, and Rate of Failed Exports from Ontario May – April 2010/2011 & May – April 2011/2012 (MW and %)

Month	Number of Hours with Failed Exports*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	295	435	806	860	137	161	6.9	4.2
June	357	341	1,484	1,033	191	180	5.7	5.7
July	415	440	838	831	149	157	4.5	5.4
August	411	456	850	1,229	137	162	4.4	6.6
September	408	405	950	1,231	146	130	3.4	5.9
October	469	369	683	638	145	95	4.5	3.3
November	259	308	431	469	80	105	1.6	3.5
December	483	258	800	1,006	185	146	4.0	4.8
January	628	454	1,260	1,013	331	119	11.9	4.6
February	501	410	1,251	1,006	205	183	9.3	6.7
March	512	484	917	1,036	225	163	10.2	5.9
April	384	494	824	859	145	165	5.2	5.4
Total/ Average	5,122	4,854	n/a	n/a	173	147	6.0	5.2

* Incidents involving less than 1 MW per hour and linked wheeling transaction failures are excluded.
** Based on those hours in which a failure occurs.
*** Total failed export MW divided by total scheduled export MW (excluding the export leg of linked wheeling transactions) in the unconstrained schedule in a month.

Causes of Export Failures

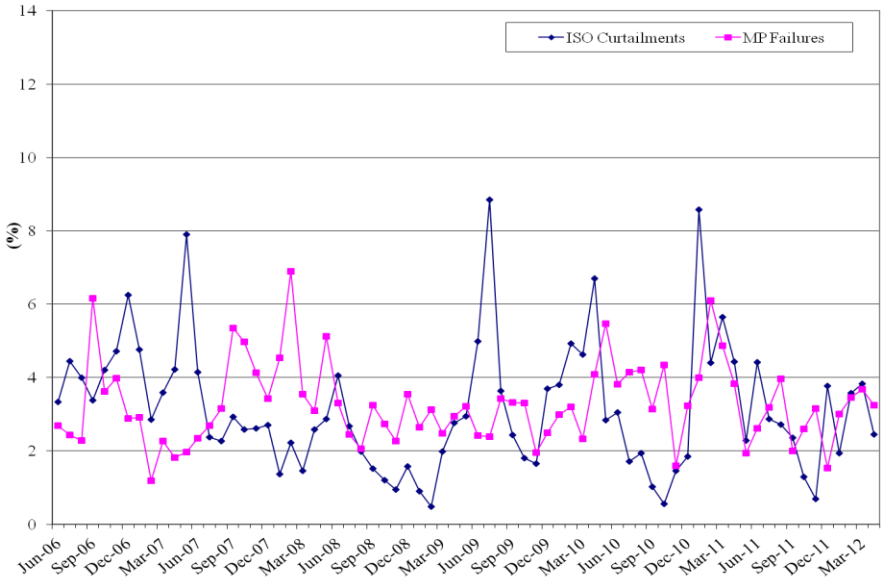
Export failures (and import failures, discussed below) can be either under the market participant's control (labelled 'MP failures') or under the control of a system operator (labelled 'ISO curtailments').[26]

Figure 1-13 plots the export failure rates by cause since June 2006.[27] The failure rate is determined as a percentage of failed to total exports in MWh per month (excluding linked wheeling transaction failures, which are rare). During the 2011/12 Annual Period, export failures were in the 2% - 4% range during most months. ISO curtailments had a high of 4.4% in May 2011 and a low of 0.7% in November 2011. MP failures had a high of 4.0% in July 2011 and a low of 1.5% in December 2011. MP failures have decreased overall in the 2011/12 Annual Period. There was a small spike in June 2011, but it did not come near the magnitude of the peaks experienced in previous years.

[26] The IESO compliance database that separates failures into ISO curtailments and MP failures does so for constrained schedule failures only. Therefore, failure rates vary slightly from the statistics reported in Tables 1-13 and 1-14, which report unconstrained schedule failures in aggregate. Some failures in the constrained schedule may not appear as failures in the unconstrained schedule, and vice versa.

[27] The June 2006 start date is used because the IESO previously applied different coding practices that make it difficult to accurately compare the earlier data.

Figure 1-13: Monthly Export Failures by Cause
June 2006 – April 2012
(% of total exports)



<u>Export Failures by Interface Group</u>

Table 1-15 reports average monthly export failures by interface group and by cause for the 2011/12 Annual Period. Export failures at the Michigan interface totalled 23.2 GWh or approximately 36.9% of total export failures. Of those failures, 82.3% were ISO curtailments. Roughly 81.0% of total MP failures occurred on the New York interface. However, the Manitoba interface had the greatest MP failure rate due to a relatively small total export volume and a high amount of failed exports. The MP failure rate at the New York interface is just below that of Manitoba, largely as a result of the process that must be used to schedule transactions on that interface.[28]

[28] Participants selling into New York must place offers to sell the energy in real-time, which allows for the possibility that transactions are not economic and not scheduled in New York even when scheduled in Ontario. The potential for mismatched economic scheduling with the New York Independent System Operator is unique among the jurisdictions directly connected to Ontario. This distinction also applies for imports to Ontario: see Table 1-17 below.

Table 1-15: Average Monthly Export Failures by Interface Group and Cause May 2011 – April 2012 (GWh and % of failures)

Interface Group	Average Monthly Exports*	Average Monthly Export Failures				Failure Rate	
		ISO Curtailment		MP Failure		ISO Curtailment	MP Failure
	GWh	GWh	%	GWh	%	%	%
New York	390.3	3.3	10.9	26.4	81.0	0.8	6.8
Michigan	478.1	19.1	63.0	4.1	12.6	4.0	0.9
Manitoba	7.2	1.9	6.3	0.5	1.5	26.4	6.9
Minnesota	14.8	2.6	8.6	0.2	0.6	17.6	1.4
Québec**	232.9	3.4	11.2	1.4	4.3	1.5	0.6
Total	1,123.4	30.3	100	32.6	100	2.7	2.9

*As determined by the one-hour ahead constrained schedule
** the Quebec interface group include all interties linking the Ontario grid with the Quebec grid.

<u>Import Failures</u>

Table 1-16 provides monthly summary statistics on the frequency and magnitude of failed import transactions over the 2010/11 and 2011/12 Annual Periods. The total number of hours when failed imports occurred decreased dramatically from 3,102 hours in the 2010/11 Annual Period to 1,230 in the 2011/12 Annual Period, a reduction of 1,872 hours (60.3%). The import failure rate decreased from 5.3% to 4.4%.

Table 1-16: Frequency, Magnitude, and Rate of Failed Imports to Ontario May – April 2010/2011 & May – April 2011/2012 (MW and %)

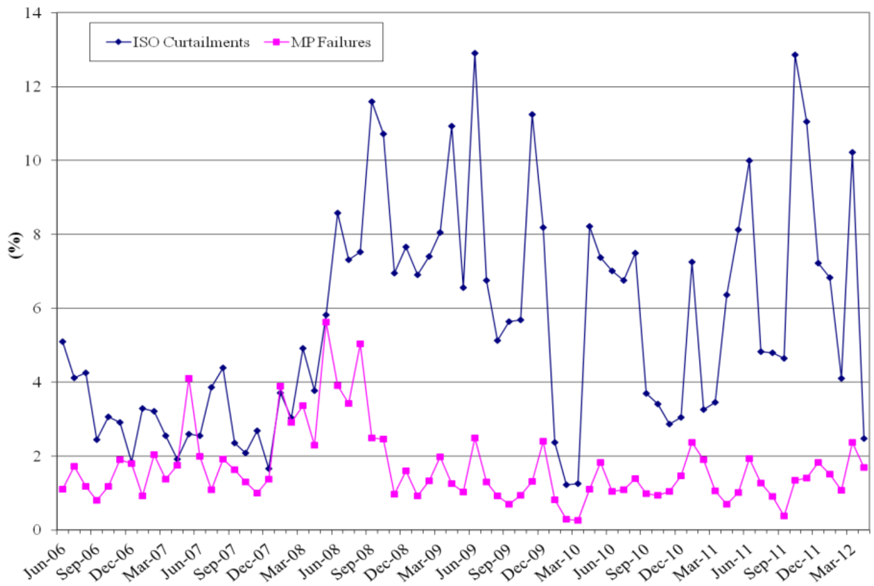
Month	Number of Hours with Failed Imports*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	324	95	857	467	119	89	7.0	4.4
June	323	81	517	595	90	137	5.9	4.7
July	349	124	730	550	142	109	6.1	3.1
August	349	167	1,274	621	153	82	7.1	3.6
September	207	108	693	250	145	71	3.7	3.4
October	233	118	685	351	95	98	4.2	6.3
November	230	91	440	441	72	101	3.4	4.7
December	210	76	329	417	80	118	3.5	5.4
January	278	130	918	640	121	97	7.9	5.2
February	206	67	514	470	85	116	4.4	3.4
March	181	114	614	538	86	122	4.2	6.6
April	212	59	388	200	90	79	5.9	2.3
Total/Average	3,102	1,230	663	462	107	102	5.3	4.4

* Incidents involving less than 1 MW per hour and linked wheeling transaction failures are excluded.
** Based on those hours in which a failure occurs.
*** Total failed import MW divided by total scheduled import MW (excluding the import leg of linked wheeling transactions) in the unconstrained schedule in a month.

Causes of Import Failures

Figure 1-14 plots the import failure rates by cause since June 2006. The failure rate is determined as a percentage of failed to total imports in MWh per month (excluding linked wheeling transaction failures, which are rare). ISO curtailments continue to account for the majority of import failures, a trend since the middle of 2008. In October 2011, ISO curtailments (as a percentage of total scheduled imports) hit 12.9%, the second highest level since 2006. ISO curtailments were primarily attributable to transmission service unavailability at the Michigan, Minnesota and Manitoba interfaces (as discussed in the following section). MP failures continued to fluctuate around 1% to 2% in the 2011/12 Annual Period, with a maximum of 2.4% in March 2012.

Figure 1-14: Monthly Import Failures by Cause
June 2006 – April 2012
(% of total imports)



<u>Import Failures by Interface Group</u>

Table 1-17 reports average monthly import failures by interface group and by cause for the 2011/12 Annual Period. High ISO curtailments have been experienced at the Midwest Independent Transmission System Operator (MISO) interfaces (Michigan, Minnesota and Manitoba). The Manitoba interface accounted for 48.2% of all import failures. It had an ISO curtailment rate of 15.7% and an MP failure rate of 2.4%. The Minnesota interface had the highest ISO curtailment rate at 20.7%, and the second highest MP failure rate at 5.2%. The Québec interface (including several interconnected interties along the Ontario – Québec border), which accounts for the majority of total imports, has extremely low failure rates.

Table 1-17: Average Monthly Import Failures by Interface Group and Cause May 2011 – April 2012 (GWh and % of failures)

Interface Group	Average Monthly Imports*	Average Monthly Import Failures				Failure Rate	
		ISO Curtailment		MP Failure		ISO Curtailment	MP Failure
	GWh	GWh	%	GWh	%	%	%
New York	7.5	0.3	1.6	0.5	13.9	4.0	6.7
Michigan	36.2	6.4	34.4	1.0	27.8	17.7	2.8
Manitoba	59.1	9.3	50.0	1.4	38.9	15.7	2.4
Minnesota	11.6	2.4	12.9	0.6	16.6	20.7	5.2
Québec	197.5	0.2	1.1	0.1	2.8	0.1	0.1
Total	311.9	18.6	100	3.6	100	6.0	1.2

*As determined by the one-hour ahead constrained schedule

2.5.3.6 Imports or Exports Setting the Final Pre-dispatch Price

The fourth factor identified by the Panel as contributing to differences between pre-dispatch and real-time prices is the frequency with which imports and exports set the pre-dispatch price. A higher frequency will lead to a greater divergence between pre-dispatch and real-time prices.[29]

Table 1-18 shows the frequency of hours in which imports and exports set the one-hour ahead pre-dispatch price in the 2010/11 and 2011/12 Annual Periods. In the 2011/12 Annual Period, imports or exports set the final pre-dispatch price in 2,734 hours, a modest reduction (4.2%) from 2,854 hours in the 2010/11 Annual Period. The largest monthly decrease occurred in July, from 275 hours in 2010 to 177 hours in 2011 (a 35% drop). The largest monthly increase occurred in November, from 166 hours in 2010 to 260 hours in 2011 (a 57% increase).

[29] For a detailed explanation of why this occurs, see the Panel's July 2007 Monitoring Report (at pp. 30-33), available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf.

Table 1-18: Frequency of Imports or Exports Setting the Final Pre-Dispatch Price May – April 2010/2011 & May – April 2011/2012 (number of hours and % of hours)

Month	2010/2011		2011/2012		Difference	
	Hours	%	Hours	%	Hours	% Change
May	223	30	315	42	92	40
June	180	25	235	33	55	32
July	275	37	177	24	(98)	(35)
August	216	29	247	33	31	14
September	281	39	262	36	(19)	(8)
October	290	39	282	38	(8)	(3)
November	166	23	260	36	94	57
December	268	36	256	34	(12)	(6)
January	193	26	205	27	12	4
February	228	34	141	19	(87)	(44)
March	238	32	170	22	(68)	(31)
April	295	41	184	26	(111)	(37)
Total	2,854	33	2,734	31	(120)	(6)

2.6 Internal Zonal Prices

Figure 1-15 and Table 1-19 summarize average nodal prices[30] (also referred to as internal zonal prices) for the 10 internal Ontario zones.[31]

As in the past, the average internal zonal prices in the Northwest and Northeast zones are much lower than in the rest of the zones. The differences among the remaining zones are moderate.

[30] Nodal prices are generated from the constrained schedule. The average nodal price for a zone is calculated as the average of the nodal prices for generators in that zone. All nodal and zonal prices have been modified to +$2000/MWh (or -$2000/MWh) when the raw interval value was higher (or lower).
[31] For a detailed description of the IESO's ten-zone division of Ontario, see IESO, "Ontario Transmission System", available at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2005jun.pdf.

Figure 1-15: Average Internal Zonal Prices
May 2011 – April 2012
($/MWh)

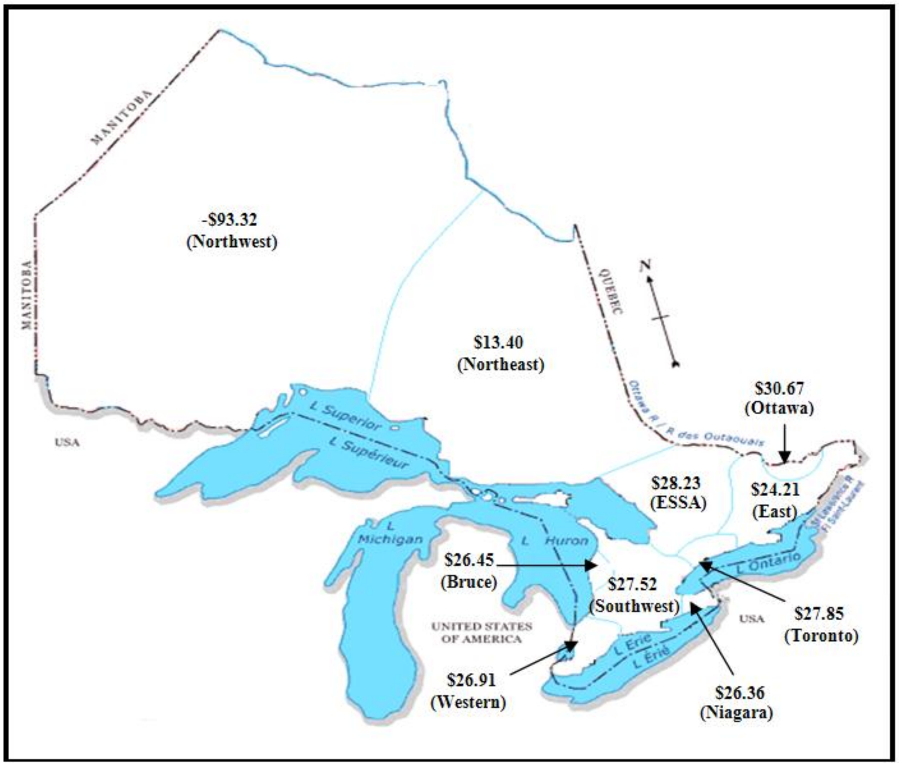


Table 1-19 shows that, with the exception of the two northern regions and Ottawa, most average internal zonal prices decreased by 20% to 40% or more in the 2011/12 Annual Period relative to the 2010/11 Annual Period. The average Richview nodal price was $28.40/MWh in the 2011/12 Annual Period, which is $8.98/MWh or 24.0% lower than in the 2010/11 Period.[32]

[32] The Richview bus is a node within the Toronto zone which is frequently used as a reference price given its central location (i.e., in the major load area).

Table 1-19: Average Internal Zonal Prices May – April 2010/2011 & May - April 2011/2012 ($/MWh and %)

Zone	May 2010 to April 2011	May 2011 to April 2012	% Change
Bruce	35.28	$26.45	-25.2%
East	36.25	$24.21	-33.2%
ESSA	37.02	$28.23	-23.7%
Niagara	35.39	$26.36	-25.5%
Northeast	32.44	$13.40	-58.7%
Northwest	-167.59	-$93.32	-44.3%
Ottawa	39.72	$30.67	-22.8%
Southwest	36.84	$27.52	-25.5%
Toronto	36.91	$27.85	-24.5%
Western	36.11	$26.91	-25.5%
Richview Node	37.38	$28.40	-24.0%

Average internal zonal prices in the Bruce, ESSA, East, Toronto, Niagara, Southwest and Western zones were all relatively close to one another, which reflects the relatively low frequency of transmission congestion between these zones. As observed in previous Panel reports, bottled supply in the Northwest is the primary reason for the large negative internal zonal prices in that zone. The average internal zonal price in the Northwest zone was -$93.32/MWh in the 2011/12 Annual Period, which is a large increase relative to the -$167.59/MWh average internal zonal price in the 2010/11 Annual Period. However, this zone clearly remains an outlier in terms of internal zonal prices.

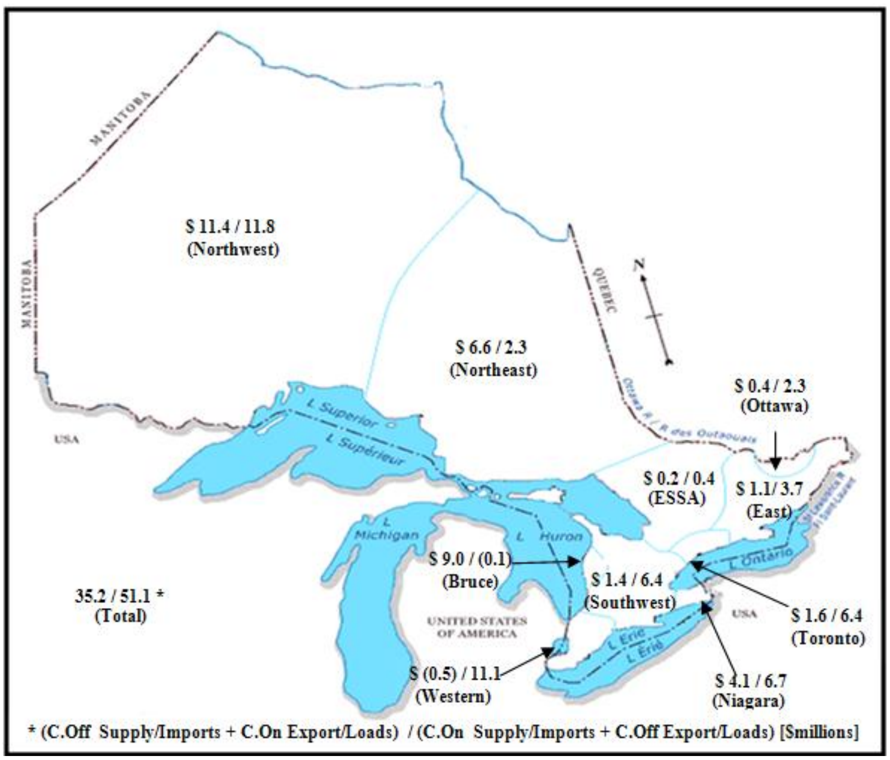
2.7 CMSC Payments

Figure 1-16 provides a summary of CMSC payments for each of the 10 internal zones for the 2011/12 Annual Period.[33] For each zone, the top portion of the figure shows the total CMSC payments made for constrained-off generation and imports plus constrained-on loads and exports from the zone (in this analysis, imports and exports are allocated to the respective zone into or out of which they flow). The data is presented in this manner

[33] CMSC payments are often a consequence of transmission limits, losses or security requirements. In addition, the 3-times ramp rate, slow ramping of fossil units and technical / regulatory limitations can each give rise to CMSC payments. CMSC payments can also be "self-induced" through, for example, voluntary ramping actions by dispatchable loads or generators.

given that the constraining on of exports/loads is an alternative to the constraining off of supply (generation plus imports) when supply is bottled (i.e., where there is oversupply in a zone). This approach therefore provides an indicator of the bottling of supply in a given zone. The bottom portion of the figure shows, for each zone, the CMSC paid for constrained-on generation and imports plus constrained-off loads and exports. This provides an indication of the need for additional or out-of merit supply in a zone (i.e., where there is insufficient supply in a zone).

Figure 1-16: Total CMSC Payments by Internal Zone
May 2011 – April 2012
($ millions)*



* The numbers are based on the estimation tables in the IESO database, and may be slightly different from the actual payment.

Of the $35.2 million of CMSC paid for constrained-off supply plus constrained-on demand, $11.2 million (31.8%) occurred in the Northwest zone, primarily as a result of the west-east flow limits that bottle the relatively low-cost supply in the area. The other major contributors to the total were the Bruce zone, at $8.9 million (25.3%), and the

Niagara zone at $6.2 million (17.6%). The CMSC payments in the Bruce zone were primarily a consequence of the constraining off of Bruce nuclear units during SBG conditions and the outages at the major transmission lines that link the Bruce area to the Toronto area. The CMSC payments in the Niagara zone were usually a consequence of Lake Erie Circulation (LEC or 'loop flow' around Lake Erie), which leads to congestion at internal interfaces as well as the New York Independent System Operator (NYISO) (and/or the MISO) interface (which are also Ontario).

CMSC payments for constrained-on supply plus constrained-off demand totalled $51.1 million and were focused in four zones in Ontario. Significant payments were made in the Northwest zone ($11.8 million or 23.1%), the Western zone ($11.1 million or 21.7%), the Niagara zone ($6.7 million or 13.1%), the Toronto zone and the Western zone ($6.4 million or 12.5% each).

2.7.1 Changes in Payments by Zone

Table 1-20 compares the CMSC payments for each zone in the 2010/11 and 2011/12 Annual Periods. The payments decreased significantly in most zones in the 2011/12 Annual Period. Total CMSC payments decreased in both oversupply and undersupply situations.

Total CMSC payments for constrained-off supply plus constrained-on demand fell by $12.5 million, or 26.2%, in the 2011/12 Annual Period, with the largest zonal decrease being in the Northwest (a $15.8 million decrease relative to the 2010/11 Annual Period). The primary reason for the decrease in the CMSC payments in that zone was a reduction in the market price at the Manitoba and Minnesota interfaces, which reflects the general decline in the HOEP in Ontario (see Table 1-1) and greater import congestion (see Chapter 3). The Bruce zone experienced the largest increase in CMSC payments in the 2011/12 Annual Period, with an additional $8.0 million relative to the 2010/11 Annual Period (an 800% increase). This increase was primarily due to increased SBG in Ontario as well as outages at the major transmission lines that transfer power out of the Bruce station, which led to Bruce nuclear units being partially constrained off. Total CMSC payments for constrained-on supply plus constrained-off demand increased slightly by $1.7 million (2.6%) from the 2010/11 Annual Period to the 2011/12 Annual Period.

Table 1-20: Total CMSC Payments by Internal Zone
May – April 2010/2011 & May – April 2011/2012
($ millions)*

Zone	Constrained-off Supply, Constrained-off Imports, Constrained-on Loads and Constrained-on Exports[34]			Constrained-on Supply, Constrained-on Imports, Constrained-off Loads and Constrained-off Exports		
	2010/2011	2011/2012	% Change	2010/2011	2011/2012	% Change
Bruce	1.0	9.0	800.0	-0.1	-0.1	0.0
East	0.3	1.1	266.7	3.0	3.7	23.3
ESSA	0.1	0.2	100.0	0.4	0.4	0.0
Niagara	4.6	4.1	-10.9	9.9	6.7	-32.3
Northeast	5.3	6.6	24.5	2.0	2.3	15.0
Northwest	27.2	11.4	-58.1	12.5	11.8	-5.6
Ottawa	-0.1	0.4	-500.0	0.1	2.3	2,200.0
Southwest	3.1	1.4	-54.8	4.1	6.4	56.1
Toronto	1.6	1.6	0.0	8.8	6.4	-27.3
Western	4.6	-0.5	-110.9	9.1	11.1	22.0
Total	47.7	35.2	-26.2	49.8	51.1	2.6

*The total CMSC payments are slightly different from the numbers in Table 1-4. The numbers here are based on the estimation tables in the IESO database, which can separate CMSC payments by resource type and by constraint type. In contrast, the numbers in Table 1-4 are actual CMSC payments which are derived from the IESO settlement tables that are not separated by resource type or constraint type.

3. Demand

3.1 Aggregate Consumption

Table 1-21 compares monthly Ontario energy demand and net exports (in the unconstrained schedule) in the 2010/11 and 2011/12 Annual Periods. Total Ontario demand plus net exports decreased by 4.48 TWh or 3.0% in the 2011/12 Annual Period relative to the 2010/11 Annual Period. The largest monthly percentage increase occurred in May at 5.9%, and the largest decrease occurred in December (a 13.0% decrease).

[34] Unlike the Panel's prior reports, this report includes CMSC payments made to dispatchable loads.

Annual Ontario demand (without accounting for net exports) decreased by 4.22 TWh, or 2.9%, from 144.03 TWh in the 2010/11 Annual Period to 139.81 TWh in the 2011/12 Annual Period. Ontario demand was lower year-over-year in every month except September and October. The month of March in the 2011/12 Annual Period saw the largest percentage decrease (7.4%) in demand relative to the same month in the 2010/11 Annual Period due to warmer than usual weather.

Total annual net exports decreased by 2.6%, from 9.25 TWh in the 2010/11 Annual Period to 9.01 TWh in the 2011/12 Annual Period. Exports and imports are discussed in greater detail in section 5 of this chapter.

Table 1-21: Monthly Domestic Energy Demand and Net Exports May – April 2010/2011 & May – April 2011/2012 (TWh)

Month	Ontario Demand			Net Exports			Total		
	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change
May	11.42	10.83	(5.2)	0.04	1.30	3,421.6	11.46	12.13	5.9
June	11.61	11.28	(2.8)	0.66	0.69	5.2	12.27	11.97	(2.5)
July	13.34	13.32	(0.1)	0.56	0.57	3.2	13.9	13.89	0.0
August	12.98	12.56	(3.2)	0.54	0.53	(2.8)	13.52	13.09	(3.2)
September	11.11	11.18	0.6	0.92	0.47	(49.5)	12.03	11.65	(3.7)
October	11.02	11.04	0.2	0.92	0.75	(19.0)	11.94	11.79	(1.3)
November	11.37	11.09	(2.5)	0.79	0.60	(23.7)	12.16	11.69	(3.9)
December	12.78	12.1	(5.3)	1.68	0.48	(71.3)	14.46	12.58	(13.0)
January	13.35	12.72	(4.7)	1.15	0.79	(31.3)	14.5	13.51	(6.8)
February	11.83	11.58	(2.1)	0.62	0.74	19.1	12.45	12.32	(1.0)
March	12.40	11.48	(7.4)	0.66	1.00	51.4	13.06	12.48	(4.4)
April	10.82	10.63	(1.8)	0.72	1.09	50.4	11.54	11.72	1.5
Total	144.03	139.81	(2.9)	9.25	9.01	(2.7)	153.29	148.81	(3.0)
Average	12.00	11.65	(2.9)	0.77	0.75	(2.7)	12.77	12.40	(3.0)

3.2 Wholesale and Distributor Consumption

Figure 1-17 plots the monthly energy consumption of wholesale loads and distributors, respectively, between January 2004 and April 2012. There are clear seasonal fluctuations in distributor demand. Typically, distributor withdrawals are highest in December/January (the heating season) and July/August (the cooling season). In the

2011/12 Annual Period, distributor demand peaked in July 2011 at 10.73 TWh, and hit a low of 8.24 TWh in April 2012. Distributor demand was declining from 2004 to early 2009, and although the downward trend is continuing the rate of decline is slowing. Factors that have contributed to a decline in distributor demand include reduced consumption by customers due to economic downturn, improved efficiency and, more recently, increased levels of embedded generation.

Consumption by wholesale loads hit its third lowest point (since 2004) in February 2012, with only 1.30 TWh consumed.

Figure 1-17: Monthly Total Energy Consumption, Distributors and Wholesale Loads January 2004 – April 2012 (MWh)

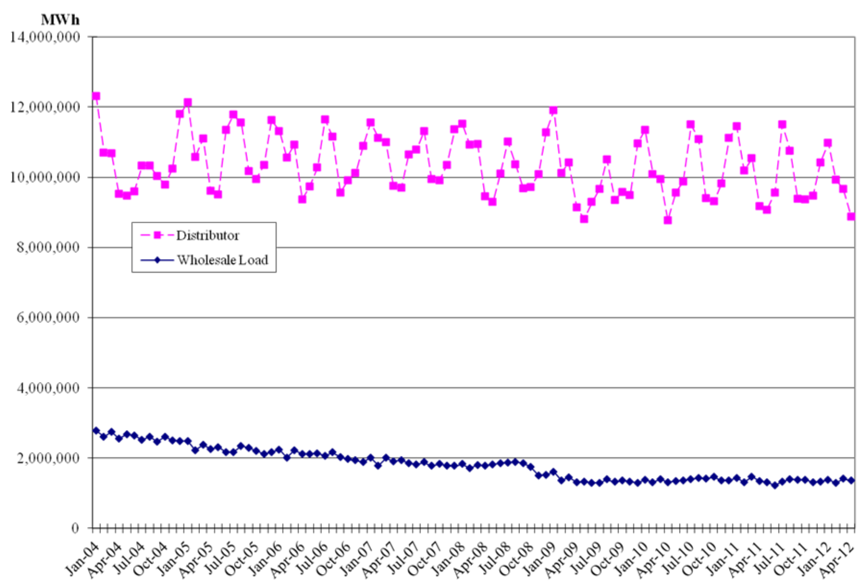
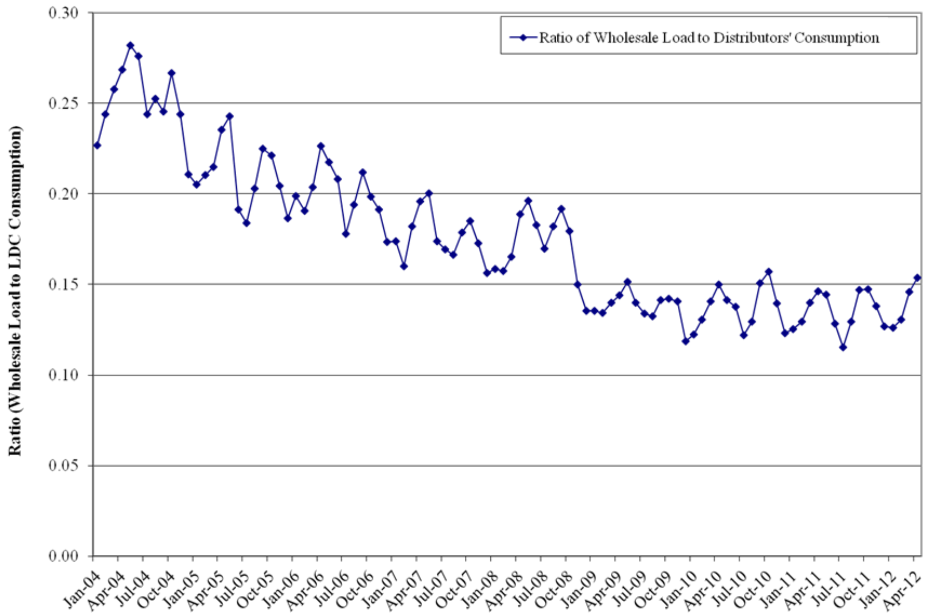


Figure 1-18 presents the ratio of wholesale load to distributor withdrawals from January 2004 to April 2012.

The short-term fluctuations in the ratio are inversely proportional to changes in distributor withdrawals, since wholesale load consumption is less volatile. The ratio appears to have been increasing very slightly since 2009, due to stable wholesale load consumption levels and slowly decreasing levels of distributor withdrawals.

Figure 1-18: Ratio of Wholesale Load to Distributor Consumption January 2004 – April 2012 (wholesale load divided by distributor consumption)



4. Supply

4.1 New Generating Facilities

During the 2011/12 Annual Period, 612 MW of new domestic generation capacity that is directly connected to the IESO-controlled grid was added to the Ontario wholesale market as follows:

- One gas-fired generation facility with two units added 464 MW to Ontario's generation capacity (York Energy Centre located in the township of King came online in March 2012)
- Two wind energy centres added a combined 148 MW of generation capacity (Pointe aux Roches Wind Farm in Essex County came online in November 2011 and Greenwich Windfarm in the district of Thunder Bay came online in August 2011).

In addition, 283 MW of renewable generation capacity (a combination of wind, solar/photovoltaic and bioenergy) under the feed-in tariff (or FIT) program came online in the 2011/12 Annual Period, as did 66 MW of renewable generation capacity under the micro-FIT program (for projects that are 10 kW or less).[35] These generators are embedded with the service areas of distributors and are not directly connected to the IESO-controlled grid. They are not counted as additions to Ontario's installed generation capacity as reported by the IESO, nor are they generally included in the analyses set out in this report. Rather, when a generator that is embedded within the service area of a distributor produces power, the distributor's demand for power from the IESO-controlled grid decreases. Embedded generation capacity is therefore reflected as a reduction in Ontario demand.

Notwithstanding the addition of new capacity, Ontario still experienced a net reduction in generating capacity due to the provincial government's policy of eliminating coal-fired generation by the end of 2014. Two Nanticoke coal-fired generation units totalling 975 MW of capacity were taken out of service by Ontario Power Generation in January 2012. This loss of capacity, when combined with the 612 MW of new directly-connected capacity referred to above, yields a net reduction in domestic generating capacity of 363 MW, or 1.0% of Ontario's generation capacity at the wholesale level.

4.2 The Supply Cushion

Tables 1-22 and 1-23 present monthly summary statistics on the pre-dispatch and real-time supply cushion for the 2010/11 and 2011/12 Annual Periods.[36] The final pre-dispatch supply cushion measure includes all sources of supply (including imports) while the real-time domestic supply cushion focuses on supply ramping capability from

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[35] Calculated using information from biweekly reports posted on the OPA's website (capacity in commercial operation on April 14, 2012 minus capacity in commercial operation on April 29, 2011). The reports are available at http://fit.powerauthority.on.ca/bi-weekly-fit-and-microfit-program-reports.

[36] The supply cushion measure used by the Panel was refined in the Panel's January 2009 Monitoring Report (at pp. 205-206), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf. It differs from the supply cushion published by the IESO.

domestic generation.[37] Both metrics measure the available but unutilized supply relative to Ontario demand (plus total OR requirements).

4.2.1 Pre-dispatch (One-hour ahead) Supply Cushion

Table 1-22 shows a decrease in the pre-dispatch supply cushion in the 2011/12Annual Period. That supply cushion decreased on average by 1.3%.

Consistent with the decline in the average pre-dispatch supply cushion, the frequency with which the supply cushion fell below 10% was also greater in the 2011/12 Annual Period as shown in Table 1-22. The total number of hours with a pre-dispatch supply cushion of less than 10% increased from 1,625 hours in the 2010/11 Annual Period to 1,884 hours in the 2011/12 Annual Period, a 15.9% jump.

[37] Imports are scheduled on an hourly basis, whereas domestic resources are scheduled on a five minute basis (i.e., they can be dispatched up and down in real-time).

Table 1-22: Final Pre-Dispatch Total Supply Cushion[38]
May – April 2010/2011 & May – April 2011/2012
(% of Ontario demand and number of hours under a 10% level)

Month	Average Supply Cushion (%)		Supply Cushion of Less Than 10% (# of Hours, % of Total Hours)			
	2010/ 2011	2011/ 2012	2010/ 2011	%	2011/ 2012	%
May	24.4	10.5	25	3.4	402	54.0
June	20.5	16.2	76	10.6	129	17.9
July	22.6	18.1	54	7.3	161	21.6
August	21.8	17.5	59	7.9	136	18.3
September	18.7	18.9	126	17.5	71	9.9
October	16.3	18.9	169	22.7	49	6.6
November	22.6	21.7	42	5.8	52	7.2
December	14.7	18.0	241	32.4	143	19.2
January	15.8	15.8	158	21.2	225	30.2
February	16.6	17.6	107	15.9	123	17.7
March	13.7	15.7	246	33.1	173	23.3
April	12.1	15.1	322	44.7	220	30.6
Average	18.3	17.0	1,625	21.3	1,884	21.4

4.2.2 Real-time Supply Cushion

Table 1-23 compares the real-time supply cushion between the 2010/11 and 2011/12 Annual Periods. As is the case with the pre-dispatch supply cushion, the real-time supply cushion has decreased, both as an annual average (by 0.8%) and in terms of monthly values. In addition, the number of hours in which the supply cushion was less than 10% of Ontario demand in real-time increased by 546 hours in the 2011/12 Annual Period relative to the 2010/11 Annual Period.

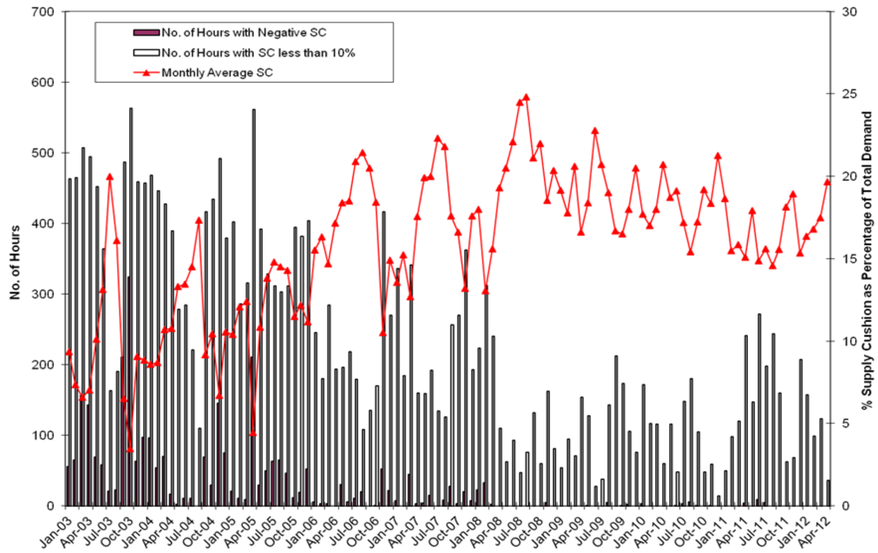
[38] The 2010-2011 figures presented in Table 1-22 and Table 1-23 have been updated relative to the numbers presented in the Panel's November 2011 Monitoring Report (at pp. 49 – 50, available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf), and now more accurately reflect the available supply from newly installed gas-fired generators.

Table 1-23: Real-time Domestic Supply Cushion May – April 2010/2011 & May – April 2011/2012 (% of Ontario demand and number of hours under a 10% level)

Month	Average Supply Cushion (%)		Supply Cushion of Less Than 10% (# of Hours, % of Total Hours)			
	2010/ 2011	2011/ 2012	2010/ 2011	%	2011/ 2012	%
May	18.7	17.9	116	15.6	147	19.8
June	19.1	14.9	48	6.7	272	37.8
July	17.2	15.6	148	19.9	198	26.6
August	15.4	14.6	180	24.2	244	32.8
September	17.2	15.5	105	14.6	160	22.2
October	19.2	18.1	48	6.5	62	8.3
November	18.4	18.9	59	8.2	68	9.4
December	21.2	15.3	14	1.9	207	27.8
January	18.6	16.4	50	6.7	157	21.1
February	15.5	16.8	98	14.6	99	14.2
March	15.8	17.5	120	16.1	123	16.5
April	15.1	19.7	241	33.5	36	5.0
Total	17.6	16.8	1,227	14.0	1,773	20.1

Figure 1-19 plots real-time domestic supply cushion summary statistics between January 2003 and April 2012. The 2011/12 Annual Period saw a decrease in the monthly average real-time supply cushion and an increase in the number of hours that the supply cushion was less than 10% of Ontario demand. However, overall long-term trends indicate a general decrease in the hours with low supply cushion and a gradual increase in monthly average supply cushion.

Figure 1-19: Monthly Real-time Domestic Supply Cushion Statistics
January 2003 – April 2012
(% of Ontario demand, and number of hours)



4.3 Baseload Supply

Table 1-24 presents average hourly baseload generation (unconstrained schedule) by category over the 2010/11 and 2011/12 Annual Periods. Overall, average hourly baseload supply increased by 0.8%, from 13.0 GW during the 2010/11 Annual Period to 13.1 GW during the 2011/12 Annual Period. Monthly baseload supply was greater from May 2011 to October 2011 than was the case in the 2010/11 Annual Period, but lower for all subsequent months.

Table 1-24 also shows the corresponding average Ontario demand and the portion of that demand that is covered by total baseload supply. There was a 5.5% decrease in the average hourly Ontario demand (from 16.4 GW in the 2010/11 Annual Period to 15.5 GW in the 2011/12 Annual Period). As a result, the share of total Ontario demand covered by baseload supply increased from 79.5% to 84.5%.

Table 1-24: Average Hourly Baseload Supply by Supply Type and Ontario Demand May – April 2010/2011 & May – April 2011/2012 (GW, unconstrained schedules)

Month	Nuclear		Baseload Hydro*		Self-Scheduling and Intermittent Supply		Total Baseload Supply		Ontario Demand		Total Baseload Supply as a % of Average Ontario Demand	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	7.7	9.3	2.1	2.3	1.0	1.2	10.8	12.8	15.3	14.1	70.4	90.8
June	9.1	9.2	2.1	2.5	1.1	1.2	12.3	12.8	16.1	15.2	76.3	84.2
July	9.5	9.8	2.0	2.3	1.1	1.0	12.6	13.2	17.9	17.5	70.3	75.4
August	9.6	10.5	1.9	2.3	1.1	1.0	12.6	13.8	17.4	16.5	72.2	83.6
September	10.0	10.3	1.9	2.2	1.1	0.9	13.0	13.3	15.4	15.1	84.2	88.1
October	9.6	9.5	2.0	2.1	1.2	1.3	12.8	12.9	14.8	14.4	86.4	89.6
November	9.5	8.8	2.1	2.2	1.3	1.6	12.9	12.6	15.3	15.0	84.4	84.0
December	11.0	9.8	2.1	2.2	1.4	1.5	14.5	13.4	17.2	15.9	84.4	84.3
January	11.0	9.5	2.1	2.2	1.3	1.8	14.4	13.4	17.9	16.7	80.3	80.2
February	10.1	9.2	2.0	2.4	1.6	1.6	13.7	13.1	17.6	16.3	77.8	80.4
March	10.0	9.3	2.3	2.3	1.4	1.7	13.7	13.3	16.7	15.0	82.2	88.7
April	9.4	8.8	2.2	2.3	1.4	1.5	13.0	12.6	14.5	14.3	89.4	88.1
Average	9.7	9.5	2.1	2.3	1.3	1.4	13.0	13.1	16.4	15.5	79.5	84.5

*Baseload hydro includes the Beck (net of pump storage operation), Saunders and DeCew hydro-electric generation facilities.

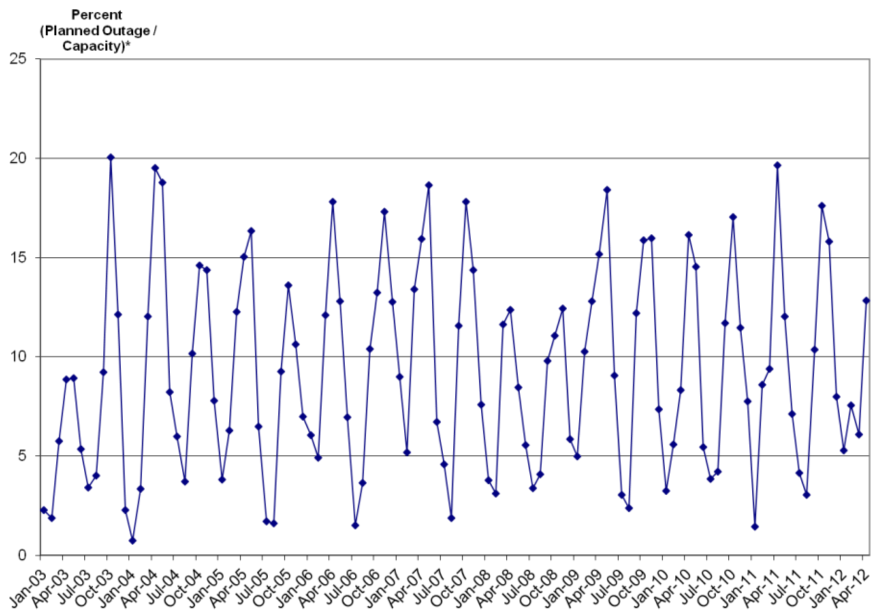
4.4 Outages

It is important to monitor generator outage patterns, as there is upward pressure on market prices when supply is removed from the market. The discussion below reports on planned and forced generator outage rates.

4.4.1 Planned Outages

Planned outages are typically taken during the spring and fall months, which are periods of lower demand. Figure 1-20 plots monthly total planned outages as a percentage of total generation capacity since 2003. Planned outage rates over the 2011/12 Annual Period showed seasonal fluctuations similar to those observed in previous years.

Figure 1-20: Planned Outages Relative to Capacity
January 2003 – April 2012
(% of capacity*)

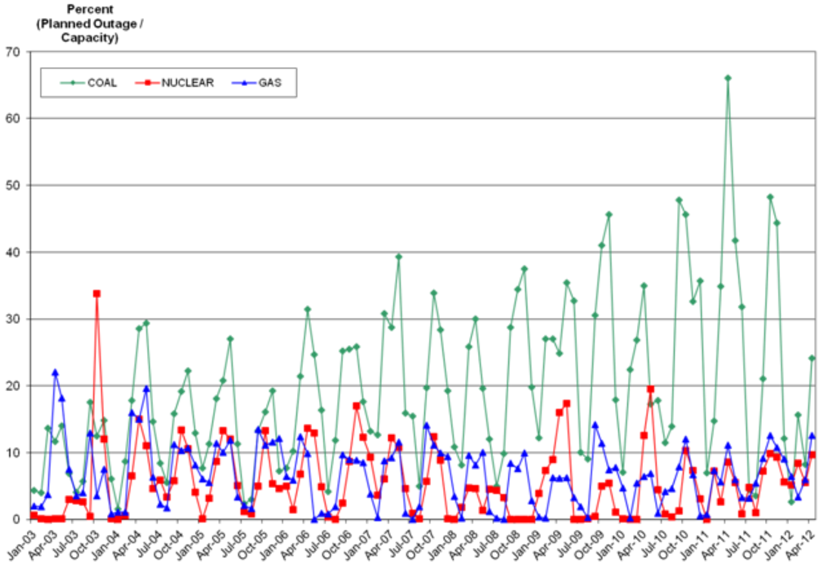


*Includes nuclear, coal and gas units.

Figure 1-21 presents planned outage rates as a percentage of total capacity by fuel type since 2003. The planned outages for each fuel type show seasonal patterns similar to those that are reflected in the aggregate planned outage information presented in Figure 1-20;[39] in other words, planned outages tend to occur during the spring and fall for all fuel types. Planned outages by coal facilities fell significantly in the 20111/12 Annual Period, but this coincided with an offsetting increase in forced outages by those facilities (see Figure 1-22).

[39] For the purposes of the outage statistics in this report, OPG's "CO_2 outages" are classified as planned outages (rather than as forced outages, which is how they are treated by the IESO). The rationale for this approach is discussed in the Panel's July 2009 Monitoring Report (at pp. 58-59), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf. This approach is only relevant for most 2009 summer months. Under OPG's 2010 and 2011 CO_2 emissions strategies, the "CO_2 outage" designation was no longer used. In addition, the capacity that was effectively removed from the market by OPG's designation of units as "NOBA" is not reflected in either the planned or forced outage statistics. The NOBA units are units that were designated as not offered but available when needed. As a result, these units were technically available (subject to their start-up lead times).

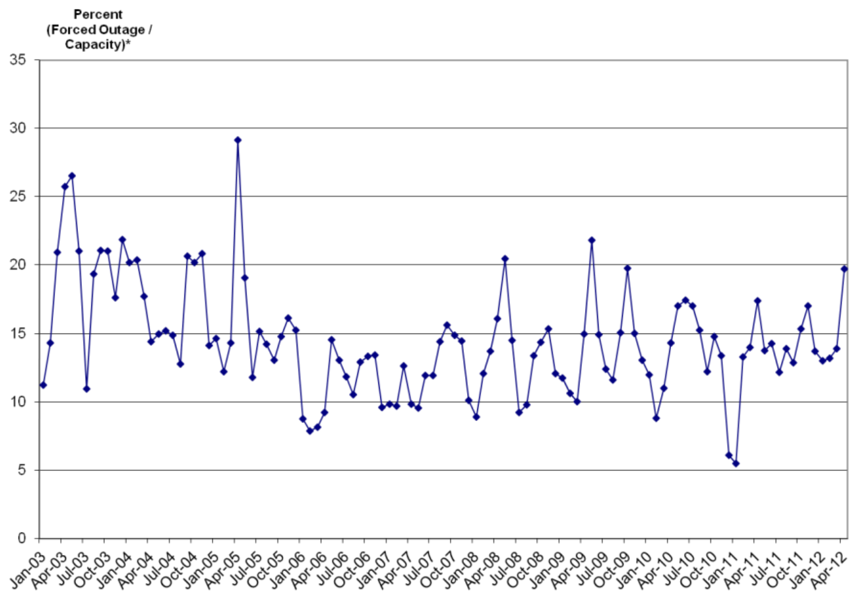
Figure 1-21: Planned Outages Relative to Capacity by Fuel Type
January 2003 – April 2012
(% of capacity)



4.4.2 Forced Outages

Given that forced outages occur unexpectedly, they do not exhibit the same level of seasonality as do planned outages. Figure 1-22 plots total forced outages as a percentage of total generation capacity since January 2003. There has been a significant increase in forced outages as a percentage of capacity in the 2011/12 Annual Period, primarily attributable to outages of coal-fired units.

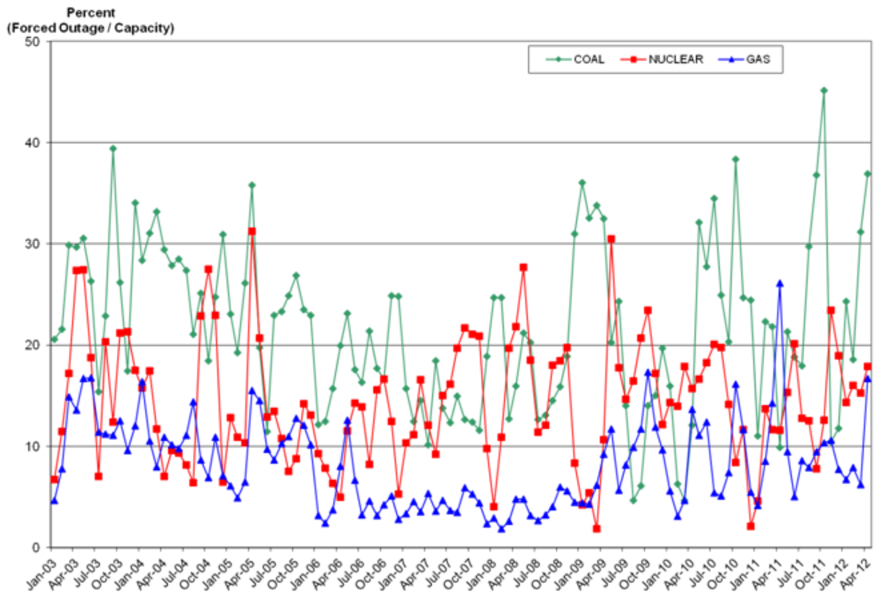
Figure 1-22: Forced Outages Relative to Capacity
January 2003 – April 2012
(% of capacity*)



*Includes nuclear, coal and gas units.

Figure 1-23 shows forced outage rates by fuel type as a percentage of capacity since 2003 (i.e. the forced outage in a category relative to the total capacity for the category minus the capacity lost to planned outages for the same category). Forced outages of coal-fired units increased significantly in the 2011/12 Annual Period; as a percentage of capacity they peaked in October 2011 at 45.9% and in April 2012 at 36.9%. The forced outage rates are higher because two coal-fired units that were seldom operated in 2011were closed down in late 2011, which reduced total coal-fired generation capacity and correspondingly increased the forced outage rate.

Figure 1-23: Forced Outages Relative to Capacity by Fuel Type
January 2003 – April 2012
(% of capacity)



4.5 Changes in Fuel Prices

Tables 1-25 and 1-26 present average monthly coal and natural gas spot prices over the 2010/11 and 2011/12 Annual Periods. Coal prices have increased from 2010/11 levels, while natural gas prices have decreased.

4.5.1 Coal Prices

Average monthly Central Appalachian (CAPP) and Powder River Basin (PRB) coal prices for prompt (i.e., immediate next) month are presented in Table 1-25 for the 2010/11 and 2011/12 Annual Periods. CAPP coal prices increased from a monthly average of \$2.69/MMBtu in the 2010/11 Annual Period to \$2.87/MMBtu in the 2011/12 Annual Period, a rise of 6.7%. PRB coal prices increased from \$0.67/MMBtu to \$0.68/MMBtu, or by 1.6%.

Table 1-25: Average Monthly NYMEX Coal Futures Settlement Prices by Type May – April 2010/2011 & April – May 2011/2012 ($CDN/MMBtu*)

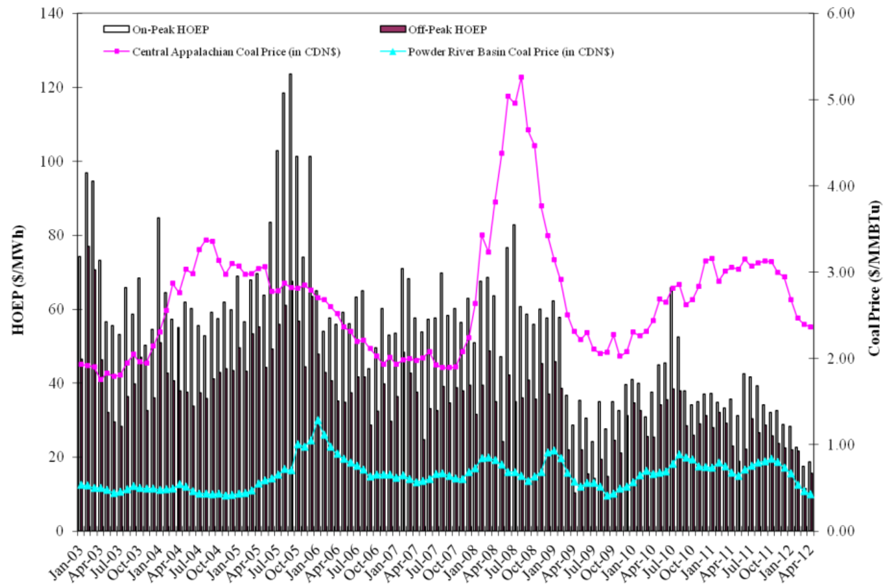
Month	NYMEX Central Appalachian (CAPP) Coal Price			NYMEX Western Rail Powder River Basin (PRB) Coal Price		
	2010/ 2011	**2011/ 2012**	**% Change**	**2010/ 2011**	**2011/ 2012**	**% Change**
May	2.69	3.04	12.9	0.67	0.64	(4.9)
June	2.65	3.15	18.9	0.69	0.71	3.1
July	2.82	3.07	8.8	0.78	0.76	(2.7)
August	2.86	3.11	8.7	0.89	0.79	(10.9)
September	2.62	3.13	19.4	0.85	0.81	(4.8)
October	2.68	3.12	46.5	0.83	0.83	0.5
November	2.84	3.00	5.5	0.75	0.80	6.5
December	3.13	2.95	(5.9)	0.74	0.73	(0.8)
January	3.16	2.68	(15.0)	0.74	0.67	(9.6)
February	2.89	2.47	(14.7)	0.79	0.54	(31.8)
March	3.01	2.40	(20.4)	0.75	0.46	(38.6)
April	3.05	2.37	(22.4)	0.68	0.42	(37.6)
Average	2.69	2.87	6.7	0.67	0.68	1.6

* Coal prices have been converted from US to $CDN using the Bank of Canada's daily noon exchange rate. The data in this table is based on information from EIA Coal News and Market Reports.

Figure 1-24 plots the monthly average CAPP and PRB coal prices, along with the on-peak and off-peak HOEP, since January 2003 (all prices are in Canadian dollars). Historically, there has not been a close correlation between the CAPP/PRB prices and HOEP. However, in the 2010/11 and 2011/12 Annual Periods, the on-peak and off-peak HOEP have roughly moved together with the PRB coal price.[40]

[40] The correlation coefficient in the 2011/12 Annual Period was 0.80 for on-peak HOEP and 0.85 for off-peak HOEP. The coefficients for the period 2003 to 2010 were 0.23 for on-peak HEOP and 0.19 for off-peak HOEP.

Figure 1-24: Central Appalachian and Powder River Basin Coal Prices and HOEP January 2003 – April 2012 ($/MWh and $/MMBtu)



4.5.2 Natural Gas Prices

The Henry Hub Spot and Dawn Daily gas prices[41] are presented in Table 1-26 for the 2010/11 and 2011/12 Annual Periods. Both prices were significantly lower in the 2011/12 Annual Period. The Henry Hub Spot price declined by $0.88/MMBtu (20.9%) while the Dawn Daily price fell by $0.91/MMBtu (19.6%). Average monthly natural gas prices in the 2011/12 Annual Period were lower than their 2010/11 counterparts in every month, the exception being the Henry Hub Spot price in October 2011.

[41] The Henry Hub is located in Erath, Louisiana, while the Union Dawn Hub is located near Sarnia, Ontario.

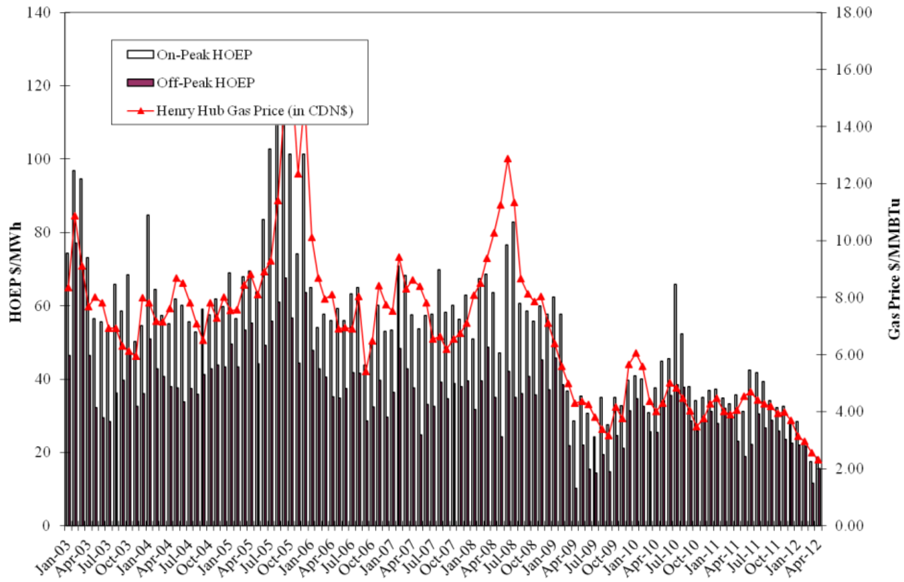
Table 1-26: Average Monthly Natural Gas Prices May – April 2010/2011 & May – April 2011/2012 ($CDN/MMBtu)

Month	Henry Hub Spot Price*			Dawn Daily Gas Price		
	2010/ 2011	**2011/ 2012**	**% Change**	**2010/ 2011**	**2011/ 2012**	**% Change**
May	4.31	4.15	(3.7)	4.67	4.54	(2.8)
June	5.01	4.43	(11.6)	5.30	4.69	(11.5)
July	4.83	4.20	(13.0)	5.06	4.41	(12.8)
August	4.49	3.98	(11.4)	4.72	4.27	(9.5)
September	4.03	3.91	(3.0)	4.44	4.19	(5.6)
October	3.48	3.63	4.3	4.04	3.94	(2.5)
November	3.77	3.29	(12.7)	4.53	3.99	(11.9)
December	4.29	3.23	(24.7)	4.70	3.70	(21.3)
January	4.47	2.71	(39.4)	4.86	3.15	(35.2)
February	4.00	2.51	(37.3)	4.47	2.97	(33.6)
March	3.89	2.15	(44.7)	4.39	2.56	(41.7)
April	4.05	1.93	(52.3)	4.45	2.31	(48.1)
Average	4.22	3.34	(20.9)	4.64	3.73	(19.6)

* Henry Hub Spot prices are converted to $CDN at Bank of Canada daily noon exchange rates

Figure 1-25 plots the monthly average Henry Hub Spot price, along with the on-peak and off-peak HOEP, since January 2003 (all prices are in Canadian dollars). As the Panel has observed in the past, movements in the HOEP appear to roughly coincide with movements in the spot market gas price. This is not surprising since gas units were the most frequent marginal resource in neighbouring markets (such as NYISO and New England) and a significant marginal resource in Ontario (they used to be the second largest marginal resource but became the largest in the 2011/12 Annual Period). Since 2003, the correlation coefficient for the spot price of natural gas and on-peak HOEP has been 0.79, and the correlation coefficient for the spot price of natural gas and off-peak HOEP has been 0.72.

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP
January 2003 – April 2012
($/MWh and $CDN/MMBtu)



5. Imports and Exports

This section reports on intertie activity, using data that is based on the unconstrained schedules as these directly affect market prices.[42]

5.1 Overview

Table 1-27 presents monthly net exports from Ontario during on-peak and off-peak hours.

Ontario remained a net exporter for both off-peak and on-peak hours during all months in the 2011/12 Annual Period. Off-peak net exports increased by 792 GWh (15.5%) while on-peak net exports decreased by 1,036 GWh (25.1%). As a result, overall net exports

[42] Although the schedules in the constrained schedule are also important for various monitoring and assessment purposes, they are not related to intertie congestion prices or to the Ontario uniform price (either in pre-dispatch or in real-time).

declined by 244 GWh (2.6%) from the 2010/11 Annual Period to the 2011/12 Annual Period. Relative to the 2010/11 Annual Period, on-peak net exports decreased from June 2011 to January 2012, while off-peak exports were more volatile after persistent gains during the first four months of the 2011/12 Annual Period.

Table 1-27: Net Exports (Imports), On-peak and Off-peak May – April 2010/2011 & May – April 2011/2012 (GWh)

Month	On-Peak			Off-Peak			Total		
	2010/ 2011	**2011/ 2012**	**% Change**	**2010/ 2011**	**2011/ 2012**	**% Change**	**2010/ 2011**	**2011/ 2012**	**% Change**
May	3	390	13271.4	34	915	2554.5	37	1303	3391.5
June	299	153	(48.8)	356	536	50.5	655	689	5.2
July	226	173	(23.4)	330	401	21.5	556	574	3.3
August	257	113	(56.1)	286	415	45.2	543	528	(2.8)
September	507	121	(76.1)	415	346	(16.7	922	466	(49.4)
October	384	267	(30.4)	540	481	(10.9)	924	748	(19.0)
November	424	233	(45.1)	365	368	1.0	788	601	(23.8)
December	816	155	(81.0)	859	326	(62.1)	1,675	481	(71.3)
January	475	324	(31.8)	671	463	(31.0)	1,146	787	(31.3)
February	290	308	6.3	332	433	30.3	622	741	19.1
March	281	410	46.1	379	588	55.0	660	999	51.2
April	176	452	157.5	546	634	16.2	722	1086	50.6
Total	4,136	3,100	(25.1)	5,114	5,906	15.5	9,250	9,006	(2.6)

Figure 1-26 reports the long-term trend in net exports since 2003. A positive number indicates net export, while a negative number net import. In earlier years, Ontario was a net importer of electricity. Over the years it has become a net exporter as supply and demand conditions in the province have improved.

Figure 1-26: Net Exports (Imports), On-peak and Off-peak
January 2003 – April 2012
(GWh)

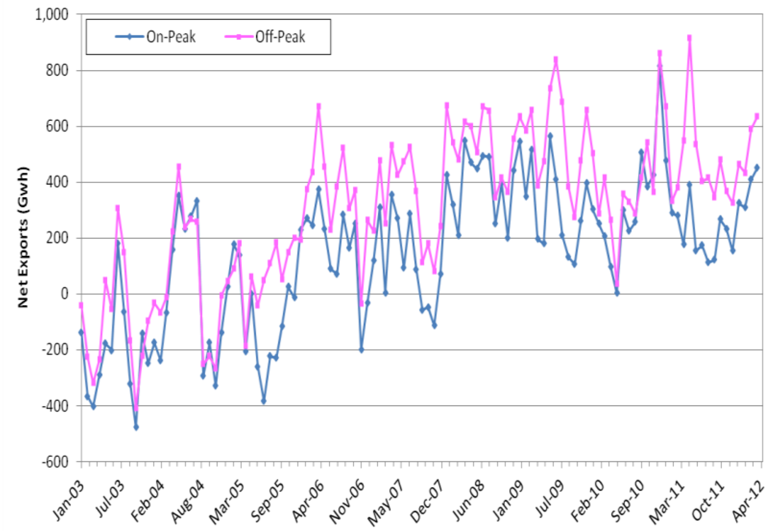


Table 1-28 presents net exports by neighbouring interface group for the 2010/11 and 2011/12 Annual Periods. It is worth noting that the sum of net exports in Table 1-28 is not equal to the numbers in Table 1-27 because of the impact of linked wheeling transactions. Linked wheeling transactions net out to zero for Ontario as a whole. These transactions, however, do have an impact on the net exports at a specific interface because the import and export legs are scheduled at different interfaces (i.e., they do not net to zero at a given interface).

Table 1-28: Net Exports (Imports) by Interface Group May – April 2010/2011 & May –April 2011/2012 (GWh)

Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2010/ 2011	**2011/ 2012**	**2010/ 2011**	**2011/ 2012**	**2010/ 2011**	**2011/ 2012**	**2010/ 2011**	**2011/ 2012**	**2010/ 2011**	**2011/ 2012**
May	(94)	(113)	176	569	(38)	(26)	98	590	(104)	287
June	(126)	(154)	661	407	(43)	(9)	111	299	51	146
July	(156)	(156)	222	606	(40)	(20)	276	398	254	(254)
August	(172)	(112)	6	393	(35)	(20)	275	315	468	(47)
September	(156)	(115)	(158)	207	(36)	(33)	486	244	787	163
October	(145)	(123)	(47)	366	(30)	(21)	283	301	863	225
November	(146)	(120)	45	430	(32)	(26)	78	164	844	154
December	(152)	(112)	640	455	(39)	(10)	458	155	767	(7)
January	(108)	(127)	703	484	(28)	(17)	364	431	215	14
February	(120)	(108)	419	528	(18)	(18)	256	378	85	(39)
March	(139)	(83)	510	541	(22)	(9)	255	667	57	(117)
April	(118)	(78)	310	726	(16)	(2)	363	738	183	(298)
Total	(1,632)	(1,401)	3,487	5,712	(377)	(212)	3,303	4,680	4,470	227

Although Ontario remained a large net exporter as a whole over the 2011/12 Annual Period, the situation varied significantly among interfaces:

- Ontario electricity exports at the Québec interface fell sharply in the 2011/12 Annual Period: they decreased by 4,243 GWh from 4,470 GWh, representing 94.9% of the exports in the 2010/11 Annual Period. Ontario was a net importer on the Québec interface in half of the months in the 2011/12 Annual Period.
- Net exports at the Michigan interface rose from 3,487 GWh to 5,712 GWh, and this 63.8% increase made it the largest net exporting interface during the 2011/12 Annual Period.
- New York remained a large export market during the 2011/12 Annual Period, and saw an increase of 1,377 GWh (41.7%) in the 2011/12 Annual Period relative to the 2010/11 Annual Period.
- Ontario remained a net importer from Manitoba and Minnesota in every month of the 2011/12 Annual Period. However, many of the imports in the unconstrained schedule were constrained off because of surplus supply in the Northwest zone of the province. Only a small fraction of the amount of net

imports at the Manitoba interface in the constrained schedule flowed into Ontario, while Ontario actually had net exports to Minnesota in the constrained schedule in 4 months during the 2011/12 Annual Period.

Imports and exports during the 2010/11 and 2011/12 Annual Periods are separately reported in Tables 1-29 and 1-30, showing for each interface both the total imports or exports and the total imports or exports net of the components of linked wheeling transactions . (Linked wheeling transactions increased from 121 GWh in the 2010/11 Annual Period to 454 GWh in the 2011/12 Annual Period, which represents 7.1% of total imports and 2.4% of total exports in the 2011/12 Annual Period.)

5.2 Imports

As reported in Table 1-29, total imports fell to 4,683 GWh in the 2011/12 Annual Period, a decrease of 1,558 GWh or 25.0% compared to the 2010/11 Annual Period. Excluding linked wheeling transactions, imports were down by 1,891 GWh, or 30.9%.

The only increase in import volumes occurred at the Québec interface, where total imports increased from 1,270 GWh in the 2010/11 Annual Period to 2,561 GWh in the 2011/12 Annual Period (an increase of 101.7%). In contrast, imports from Michigan decreased from 2,598 GWh in the 2010/11 Annual Period to 330 GWh in the 2011/12 Annual Period (a decrease of 87.3%).

Table 1-29: Imports by Interface Group
May – April 2010/2011 & May - April 2011/2012
(GWh)

Interface Group	Total Imports			Total Excluding Linked Wheeling Transactions		
	2010/2011	2011/2012	%Change	2010/2011	2011/2012	% Change
Manitoba	1,663	1,412	(15.1)	1,663	1,412	(15.1)
Michigan	2,598	330	(87.3)	2,593	329	(87.3)
Minnesota	417	265	(36.5)	417	265	(36.5)
New York	293	115	(60.8)	270	81	(72.0)
Québec	1,270	2,561	101.7	1,177	2,142	82.0
Total	6,241	4,683	(25.0)	6,120	4,229	(30.9)

5.3 Exports

As shown in Table 1-30, total exports decreased by 1,802 GWh or 11.6% in the 2011/12 Annual Period relative to the 2010/11 Annual Period. Excluding linked wheeling transactions, the decline was 2,136 GWh or 13.9%. The New York interface saw an increase in total exports of 1,200 GWh (33.4%) and an increase of 1,175 GWh (32.8%) without linked wheeling transactions. In contrast, the Québec interface saw a decrease in total exports of 2,952 GWh (51.4%) and a decrease of 3,371 GWh (58.6%) when linked wheeling transactions are excluded.

Table 1-30: Exports by Interface Group
May – April 2010/2011 & May – April 2011/2012
(GWh)

Interface Group	Total			Total Excluding Linked Wheeling Transactions		
	2010/2011	2011/2012	% Change	2010/2011	2011/2012	% Change
Manitoba	30	11	(63.3)	30	11	(63.3)
Michigan	6,084	6,041	(0.7)	5,973	6,040	1.1
Minnesota	41	53	29.3	41	53	29.3
New York	3,595	4,795	33.4	3,586	4,761	32.8
Québec	5,740	2,788	(51.4)	5,740	2,369	(58.7)
Total	15,490	13,688	(11.6)	15,370	13,234	(13.9)

5.4 Congestion at Interties

In general, intertie congestion levels tend to increase as the volume of inter-jurisdictional transactions increase or intertie capability decreases. Due to the two-schedule design of the Ontario market, there are two types of intertie congestion: congestion in the constrained schedule and congestion in the unconstrained schedule.[43] The congestion level can be measured by the intertie congestion price (unconstrained) or nodal price (constrained) difference at the two ends of an intertie. Congestion may occur in the constrained schedule without occurring in the unconstrained schedule, and vice versa. Except as otherwise noted, this section discusses congestion in the unconstrained schedule only.

5.4.1 Import Congestion

Table 1-31 reports the number of occurrences of import congestion by month and interface group over the 2010/11 and 2011/12 Annual Periods. Total hours of import congestion declined from 8,239 to 4573 (a 44% decrease). This represents an import congestion rate of 10.4% during the 2011/12 Annual Period (down from 18.8% in the 2010/11 Annual Period). Congestion at the Minnesota interface saw a pronounced decline: from 4,264 hours to 2,042 hours, or a 52.1% decrease.[44] The Manitoba interface also saw a decline in congestion of 1,319 hours, which represents a 34.5% decrease. Of the remaining three import regions, the New York interface saw a decline in congestion from 27 hours to 0; the Québec interface saw an 11 hour increase in congestion to 31 hours, up from 20 hours in the 2010/11 Annual Period; and the Michigan interface saw a decrease in congestion from 110 hours to a single hour.

[43] Congestion in the constrained schedule reflects that the power flow has reached the maximum capability allowed for the interface. Congestion in the unconstrained schedule reflects that the economic transactions have reached the thermal limit at the interface. The former has little impact on price, but traders may be compensated through CMSC payments for constrained-off exports or imports (or uneconomic exports/imports that are constrained on to relieve congestion). In contrast, the latter generates a price difference between the external zone and the Ontario zone, which is manifested in the Intertie Congestion Price (ICP).

[44] Although the numbers of hours with import congestion at the Minnesota interface has decreased in the 2011/12 Annual Period, the seriousness of congestion (measured by the average Intertie Congestion Price during the congestion hours) has actually increased. For more details, see Chapter 3.

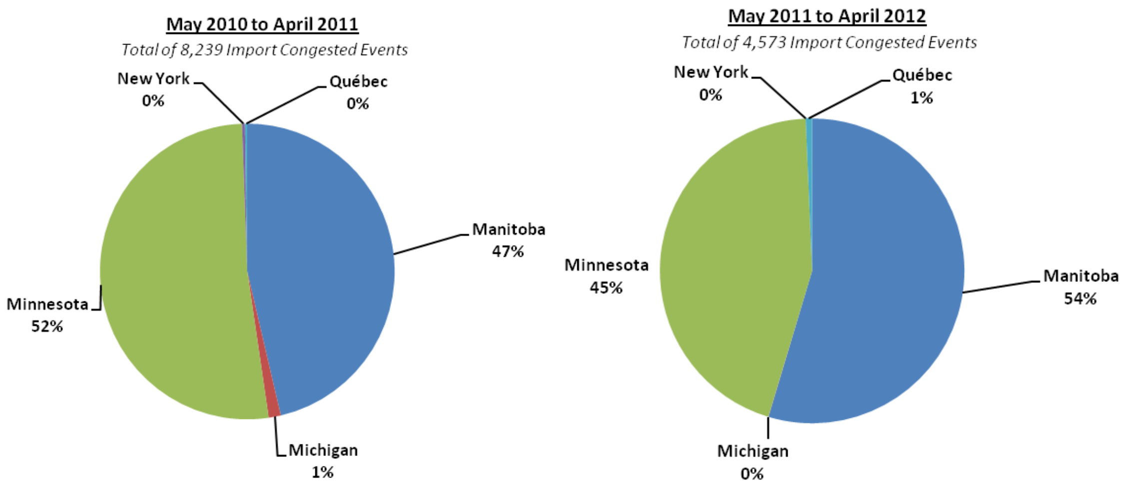
Table 1-31: Import Congestion by Interface Group May – April 2010/2011 & May – April 2011/2012 (number of hours in the unconstrained schedule)

Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	321	230	10	0	404	273	26	0	7	1
June	334	314	0	1	429	90	0	0	1	7
July	244	264	3	0	449	150	1	0	6	8
August	471	167	26	0	463	113	0	0	0	6
September	284	215	69	0	292	216	0	0	0	2
October	403	198	1	0	342	230	0	0	1	0
November	337	172	0	0	419	181	0	0	0	0
December	235	129	0	0	307	66	0	0	0	0
January	187	297	0	0	157	291	0	0	1	0
February	410	232	0	0	307	72	0	0	2	0
March	381	141	0	0	406	205	0	0	0	0
April	211	140	0	0	293	155	0	0	2	7
Total	3,818	2,499	110	1	4,264	2,042	27	0	20	31

Figure 1-27 compares the share of import congestion events[45] by interface group for the 2010/11 and 2011/12 Annual Periods. Of the 43,920 total hours (8,784 hours × 5 interface groups) during the 2011/12 Annual Period, there were 4,573 import congested events, which is a 44.5% decrease from the level in the 2010/11 Annual Period. The interfaces in the Northwest (Manitoba and Minnesota) have accounted for the vast majority of congestion hours in both the 2010/11 and 2011/12 Annual Periods. The share accounted for by the Manitoba interface increased by 7% in the 2011/12 Annual Period, with a corresponding reduction at the Minnesota interface.

[45] It is possible to have more than one intertie import (export) congested during the same hour. For the purposes of the pie charts below, these are treated as individual import (export) congestion events.

Figure 1-27: Share of Import Congestion by Interface Group May – April 2010/2011 & May – April 2011/2012 (% of congested events in the unconstrained schedule)



5.4.2 Export Congestion

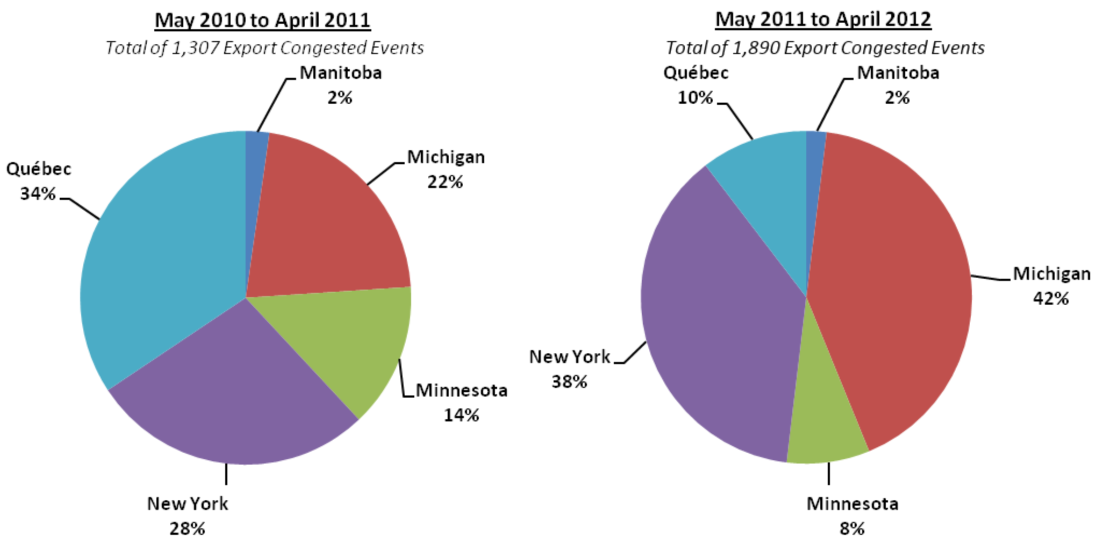
Table 1-32 reports the number of occurrences of export congestion by month and interface group for the 2010/11 and 2011/12 Annual Periods. The total number of export congestion events increased from 1,721 to 1,890 hours (9.8%). This represents a congestion rate of 4.3% of total hours during the 2011/12 Annual Period (up from 3.9% in the 2010/11 Annual Period). The greatest year-to-year increase was seen at the Michigan interface, with export congestion increasing by 508 hours or 179.5%. The New York interface also saw an increase in export congestion hours (97.2%), while congestion at the Québec interface decreased (56.1%).

Table 1-32: Export Congestion by Interface Group May – April 2010/2011 & May – April 2011/2012 (number of hours in the unconstrained schedule)

Month	Manitoba		Michigan		Minnesota		New York		Québec	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0	0	15	77	2	14	0	170	7	63
June	1	0	98	55	9	3	5	80	18	13
July	0	0	41	138	3	23	8	51	13	8
August	0	2	19	26	11	22	14	12	22	2
September	0	2	17	9	0	26	101	30	84	11
October	0	2	1	6	3	1	60	90	81	79
November	2	1	0	12	40	5	0	0	90	20
December	11	3	0	86	9	8	0	0	52	0
January	6	2	60	28	13	3	26	11	56	0
February	3	1	19	105	44	6	9	8	1	0
March	1	11	13	99	23	14	1	122	0	1
April	6	13	0	150	27	28	137	138	25	0
Total	30	37	283	791	184	153	361	712	449	197

Figure 1-28 compares the share of export congestion events by interface group for the 2010/11 and 2011/12 Annual Periods. The Michigan interface overtook the Québec interface as the most congested interface. The New York interface also increased its share of total congestion hours, while the Québec and the Minnesota interfaces saw their shares decline significantly.

Figure 1-28: Share of Export Congestion Events by Interface Group May – April 2010/2011 & May – April 2011/2012 (% of congested events in the unconstrained schedule)



5.4.3 Congestion Rent

Congestion rent is the result of different prices in the unconstrained schedule at either end of an intertie. These price differences are induced by congestion at the interface (i.e., net schedules of economic transactions have reached the maximum thermal limit at the interface). In such situations, the importers or exporters are receiving or paying the intertie price, while Ontario generators and loads are receiving or paying the uniform Ontario price (either the interval MCP or the HOEP).

When there is export congestion, the intertie price rises above the uniform Ontario price. Congestion rent results from the IESO collecting a higher price from exporters while paying the (lower) uniform price to generators. When there is import congestion, the intertie price falls below the uniform Ontario price, and congestion rent results from the IESO paying a lower price to importers relative to the (higher) uniform price.[46]

[46] The congestion rent is the price difference between the external zone and the Ontario zone (the Intertie Congestion Price or ICP) times the net schedules (net imports or net exports) on that intertie. For example, if an intertie has export congestion with an ICP of $10/MWh and net exports are 100 MW, then the congestion rent is $1,000 for the hour. The congestion arises in respect of those exports or imports which

Congestion rent effectively represents a reduction in profit to traders, either in the form of a congestion price premium paid for exports or a reduction in the payment made for imports, compared to the uniform Ontario price.[47]

Tables 1-33 and 1-34 present the congestion rent by interface group during the 2010/11 and 2011/12 Annual Periods.

Table 1-33 indicates that total congestion rent for import events in the 2011/12 Annual Period decreased by approximately $807,000 (or 15.6%) from 2010/11 Annual Period levels. The Manitoba interface saw the largest decrease at approximately $1.9 million (37.1%). In the 2011/12 Annual Period, the Michigan interface had no import congestion rent, compared with $635,000 in the 2010/11 Annual Period. Similarly, the New York interface had no import congestion rent, compared with $264,000 in the 2010/11 Annual Period. The Minnesota interface had the greatest increase, from -$788,000 in the 2010/11 Annual Period to $864,000 in the 2011/12 Annual Period.

are scheduled in the constrained schedule and that flow in real-time. When a transaction is not scheduled in the constrained schedule but is scheduled in the unconstrained schedule, the transaction may attract CMSC and/or Intertie Offer Guarantee (or IOG) payments. Congestion rent can be negative if power flows in the direction opposite to that of the unconstrained congestion. For example, the Minnesota interface is import congested due to cheaper import offers, but power actually flows out of Ontario due to exports being constrained on.

[47] However, traders that have transactions in the direction opposite to that of the congested flow may actually benefit from these differentials. For example, an import on an export-congested intertie would receive a higher payment than the HOEP because of the higher intertie price. Similarly, an export on an import-congested intertie would pay a lower price than the HOEP. Such counter-flows in the constrained schedule can induce the negative components in the congestion rent that are occasionally observed below.

*Table 1-33: Import Congestion Rent by Interface Group May – April 2010/2011 & May – April 2011/2012 ($ thousands)**

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	(8)	119	51	0	(64)	(110)	264	0	0	0	243	8
June	317	341	0	0	(54)	(74)	0	0	3	10	266	276
July	628	396	7	0	(85)	(175)	1	0	57	222	609	443
August	1,114	138	79	0	(208)	8	0	0	0	83	985	230
September	522	252	499	0	(23)	89	0	0	0	5	998	345
October	637	142	0	0	(22)	150	0	0	0	0	615	292
November	550	105	0	0	(52)	37	0	0	0	0	498	142
December	236	74	0	0	0	4	0	0	0	0	236	77
January	169	104	0	0	13	282	0	0	1	0	182	386
February	204	503	0	0	56	18	0	0	1	0	261	520
March	303	930	0	0	(208)	524	0	0	0	0	95	1,454
April	340	54	0	0	(142)	112	0	0	1	40	198	206
Total	5,012	3,155	635	0	(788)	864	264	0	63	360	5,186	4,379

*Negative amounts represent net flows in the direction opposite to the congestion as indicated in the unconstrained schedule

As can be seen from Table 1-34, total export congestion rent was high in the 2011/12 Annual Period at over $28.3 million, an increase of approximately $12.1 million or 74.7%. There were minor decreases in export congestion rent at the Manitoba and Minnesota interfaces. The Québec interface saw $2.4 million (39.3%) less export congestion rent than in the 2010/11 Annual Period. In contrast, the New York interface saw $5.4 million (145.1%) more export congestion rent than in the 2010/11 Annual Period, and the Michigan interface experienced a $9.1 million (144.3%) increase.

Table 1-34: Export Congestion Rent by Interface Group
May – April 2010/2011 & May – April 2011/2012
($ thousands)*

Month	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0	0	220	3,580	0	5	0	2,622	5	948	225	7,154
June	0	0	1,598	1,389	8	0	28	810	105	76	1,739	2,273
July	0	0	1,383	5,987	0	16	79	2,409	116	31	1,578	8,443
August	0	0	646	805	5	15	104	95	342	9	1,097	923
September	0	(4)	197	81	0	20	1,138	173	1,124	171	2,459	441
October	0	0	(3)	86	0	0	658	622	838	2,374	1,494	3,082
November	0	0	0	195	7	0	0	0	858	79	865	274
December	2	0	0	531	10	11	0	0	318	0	330	542
January	(4)	0	1,546	267	8	(1)	471	141	2,071	0	4,093	407
February	0	0	571	573	28	0	144	35	1	0	744	610
March	0	5	179	816	3	(13)	19	1,158	0	2	201	1,967
April	45	1	0	1,174	8	4	1,072	1,036	298	0	1,423	2,217
Total	43	2	6,338	15,486	78	58	3,713	9,099	6,076	3,690	16,248	28,334

*Negative amounts represent net flows in the direction opposite to the congestion as indicated in the unconstrained schedule

There are several factors which can influence congestion rent since it is based on both the magnitude of the actual net schedule in the constrained schedule at the intertie and the Intertie Congestion Price or ICP. The ICP in turn depends on the offer price of the marginal import or export at the intertie, relative to the offer price of the marginal resource within Ontario in the unconstrained schedule. The magnitude of the actual net schedule in the constrained schedule is dependent on:

- the maximum thermal capability of the intertie;
- temporary reductions in the intertie capability;
- inadvertent flows, which use up part of the intertie capability in the direction of the inadvertent flow but increase the capability in the opposite direction;
- import or export failures; and

- the impact of parallel flow effects resulting from congestion on other transmission lines.[48]

5.4.4 Transmission Rights

As noted above, congestion rent is the dollar amount difference that results from an importer being paid less than the Ontario uniform price or an exporter being charged more than the uniform price. Events where congestion rent is "collected" occur when in the unconstrained schedule the demand for transmission exceeds available transmission, leading to a divergence between the intertie zonal price and the market clearing price, and the transactions are scheduled in the constrained schedule.

Congestion on an intertie represents a financial risk to traders. Transmission rights (TRs) provide a financial hedge against that risk by compensating the TR holder for differences between the intertie and Ontario prices. In its August 2010 Monitoring Report, the Panel observed that TR payments by the IESO (the non-negative ICP times the TRs that have been sold) generally exceed the congestion rent received by the IESO, leading to a congestion rent shortfall which then was offset by TR auction revenues.[49] Tables 1-35 and 1-36 show TR payous by interface group for each month in the 2010/11 and 2011/12 Annual Periods for imports and exports, respectively.

As shown in Table 1-35, TR payouts for imports totalled $15.6 million in the 2011/12 Annual Period, which is a decrease of more than $5.8 million (27%) relative to the 2010/11 Annual Period. There were almost no TR payouts associated with the Michigan or New York interfaces, reflecting the lack of import congestion at these interfaces. The Manitoba interface had a relatively large decrease in TR payouts from $15.6 million in the 2010/11 Annual Period to $9.4 million in the 2011/12 Annual Period (a 40.1%

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[48] For example, due to congestion at the Queenston Flow West (QFW) interface within Ontario, scheduled exports or imports at the New York intertie may be reduced even though there is still transfer room at the New York intertie.

[49] See the Panel's August 2010 Monitoring Report (at pp. 140-167), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.

decrease). TR payouts associated with the Minnesota interface increased by $2.0 million, or 54.3%, in the 2011/12 Annual Period. The issue of import congestion at the Minnesota interface is discussed in greater detail in Chapter 3.

Table 1-35: Monthly Import Transmission Rights Payments by Interface Group May – April 2010/2011 & May –April 2011/2012 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	572	985	357	0	282	228	835	0	180	1	2,226	1,214
June	774	1,693	0	4	317	153	0	0	5	11	1,096	1,860
July	1,628	1,203	5	0	373	155	1	0	115	232	2,122	1,590
August	3,123	322	74	0	421	45	0	0	0	213	3,619	581
September	1,186	682	424	0	175	261	0	0	0	5	1,785	948
October	1,874	377	0	0	249	897	0	0	3	0	2,126	1,275
November	983	254	0	0	420	78	0	0	0	0	1,403	332
December	580	120	0	0	206	21	0	0	0	0	786	141
January	328	343	0	0	81	1,300	0	0	2	0	410	1,643
February	2,038	709	0	0	532	42	0	0	1	0	2,571	751
March	1,885	1,774	0	0	427	1,938	0	0	0	0	2,312	3,713
April	657	897	0	0	226	606	0	0	1	21	884	1,523
Total	15,628	9,359	860	4	3,709	5,724	836	0	307	483	21,340	15,571

As shown in Table 1-36, total TR payouts for exports were $38.8 million in the 2011/12 Annual Period, which is 118.7% higher than in the 2010/11 Annual Period. The greatest increase in monthly export TR payouts was at the Michigan interface, which saw a $14.3 million (191.2%) increase. The New York and Québec interfaces also had higher TR payouts in the 2011/12 Annual Period, with increases of $6.7 million (201.8%) and $0.7 million (13.5%),[50] respectively, relative to the 2010/11 Annual Period. Over 27% of all export TR payouts in the 2011/12 Annual Period occurred in July 2011.

[50] The large TR payouts at the Québec interface in October 2011 were mainly due to an overselling of TRs at the PQAT intertie. For more details, see the Panel's April 2012 Monitoring Report (at pp. 72-86), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf.

Table 1-36: Monthly Export Transmission Rights Payments by Interface Group May – April 2010/2011 & May – April 2011/2012 ($ thousands)

Month	Manitoba		Michigan		Minnesota		New York		Québec		Total	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	0	0	159	4,844	0	309	0	1,489	3	1,182	162	7,824
June	5	0	1,776	2,504	97	32	41	1,258	131	72	2,050	3,867
July	0	0	1,588	7,264	1	32	50	3,375	179	44	1,819	10,714
August	0	2	723	866	43	25	77	114	298	8	1,142	1,015
September	0	12	246	86	0	25	1,003	119	974	237	2,224	480
October	0	56	16	102	16	5	756	761	826	4,676	1,614	5,600
November	1	0	0	213	83	21	0	0	810	88	894	321
December	19	1	0	1,013	51	12	0	0	287	0	356	1,026
January	7	0	1,843	456	51	6	342	275	1,779	0	4,023	738
February	1	0	863	1,097	200	11	96	43	0	0	1,161	1,151
March	2	5	257	1,559	139	91	15	1,103	0	1	414	2,759
April	326	2	0	1,748	323	27	950	1,512	272	0	1,871	3,289
Total	361	78	7,471	21,752	1,004	596	3,330	10,049	5,559	6,308	17,730	38,784

5.5 Wholesale Electricity Prices in Neighbouring Markets

Table 1-37 provides average wholesale market prices for Ontario and its neighbouring jurisdictions over the 2010/11 and 2011/12 Annual Periods.[51] All jurisdictions experienced significant price declines in the 2011/12 Annual Period relative to the 2010/11 Annual Period. For several years, energy prices in Ontario were generally the lowest of the five jurisdictions until the 2010/11 Annual Period. In that Annual Period, the Ontario price was slightly higher than the Michigan price in both on-peak and off-peak hours. In the 2011/12 Annual Period, Ontario returned to having the lowest average price relative to neighbouring markets. As between neighbouring jurisdictions, the average Ontario HOEP saw the largest percentage decrease, the sole exception being the decrease in on-peak and overall average (all hours) prices experienced in New England (Internal Hub).

[51] These price comparisons can provide a useful overall indicator of the export and import market opportunities available to traders. However, caution should be used when comparing market prices across jurisdictions for other purposes due to the differing market designs and payment structures. For example, in Ontario the GA and various uplift charges represent actual charges to domestic loads that are not reflected in the average HOEP or the price paid by exporters. As another example, other jurisdictions such as ISO New England, NYISO and PJM have capacity markets where customers pay capacity charges.

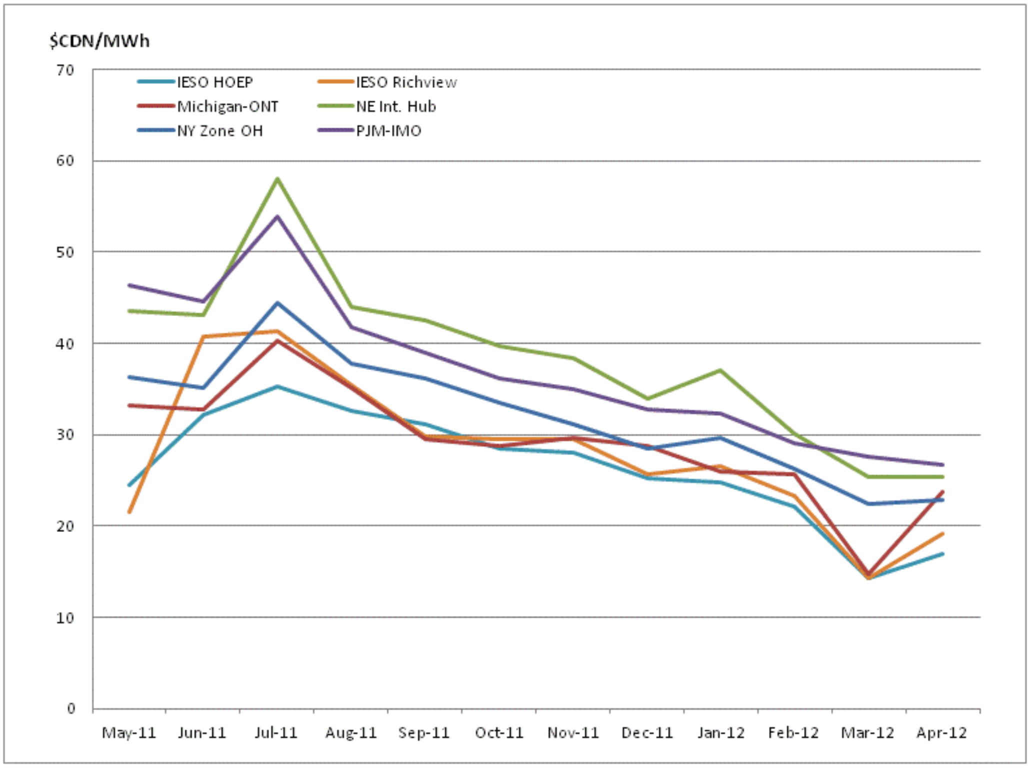
Table 1-37: Average HOEP Relative to Neighbouring Market Prices May – April 2010/2011 & May – April 2011/2012 ($CDN/MWh)*

Markets	All Hours			On-peak Hours			Off-peak Hours		
	2010/2011	2011/2012	% Change	2010/2011	2011/2012	% Change	2010/2011	2011/2012	% Change
Ontario - HOEP	35.64	26.29	(26.2)	41.19	30.78	(25.3)	31.01	22.44	(27.6)
MISO – ONT	34.13	29.03	(14.9)	40.87	34.92	(14.6)	28.52	23.76	(16.7)
NYISO – Zone OH	39.78	32.04	(19.5)	44.73	36.10	(19.3)	35.64	28.26	(20.7)
PJM – IMO	43.94	37.15	(15.5)	51.22	43.68	(14.7)	37.87	31.18	(17.7)
New England – Internal Hub	52.36	38.47	(26.5)	59.88	42.78	(28.6)	46.11	34.41	(25.4)
Average	41.17	32.60	(20.8)	47.58	37.65	(20.9)	35.83	27.97	(21.9)

*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

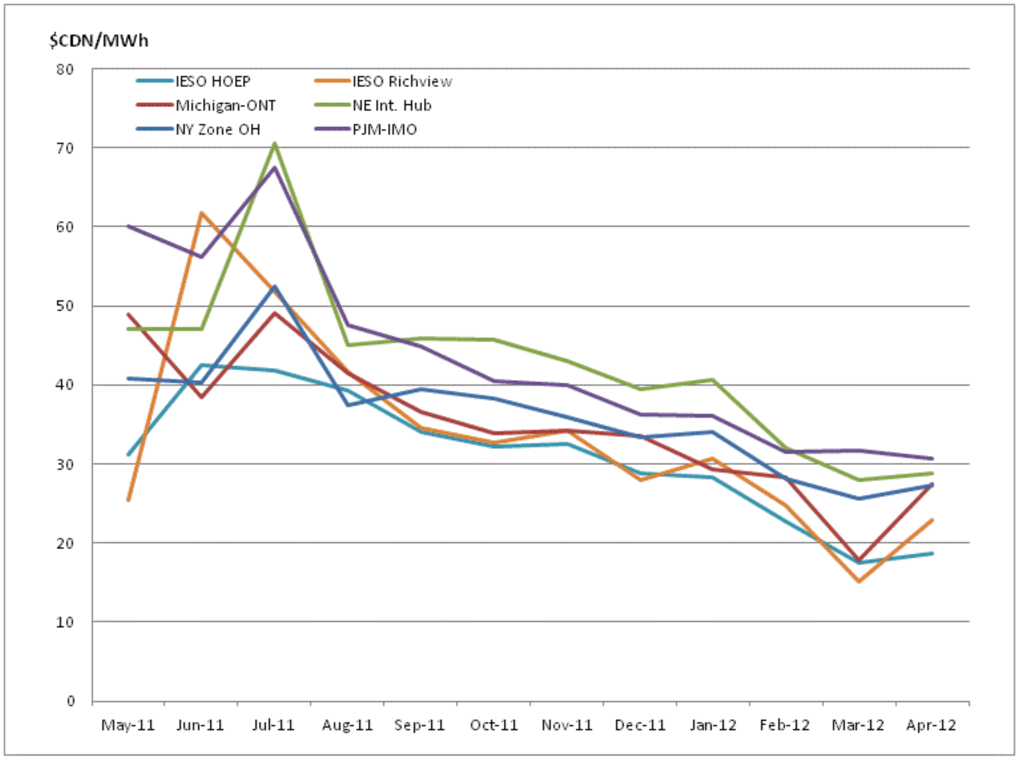
Figures 1-29 to 1-31 compare monthly average prices for Ontario and its neighbouring jurisdictions for the 2011/12 Annual Period, for all hours, for on-peak hours and for off-peak hours, respectively. The Richview nodal price is also shown since it is regarded as a useful indicator of the marginal cost of incremental output in the major load area. The Ontario HOEP followed the same general trends as prices in neighbouring jurisdictions. The New England and PJM electricity prices are regularly and distinctly greater than those of their neighbours (as they have been historically). The Ontario HOEP is the generally the lowest price, but it is occasionally greater than the Michigan electricity price.

Figure 1-29: Average Monthly HOEP and Richview Nodal Price Relative to Neighbouring Market Prices, All Hours
May 2011 – April 2012
($CDN/MWh)*



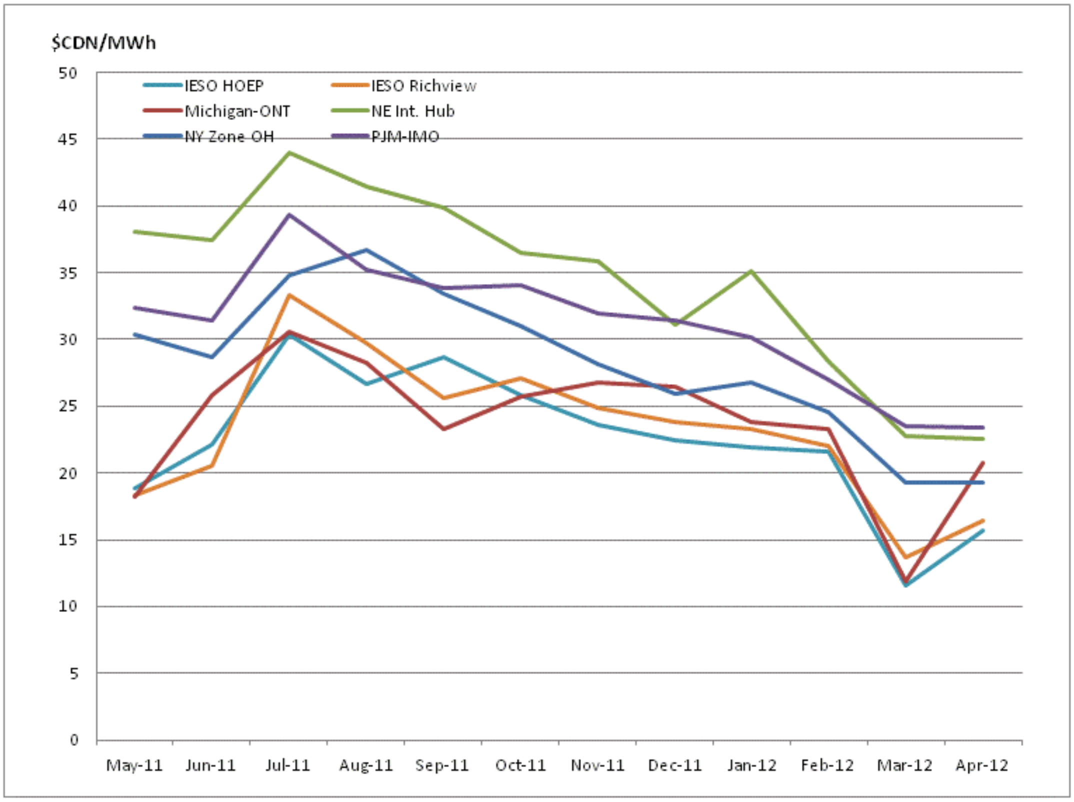
*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

Figure 1-30: Average Monthly HOEP and Richview Nodal Price Relative to Neighbouring Market Prices, On-Peak May 2011 – April 2012 ($CDN/MWh)



*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

Figure 1-31: Average Monthly HOEP and Richview Nodal Price Relative to Neighbouring Market Prices, Off-Peak
May 2011 – April 2012
($CDN/MWh)



*All $US amounts converted to $CDN at Bank of Canada daily noon exchange rates.

6. Operating Reserve

6.1 Operating Reserve Requirements

The operating reserve (OR) requirement is determined by the IESO in accordance with reliability standards established by authorities such as NERC and the Northeast Power Coordinating Council. OR requirements (in MW) are based on the largest single unexpected event (contingency) plus half of the second largest contingency. However, during shortage conditions or when OR is activated, the OR requirement can be reduced. The average OR requirement for the 2010/11 Annual Period was 1,520MW, while in the 2011/12 Annual Period the requirement was slightly lower at 1,516 MW.

6.2 Supply

Table 1-38 below reports OR scheduled by source and by month during the 2011/12 Annual Period in real-time. Hydro resources provided slightly more than half of the total required OR in the 2011/12 Annual Period, with dispatchable loads and gas-fired generators supplying approximately 16% and 15%, respectively. The balance of the required OR was provided by coal-fired generators, imports and control action OR (CAOR).[52]

Table 1-38: Operating Reserve Scheduled by Source and Generation Type May 2011 – April 2012 (%)

Month	Coal	Gas/Oil	Hydro	Dispatchable Load	Imports	CAOR
May	2.4	24.2	41.3	18.5	8.1	5.6
June	6.9	18.7	48.7	16.0	5.8	4.0
July	9.8	10.4	55.8	14.5	7.6	2.0
August	4.6	10.1	61.4	14.1	8.4	1.5
September	3.2	11.4	60.2	16.3	7.8	1.1
October	1.3	16.3	59.4	16.4	6.3	0.5
November	2.5	16.8	56.5	16.5	6.9	0.7
December	4.5	12.1	61.0	13.6	8.5	0.4
January	5.4	11.9	59.3	16.4	5.9	1.1
February	6.1	11.2	54.9	17.1	10.2	0.5
March	5.2	20.4	41.6	18.4	12.1	2.3
April	5.5	14.9	50.3	19.4	9.1	0.8
2011-2012	5.8	15.0	54.7	16.4	8.1	2.0

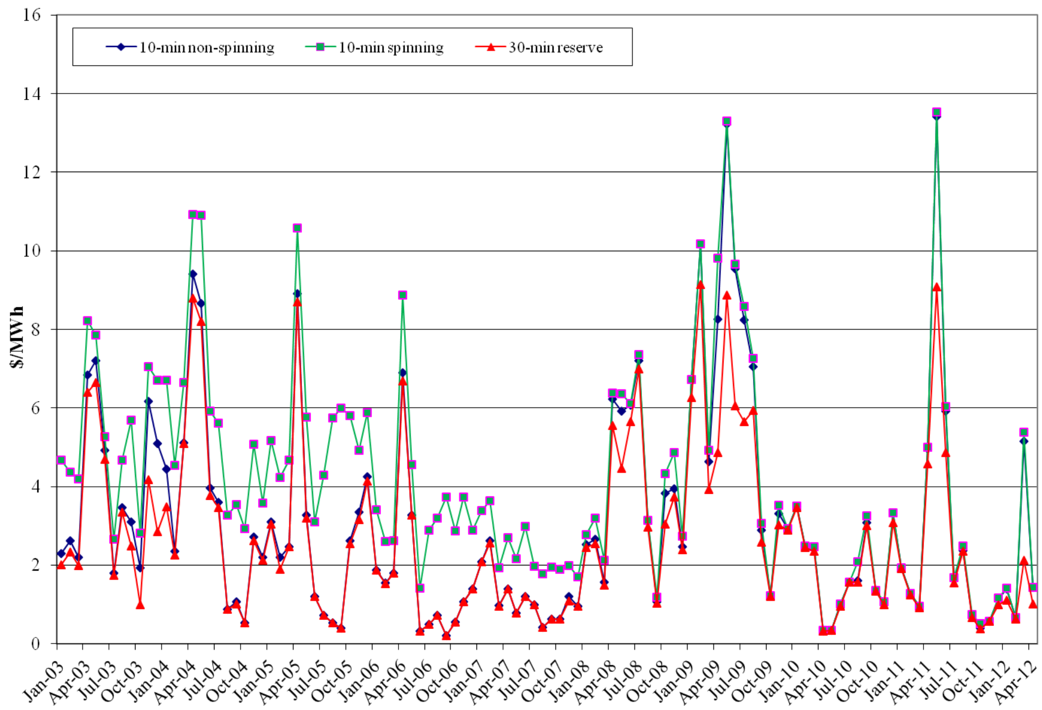
6.3 Prices

Figure 1-32 shows monthly average prices since 2003 for the three categories of OR: 10-minute spinning (10S), 10-minute non-spinning (10N), and 30-minute reserve (30R). From 2003 to early 2008, OR prices were generally declining. They then trended

[52] In real-time, CAOR has a standing offer of 800 MW, with $30/MW per hour for 400 MW, $75 per hour for the first incremental 200 MW and $100/MW per hour for the last incremental 200 MW. CAOR is backed by reducing the grid voltage, which rarely happened. The reduction in voltage can lead to decreased electricity consumption.

upwards from early 2008 to late 2009 as a result of a decline in available OR resources.[53] Since October 2009, OR prices have dropped and returned to pre-2008 levels. The main exception is a spike in May 2011, which is attributable to a few hydro generators offering into the OR market at an increased price or not at all (typically, these generators supply OR at a low price when water doesn't have to be spilled).

Figure 1-32: Monthly Operating Reserve Prices by Category, All Hours January 2003 – April 2012 ($/MW per hour)



6.3.1 On-Peak Operating Reserve Prices

Table 1-39 presents average monthly OR prices during on-peak hours over the 2010/11 and 2011/12 Annual Periods. On-peak prices for 10-minute spinning, 10-minute non-spinning, and 30-minute reserve increased by 17.4%, 16.7% and 4.8%, respectively, in the 2011/12 Annual Period relative to the 2010/11 Annual Period. All three categories

[53] The factors leading to the increase in OR prices observed in 2008 and 2009 were discussed in the Panel's July 2009 Monitoring Report (at pp. 45-46), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf.

saw increases in OR prices in May-August, and in March. The price difference was very high in the months of May and June. The high OR prices in these two months were primarily due to the fact that many peaking hydro facilities stopped offering OR because of abundant water supply.

Table 1-39: Average Monthly Operating Reserve Prices by Category, On-Peak May – April 2010/2011 & May – April 2011/2012 ($/MW per hour)

Month	10S			10N			30R		
	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change
May	0.51	20.10	3841.2	0.51	19.95	3811.8	0.51	11.40	2135.3
June	1.75	10.41	494.9	1.75	10.27	486.9	1.62	8.41	419.1
July	3.06	3.34	9.2	3.04	3.29	8.2	3.04	3.12	2.6
August	3.24	4.27	31.8	2.76	4.22	52.9	2.65	4.20	58.5
September	4.42	1.16	(73.8)	4.33	1.13	(73.9)	4.18	1.10	(73.7)
October	2.37	0.68	(71.3)	2.37	0.63	(73.4)	2.34	0.61	(73.9)
November	1.70	0.94	(44.7)	1.70	0.93	(45.3)	1.66	0.93	(44.0)
December	5.72	1.83	(68.0)	5.72	1.83	(68.0)	5.25	1.53	(70.9)
January	3.43	2.34	(31.8)	3.43	2.34	(31.8)	3.38	1.73	(48.8)
February	2.06	0.69	(66.5)	2.06	0.69	(66.5)	2.00	0.62	(69.0)
March	1.35	7.94	488.1	1.35	7.48	454.1	1.25	1.49	19.2
April	7.75	2.08	(73.2)	7.72	2.08	(73.1)	6.83	1.21	(82.3)
Average	3.11	4.65	49.5	3.06	4.57	49.3	2.89	3.03	4.6

6.3.2 Off-Peak Operating Reserve Prices

Table 1-40 presents average monthly operating reserve prices during off-peak hours over the 2010/11 and 2011/12 Annual Periods. Off-peak prices for 10-minute spinning, 10-minute non-spinning, and 30-minute reserve increased by 55.6%, 62.2% and 48.3%, respectively, in the 2011/12 Annual Period relative to the 2010/11 Annual Period. Two categories of OR saw some price jumps in May-August (the exception being 10-minute spinning) and all saw increases in March relative to the 2010/11 Annual Period. As with on-peak hours, OR prices in May 2011 and, to a lesser extent, June 2011 were substantially higher than in all other months.

Table 1-40: Average Monthly Operating Reserve Prices by Category, Off-Peak May – April 2010/2011 & May – April 2011/2012 ($/MW per hour)

Month	10S			10N			30R		
	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change	2010/ 2011	2011/ 2012	% Change
May	0.22	8.13	3595.5	0.22	8.03	3550.0	0.22	7.19	3168.2
June	0.33	1.84	457.6	0.33	1.77	436.4	0.32	1.48	362.5
July	0.35	0.42	20.0	0.35	0.38	8.6	0.34	0.36	5.9
August	1.13	0.90	(20.4)	0.66	0.70	6.1	0.65	0.70	7.7
September	2.24	0.38	(83.0)	2.00	0.29	(85.5)	1.99	0.29	(85.4)
October	0.58	0.41	(29.3)	0.58	0.21	(63.8)	0.58	0.21	(63.8)
November	0.45	0.25	(44.4)	0.37	0.22	(40.5)	0.36	0.22	(38.9)
December	1.36	0.66	(51.5)	1.32	0.62	(53.0)	1.32	0.60	(54.5)
January	0.82	0.63	(23.2)	0.80	0.63	(21.3)	0.80	0.59	(26.3)
February	0.64	0.65	1.6	0.64	0.65	1.6	0.63	0.61	(3.2)
March	0.57	3.09	442.1	0.57	3.08	440.4	0.57	2.70	373.7
April	3.00	0.95	(68.3)	2.97	0.95	(68.0)	2.93	0.88	(70.0)
Average	0.97	1.53	57.7	0.90	1.46	62.2	0.89	1.32	48.3

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Chapter 2: Analysis of Market Outcomes

1. Introduction

The Market Surveillance Panel is responsible for monitoring activities related to the IESO-administered markets and the conduct of market participants with a view to identifying, among others, anomalous market conduct and activities of the IESO that may have an impact on market efficiencies or effective competition. The Panel also monitors and reports on market outcomes that fall outside of predicted patterns or norms, which contributes to transparency and enhances market participant understanding of the market.

Day-to-day monitoring of the market is undertaken by the IESO's Market Assessment Unit (MAU) under the direction of the Panel. In addition to identifying high- and low-price hours (as defined below), the MAU also reviews:

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

Where anomalous events are identified through this daily monitoring, the matter may be discussed with the relevant market participant(s) or the IESO, or may be the subject of more detailed examination. Where appropriate, the Panel makes recommendations for changes to the Market Rules or to IESO processes, procedures or tools. Where warranted, the Panel may also initiate an investigation into a matter.

The Panel defines high-price hours as all hours in which the Hourly Ontario Energy Price (HOEP) is greater than \$200/MWh, and defines low-price hours as all hours in which the HOEP is less than \$20/MWh[54] or is negative.

As discussed further in section 2.1, there were three hours during the November 2011 through April 2012 period (the "Winter 2012 Period") when the HOEP was greater than \$200/MWh.

As discussed further in section 2.2, in the Winter 2012 Period there were 1,690 hours in which HOEP was less than \$20/MWh, including 87 hours where the HOEP was negative.

In section 2.3, the Panel reports on hours with anomalously high uplift payments; namely, Congestion Management Settlement Credit (CMSC) payments in excess of \$500,000/hour or of \$1,000,000/day, Intertie Offer Guarantee (IOG) payments in excess of \$500,000/hour or of \$1,000,000/day, and Operating Reserve (OR) payments in excess of \$100,000/hour.[55] It was the past practice of the Panel to report on instances where CMSC payments on the interties exceeded \$1,000,000 for a given day. While the Panel still considers such events to be anomalous, it has expanded the daily CMSC threshold to include all CMSC payments made in the province, not simply those on the interties. The threshold value remains at \$1,000,000 per day. Additionally, the Panel reports on the hour or day in which the largest payments in each of these uplift categories were incurred, even if those payments do not exceed the threshold set by the Panel.

The sections below discuss the factors contributing to high-price and low-price hours and to hours with anomalous uplift payments in the Winter 2012 Period, and include comparative data from preceding years as relevant. References in this chapter to a winter period are to the period running from November to April, inclusive.

[54] Historically, \$200/MWh has been a rough upper bound, and \$20/MWh a rough lower bound, for the marginal cost of a fossil fuel-fired generation unit.
[55] For a discussion of the thresholds established for each category of uplift payment, see the Panel's January 2009 Monitoring Report (at pp. 178-184), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf .

2. Anomalous HOEP

2.1 Analysis of High-Price Hours

Table 2-1 depicts the total number of hours per month in which the HOEP exceeded $200/MWh in the Winter 2012 Period and the preceding four winter periods.

Table 2-1: Number of High-Price Hours (HOEP > $200/MWh)
November – April, 2007/2008 to November – April 2011/2012
(Number of Hours)

Month	Number of Hours with HOEP >$200/MWh				
	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012
November	0	0	0	0	0
December	0	2	0	0	0
January	0	3	1	0	0
February	1	2	0	0	1
March	0	1	0	0	2
April	1	0	0	1	0
Total	**2**	**8**	**1**	**1**	**3**

In previous reports, the Panel has noted that the HOEP is greater than $200/MWh typically in 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 are unavailable in real-time as a result of a forced outage, de-rating, or participant error; and/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%.[56]

The following analysis examines the circumstances surrounding the three high-price hours that were experienced during the Winter 2012 Period, two of which occurred in succession on the same day.

2.1.1 February 18, 2012 HE 19

The HOEP was $280.73/MWh in HE 19 on Saturday, February 18, 2012. The greater part of the price spike occurred in the middle intervals of that hour, with the market clearing price (MCP) reaching $477.72/MWh in intervals 7 through 9. The primary reason for the price spike was a sharp decline in the real-time output from self-scheduling and intermittent generation resources, more specifically wind generation, relative to the levels forecasted in pre-dispatch.

Prices, Demand and Supply

Table 2-2 lists real-time MCP, Ontario demand and net exports for Hour Ending (HE) 19 on February 18, 2012.

Ontario demand started at 17,657 MW for the hour, and reached an hourly peak of 17,876 MW in interval 6 before declining to 17,574 MW by the end of the hour. Over the course of HE 19, Ontario demand dropped 83 MW. The most drastic drops in demand occurred in the final three intervals, coinciding with drops in the MCP. The largest interval-over-interval demand increase occurred in interval 3, when demand increased by 113 MW and contributed to a jump in the MCP from $75.18/MWh to $227.10/MWh.

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[56] In its March 2003 Monitoring Report (available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_240303.pdf), the Panel noted that a supply cushion lower than 10% is more likely to be associated with a price spike (see pp. 11-16). The Panel began reporting a revised supply cushion calculation in its August 2007 Monitoring Report (at pp. 79-81), available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf). It remains the case that as the supply cushion falls below 10%, a price spike becomes increasingly likely.

Real-time net exports of 1,821 MW fell by 249 MW (12%) in HE 19 relative to the previous hour. This resulted in a net reduction in Ontario demand plus net exports of 215 MW in interval 1, and the lowest MCP of the hour at $64.94/MWh.

Table 2-2: Real-time MCP, Ontario Demand and Net Exports February 18, 2012 HE 19 (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)
19	1	64.94	17,657	1,821	19,478	-215	-249
19	2	75.18	17,727	1,821	19,548	70	-249
19	3	227.10	17,840	1,821	19,661	113	-249
19	4	228.10	17,851	1,821	19,672	11	-249
19	5	269.23	17,845	1,821	19,666	-6	-249
19	6	416.01	17,876	1,821	19,697	31	-249
19	7	477.72	17,860	1,821	19,681	-16	-249
19	8	477.72	17,852	1,821	19,673	-8	-249
19	9	477.72	17,840	1,821	19,661	-12	-249
19	10	415.92	17,782	1,821	19,603	-58	-249
19	11	172.13	17,733	1,821	19,554	-49	-249
19	12	66.93	17,574	1,821	19,395	-159	-249
Average		**280.73**	**17,786**	**1,821**	**19,607**	**-25**	**-249**

Pre-dispatch Conditions

With February 18, 2012 being a Saturday, day-ahead forecasts of market demand and prices were relatively low. Accordingly, several large gas-fired generators did not get committed in the day-ahead schedule. With iterative pre-dispatch runs continuing to forecast adequate supply conditions and low-to-moderate prices in the hours leading up to real-time, several gas-fired generators who failed to receive a day-ahead commitment removed their offers from the real-time market. This action was likely taken to eliminate the risk of being scheduled in real-time without the protection of a guarantee program. Regardless of the reason, it remains that when supply-demand conditions tightened in real-time, those gas-fired generators were not online to cushion the upward pressure on prices.

Table 2-3 displays pre-dispatch prices, Ontario demand and net exports for the five pre-dispatch hours leading up to HE 19 on February 18, 2012. The pre-dispatch MCP increased modestly every hour until the final pre-dispatch run. While there was a gradual upward revision of Ontario demand as real-time approached, there were also decreases in net exports from five hours ahead to one hour ahead of real-time.

Table 2-3: Pre-dispatch Demand, MCP and Net Exports Hours leading up to February 18, 2012 HE 19 (MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Ontario Demand plus Net Exports (MW)
5	24.82	17,787	109	2,412	2,303	20,090
4	26.26	17,886	314	2,512	2,198	20,084
3	27.09	18,004	314	2,361	2,047	20,051
2	30.18	18,024	378	2,234	1,856	19,880
1	32.84	18,107	378	2,199	1,821	19,928

Table 2-4 displays forecasted and actual average wind output for HE 19 on February 18, 2012, as well as for hours leading up to and beyond HE 19. Wind output fell precipitously in the hours leading up to HE 19, significantly under-delivering relative to forecasted levels. The large discrepancy in HE 17 did not lead to a material reduction in the forecast for HE 19, and the final pre-dispatch price for HE 19 did not reflect the significant loss of wind output that continued through that hour.

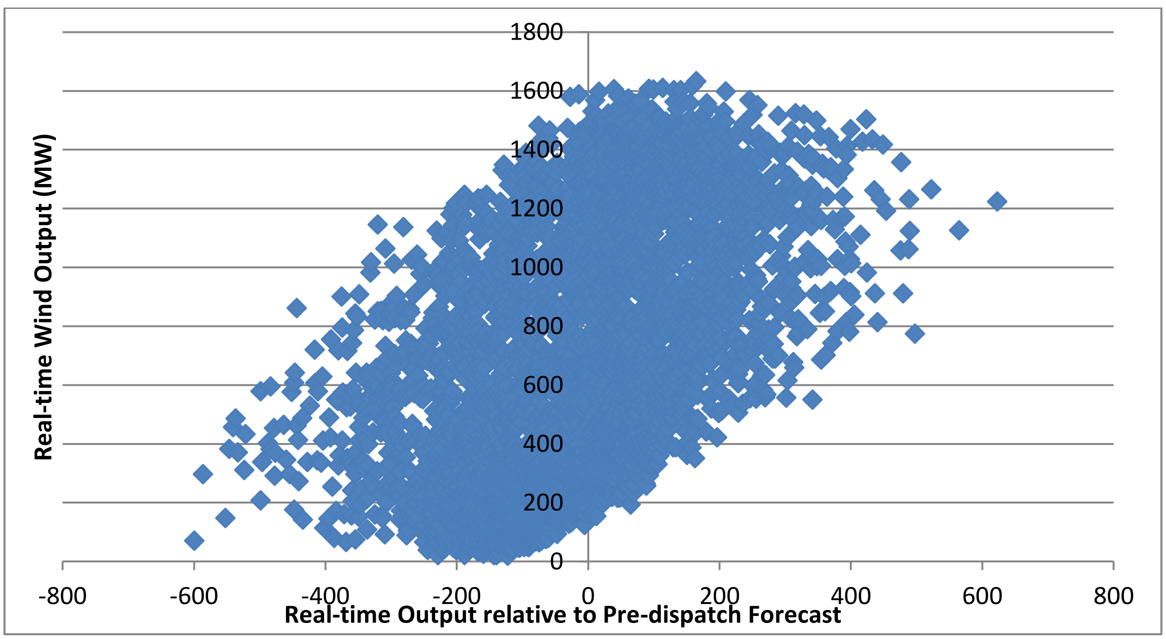
Table 2-4: Pre-dispatch to Real-time Wind Output Discrepancy February 18, 2012 HE 15 to 20 (MW)

Hour Ending	Final Pre-dispatch Average Wind Output Forecast (MW)	Real-time Average Wind Output (MW)	Average PD to RT Discrepancy (MW)
15	1,077	1,112	35
16	1,025	1,013	-12
17	1,182	832	-350
18	1,023	607	-416
19	998	457	-541
20	627	389	-238

In HE 19, wind under-delivered by 541 MW relative to the pre-dispatch forecast. This was the fifth largest hourly wind output shortfall during the Winter 2012 Period. Wind output continued to fall in HE 20, producing an average of 389 MW across that hour. With wind output trending much lighter than forecasted, the wind generators revised their pre-dispatch forecasts down by a total of 350 MW to 627 MW (36%) in advance of the final pre-dispatch run. This considerably reduced the pre-dispatch to real-time supply discrepancy and, when coupled with falling demand, resulted in the normalization of the HOEP to $32.91/MWh in HE 20.

Figure 2-1 below plots the hourly pre-dispatch to real-time wind output discrepancy for all hours in the Winter 2012 Period.

Figure 2-1: Hourly Pre-dispatch to Real-time Wind Output Discrepancy November 2011 to April 2012 (MW)



Lower levels of real-time wind output are associated with under-delivery relative to pre-dispatch forecast levels (i.e., larger wind output shortfalls), while higher levels of real-time wind output are associated with instances of over-delivery relative to pre-dispatch forecast levels. Events plotted further to the left of the Y-axis are more likely to trigger high-price events, while events further to the right are more likely to trigger low-price (including negative-price) events.

Real-Time Conditions

Average real-time wind output in HE 19 on February 18, 2012 fell to 457 MW, creating a 541 MW (54%) shortfall between forecasted and actual wind production.
While wind generation accounted for the majority of the discrepancy between forecasted and actual output levels from self-scheduling and intermittent generation resources in HE 19, a lack of output from other self-scheduling and intermittent resources accounted for an additional 35 MW in average shortfall across the hour, for a total average shortfall of 576 MW.

Although self-scheduling and intermittent resources under-delivered by an average of 576 MW relative to forecasted levels, real-time demand ran lighter than forecasted and helped converge the real-time supply-demand conditions with the forecasted conditions. On average, real-time demand was 321 MW (1.7%) less than forecasted, reducing the total pre-dispatch to real-time discrepancy to an average of 255 MW across the hour.

As shown in Table 2-2, the real-time MCP experienced an initial jump to $227.10/MWh in interval 3 of HE 19. This increase coincided with a 113 MW increase in demand and an 11 MW drop in output from self-scheduling and intermittent generation resources, for a total interval-over-interval change of 124 MW. The real-time MCP experienced an additional jump to $416.01/MWh in interval 6 when demand hit an hourly peak of 17,876 MW and supply from self-scheduling and intermittent resources dropped a further 23 MW from the previous interval.

Table 2-5 displays pre-dispatch versus real-time demand and supply conditions for each interval in HE 19 on February 18, 2012.

Table 2-5: Pre-dispatch and Real-time Demand & Supply Conditions February 18, 2012 HE 19 (MW)

HE	Interval	Ontario Demand (MW)			Self-Scheduling and Intermittent (MW)			Net Exports (MW)			Total PD vs. RT Discrepancy (MW)
		PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	
19	1	18,107	17,657	450	1,884	1,402	-482	1,821	1,821	0	-32
19	2	18,107	17,727	380	1,884	1,370	-514	1,821	1,821	0	-134
19	3	18,107	17,840	267	1,884	1,359	-525	1,821	1,821	0	-258
19	4	18,107	17,851	256	1,884	1,360	-524	1,821	1,821	0	-268
19	5	18,107	17,845	262	1,884	1,343	-541	1,821	1,821	0	-279
19	6	18,107	17,876	231	1,884	1,320	-564	1,821	1,821	0	-333
19	7	18,107	17,860	247	1,884	1,262	-622	1,821	1,821	0	-375
19	8	18,107	17,852	255	1,884	1,244	-640	1,821	1,821	0	-385
19	9	18,107	17,840	267	1,884	1,237	-647	1,821	1,821	0	-380
19	10	18,107	17,782	325	1,884	1,247	-637	1,821	1,821	0	-312
19	11	18,107	17,733	374	1,884	1,268	-616	1,821	1,821	0	-242
19	12	18,107	17,574	533	1,884	1,280	-604	1,821	1,821	0	-71
Average		**18,107**	**17,786**	**321**	**1,884**	**1,308**	**-576**	**1,821**	**1,821**	**0**	**-255**

Table 2-6 displays real-time MCPs and the fuel type of the marginal resource for each interval in HE 19 on February 18, 2012. A combined cycle facility (combined gas and steam generation) was at the margin in the first two intervals, followed by peaking hydro facilities in intervals 3 through 11. A combined cycle facility once again set the price in interval 12, after supply-demand conditions loosened.

Table 2-6: Real-time MCP and Marginal Resources February 18, 2012 HE 19 ($/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)
19	**1**	64.94	Combined Cycle
19	**2**	75.18	Combined Cycle
19	**3**	227.10	Water
19	**4**	228.10	Water
19	**5**	269.23	Water
19	**6**	416.01	Water
19	**7**	477.72	Water
19	**8**	477.72	Water
19	**9**	477.72	Water
19	**10**	415.92	Water
19	**11**	172.13	Water
19	**12**	66.93	Combined Cycle
Average		**280.73**	

2.1.2 March 4, 2012 HE 19 & 20

In HE 19 and HE 20 on Sunday, March 4, 2012, the HOEP reached $263.82/MWh and $389.66/MWh, respectively. These high prices were primarily caused by higher-than-forecasted demand, under-delivery by self-scheduling and intermittent generation resources, the removal of offers by a gas-fired generator between pre-dispatch and real-time, and the partial de-rating of a coal-fired generator. A failed import was also a contributing factor in respect of HE 20.

Prices, Demand and Supply

Table 2-7 lists real-time MCP, Ontario demand and net exports for HE 19 and HE 20 on March 4, 2012.

Table 2-7: Real-time MCP, Ontario Demand and Net Exports March 4, 2012 HE 19 & HE 20 (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)
19	**1**	25.62	18,206	1,129	19,335	-192	608
19	**2**	55.86	18,339	1,129	19,468	133	608
19	**3**	56.13	18,481	1,129	19,610	142	608
19	**4**	59.48	18,522	1,129	19,651	41	608
19	**5**	67.42	18,681	1,129	19,810	159	608
19	**6**	217.03	18,832	1,129	19,961	151	608
19	**7**	201.00	18,847	1,129	19,976	15	608
19	**8**	466.32	18,905	1,129	20,034	58	608
19	**9**	472.00	18,938	1,129	20,067	33	608
19	**10**	472.00	18,941	1,129	20,070	3	608
19	**11**	473.00	18,951	1,129	20,080	10	608
19	**12**	600.01	19,098	1,129	20,227	147	608
Average		**263.82**	**18,728**	**1,129**	**19,857**	**58**	**608**
20	**1**	556.19	18,901	1,279	20,180	323	150
20	**2**	575.01	18,940	1,279	20,219	39	150
20	**3**	557.40	18,915	1,279	20,194	-25	150
20	**4**	575.02	18,980	1,279	20,259	65	150
20	**5**	473.00	18,868	1,279	20,147	-112	150
20	**6**	320.13	18,845	1,279	20,124	-23	150
20	**7**	472.00	18,892	1,279	20,171	47	150
20	**8**	227.10	18,824	1,279	20,103	-68	150
20	**9**	320.13	18,875	1,279	20,154	51	150
20	**10**	227.10	18,843	1,279	20,122	-32	150
20	**11**	145.72	18,805	1,279	20,084	-38	150
20	**12**	227.10	18,825	1,279	20,104	20	150
Average		**389.66**	**18,876**	**1,279**	**20,155**	**21**	**150**

Interval-over-interval demand rose in all intervals of HE 19, resulting in a cumulative hourly increase of 892 MW (4.9%). In HE 20, real-time Ontario demand fluctuated within a 175 MW band, dropping a total of 76 MW over the course of the hour.

Ontario was a net exporter in HE 19 with net exports of 1,129 MW, a 608 MW increase (117%) over HE 18. There was a further increase to 1,279 MW (13%) in HE 20.

Pre-Dispatch Conditions

Tables 2-8 and 2-9 display prices, Ontario demand and net exports for the five pre-dispatch hours leading up to HE 19 and HE 20, respectively, on March 4, 2012. The pre-dispatch prices in HE 19 were persistently projected in the $24/MWh range. Relatively consistent pre-dispatch prices were accompanied by a gradual 209 MW increase in expected net exports from five hours ahead to one hour ahead. The Ontario demand forecast was revised up considerably from five hours ahead to two hours ahead, but was subsequently revised back down by 264 MW in final pre-dispatch as real-time demand was trending light in advance of HE 19.

Table 2-8: Pre-dispatch Demand, Prices and Net Exports
Hours leading up to March 4, 2012 HE 19
(MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Ontario Demand plus Net Exports (MW)
5	21.49	18,416	392	1,312	920	19,336
4	23.71	18,655	392	1,312	920	19,575
3	23.84	18,705	392	1,472	1,080	19,785
2	23.97	18,868	708	1,837	1,129	19,997
1	23.57	18,604	708	1,837	1,129	19,733

Similarly, the pre-dispatch prices in HE 20 were persistently projected in the $24/MWh range, with expected net exports increasing modestly from 1,020 MW five hours ahead to 1,119 MW one hour ahead. The Ontario demand forecast was decreased by 87 MW from five hours ahead to one hour ahead.

Table 2-9: Pre-dispatch Demand, Prices and Net Exports
Hours Leading up to March 4, 2012 HE 20
(MW & $/MWh)

Hours Ahead	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
5	23.68	18,649	292	1,312	1,020
4	23.71	18,699	292	1,312	1,020
3	23.70	18,680	292	1,412	1,120
2	23.66	18,598	452	1,592	1,140
1	24.72	18,562	473	1,592	1,119

Real-Time Conditions

Table 2-10 lists the pre-dispatch and real-time Ontario demand, self-scheduling and intermittent generation and net exports for HE 19 and HE 20 on March 4, 2012. On average, Ontario demand was under-forecast by 124 MW (0.6%) in HE 19 and by 314 MW (1.7%) in HE 20. Relative to forecast levels, self-scheduling generation resources over-delivered by 17 MW (1.9%) and 15 MW (1.7%) in HE 19 and 20, respectively, but wind generation resources under-delivered by 174 MW (41%) in HE 19 and by 132 MW (29%) in HE 20. Overall, self-scheduling and intermittent generators produced less than anticipated, averaging output levels at 157 MW (12%) and 117 MW (8.7%) below forecast in HE 19 and HE 20, respectively. There was one failed intertie transaction in one of the two high-price hours—a 160 MW import on the Manitoba interface that failed in HE 20 because the participant failed to acquire transmission capacity. The total pre-dispatch to real-time supply and demand discrepancy averaged 281 MW in HE 19 and 591 MW in HE 20.

Table 2-10: Pre-dispatch and Real-time Demand and Supply Conditions March 4, 2012 HE 19 & HE 20 (MW)

HE	Interval	Ontario Demand (MW)			Self-Scheduler and Intermittent Output (MW)			Net Exports (MW)			Total PD vs. RT Discrepancy (MW)
		PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	
19	1	18,604	18,206	398	1,312	1,152	-160	1,129	1,129	0	238
19	2	18,604	18,339	265	1,312	1,144	-168	1,129	1,129	0	97
19	3	18,604	18,481	123	1,312	1,137	-175	1,129	1,129	0	-52
19	4	18,604	18,522	82	1,312	1,130	-182	1,129	1,129	0	-100
19	5	18,604	18,681	-77	1,312	1,135	-177	1,129	1,129	0	-254
19	6	18,604	18,832	-228	1,312	1,131	-181	1,129	1,129	0	-409
19	7	18,604	18,847	-243	1,312	1,147	-165	1,129	1,129	0	-408
19	8	18,604	18,905	-301	1,312	1,160	-152	1,129	1,129	0	-453
19	9	18,604	18,938	-334	1,312	1,176	-136	1,129	1,129	0	-470
19	10	18,604	18,941	-337	1,312	1,179	-133	1,129	1,129	0	-470
19	11	18,604	18,951	-347	1,312	1,185	-127	1,129	1,129	0	-474
19	12	18,604	19,098	-494	1,312	1,187	-125	1,129	1,129	0	-619
Average		**18,604**	**18,728**	**-124**	**1,312**	**1,155**	**-157**	**1,129**	**1,129**	**0**	**-281**
20	1	18,562	18,901	-339	1,347	1,194	-153	1,119	1,279	-160	-652
20	2	18,562	18,940	-378	1,347	1,187	-160	1,119	1,279	-160	-698
20	3	18,562	18,915	-353	1,347	1,192	-155	1,119	1,279	-160	-668
20	4	18,562	18,980	-418	1,347	1,204	-143	1,119	1,279	-160	-721
20	5	18,562	18,868	-306	1,347	1,215	-132	1,119	1,279	-160	-598
20	6	18,562	18,845	-283	1,347	1,235	-112	1,119	1,279	-160	-555
20	7	18,562	18,892	-330	1,347	1,243	-104	1,119	1,279	-160	-594
20	8	18,562	18,824	-262	1,347	1,249	-98	1,119	1,279	-160	-520
20	9	18,562	18,875	-313	1,347	1,262	-85	1,119	1,279	-160	-558
20	10	18,562	18,843	-281	1,347	1,269	-78	1,119	1,279	-160	-519
20	11	18,562	18,805	-243	1,347	1,259	-88	1,119	1,279	-160	-491
20	12	18,562	18,825	-263	1,347	1,250	-97	1,119	1,279	-160	-520
Average		**18,562**	**18,876**	**-314**	**1,347**	**1,230**	**-117**	**1,119**	**1,279**	**-160**	**-591**

Table 2-11 displays real-time MCPs, the fuel type of the marginal resource and any notable outage/de-rating events for each interval in HE 19 and HE 20 on March 4, 2012. In the first interval of HE 19, the MCP was set by a baseload hydroelectric generator. The MCPs in intervals 2 through 5 were set by combined cycle facilities. 18 of the remaining 19 intervals in HE 19 and HE 20 had MCPs set by peaking hydro facilities, with a gas-fired plant setting the MCP in the other interval.

Table 2-11: Real-time MCP and Marginal Resources March 4, 2012 HE 19 & HE 20 ($/MWh)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Marginal Resource (Fuel Type)	Notable Events
18	**<=12**			A gas-fired generator scheduled for 265 MW in pre-dispatch for HE 19 was not scheduled in real-time due to equipment concerns
19	**1**	25.62	Water	
19	**2**	55.86	Combined Cycle	
19	**3**	56.13	Combined Cycle	
19	**4**	59.48	Combined Cycle	
19	**5**	67.42		The same gas-fired generator was scheduled for 13.2 MW in pre-dispatch for HE 20 but was not scheduled in real-time due to equipment concerns
19	**6**	217.03	Water	
19	**7**	201.00	Water	Coal-fired generator derated 30 MW until HE 21
19	**8**	466.32	Water	
19	**9**	472.00	Water	
19	**10**	472.00	Water	
19	**11**	473.00	Water	
19	**12**	600.01	Water	
Average		**263.82**		
20	**1**	556.19	Water	Failed import of 160 MW
20	**2**	575.01	Water	
20	**3**	557.40	Water	
20	**4**	575.02	Water	
20	**5**	473.00	Water	
20	**6**	320.13	Water	
20	**7**	472.00	Water	
20	**8**	227.10	Water	
20	**9**	320.13	Water	
20	**10**	227.10	Water	
20	**11**	145.72	Combined Cycle	
20	**12**	227.10	Water	
Average		**389.66**		

Contributing to lower than expected real-time supply, a gas-fired generator (referred to in Table 2-11) was scheduled to synchronize to the grid in HE 13 under the spare generation on-line (SGOL) program, but failed to ignite, resulting in nearly 300 MW of lost capacity. When a unit is committed under the SGOL program, a constraint is entered into the dispatch scheduling optimizer (DSO) ensuring that the unit is never dispatched below its minimum loading point for the duration of the commitment. With the unit unavailable, the market participant called the

IESO control room requesting permission to remove its offers, a necessary step when committed under the SGOL program. The IESO approved the request, but the market participant failed to remove its offers from the energy market. With valid offers still in the market, the unit continued to receive one-hour ahead pre-dispatch schedules, most notably for 265 MW in HE 19 and 13.2 MW in HE 20. While the unit continued to be scheduled in iterative pre-dispatch runs, the unit was never scheduled in the real-time unconstrained schedule because the unit's station breaker was open, preventing the DSO from giving it a real-time schedule. The failure of the market participant to remove its offers resulted in the scheduling of megawatts in pre-dispatch that were not available in real-time, creating a suppressed pre-dispatch price for the high-price hours.[57]

During interval 7 of HE 19, a coal-fired generator was derated due to equipment concerns, removing 30 MW of previously-scheduled generation from the supply stack. This loss of supply contributed to a price spike, from $201.00/MWh in interval 7 to $466.32/MWh in interval 8. The de-rating also had implications for HE 20, as 30 MW of generation that was scheduled in pre-dispatch was unavailable in real-time. The end of the de-rating in HE 21 contributed to the normalization of prices following the two high-price hours.

2.1.3 Overall Assessment of High-Price Hours

The three high-price hours in the Winter 2012 Period were primarily caused by lower than anticipated supply, mainly from self-scheduling and intermittent resources (particularly wind), coupled with higher than forecasted demand for the March 4, 2012 high-price hours.[58]

With all three high-price hours occurring on a weekend when forecasted demand is relatively lower than weekday forecasts, the day-ahead commitment process committed relatively fewer

[57] The same effect was at play during other hours of the SGOL run. However, the pre-dispatch to real-time supply discrepancy created by the participant's failure to remove offers was not enough to trigger a high-price event in those hours.
[58] As noted in Chapter 1, the IESO implemented a centralized wind forecasting program effective October, 2012. This is expected to alleviate some of the forecast errors associated with wind generation.

not quick start units day-ahead.[59] When real-time arrived and supply-demand conditions tightened, there were fewer not quick start units online to cushion the tightening conditions, requiring the DSO to dispatch a faster ramping and more expensive unit, thus contributing to the high-price events.

2.2 *Analysis of Low-Price Hours*

Table 2-12 presents the number of hours when the HOEP was less than $20/MWh (including when it was negative), by month, in the Winter 2012 Period and the preceding four winter periods. The total number of low-price hours increased by 1,175 hours (228%) to 1,690 in the Winter 2012 Period relative to the previous winter period.

Table 2-12: Number of Hours with Low (<$20/MWh) and Negative HOEP November – April, 2007/2008 to November – April 2011/2012 (Number of Hours)

Month	Hours when HOEP < $20/MWh					Hours when HOEP < $0/MWh				
	2007 /2008	2008 /2009	2009 /2010	2010 /2011	2011 /2012	2007 /2008	2008 /2009	2009 /2010	2010 /2011	2011 /2012
November	10	31	181	75	101	0	0	16	3	13
December	78	62	50	62	151	0	5	0	9	14
January	59	25	11	73	81	0	0	1	11	9
February	30	25	2	27	136	4	0	0	0	2
March	0	192	112	67	589	0	58	0	3	44
April	84	354	104	211	632	1	156	9	27	5
Total	**261**	**689**	**460**	**515**	**1,690**	**5**	**219**	**26**	**53**	**87**

As outlined in previous Panel reports, the primary factors leading to low-price hours are:[60]

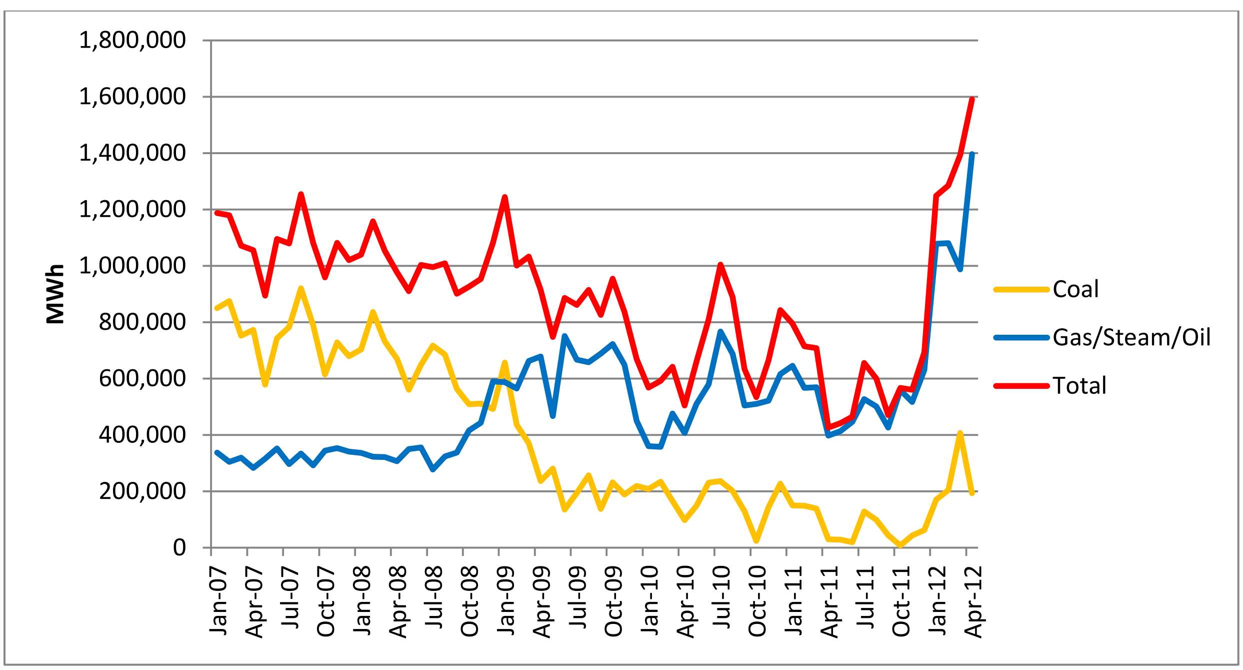
- low market demand;
- abundant low-priced supply, defined as supply that is offered at a price of less than $20/MWh (typically offered by nuclear, baseload hydro, self-scheduling and intermittent generation, and fossil fuel-fired generation up to minimum loading point);

[59] A not quick start unit is one that cannot synchronize and follow a dispatch instruction within a 5-minute dispatch interval.
[60] These factors were first identified in the Panel's June 2004 Monitoring Report (at pp. 84-85), available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_140604.pdf

- pre-dispatch to real-time 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 by reducing demand in real-time relative to pre-dispatch).

Much of the increase in the number of low-price hours experienced in the Winter 2012 Period can be attributed to a sharp increase in the amount of fossil fuel-fired generation being offered at less than $20/MWh, particularly gas-fired generation. More gas-fired generation offered at low prices leads to low-price hours even at higher levels of demand. As shown in Tables 2-13 and 2-14, average demand during low-price hours was 14,714 MW in the Winter 2012 Period, up from an average of 14,144 MW in the 2010/2011 winter period. Figure 2-2 displays the total MWs offered at less than $20/MWh by fossil fuel-fired generators by month from January 2007 to April 2012.

Figure 2-2: Fossil Fuel-Fired Generation Offered at < $20/MWh
January 2007 to April 2012
(MWh)

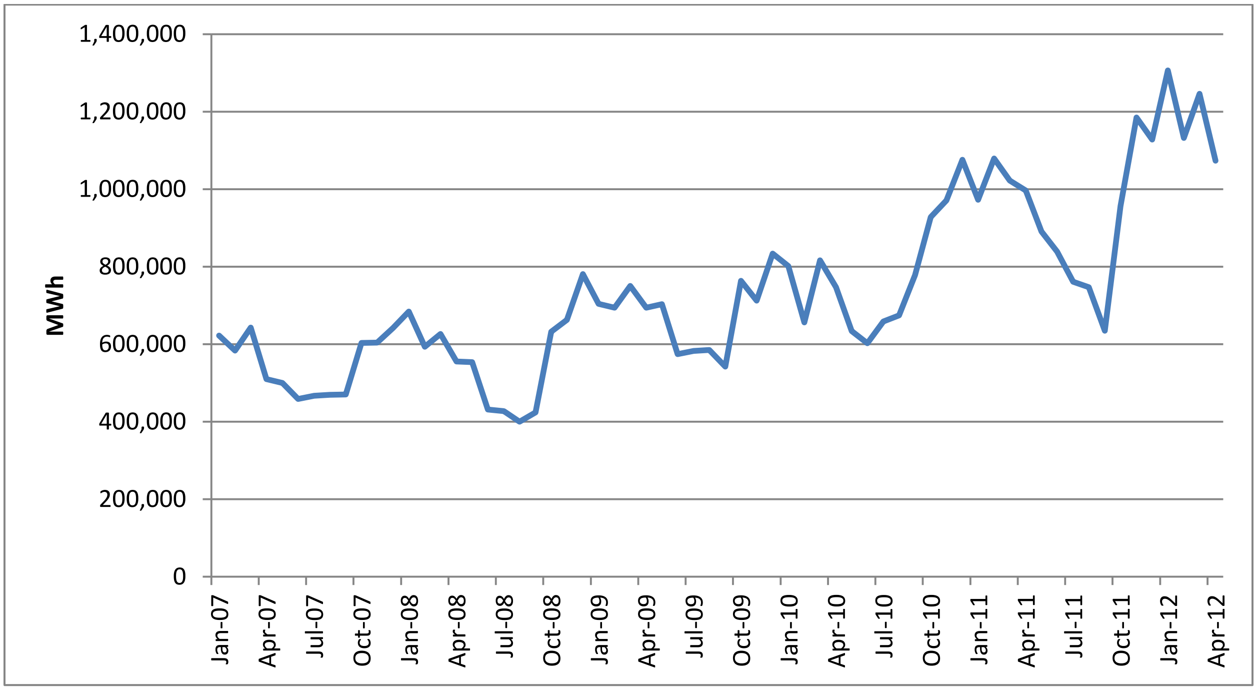


Total low-priced supply from fossil fuel-fired units declined considerably from January 2007 to April 2011. This trend was largely driven by decreases in low-priced supply from coal-fired generators as some units were decommissioned and others offered reduced capacity. Low-priced supply from fossil fuel-fired units then spiked in late 2011, as the amount of gas-fired generation (and associated steam-fired generation) offered at less than $20/MWh increased considerably. The increase in the amount of low-priced supply from gas-fired generators in the Winter 2012 Period was in part due to increases in the installed capacity of gas generation and sharp decreases in the price of gas from $4.19/MMBtu in September 2011 to $2.31/MMBtu in April 2012 (for the Dawn average monthly spot price, see Table 1-26).[61]

The amount of real-time self-scheduling and intermittent generation had a considerable effect on the frequency of low-price hours. Due to the non-dispatchable nature of these generators, all real-time megawatts that they produce are priced at the minimum market clearing price of -$2,000/MWh to ensure that they are dispatched. Any increase in the amount of self-scheduling and intermittent generation therefore increases the amount of negative-priced supply in the real-time energy market, thus leading to low-price hours even at higher levels of demand. Figure 2-3 displays total real-time generation from self-scheduling and intermittent resources by month from January 2007 to April 2012.

[61] The Panel has noted that the amount of low-priced supply offered by fossil fuel-fired generators increased considerably around the time that the enhanced day-ahead commitment process was implemented in October 2011. The Panel has yet to conduct an analysis of the enhanced day-ahead commitment process, but on a preliminary basis it appears that changes in offer behaviour associated with that process may be contributing to the increased amount of low-priced supply offered by fossil fuel-fired generators.

Figure 2-3: Self-Scheduling and Intermittent Generation
January 2007 to April 2012
(MWh)



Monthly output from self-scheduling and intermittent generation resources has more than doubled since January 2007, coinciding with the increased frequency of low-price hours over the same period. This increase in output is primarily the result of significant additions to the installed capacity of wind generation across the province. Total monthly output from self-scheduling and intermittent resources has exhibited a strong seasonal pattern – there is considerably less production in the summer months than in the remainder of the year. Lower levels of output in the summer reflect the decrease in production from wind generators due to lower wind levels relative to the winter months. Run-of-the-river hydroelectric facilities also produce less in the summer, as water levels are lower at that time, relative to the freshet conditions experienced during the spring. The difference in output from self-scheduling and intermittent generation resources between the winter output peaks and the summer troughs has become more pronounced as more wind generation capacity has been added to the system.

As shown in Table 2-12, the number of hours when the HOEP was negative also increased substantially in the Winter 2012 Period relative to the previous winter period. There were 87 negative-price hours, up 34 hours (64%) from 53 hours in the previous winter period. However, the number of negative-price hours in the Winter 2012 Period was still much lower than the total during the 2008/2009 winter period. For the first time in the last five winter periods, every month in the Winter 2012 Period had at least one negative-price hour.

Table 2-13 shows real-time scheduled supply by resource or transaction type, including average hourly scheduled imports (but excluding linked wheeling transactions), as well as unscheduled generation that offered at prices less than $20/MWh for all low-price hours in the Winter 2012 Period. For comparative purposes, Table 2-14 shows the same for all low-price hours in the 2010/2011 winter period. Generation resources are shown by resource type as follows: nuclear, baseload hydro,[62] other hydroelectric,[63] self-scheduling and intermittent, and gas-/coal-fired (including steam units at combined cycle plants).

Table 2-13: Low-Priced Supply During Low-Price Hours November 2011 to April 2012 (MW)

Month	Low-Priced Supply							Total
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Scheduled Gas/Coal (including steam)	Imports (excluding linked wheels)	Unscheduled Generation (offering <$20/MWh)	
November	8,838	1,856	1,838	876	977	221	577	15,183
December	9,758	1,858	1,813	1,182	839	200	706	16,356
January	9,492	1,929	2,082	1,199	957	286	698	16,643
February	9,189	2,207	1,808	1,254	1,386	239	1,040	17,123
March	9,311	2,335	1,716	1,862	1,203	346	1,498	18,271
April	8,804	2,341	1,510	1,877	1,589	463	1,174	17,758
Average	**9,132**	**2,236**	**1,680**	**1,667**	**1,304**	**358**	**1,176**	**17,553**

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

62 For the purposes of the current analysis, baseload hydro resources include the generators at the Beck, Saunders, and DeCew Falls stations owned by Ontario Power Generation. Payment amounts for the output from these facilities are set by the Ontario Energy Board.

63 Market participants that operate non-baseload hydro units may wish to operate even when market prices are low when the supply of water is abundant, as spilling is the only alternative.

Freshet conditions led to increases in scheduled generation from both baseload and other hydro resources, and contributed to increases in total low-priced supply during the spring months.[64] As discussed under Figure 2-2, the considerable amount of gas-fired generation being offered and scheduled at prices below $20/MWh in the Winter 2012 Period can be partly attributed to increases in the installed capacity of gas generation coupled with low gas prices.

As noted above, the number of low-price hours increased considerably from 515 in the 2010/2011 winter period to 1,690 in the Winter 2012 Period, with supply-side factors (particularly wind and gas-fired generation) playing a large role in that increase.

Table 2-14: Low-Priced Supply During Low-Price Hours November 2010 to April 2011 (MW)

Month	Low-Priced Supply							Total
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Scheduled Gas/Coal (including steam)	Imports (excluding linked wheels)	Unscheduled Generation (offering <$20/MWh)	
November	9,769	1,678	1,684	781	876	677	1,598	17,063
December	10,999	1,787	1,646	1,378	882	443	643	17,778
January	11,267	1,841	1,627	1,305	837	174	650	17,702
February	10,111	1,953	1,922	1,745	1,049	364	485	17,629
March	10,020	2,044	1,670	1,170	841	298	403	16,446
April	9,416	2,015	1,506	1,663	472	276	671	16,019
Average	**10,035**	**1,914**	**1,609**	**1,390**	**710**	**347**	**755**	**16,761**

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

Average low-priced supply during low-price hours increased from 16,761 MW in the 2010/2011 winter period to 17,553 MW in the Winter 2012 Period, an increase of 4.7%. Scheduled fossil fuel-fired generation increased by 594 MW (84%) to 1,304 MW, while capacity offered by units that went unscheduled (typically top of the supply stack gas-fired generation) increased 421 MW (56%) to 1,176 MW. Scheduled output from both baseload and peaking hydroelectric facilities also increased by a combined 599 MW (18%). Despite significant increases in the amount of self-scheduling and intermittent generation in the Winter 2012 Period

[64] Freshet is a condition in which melting snow and heavy rains during the spring months lead to high water levels.

relative to the preceding winter period, their output during low-price hours only increased by 71 MW (4.4%) to 1,680 MW. With increases in self-scheduling, intermittent, and hydroelectric supply offered at deeply negative prices, nuclear generation was pushed further up the supply stack, resulting in an average decrease in scheduled nuclear generation of 903 MW (9%) in the Winter 2012 Period relative to the 2010/2011winter period.

Summary statistics related to demand conditions during the Winter 2012 Period low-price hours are presented in Table 2-15. The table includes monthly average Ontario demand, exports (excluding linked wheeling transactions) and total market demand during the low-price hours. Excess low-priced supply is presented in the final column of Table 2-15, and is calculated as the difference between low-priced supply (see Table 2-13) and market demand over all low-price hours.

Table 2-15: Demand and Excess Low-Priced Supply During Low-Price Hours November 2011 to April 2012 (MW)

Month	Number of Low-Price Hours	Demand			Excess Low-Priced Supply
		Ontario Demand	Exports (excluding linked wheels)	Market Demand	
November	101	13,275	1,330	14,605	577
December	151	14,458	1,192	15,650	706
January	81	14,598	1,346	15,944	698
February	136	14,831	1,251	16,082	1,040
March	589	15,093	1,679	16,772	1,498
April	632	14,641	1,944	16,585	1,174
Average	**1,690**	**14,714**	**1,663**	**16,377**	**1,176**

On average, excess low-priced supply (including scheduled imports) was 1,176 MW (7.2%) higher than total market demand during the low-price hours in the Winter 2012 Period. Despite March having the highest average monthly market demand during low-price hours, excess low-priced supply reached a Winter 2012 Period maximum of 1,498 MW during that month. Excess low-priced supply in the Winter 2012 Period was lowest in November 2011, at 577 MW.

Table 2-16 provides additional summary information by month for all low-price hours in the Winter 2012 Period, 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 from differences between peak and average demand within an hour. Pre-dispatch prices during the low-price hours were on average $4.30/MWh (34%) above real-time prices in the Winter 2012 Period. An average demand discrepancy of 94 MW (0.6%) from pre-dispatch to real-time was the primary reason for the price divergence, while average failed net exports of -61 MW (i.e. failed imports, representing a loss of expected supply) put upward pressure on real-time prices. The largest discrepancy between real-time and pre-dispatch prices occurred in November 2011, when on average 172 MW of forecasted demand and 22 MW of net exports failed to materialize in real-time. These discrepancies led to real-time prices that were, on average, $15.94/MWh (77%) below the pre-dispatch price.

Table 2-16: Average Monthly Summary Data for Low-Price Hours November 2011 to April 2012 (MW & $/MWh)

Month	Excess Low-Priced Supply (MW)	Failed Net Exports (MW)	RT Average Demand (MW)	PD Demand Forecast (MW)	PD to RT Demand Deviation (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)	Price Difference (HOEP - PD) ($/MWh)
November	578	22	13,275	13,447	172	4.70	20.64	-15.94
December	706	10	14,458	14,646	188	10.46	18.98	-8.52
January	699	-59	14,598	14,736	138	7.83	18.09	-10.26
February	1,041	-38	14,831	14,957	126	17.36	19.15	-1.79
March	1,499	-58	15,093	15,178	85	10.36	15.28	-4.92
April	1,173	-98	14,641	14,696	55	15.84	16.46	-0.62
Average	**1,176**	**-61**	**14,714**	**14,808**	**94**	**12.52**	**16.82**	**-4.30**

The following analysis outlines the market conditions that led to four consecutive negative-price hours, including the Winter 2012 Period's lowest-price hour, in the early morning of January 2, 2012.

2.2.1 January 2, 2012 HE 2 to HE 5

On Monday, January 2, 2012 (a statutory holiday), the HOEP dropped to -$69.78/MWh in HE 2, the first of four consecutive negative-price hours. One hour later in HE 3, the HOEP reached a Winter 2012 Period low of -$128.25/MWh, the sixth lowest HOEP since market opening.[65] The HOEP remained negative for two more hours before returning to a positive price in HE 6. The prolonged decrease in price was caused by low overnight demand, surplus baseload generation (SBG), over-forecasted demand, and numerous exports being cut by external jurisdictions in real-time due to SBG conditions in those areas. Discrepancies between the forecast and actual output from self-scheduling and intermittent generation resources had moderate effects on pre-dispatch to real-time price differences in respect of the four negative-price hours.

Prices, Demand and Supply

Table 2-17 displays HOEP, real-time hourly average Ontario demand and net exports for HE 1 to HE 6 on January 2, 2012.

Table 2-17: HOEP, Ontario Demand and Net Exports January 2, 2012 HE 1 to HE 6 (MW & $/MWh)

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)
1	15.52	13,516	1,008	14,524	-428
2	-69.78	13,018	1,034	14,052	-472
3	-128.25	12,775	738	13,513	-539
4	-128.23	12,699	786	13,485	-28
5	-80.75	12,735	1,302	14,037	552
6	24.57	13,118	1,780	14,898	861

Ontario demand followed its typical overnight decline and the HOEP became negative as the market transitioned into the overnight demand trough. Ontario demand fell consistently until it bottomed out in HE 4 at 12,699 MW, after which it started to pick back up for the typical

[65] The lowest HOEP in the history of the Ontario market was -$138.79/MWh on April 30, 2011 in HE 24: see the Panel's November 2011 Monitoring Report (at pp. 105-107), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf

morning increase in demand. Real-time net exports varied greatly hour-to-hour due to substantial cuts to real-time exports in some hours.

Table 2-18 below shows real-time scheduled supply by resource or transaction type, including average hourly scheduled imports (but excluding linked wheeling transactions), as well as unscheduled generation that offered at prices less than $20/MWh for the four consecutive negative-price hours on January 2, 2012. Total low-priced supply averaged 15,922 MW during the four-hour period, with scheduled nuclear generation contributing an average of 8,874 MW (56%) per hour. Gas- and steam-fired generation continued to be scheduled during negative-price hours at an average rate of 474 MW per hour (several gas-fired generators offer at deeply negative prices to ensure dispatch, but get paid the HOEP). Self-scheduling and intermittent generation resources contributed significantly to the amount of generation, producing an average of 2,504 MW an hour.

Table 2-18: Low-Priced Supply During Negative-Price Hours
January 2, 2012 HE 2 to HE 5
(MW)

Delivery Hour	Low-Priced Supply							Total
	Scheduled Nuclear	Scheduled Baseload Hydro*	Scheduled Self-Scheduling and Intermittent	Other Scheduled Hydro	Scheduled Gas (including steam)	Imports (excluding linked wheels)	Unscheduled Generation (offering <$20/MWh)	
2	8,972	1,774	2,530	293	483	0	2,073	16,125
3	8,664	1,533	2,538	312	467	55	2,266	15,835
4	8,689	1,533	2,484	312	467	0	2,385	15,870
5	9,169	1,562	2,462	365	480	35	1,777	15,850
Average	**8,874**	**1,601**	**2,504**	**321**	**474**	**23**	**2,125**	**15,922**

Table 2-19 shows average Ontario demand, exports (excluding linked wheeling transactions) and total market demand during the four negative-price hours on January 2, 2012. Excess low-priced supply is presented in the final column of Table 2-19, and is calculated as the difference between low-priced supply (see Table 2-18) and market demand over all low-price hours. On average, there was 2,128 MW of excess low-priced supply, with a maximum excess of 2,385 MW in HE 4 when market demand was lowest.

Table 2-19: Demand and Excess Low-Priced Supply during Negative-Price Hours January 2, 2012 HE 2 to HE 5 (MW)

Delivery Hour	Demand			Excess Low-Priced Supply
	Average Ontario Demand	Exports (excluding linked wheels)	Market Demand	
2	13,018	1,034	14,052	2,073
3	12,775	793	13,568	2,267
4	12,699	786	13,485	2,385
5	12,735	1,337	14,072	1,778
Average	**12,807**	**988**	**13,794**	**2,128**

Low demand and considerable baseload generation meant that the IESO was operating under SBG conditions. Having forecasted these conditions a day in advance, the IESO control room re-priced all wind offers from -$1/MWh to -$2,000/MWh to create more accurate pre-dispatch schedules and prices.[66] The SBG conditions between HE 1 and HE 5 also led the IESO to ramp down two nuclear units and curtail most imports to balance supply and demand.

Table 2-20 displays pre-dispatch prices as well as pre-dispatch Ontario demand and net exports for the four negative-price hours on January 2, 2012.

[66] For more information regarding the process and implications of re-pricing wind generation, see the Panel's April 2012 Monitoring Report, available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf

***Table 2-20: Pre-dispatch Demand, MCP and Net Exports
January 2, 2012 HE 2 to HE 5
(MW & $/MWh)***

Delivery Hour	Pre-dispatch Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)
2	11.40	13,120	310	1,505	1,195
3	15.52	13,008	440	1,501	1,061
4	7.99	12,885	0	1,094	1,094
5	13.15	12,954	335	1,501	1,166

Final pre-dispatch prices were positive for all four of the consecutive negative-price hours, hence failing to provide a reliable prediction of real-time market conditions. Pre-dispatch import and export levels in HE 4 were lower relative to the other three hours because of the preemptive curtailment (i.e. cut prior to the final pre-dispatch run) of imports by the IESO and of exports by external jurisdictions. Some exports were also preemptively curtailed in HE 5.

Table 2-21 shows all intertie transactions and curtailments by jurisdiction for the four consecutive negative-price hours on January 2, 2012. Transactions that were preemptively curtailed (in advance of the final pre-dispatch run) and thus did not contribute to pre-dispatch to real-time discrepancies are shown separately from those that were curtailed in real-time (following the final pre-dispatch run) and that led to pre-dispatch to real-time supply-demand discrepancies. Given forecasted SBG conditions, the IESO made the initial curtailments to imports, following which some exports were curtailed by external jurisdictions. All imports from Manitoba, Michigan, and Québec were curtailed, leaving no further maneuverability for the purposes of trying to alleviate SBG conditions. Import transactions from Minnesota and New York totaling 55 MW in HE 3 and 60 MW in HE 5 were scheduled in real-time and could have been curtailed had SBG conditions worsened. According to IESO control room logs, export transactions wheeled through Michigan and Québec were heavily curtailed due to SBG conditions in their destination markets—PJM and ISO New England, respectively. All export transactions destined for New York that did not flow in real-time were transactions that failed for non-SBG related reasons (typically by reason of the participant failing to match schedules in both markets and acquire the necessary transmission). They were not curtailed. With considerable real-time export transactions still flowing to New York, it is possible that a more accurate pre-dispatch price could have led to greater net exports scheduled at this interconnection, helping to partially alleviate SBG conditions in Ontario.

Table 2-21: Intertie Transactions and Curtailments by Jurisdiction
January 2, 2012 HE 2 to HE 5
(MW)

Intertie Zone	Delivery Hour	Curtailments (MW)			Real-Time Transactions (MW)		
		Import	Export	Net	Import	Export	Net
Manitoba	**2**	275	0	-275	0	0	0
	3	275	0	-275	0	0	0
	4	226*	0	-226	0	0	0
	5	275	0	-275	0	0	0
Michigan	**2**	0	325	325	0	325	325
	3	75	600	525	0	0	0
	4	100*	758*	658	0	0	0
	5	0	350*	350	0	225	225
Minnesota	**2**	35	0	-35	0	0	0
	3	35	0	-35	55	0	-55
	4	35*	0	-35	0	0	0
	5	0	0	0	35	0	-35
New York	**2**	0	55†	55	0	440	440
	3	0	100†	100	0	390	390
	4	0	308†	0	0	375	375
	5	0	25†	25	25	865	840
Quebec	**2**	0	91	91	0	269	269
	3	0	8	8	0	403	403
	4	0	0	0	0	411	411
	5	0	114	114	0	272	272

* Denotes an intertie transaction that was preemptively curtailed (i.e., curtailed before the final pre-dispatch run). Only 450 MW of the 758 MW curtailed in HE 4 in Michigan were preemptively curtailed
† Denotes an intertie transaction that failed for reasons other than SBG. These transactions were not curtailed

Table 2-22 displays the supply and demand forecast discrepancy that contributed to the price differential between final pre-dispatch and real-time for the four negative-price hours on January 2, 2012.

Table 2-22: Pre-dispatch and Real-time Demand and Supply Conditions January 2, 2012 HE 2 to HE 5 (MW)

HE	Average Ontario Demand (MW)			Average Self-Scheduling and Intermittent Generation (MW)			Net Exports (MW)			Total PD vs. RT Discrepancy
	PD	RT	PD - RT	PD	RT	RT - PD	PD	RT	Failed	
2	13,120	13,018	102	2,458	2,530	72	1,195	1,034	161	335
3	13,008	12,775	233	2,454	2,538	84	1,061	738	323	640
4	12,885	12,699	186	2,416	2,484	68	1,094	786	308	562
5	12,954	12,735	219	2,467	2,462	-5	1,166	1,302	-136	78

Real-time average hourly Ontario demand was over-forecast in all four negative-price hours, reaching a maximum average discrepancy of 233 MW (1.8%) in HE 3. Although imports were curtailed to reduce market supply, real-time demand from net exports was nonetheless lower than scheduled in pre-dispatch due to the curtailment of Ontario exports by neighbouring jurisdictions. In HE 5, an increased flow of exports into Michigan, coupled with significant cuts to imports, helped rebalance supply-demand conditions and put upward pressure on the real-time price.

Self-scheduling and intermittent generators contributed in a moderate fashion to the downward pressure on prices in HE 2 through HE 4. These units over-supplied by about 3% over forecasted levels, exacerbating excess supply conditions.

In summary, the four consecutive low-price hours experienced on January 2, 2012 were a result of low overnight demand, SBG, over-forecasted demand, and numerous exports being cut by external jurisdictions in real-time due to SBG conditions in those areas. Discrepancies between pre-dispatch and real-time demand and sources of supply led to poor pre-dispatch price fidelity. A more accurate pre-dispatch price may have helped partially relieve excess supply conditions, as a negative pre-dispatch price could have induced greater scheduled net exports during the negative-price hours. However, some of those additional exports would likely have been curtailed by other jurisdictions due to the SBG conditions that prevailed there.

3. Anomalous Uplift

3.1 Congestion Management Settlement Credit Payments

As noted earlier in this chapter, the Panel considers hours in which CMSC payments exceed \$500,000 to be anomalous. In the Winter 2012 Period, one hour met this threshold.

Transactions in HE 19 on February 12, 2012 attracted a total of \$575,529 in CMSC payments. Payments made in respect of exports on the Outaouais interface accounted for \$559,052 (97%) of that total amount. An internal transmission constraint at the Hawthorne transmission station necessitated that all exports on the Outaouais intertie be cut in real-time, resulting in large constrained-off CMSC payments to multiple market participants transacting at the interface.[67] Aside from the payments associated with these exports, no market participant received more than \$6,000 in CMSC payments per facility in respect of HE 19.

As also noted above, the Panel considers CMSC payments in excess of \$1,000,000 on a given day to be anomalous. There were no such days in the Winter 2012 Period.

The highest CMSC payments per day were incurred on November 6, 2011, in respect of which a total of \$845,040 was paid to numerous market participants across the province. Of that total, \$476,728 was paid in respect of three nuclear units at the same facility. Those units were constrained-off for the majority of the day due to a planned outage on two transmission lines in close proximity to the facility. With two critical lines out of service, the nuclear facility was required to reduce its output to avoid overloading the local transmission system in the event that a further contingency were to occur.

Fossil fuel-fired generators also received \$194,347 in CMSC payments in respect of numerous facilities on November 6, 2011. Of that total, \$145,298 (75%) was paid to gas-fired generators who were committed under the day-ahead commitment process but were uneconomic in real-time, and were constrained-on as a result. This typically occurs during the lower-priced overnight hours when the day-ahead scheduling process determines that keeping a not quick start

[67] These types of transactions are reviewed by the IESO under its local market power framework. The IESO has historically clawed back the majority of CMSC payments under similar conditions

facility generating and receiving CMSC payments is a more economic option than shutting that facility down and restarting it later in the day given the additional start-up costs.

A further $128,338 in CMSC payments were made on November 6, 2011 in respect of various intertie transactions, primarily on the Michigan, New York, and Québec interties. The remainder of the CMSC payments were made to various hydroelectric generators and dispatchable loads.

3.1 Operating Reserve Payments

As noted earlier in this chapter, the Panel considers hours in which total OR payments exceed $100,000 to be anomalous. There were no such hours in the Winter 2012 Period.

High OR payments are associated with instances of high OR prices. Due to the joint optimization of the energy and OR markets, energy and OR prices typically move in the same direction as supply and demand conditions change. Instances of high OR prices and OR payments are typically associated with tight supply conditions in both the energy and OR markets. Three of the five highest OR payment hours in the Winter 2012 Period occurred during or immediately after the March 4, 2012 high-price hours that were discussed in section 2.1.

3.2 Intertie Offer Guarantee Payments

As noted earlier in this chapter, IOG payments in excess of $500,000 for a given hour or in excess of $1,000,000 for a given day are considered anomalous by the Panel. There were no such hours or days in the Winter 2012 Period.

The largest hourly IOG payments were incurred on March 5, 2012 in HE 23, in respect of which $325,407 was paid, all to a single participant. This uplift event is discussed in detail in chapter 3. This highest IOG payment hour in turn contributed to the highest IOG daily payments for the Winter 2012 Period, totalling $377,609 on March 5, 2012.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. Introduction

This Chapter summarizes notable changes and developments that affect the efficient operation of the IESO-administered markets, making recommendations where relevant to promote market objectives. Section 2 identifies a material change that has occurred in the market since issuance of the Panel's last monitoring report, while section 3 provides an update on Panel investigations. In section 4, the Panel discusses four matters: the enhanced day-ahead commitment process and a related design issue, issues arising in the transmission rights market, specific transmission rights issues at the Minnesota interface, and issues associated with import congestion at the Manitoba interface.

2. Material Change to the Market

This section provides an update on the installation of phase angle regulators (PARs) at the Michigan interface.

2.1 Operation of the Phase Angle Regulators at the Michigan Interface

A PAR is a special transformer that is used to control the power flowing over a transmission line. There are currently five PARs on four transmission lines at the Ontario-Michigan interface (three owned by Ontario's Hydro One and two by Michigan's International Transmission Company (ITC)), with an estimated capability of controlling up to 600 MW of Lake Erie Circulation (LEC), often referred to as "loop flow".[68] To effectively control LEC, PAR control is required on all in-service circuits. With any one of the PARs out of service or by-passed, the remaining PARs have limited capability to control LEC.

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[68] For an explanation of the causes and implications of loop flow, see the Panel's July 2009 Monitoring Report (at pp. 166-180), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf

The two PARs owned by ITC were installed in 2009 but did not come into service until April 5, 2012[69] following lengthy regulatory proceedings in the United States.

The Panel had recommended on multiple occasions that all PARs be brought into service as soon as possible due to the potentially large efficiency gains to Ontario and external markets that were expected to ensue.[70] The Panel commends the considerable efforts expended by the IESO over a prolonged period of time to get the ITC PARs into operation. Since the two ITC PARs began operating in April 2012, the Panel has observed significant reductions in LEC. Further analysis may be included in a future report.

3. Panel Investigations

3.1 Completion of Investigations Regarding Infeasible Import Transactions Offered by Two Market Participants

In March 2011, the then Chair of the Ontario Energy Board (OEB) requested that the Panel undertake an investigation into the circumstances that lead to Congestion Management Settlement Credit (CMSC) payments being made to two market participants for constrained-off imports at the Manitoba interface. The import offer transactions at issue, which in the aggregate attracted CMSC payments of approximately $162,500, occurred over a two-day period during which a transmission de-rating in Manitoba precluded transactions from flowing.[71]

[69] For a more detailed chronology, refer to the Panel's March 2011 Monitoring Report (at pp. 66-67), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf
[70] See the following Panel Monitoring Reports, all available at http://www.ontarioenergyboard.ca/OEB/Industry/About the OEB/Electricity Market Surveillance/Market Surveillance Panel Reports: December 2005 Monitoring Report, pp. 79-82; July 2006 Monitoring Report, pp. 100-102; January 2008 Monitoring Report, pp. 146-151; July 2009 Monitoring Report, pp. 164-181; and January 2010 Monitoring Report, pp. 69-84.
[71] The transactions were discussed in the Panel's March 2011 Monitoring Report (at pp. 67-70), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf

The Panel commenced separate gaming investigations in respect of each of the two market participants – TransAlta Energy Marketing Corp. and West Oaks NY/NE, LP – and issued its reports in October 2012.[72]

In its reports, the Panel confirmed that gaming encompasses, among others, conduct that involves the four following elements: (i) a "market defect" (being a defect in the market design, poorly specified rules or procedures, or a gap in the Market Rules or procedures); (ii) exploitation of the market defect by the market participant; (iii) profit or other benefit to the market participant; and (iv) expense or disadvantage to the market.

The Panel concluded that neither market participant exploited the Manitoba de-rating for the purpose of receiving CMSC payments, and therefore that neither market participant engaged in gaming in respect of the transactions at issue. Among other things, the Panel noted that information detailing the Manitoba de-rating was not identified in the IESO's System Status Reports (or similar reports) or on the Midwest Independent Transmission System Operator (MISO) OASIS (the website used to obtain transmission capacity in Manitoba).

The Panel also noted that, in many hours of the period covered by the investigations, the import transactions at issue were constrained off as a result of internal constraints in Ontario, resulting in CMSC payments regardless of the transmission de-rating in Manitoba. In certain hours, the IESO pre-emptively curtailed the imports prior to pre-dispatch and, as a result, those transactions did not attract CMSC payments. Pre-emptive curtailment therefore avoided CMSC payments in those cases.

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[72] The Panel's October 22, 2012 "Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions Offered by TransAlta Energy Marketing Corp. on the Manitoba-Ontario Intertie" (the TA Report) is available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Investigation_TranAlta_20121022.pdf and its "Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions Offered by West Oaks NY/NE, LP on the Manitoba-Ontario Intertie" (the WO Report), also dated October 22, 2012, is available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Investigation_WestOaks_20121022.pdf

While the Panel concluded that gaming did not occur, it did identify enhancements that could be made to the procedures of the IESO that it believes would serve to avoid unwarranted CMSC payments and to inform market participants about intertie conditions in the future. The Panel's recommendations in this regard are as follows:

> *Where the IESO is aware that an external constraint would prevent a transaction from flowing over an intertie at a given time, the IESO should remove that transaction from the unconstrained schedule. By removing the transaction from the unconstrained schedule unwarranted CMSC payments will be avoided.*[73]
>
> *Where the IESO is aware of conditions that will prevent or reduce the ability for power to flow at an Ontario intertie, the IESO should reflect this information in its public reports.*[74]

With respect to the first recommendation, the Panel understands that IESO staff does not consider that the removal of infeasible transactions from the unconstrained schedule is appropriate for all circumstances. Rather, they suggest that situations of the type that underpinned the two above-described investigations are best addressed through the monitoring of participant behaviour, complemented by the application of existing procedures for pre-emptive curtailments and the recent Market Rule amendment that limits CMSC payments in respect of imports injected into a "designated chronically congested area".[75]

The Panel generally considers that the best approach to addressing a design issue that creates opportunities for unwarranted payments is to change the design so that those opportunities are

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[73] TA Report at pp. 2 and 30, and WO Report at pp. 2 and 29.
[74] *Ibid.*
[75] Under amendments to Chapters 9 and 11 of the Market Rules that came into effect on October 1, 2012, an import transaction in a "designated chronically congested area" that is constrained off in the last pre-dispatch run prior to the dispatch hour is not eligible for constrained-off CMSC payments. A "designated chronically congested area" is an area within Ontario, including connected intertie zones, that has been designated as such by the IESO by reason of oversupply due to transmission constraints. Currently, only one area – the Northwest (which includes the Manitoba and Minnesota interties) – has been so designated. For details, see Market Rule Amendment Proposal MR-00395-R00, available at http://www.theimo.com/imoweb/pubs/mr2012/MR-00395-R00_Amendment_Proposal_v5_Board_Approved.pdf.

eliminated. As was revealed in these two investigations, the potential for unwarranted payments may exist in the absence of any gaming behaviour by market participants.

The Panel also notes that the recent Market Rule amendment referred to above currently only applies in the Northwest zone (including the Manitoba and Minnesota interties) and, as such, cannot be applied to address similar issues were they to arise on the Québec, New York or Michigan interties. Pre-emptive curtailment, which occurred in respect of some but not all of the transactions covered by the Panel's two investigations, appears in the Panel's view to be both a readily available and more broad-based option for avoiding unwarranted CMSC payments.

With respect to the Panel's second recommendation, the Panel understands that IESO staff does not consider it appropriate to publish information on external transmission limitations if the completeness or accuracy of that information is in question. The Panel generally agrees that dissemination of this type of information should be the primary responsibility of the scheduling entity that is experiencing the restriction, and is most appropriately communicated by that entity. In the Panel's view, however, as the market and system operator for Ontario the IESO has a role in clarifying or confirming external system conditions that might affect the efficiency of the Ontario market in circumstances where the IESO has some knowledge of the conditions.

In terms of the circumstances that prevailed at the time that the investigated transactions occurred, the Panel notes that the IESO received advance information from Manitoba Hydro outlining a reduction in the east and west transfer limits from Manitoba to Ontario.[76] The Panel acknowledges that the Manitoba de-rating was not clearly identified on the MISO OASIS. The Panel also acknowledges, as noted by IESO staff, that the Balancing Authority for trades over the Manitoba intertie is MISO, and that the IESO coordinates those trades with MISO and not with Manitoba Hydro. However, having been made aware of an issue by Manitoba Hydro, the IESO should in the Panel's view have sought to obtain clarity in respect of forecast system

[76] The notification from Manitoba Hydro was sent on July 9, 2010, and pertained to a reduction in transfer limits from HE 10 on July 13, 2010 to HE 18 on July 15, 2010. See the TA Report at pp. 22 and the WO Report at pp. 15-16.

conditions on the Manitoba intertie and then reflected the pertinent information in its System Status Reports.

This is not to say that market participants bear no responsibility for ascertaining system conditions that are germane to their market transactions. As noted in its reports on the two investigations, it is open to the Panel to consider that there has been gaming in circumstances where relevant information can reasonably be expected to be identified or obtained and the market participant failed to do so.[77]

3.1.1 Other Investigations

The Panel currently has six investigations in progress. These investigations relate to possible gaming issues involving CMSC and other payments. As each of these investigations is completed, the Panel will submit its investigation report to the Chair of the OEB and the report will be published on the OEB's website.[78]

4. New Matters

4.1 The Enhanced Day-Ahead Commitment Process

4.1.1 Introduction

In the summer of 2005, Ontario experienced several heat waves that contributed to tight supply conditions on the power system. In an effort to avoid similar conditions in the future, the IESO developed the Day-Ahead Commitment Process (DACP). The DACP was implemented as a

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[77] In the two investigations, the Panel concluded that it was not necessary to determine the precise standard applicable to the exploitation element of gaming (actual knowledge versus failure to identify or obtain information), as the Panel was satisfied that the market participants were not gaming regardless of which standard was applied. See the TA Report at pp. 19 and the WO Report at pp. 19.

[78] The submission and posting of Panel investigation reports is addressed in Article 7 of the OEB's By-law #3 (Market Surveillance Panel), available at http://www.ontarioenergyboard.ca/OEB/_Documents/About the OEB/OEB_bylaw_3.pdf.

reliability program in June 2006, in advance of the summer peak demand season. Under the DACP, non-quick start units (now referred to as "not quick start" units) (primarily gas- and coal-fired units) [79] were committed one day ahead and were guaranteed recovery of their start-up and minimum generation costs by means of a top-up payment (a "generation cost guarantee") when their real-time market revenues were insufficient to cover those costs.[80] Generators submitted their start-up (fuel and incremental operating and maintenance) and minimum generation costs within a certain period following the dispatch day in question.

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 dispatch inefficiency.[81] In its August 2007 Report, the Panel suggested that the IESO adopt a three-part bidding system with 24-hour optimization and that, in the interim, the IESO should consider mechanisms allowing the "all-in" costs of generators to be measured during scheduling.[82]

The DACP was originally intended to be in place from June 1, 2006 until November 30, 2006,[83] but its use was extended by resolution of the IESO Board of Directors.[84] In the year following the DACP's implementation, the IESO began the process of considering improvements,

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[79] A non-quick start unit is "one that cannot synchronize and follow a dispatch instruction within a 5-minute dispatch interval". See "Quick Takes: Real Time Generation Cost Guarantee", April 2011, available at http://www.ieso.ca/imoweb/pubs/training/QT9_SGOL.pdf.

[80] The DACP also guaranteed importers their offer price if the real-time price turned out to be lower than the importer's offer price.

[81] For details, see the Panel's August 2007 Monitoring Report (at pp. 114-121), available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf and the Panel's April 2012 Monitoring Report (at p. 42), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf

[82] See the Panel's August 2007 Monitoring Report(at p. 120), available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf

[83] See IESO, "IESO Reliability Measures 2006 - Day-Ahead Commitment Process with Reliability Guarantees" (at p. 2), available at http://www.ieso.ca/imoweb/pubs/consult/se16/se16_DACP-design-description-v3.pdf.

[84] See IESO "Participant News, Board Approves Continuation of DACP", November 21, 2006, available at http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3136. At its November 17, 2006 meeting, the IESO Board decided to continue the DACP until such time as another program was implemented and that provided at least equivalent reliability benefits. The IESO Board also resolved that IESO management would conduct and publish a review of the operation and performance of the Day-Ahead Commitment Process on an annual basis. This was done for two years, at which time it was agreed by the IESO Board it was not required to be repeated (see http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20081113-Bentz-Note_to_IESO_BofD.pdf, at p. 2). The Day-Ahead Commitment Process 2007 Annual Report (the 2nd annual report issued by IESO) is available at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20071205-Item8_DACP_Annual_Report_2007.pdf

including a three-part offer process and the possible evolution to a full day-ahead market.[85] After a lengthy stakeholder consultation, the IESO elected to develop an Enhanced Day-Ahead Commitment Process (Enhanced DACP) and in February 2009 released a design document entitled "EDAC Market Design".[86] While the Enhanced DACP was under development, the IESO made some changes to tighten generators' eligibility for cost guarantees.[87]

In its March 2011 report, the Panel recommended that the IESO investigate whether the real-time Generation Cost Guarantee (GCG) program (also known as the Spare Generation On-Line program) continues to provide a net benefit to the Ontario market once the Enhanced DACP is implemented.[88] The Panel understands that such an assessment will be undertaken as part of a future stakeholder engagement consultation which is slated to commence in the first quarter of 2013.[89]

On October 12, 2011, the IESO implemented the Enhanced DACP.[90] Under the Enhanced DACP, all not quick start generators are required to submit three-part offers setting out the basis on which they are willing to be committed day-ahead. However, generators that are not committed in the Enhanced DACP or that have additional capacity that was not scheduled in the Enhanced DACP may still offer into the market and be scheduled in real-time (with or without participating in the real-time GCG program).

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85 See IESO "Day Ahead Market Evolution (SE – 21)", available at http://www.ieso.ca/imoweb/consult/consult_se21.asp
86 See IESO "EDAC Market Design", available at http://www.ieso.ca/imoweb/pubs/consult/se21-edac/se21-20090206-EDAC_Market_Design_v1.pdf. The EDAC Market Design document served as a reference document to facilitate further design discussions with stakeholders and to support the subsequent development of Market Rules, market manuals, and business processes and procedures.
87 See IESO, Market Rule amendment MR-00356-R00, available at: http://www.ieso.ca/imoweb/pubs/mr2009/MR-00356-R00-R02-BA.pdf. That Market Rule amendment removed after-the-fact cost submissions for the costs associated with a generator's minimum generation block run time, and instead tied the minimum generation block run time component of the cost guarantee payment directly to the generator's minimum generation block run time offer price.
88 For details, see the Panel's March 2011 Monitoring Report (at pp. 86-96), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20110310.pdf
89 See "Amendment Submission Q00" from "Agenda Item 4: MR-00396: HE 1 Day-Ahead Production Cost Guarantees Triggered by Ramping Limitations", IESO Technical Panel Meeting Materials, September 18, 2012, available at: http://ieso.ca/imoweb/amendments/tp_meetings.asp and which refers to a stakeholder review of generator guarantee programs. As of the date of this report, the IESO had not launched a formal stakeholder engagement consultation process.
90 For more details on the original and Enhanced DACP programs, see the Panel's April 2012 Monitoring Report (at pp. 41-43), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf

Like its predecessor, the Enhanced DACP is still a commitment process as opposed to a full day-ahead market. The major change is that the Enhanced DACP optimizes the day-ahead schedules based on total not quick start generators' costs (start-up, speed no-load and incremental energy costs via three-part offers) within a 24-hour time horizon, as opposed to just incremental hourly energy offer prices. In other words, the IESO's dispatch algorithm attempts to minimize system-wide costs by taking into account all of the cost components submitted by generators. Generators that are scheduled (committed) in the Enhanced DACP are guaranteed to receive, at a minimum, their as-offered costs as set out in their day-ahead three-part offers. A top-up payment, called a Production Cost Guarantee or PCG payment, is made whenever a generator's real-time market revenue is insufficient to cover its as-offered costs for the hours and megawatts included in its Enhanced DACP schedule (from the first hour to the last consecutive hour of their Enhanced DACP schedule).

The Enhanced DACP is, in principle, a significant improvement over its predecessor, which did not incorporate start-up or speed no-load costs for the purposes of making scheduling decisions.[91] Prior to implementing the Enhanced DACP, the IESO estimated that the program would improve market efficiency by $13 to $19 million per year.[92] The IESO recently estimated that the Enhanced DACP resulted in estimated unit commitment efficiencies of $11 million during a 57 day random sample from 2012.[93] The Panel has not yet had occasion to independently confirm this estimate.

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[91] Under the original DACP, start-up costs were submitted after-the-fact. The Panel has previously reviewed IESO cost guarantee programs (the original day-ahead and the real-time generation cost guarantees) in its July 2009 Monitoring Report (at pp. 197–202), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200907.pdf, and concluded that after-the-fact cost submissions could lead to excess compensation. The Enhanced DACP requires generators that want to be eligible for the cost guarantee to submit their start-up costs before the algorithm makes the scheduling decisions. The competitive bidding process within the Enhanced DACP should largely mitigate excess compensation.

[92] For a study of various options that were considered in relation to the evolution of the cost guarantee programs and anticipated benefits, see IESO "Day Ahead Market Evolution Preliminary Assessment", May 6, 2008, available at http://www.ieso.ca/imoweb/pubs/corp2/EB-2008-3040-IESO-B-4-1-Appendix-A-DAM.pdf

[93] See IESO "Enhanced Day-Ahead Commitment (EDAC) Assessment", October 24, 2012, available at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20121024-Item3.pdf.

As at the end of April 2012, the Enhanced DACP has been operational for only 6 1/2 months, none of which were summer months which typically see peak demand conditions. Accordingly, there is insufficient data on the basis of which to undertake a meaningful review of the new program design and consider whether the intended efficiency benefits have been realized. The Panel intends to undertake a comprehensive study on the impact of the new program design and detail its findings in a future report. The Panel has also instructed the MAU to continue to monitor the Enhanced DACP and to assess its interaction with the real-time GCG program.

In the remainder of this section, the Panel reports on one specific issue identified thus far in the operation of the Enhanced DACP.

4.1.2 Operation of the Production Cost Guarantee in Hour Ending 1 (HE 1)

The MAU identified a design issue that resulted in large unwarranted PCG payments in Hour Ending (HE) 1. The MAU first observed the issue on November 3, 2011, and subsequently referred it to both the Panel and the IESO for further assessment.

The Enhanced DACP commits imports, exports and not quick start units in a single run that is typically completed by HE 14 of the current day (day-at-hand) for all hours of the next day (day-ahead). When determining the schedule of a generator in HE 1 of the day-ahead, the Enhanced DACP algorithm must check the status of the unit in HE 24 of the day-at-hand. If a unit is projected to be online in HE 24 of the day-at-hand, the Enhanced DACP will provide a transitional schedule, if necessary, in HE 1 and subsequent hours of the day-ahead that respects the generator's technical limitations of minimum generation block run time (MGBRT) and ramping capability.

Where a unit is found to be online in HE 24 of the day-at-hand but has not yet finished its MGBRT due to a start from the previous day's Enhanced DACP, the Enhanced DACP must schedule the unit (to at least its Minimum Loading Point or MLP) in HE 1 and in any subsequent hours of the day-ahead until the end of the generator's MGBRT. For all of these hours (including HE 1), the generator is not eligible to receive a PCG payment and will effectively be a price-taker.

Provided that MGBRT is not an issue, the Enhanced DACP will check the quantity of the HE 24 schedule in the day-at-hand in order to assess the ramping capability for HE 1. The HE 24 schedule can be the result of either:

i. a commitment made under the previous day's Enhanced DACP in HE 24 (day-ahead), or
ii. an economic schedule in HE 24 from the latest pre-dispatch run (day-at-hand).

Under either of the above conditions, the generator will be scheduled in HE 1 according to the economics of its offer and the ramping capability from HE 24. Where the generator is found to be uneconomic in HE 1, the unit will be ramped off. According to the Enhanced DACP algorithm, a generator can be successfully ramped off provided that its scheduled quantity in HE 24 is less than or equal to its MLP plus the amount it is capable of ramping down in 30 minutes. If the quantity scheduled in HE 24 exceeds this level, the generator will not be shut down in HE 1. Instead, the unit will receive a schedule for a HE 1[94] to produce at a quantity equal to the greater of (i) the level that its 60-minute ramp down capability permits, or (ii) its MLP, notwithstanding the uneconomic HE 1 offer price.

As a result of the foregoing scheduling process, the Enhanced DACP provides a PCG payment to the generator if the revenue earned by it in the real-time market is less than the unit's day-ahead incremental energy offer and speed-no-load offer for HE 1. The resulting PCG payment is determined based on the generator's Enhanced DACP schedule (or its actual output, if smaller) multiplied by the difference between its HE 1 incremental energy offer price and the real-time market clearing price (MCP) for each interval, plus any speed-no-load cost for the hour. High

[94] The example describes a single hour day-ahead schedule for HE 1. The example assumes that the uneconomic resource can reach its MLP by the end of HE 1 according to its ramp down capability and that the generator can therefore be successfully ramped off. If this was not the case, the resource would continue to receive decreasing day-ahead schedules following HE 1 until the point where the unit could be successfully taken offline. This scenario would increase the duration of the day-ahead schedule and the number of hours to which the PCG treatment described below applies.

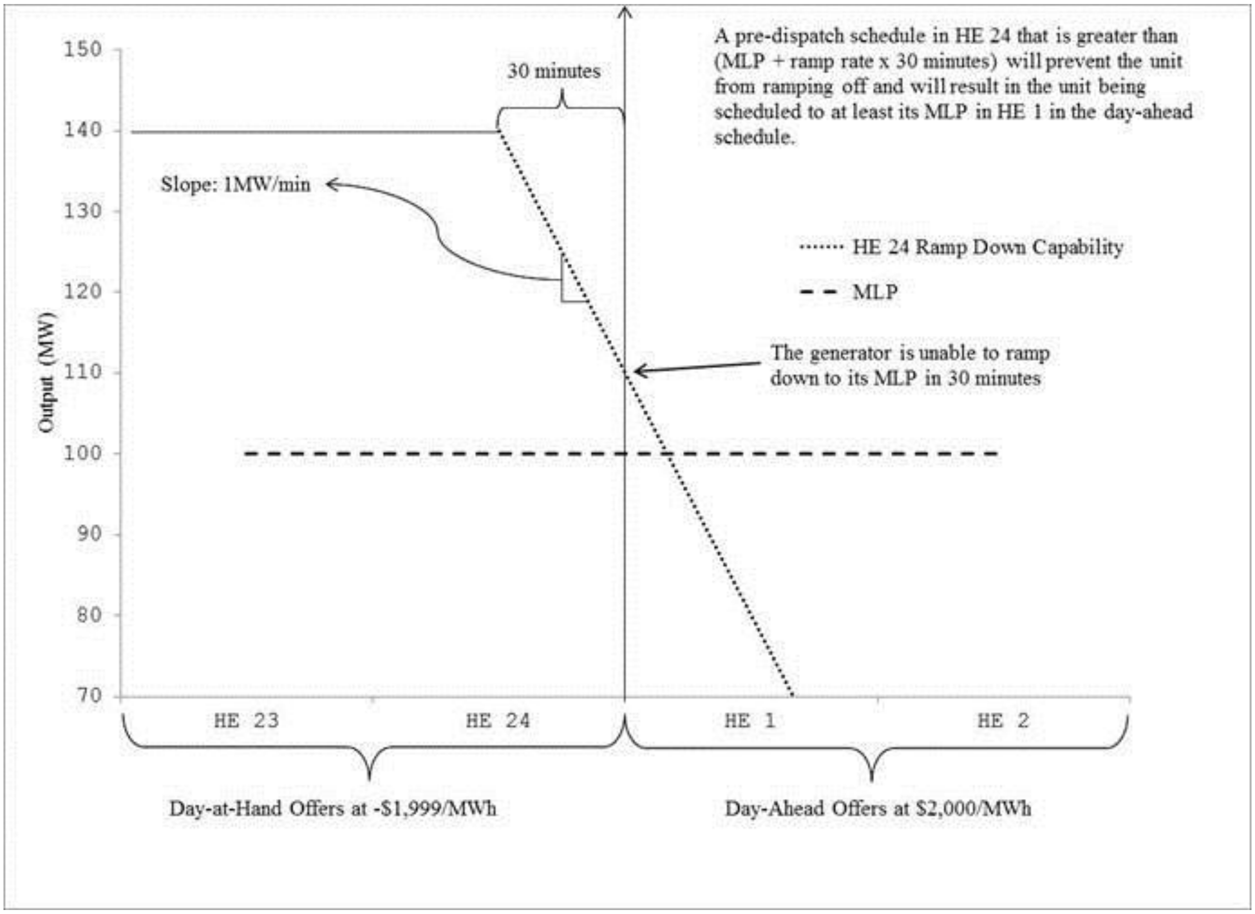
incremental energy and speed-no-load offers can lead to substantial PCG payments for HE 1 in such situations.

Figure 3-1 illustrates how the Enhanced DACP schedule is calculated for HE 1. In this example, a generator (with an MLP of 100 MW and a ramp down rate of 1 MW/minute) has offers in the Enhanced DACP at $2,000/MWh for each hour in the day-ahead, suggesting that it desires not to operate. For the day-at-hand, the generator has an offer of -$1,999/MWh for HE 24, virtually ensuring that it receives a pre-dispatch schedule in HE 24. When the Enhanced DACP is run, the most recent pre-dispatch schedule for day-at-hand HE 24 will be the quantity that was offered at -$1,999/MWh — in this example, 140 MW. If the incremental energy offer price starting in HE 1 for the day-ahead is uneconomic (as would be expected with a $2,000/MWh offer), the Enhanced DACP algorithm would seek to schedule the unit to ramp off in the day-ahead schedule for HE 1. However, the Enhanced DACP must respect generator ramp rates, and because the generator's HE 24 pre-dispatch schedule quantity (140 MW) is greater than its MLP plus 30 minutes of ramping (100MW + 30MW), the algorithm will not schedule the unit to shut down.[95] As a result, the Enhanced DACP will commit the unit online in HE 1 at its MLP. If the unit generates to its MLP (or above) in real-time, and assuming an MCP of $30/MWh, it will receive a PCG payment of approximately $197,000 (100 MW × ($2,000/MWh – $30/MWh)) associated with its day-ahead energy offer, plus the amount of its day-ahead speed-no-load offer.[96]

[95] The Enhanced DCAP algorithm assumes that the pre-dispatch schedule is the output level in the middle of HE 24. To shut a unit down, it must be able to ramp down to its MLP from the midpoint in HE 24 to the beginning of HE 1 (i.e., a period of 30 minutes). The algorithm assumes that if a unit is at its MLP at the beginning of the hour, it can be ramped off by the end of the hour and can therefore be given a schedule of 0 MW. If the unit cannot reach its MLP by the beginning of HE 1 (i.e., it cannot shut down), then the algorithm will develop a schedule for HE 1 based on 60 minutes of ramping, from the midpoint in HE 24 to the midpoint in HE 1. This schedule cannot be lower than the unit's MLP.

[96] This calculation assumes a speed-no-load offer of $0. The maximum hourly speed-no-load cost offer is $99,999 per hour. In this example, if the unit had submitted an HE 1 speed-no-load offer of $99,999, it would have received an HE 1 PCG payment of $296,999.

Figure 3-1: Conditions for Day-Ahead Production Cost Guarantee Payment in HE 1 (MW)



While PCG payments can arise in respect of any hour, the operation of the algorithm between HE 24 of day-at-hand and HE 1 of day-ahead allows generators to trigger (i.e., self-induce) a PCG payment in HE 1 if each of the following three conditions are met:

1. A day-at-hand HE 24 schedule in pre-dispatch that is greater than the generator's MLP plus 30 minutes of ramping as a result of:
   - an economic offer in HE 24 of pre-dispatch; or
   - an Enhanced DACP commitment in HE 24, and where the generator has finished its MGBRT
2. a day-ahead three-part offer that is uneconomic in HE 1, and where the generator is unable to ramp down to its MLP in 30 minutes
3. there is real-time output by the generator in HE 1.

The Panel believes that, when an HE 1 PCG payment is self-induced by a generator that is planning to shut down, the payment does not contribute to market efficiency. In such situations, the PCG payment has some similarities to CMSC payments that are induced by generators using high offer prices to signal their intention to come offline, which the Panel has recommended the IESO eliminate entirely.[97]

4.1.3 Production Cost Guarantee Payments in HE 1

Table 3-1 below lists all PCG payments made to generators with single hour schedules related to ramp down in HE 1 from October 13, 2011 to April 30, 2012.[98] Participant A received almost $5.6 million in self-induced PCG payments in circumstances similar to those discussed above (an economic schedule in HE 24 from the latest pre-dispatch run (day-at-hand)). The Panel is currently investigating Participant A's activities in respect of the Enhanced DACP and HE 1 PCG payments.

[97] In August 2011, the Panel issued a Monitoring Document entitled "Generator Offer Prices Used to Signal an Intention to Come Offline", which sets out the evaluative criteria that the Panel will use in monitoring for gaming in relation to prices offered by generators in order to signal an intention to take their units offline. The Monitoring Document, intended to provide guidance to market participants until such time as a permanent rule-based solution is implemented, states that where there are *bona fide* business reasons for a generator to come offline, the Panel normally would not consider a gaming investigation to be warranted where the generator's offer price does not exceed the greater of (i) 130% of the generator's 3-hour ahead pre-dispatch constrained schedule (shadow) price, or (ii) the generator's marginal (or other incremental or opportunity) cost. The Monitoring Document is available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MonitoringDocument_GeneratorOfferPrices_20110819.pdf

[98] Although 15 other starts were identified as related to stand-alone HE 1 schedules, they were not related to HE 24 to HE 1 ramp down and have therefore not been included in Table 3-1.

Table 3-1: Total Production Cost Guarantee Payments in HE 1 Associated with Ramping Limitations October 13, 2011 to April 30, 2012 ($ and $/MWh)

Participant	Self-induced PCG Incidents (#)	PCG Payments ($)	Total MWh	$/MWh	# PCG Incidents due to Pre-Dispatch Schedule	# PCG Incidents due to Commitment under Previous Day's DACP
A	29	$5,567,066	1755.7	$3,170.85	29	0
B	10	$521,663	290	$1,798.84	1	9
Others	16	$8,093	2835.8	$2.85	16	0
Total	**55**	**$6,096,822**	**4,881.5**	**N/A**	**46**	**9**

4.1.4 Actions Taken by the IESO

On June 11, 2012, the IESO initiated a conference call with generators that participate in the Enhanced DACP in which it identified the two scenarios discussed above (commitment under the previous day's Enhanced DACP and an economic HE 24 pre-dispatch schedule) that had given rise to unwarranted HE 1 PCG payments.[99] On June 15, 2012, the IESO initiated a Stakeholder Engagement process (SE-102) to deal with this issue.[100] The IESO submitted a proposed Market Rule amendment to the Technical Panel on September 18, 2012, which was determined by the Technical Panel to warrant consideration.[101] On October 16, 2012, the Technical Panel unanimously voted to recommend that the IESO Board approve the Market Rule amendment. The IESO Board approved the amendment, and it will come into force on December 21, 2012.

[99] For details, see IESO "HE 1 Production Cost Guarantee Payments June 11, 2012 Conference Call", available at http://www.theimo.com/imoweb/pubs/consult/se102/se102-background_HE1_PCG_memo.pdf.
[100] For details and the status of the process, see http://ieso.ca/imoweb/consult/consult_se102.asp.
[101] For details, see http://ieso.ca/imoweb/amendments/tp_meetings.asp.

The Market Rule amendment will address HE 1 PCG payments that are associated with an HE 24 schedule due to pre-dispatch economics (primarily the case for Participant A). Had it been in place during the reporting period, the rule would have prevented approximately 93% of the PCG payments referred to in Table 3-1 above, including all PCG payments made to Participant A.[102]

The Market Rule amendment does not cover HE 1 PCG payments that are associated with a commitment made under the previous day's Enhanced DACP in HE 24 (primarily the case for Participant B). The IESO opted not to address this scenario on the grounds that the materiality and frequency of payments under the scenario did not warrant the costs of implementing the necessary tool changes, and that some of these HE1 PGC payments might be appropriate in certain circumstances. However, the IESO has made a commitment to examine any issues associated with payments under this scenario as part of its review of generator guarantee programs (which would include the Enhanced DACP), which is expected to commence in the first quarter of 2013.[103] The IESO has also informed stakeholders that an urgent Market Rule amendment may be implemented if the IESO observes generators taking advantage of the PCG program under this scenario.[104]

The Panel commends the IESO for promptly addressing the bulk of the unwarranted HE 1 PCG payments arising from the design issue identified by the MAU, and is encouraged by the IESO's commitment to take further action if necessary.

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[102] The Market Rule amendment would have eliminated PCG payments in 46 of the 55 incidents mentioned in Table 3-1 (in monetary terms, this would have eliminated $5,672,169 of the $6,096,822 in PCG HE 1 payments).
[103] For details, see "Amendment Submission Q00" from "Agenda Item 4: MR-00396: HE 1 Day-Ahead Production Cost Guarantees Triggered by Ramping Limitations", IESO Technical Panel Meeting Materials, September 18, 2012, available at http://ieso.ca/imoweb/amendments/tp_meetings.asp. Specifically, see "Scenario 1". Under Scenario 1, HE 1 PCG payments will continue to be made where a generator is economically scheduled in the Enhanced DACP for HE 24, the generator has completed its MBGRT run and the generator is uneconomic in HE 1 but, due to offered ramp down rates, is unable to come offline in HE 1.
[104] See the minutes of the September 18, 2012 IESO Technical Panel meeting (at p. 3), available at http://ieso.ca/imoweb/pubs/icms/tp/2012/10/IESOTP_265_1_Final.pdf.

4.2 Issues Arising in the Transmission Rights Market

In 2010, the Panel conducted an in-depth review of the operation of the transmission rights ("TR") market, and made a number of recommendations in that regard. While the IESO accepted those recommendations,[105] it did not address them given other urgent priorities. Since then, the Panel has identified specific concerns relating to the sale of TRs by the IESO in respect of a Québec interface in its April 2012 report,[106] and in this report discusses issues associated with TRs at the Minnesota interface (see section 4.3 below) as well as issues associated with the interplay between TRs and day-ahead intertie offer guarantee payments (see section 4.4 below).

The Panel believes that the concerns identified in its 2010 analysis remain valid. Given that the TR market involves approximately $20 million to $30 million per year (as measured by auction revenues) and that there is now a large accumulated surplus in the TR Clearing Account, the Panel provides an update and extension of its 2010 analysis and recommendations below before addressing the additional specific experience observed in respect of TRs at the Minnesota interface.

4.2.1 Intertie Congestion

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. They act as proxies for the external market or jurisdiction to which they are linked and reflect the limited transmission capability that links Ontario with that external market or jurisdiction.

The IESO runs two dispatch schedules. The constrained schedule takes into account most physical constraints in the electricity network (including some characteristics of external

[105] See the Panel's August 2010 Monitoring Report (at pp. 140-267), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[106] See the Panel's April 2012 Monitoring Report (at pp. 72-85), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf

networks), while the unconstrained schedule ignores most of these constraints. Both schedules take into account the bi-directional Scheduling Limit (import and export limits), which is typically the intertie-specific transfer capability (subject to adjustments for outages, projected loop flow induced by external control areas, reliability margin, etc). On the basis of Scheduling Limits, the constrained schedule further accounts for the impact of internal transmission and generation conditions on the interface. This is referred to as an Operating Security Limit (OSL). In other words, the unconstrained schedule uses the Scheduling Limit, while the constrained schedule uses either the Scheduling Limit or the OSL, whichever is lower.[107]

Congestion can be reflected in either schedule. An interface is congested in the constrained schedule when the physical power flow at the interface reaches its OSL and/or Scheduling Limit. In the unconstrained schedule, congestion occurs when the net schedules reach the Scheduling Limit.[108]

The relevant price for settling transactions at a given intertie is equal to the real-time unconstrained Ontario zonal price (Ontario MCP) plus the Intertie Congestion Price (ICP). The ICP is set in the one hour ahead pre-dispatch unconstrained schedule, and is equal to the price difference between the external zonal price and the Ontario zonal price. The ICP as determined in the final pre-dispatch schedule is locked in and carried over to real-time.

When an interface is congested in the unconstrained schedule, the price in the relevant external zone differs from the price in the Ontario zone (i.e., the Ontario MCP):

- When an intertie is import congested, there are offers that are economic in the external zone and that are in excess of the Scheduling Limit. With the unconstrained schedule only able to select net imports up to the Scheduling Limit, the lowest priced imports are scheduled, with the next additional megawatt over the Scheduling Limit setting the

[107] The OSL and the Scheduling Limit will be the same where internal transmission and generation conditions do not affect transfer capability on the intertie.
[108] When an interface is congested in the constrained schedule, the associated congestion price is not applied for settlement purposes; rather, it is used to determine the schedules. Unless otherwise stated, all further references to 'congestion' in this chapter refer to congestion in the unconstrained schedule.

external zonal price. The result of import congestion is an external zonal price that is equal to or less than the Ontario zonal price. For example, import offers in pre-dispatch may give rise to an external zonal price of $10/MWh whereas the Ontario zonal price is $30/MWh. This $20/MWh price difference sets the ICP, which is carried over to real-time. Provided that there is no change in the Ontario zonal price from pre-dispatch to real-time, Ontario loads are charged $30/MWh for the imported power while the importer is paid $10/MWh for delivering power. The $20/MWh discrepancy is referred to as congestion rent and is allocated to the TR Clearing Account that is administered by the IESO (as described more fully below).

- When an intertie is export congested, there are economic export bids in pre-dispatch in excess of the Scheduling Limit. With the unconstrained schedule only able to select net exports up to the Scheduling Limit, the highest priced bids are scheduled. The result of export congestion is an external zonal price that is equal to or higher than the Ontario zonal price. For example, in pre-dispatch, export bids may give rise to an external zonal price of $50/MWh whereas the Ontario zonal price is $30/MWh. The ICP is set at $20/MWh and carried over to real-time. Provided that there is no change in the Ontario zonal price from pre-dispatch to real-time, the exporter is charged $50/MWh while internal generators are paid $30/MWh. As with the import example, the incremental $20/MWh collected by the IESO as congestion rent is allocated to the TR Clearing Account.

4.2.2 Transmission Rights

TRs are financial instruments established and auctioned by the IESO. They can be used by intertie traders to hedge the risks associated with congestion at an interface. TRs may also be held for speculative purposes (i.e., held by participants not hedging physical transactions).

When an intertie is not congested the Ontario zonal price and the external zonal price are the same. When an intertie is congested in the direction for which the TR holder owns TRs, the TR holder is entitled to a payment (payout) equal to the absolute price difference between the external zonal price and the MCP. By hedging a physical transaction with a TR, an importer ensures that it will receive the equivalent of the MCP to deliver power, while an exporter ensures that it will pay the equivalent of the MCP to purchase power. Using the import example from above, an importer is paid $10/MWh to deliver power into Ontario while Ontario loads are charged $30/MWh. The $20/MWh in congestion rent is allocated to the TR Clearing Account. If the importer held TRs, it would receive a $20/MWh payout for each TR that it held. If the importer held a TR for every MW it imported, its transaction would be entirely hedged. On a net basis the importer would receive $30/MWh, composed of a $10/MWh energy payment and a $20/MWh TR payout.

The IESO offers both short-term and long-term TRs for sale. Short-term TRs are valid for the following month, while long term TRs are valid for a period of 12 months. Both guarantee the TR holder a payout for each hour in which there is congestion during the period when the TR is valid.

4.2.3 Transmission Rights Clearing Account

As required by the Market Rules,[109] the IESO maintains a TR Clearing Account. There are three main cash flows into or out of the TR Clearing Account: congestion rent collected, revenue from TR auctions, and payouts to TR holders:

- As noted above, congestion rent is the cash flow generated by the difference between the relevant prices in the Ontario zone and in the applicable external zone. For any given hour, the difference between the two prices (i.e., the ICP) times the real-time net import/export schedules in the *constrained* schedule is the congestion rent collected by the IESO.
- TR auction revenue is the money received by the IESO for the sale of short-term and long-term TRs.

[109] See section 4.18.1 of Chapter 8 of the Market Rules, available at http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter8.pdf.

- TR payouts are equal to the amount paid by the IESO to TR holders for congestion in the pre-dispatch *unconstrained* schedules and are calculated as the absolute value of the ICP times the quantity of outstanding TRs. The TR payouts for a given intertie will be roughly equal to the congestion rent collected on that intertie provided that the quantity of TRs sold is close to the OSL and no transactions fail or are constrained off in real-time.

4.2.4 Design of the Transmission Rights Market

In Ontario, TRs are essentially options contracts. The most a TR holder can lose is the price it paid to acquire the TRs. This would occur if the intertie for which the TR was held was never congested during the period that the TR was valid. The holder will receive a payout when there is congestion in the direction of the TR, but is not required to pay the IESO when there is congestion in the other direction. TR payouts are always made in full, and are not limited to the amount of congestion rent collected by the IESO.

The Panel's 2010 study of the TR market resulted in the following findings:[110]

- Financial participants that have never had a physical import or export transaction in the Ontario market purchased 23% of TRs. Additionally, for 64% of intertie transactions there were no associated TRs. This data indicated that most TRs purchased were not used for hedging purposes.
- There was substantial "overselling"[111] of TRs by the IESO (see the further discussion in section 4.2.5 below).
- The overselling was leading to congestion rent shortfalls that were effectively being funded by auction revenues, leading to lower-than-contemplated offsets to the transmission service charges payable by loads.
- TR holders were able, on average, to achieve very substantial returns on their investments in short-term or long-term TRs.

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[110] See the Panel's August 2010 Monitoring Report (at pp. 140-267), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[111] As discussed below, the Panel defines "overselling" as occurring where the real-time intertie transfer capability is less than the level of TRs outstanding, usually as a result of planned or forced outages.

- It was not clear that the Ontario TR market design was as effective as it could be in contributing to efficient import and export transactions.

As a result, the Panel recommended that:

> *The IESO should reassess the design of the Ontario Transmission Rights market to determine whether it can play a more effective role in supporting efficient trade with neighbouring jurisdictions.*[112]

The IESO responded[113] that it agreed that a reassessment would be useful but that efforts to address this recommendation needed to be put on hold to enable the IESO to address other priorities, including various issues relating to the implementation of the *Green Energy and Green Economy Act, 2009* (GEA).[114]

As noted above, the Panel believes that the conclusions set out in its August 2010 report remain valid.[115] The Panel also notes that many transmission rights markets in the United States include active secondary markets. The Ontario Market Rules contemplate the existence of a secondary / resale market for TRs, but none has been implemented. The Panel believes that a fundamental review of the TR market could usefully include consideration of whether an IESO-administered secondary market would help to facilitate efficient inter-jurisdictional trade.

Implementation of the GEA is substantially advanced and should no longer be an impediment to addressing TR market design issues. Given the size of the TR market (approximately $20 million to $30 million per year based on auction revenues), and the concerns identified by the Panel in recent reports as well as in this one, the Panel believes that the IESO should, as a matter of some priority, conduct a reassessment of the design of Ontario's TR market design to

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[112] See Recommendation 3-6 in the Panel's August 2010 Monitoring Report (at p. 167), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[113] See "*IESO Responses to the Market Surveillance Panel (MSP) Report (Period: November 2009 to April 2010)*" available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf.
[114] *Green Energy and Green Economy Act, 2009* available at http://www.e-laws.gov.on.ca/html/source/statutes/english/2009/elaws_src_s09012_e.htm
[115] Section 4.2.5 below contains an updated analysis relating to congestion rent shortfalls and TR auction revenues.

determine whether it is achieving its intended purpose. The Panel also notes that the IESO's Chief Executive Officer recently announced that the IESO will be undertaking work to attempt to move to the more frequent dispatch of intertie transactions[116] (which is already occurring among various northeastern US system operators). Since TRs are currently structured on an hourly basis, consistent with the hourly dispatch of imports and exports, a review of the TR market design would be particularly timely in parallel with the potential changes to intertie transaction dispatch frequency.

Recommendation 3-1:

> ***The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.***

4.2.5 Congestion Rent Shortfall

In addition to recommending a fundamental reassessment of the TR market, the Panel's August 2010 Report addressed the continuing issue of the imbalance between TR payouts and congestion rent collected.

The Panel defines congestion rent shortfall (or surplus) as the difference between the congestion rent collected and the payouts to TR holders.[117] In its August 2010 assessment of the TR market, the Panel identified three causes of congestion rent shortfall:

(i) The **two-schedule design**, including differences between the intertie limit in the unconstrained schedule versus the constrained schedule. Additionally, congestion in the

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[116] Remarks by Mr. Paul Murphy to the APPrO Conference, November 6, 2012. The Panel recommended that the IESO examine the feasibility of more frequent (e.g., 15 minute) dispatch for imports and exports in its November 2011 Monitoring Report (Recommendation 2-2, at pp. 99-100), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20111116.pdf. The Electricity Market Forum subsequently recommended that the IESO maximize potential benefits to Ontario from greater alignment with regional markets through intertie transactions. See "Report of the Electricity Market Forum" (December 2011) (Recommendation 12, at p. 18), available at http://www.ieso.ca/imoweb/pubs/consult/Market_Forum_Report.pdf .

[117] Congestion rent shortfall is similarly defined in other markets, such as New York Independent System Operator, Midwest Independent System Operator and California Independent System Operator.

pre-dispatch unconstrained schedule (and, hence, TR payouts), but constrained-off transactions in the real-time constrained schedule (resulting in reduced congestion rent collected) also leads to congestion rent shortfall. The Panel estimated this accounted for $50 million (43%) of the $117 million total shortfall as of April 2010;

(ii) **Overselling of transmission rights** relative to the real-time intertie transfer capability, which contributed to $43 million (37%) of the total shortfall; and

(iii) **Transaction failures,** which accounted for $24 million (20%) of the total. [118]

In its August 2010 Report, the Panel concluded that "payouts to TR holders should not exceed congestion rents since congestion rents reflect the conceptual value of the TR right."[119] The Panel also noted that it believed the Market Rules support this approach.[120] If this approach were to be implemented, the revenues received by the IESO when TRs are auctioned would be available to offset transmission service charges to Ontario loads, as provided for in section 4.18.2 of Chapter 8 of the Market Rules.

The Ontario TR market has, however, been operated in a much different manner, and there have been significant congestion rent shortfalls that have had to be covered by TR auction revenues. As the Panel acknowledged in its August 2010 Report, the IESO's position has been that it is appropriate to use auction revenues to cover TR payouts where there are congestion rent shortfalls. This position was clearly set out in the following IESO response in 2010 to questions from OEB staff on past Panel reports: "[T]he TR market is a 'closed' design which is entirely funded by TR auction rights proceeds and 'congestion' rents, and it is designed so that those proceeds and rents are sufficient to fund TR payouts… [t]he market is designed to maintain a

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[118] For details, see the Panel's August 2010 Monitoring Report (at pp. 140–267), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.
[119] For details, see the Panel's August 2010 Monitoring Report (at p. 151), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf
[120] section 4.6.1 of Chapter 8 of the Market Rules states as follows: "The *IESO* shall conduct a simultaneous feasibility test during each *TR auction* 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* ... in respect of all *transmission rights* outstanding and all *transmission rights* to be offered during the *TR auction*". Recognizing the potential for congestion rent shortfall in some periods, section 4.7.1 goes on to state that "(t)he *IESO Board* shall establish a confidence level reflecting the degree to which the congestion rents collected by the *IESO* in a given period described in section 4.18.1.1 will be sufficient to cover the *IESO's* payment obligations to *TR holders* under section 4.4.1 for that period".

rolling balance of $20 million and to not rebate any surplus to Ontario consumers."[121] This interpretation of the Ontario market design has, in the Panel's view, led to the overselling of TRs, resulting in additional congestion rent shortfalls that have had to be covered by TR auction revenues.

In its August 2010 Report, the Panel stated that it disagreed with the IESO's interpretation of the market design for various reasons.[122]

In the Panel's view, TR auction revenues ought to be paid to loads as a reduction in transmission charges. If there were no TRs in Ontario, but all other aspects of the market design were retained, congestion rent would still be collected by the IESO whenever there was congestion on an intertie. Those congestion rents are the price importers and exporters are prepared to pay for scarce transmission capacity, suggesting that the rents might be paid to transmission owners. But as the transmission companies are rate regulated entities, any congestion rents paid to them would presumably be used to offset their regulated revenue requirement. Thus, their customers (Ontario loads) would benefit from congestion rents.

Once TRs are introduced, congestion rents are effectively diverted to TR holders in the form of TR payouts. In return, TR holders pay for TRs (in the periodic auctions), the prices of which presumably reflect their assessment of the amount of future congestion rent at an intertie. If loads are not entitled to receive TR auction revenues then, in the Panel's view, loads would be worse off with a TR market than without one. The Panel believes that such a result is neither appropriate nor intended by the designers of the Ontario market.

[121] Questions for IESO at Technical Conference Relating to MSP Monitoring Report on the IESO-Administered Electricity Markets for the Period from May 2009 – October 2009 (and previous MSP reports), EB-2009-0377, filed February 22, 2010. This position was informed by a July 2003 decision of the Board of Directors of the Independent Electricity Market Operator and by related Market Rule amendments that came into effect on January 6, 2004. See IMO Market Rule Amendment Proposal MR-00242-R00, available at: http://www.ieso.ca/imoweb/pubs/mr/mr_00242-R00-R04_BA.pdf.
[122] For details, see the Panel's August 2010 Monitoring Report (at pp. 151-152), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf

Since April 2010, the accumulated congestion rent shortfall has continued to grow. Table 3-2 below shows TR payouts, congestion rent collected, congestion rent shortfall, and TR auction revenue since market opening. From market opening until April 2012, TR payouts totalled $564.7 million, compared with congestion rent collected of $414.6 million, resulting in a total congestion rent shortfall of $150.1 million since May 2002.

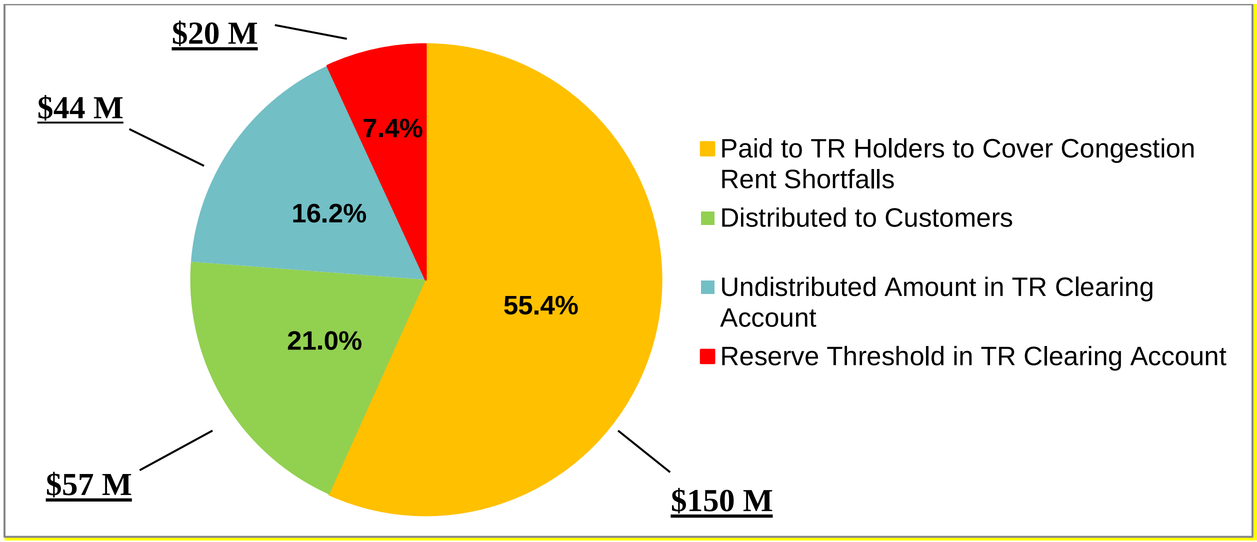
Table 3-2: Transmission Rights Payouts, Congestion Rent, Congestion Rent Shortfall and Transmission Rights Auction Revenues May 2002 to April 2012 ($ millions)

Annual Period	TR Payouts	Congestion Rent Collected	Congestion Rent Shortfall	TR Auction Revenue
May 02-Apr 03	82.2	81.4	0.8	11.6
May 03-Apr 04	38.1	34.9	3.3	16.7
May 04-Apr 05	29.0	22.1	6.9	27.5
May 05-Apr 06	90.6	65.0	25.6	40.7
May 06-Apr 07	25.8	16.2	9.6	39.5
May 07-Apr 08	69.3	41.6	27.7	25.6
May 08-Apr 09	97.9	68.3	29.6	28.4
May 09-Apr 10	38.4	27.2	11.2	30.4
May 10-Apr 11	38.9	26.2	12.7	19.8
May 11-Apr 12	54.4	31.8	22.6	31.0
Total	**564.7**	**414.6**	**150.1**	**271.2**

Since market opening, the TR payouts were 136% of the congestion rent collected. Because the TR Clearing Account is used to fund the congestion rent shortfall, 55% of the total auction revenues collected have flowed back to TR holders.

Figure 3-2 displays cumulative auction revenue from market opening until April 2012 and how that revenue has been distributed.

Figure 3-2: Distribution of TR Auction Revenues
May 2002 to April 2012



Between market opening and April 2012, 55.4% of all TR auction revenue collected has been paid to cover congestion rent shortfalls, and hence $150 million of accumulated auction revenue has not been available to offset transmission service charges payable by Ontario loads. The Panel does recognize, however, that the current design has very likely increased TR auction revenues than would have been the case had the IESO sold TRs at a level designed to balance TR payouts with congestion rent collected.[123]

Of the remaining amount, $57 million (21%) was distributed to wholesale customers in 2007 and 2008, while $64 million (23.6%) remained in the TR Clearing Account. As of October 2012, the amount in the TR Clearing Account was $69 million.

The Panel acknowledges that it is not possible to ensure that congestion rents will always equal TR payouts. The Panel identified TR "overselling" as situations where the real-time intertie transfer capability in an hour is less than the amount of TRs outstanding, usually due to planned outages unknown to the IESO at the time of the relevant TR auction, or to forced outages. The

[123] All else being equal, the more TR's sold, the greater the TR auction revenues. It is also possible that the greater the number of TRs outstanding the higher probability of congestion, thereby increasing the value associated with holding a TR.

Panel recognizes that there will be many cases in which an overselling of TRs becomes apparent only after the TR auction has occurred. Similarly, constrained-on or constrained-off transactions and differences between the limits in the unconstrained and constrained schedules will be difficult to determine within the lead times applicable to TR auctions, and specific transaction failures are not ascertainable until real-time. Nevertheless, the Panel expects that it may be possible to use historical data to estimate average ratios that could be used to mitigate the impact of these chronic sources of congestion rent shortfall.[124] As discussed in section 4.3. below, changes to the IESO's policies related to the auction quantities for short-term and long-term TRs could also help to reduce the overselling risk by increasing the prospect of outages being known and taken into account in determining the number of TRs to be auctioned at any given time.

Given the significant continuing congestion rent shortfalls observed in 2011 and 2012, the Panel believes that this issue should be promptly addressed by the IESO. The Panel therefore reiterates the recommendation that it originally made in its August 2010 Report: [125]

<u>Recommendation 3-2:</u>

> ***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.***

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[124] Recognizing that the TR market is settled on an hourly basis, whereas TRs cover a period of one month or one year, the Market Rules contemplate that the TR Clearing Account may temporarily fall out of balance. For example, an interface de-rating that was either unexpected or went beyond normal contingency planning would result in the effective transfer capability of the line being less than the quantity of outstanding TRs. Accordingly, if the intertie were to become congested, TR payouts would exceed congestion rent collected. To manage these potential imbalances, section 4.18.3 of Chapter 8 of the Market Rules requires that the IESO Board of Directors establish a Reserve Threshold for the TR Clearing Account. The Reserve Threshold was $10 million until 2007, when it was increased to the current level of $20 million.

[125] See Recommendation 3-5 in the Panel's August 2010 Monitoring Report (at p. 164), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf. At the time, the IESO noted that it also agreed with this recommendation, but again that efforts to address this recommendation needed to be put on hold. See "*IESO Responses to the Market Surveillance Panel (MSP) Report (Period: November 2009 to April 2010)"* available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf.

4.2.6 Disposition of Auction Revenues Credited to the TR Clearing Account

Prior to market opening, the Minister of Energy commissioned the Market Design Committee (MDC) to advise on the structure of the proposed Ontario electricity market. The MDC's final report established the fundamental framework for the eventual design of the Ontario market, and included the following recommendation regarding the TR market:

> *We recommend that the congestion rentals collected from the intertie pricing approach be used by the IMO to support a system of "financial" rights or hedges that would be allocated, through IMO auctions, to market participants as a means to hedge the price uncertainties associated with congestion-related price differences on IMO-controlled interties. Net auction revenues should be used to offset revenue requirements for Basic Use [transmission] Service. The amounts by which the settlement surplus from intertie transactions exceed or are less than the payment obligations of the allocated rights for any settlement period should be managed through an uplift account.*[126] (emphasis added)

In the Panel's view, the MDC's implicit expectation that the use of congestion rents to support a system of financial rights or hedges would involve congestion rents being collected in amounts that should approximately equal TR payouts has been reflected in the Market Rules.[127]

Similarly, the Market Rules also incorporate the MDC's recommendation that net auction revenues should be used to offset transmission charges. Specifically, the Market Rules authorize

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[126] See Chapter 4 of the Market Design Committee's Final Report, particularly p. 13, available at http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/FinalReport/Vol1/chapter4-TransmissionDistribution.pdf. Along the same lines, the Transmission and Distribution Technical Panel (a working group established under the auspices of the MDC to assist in the development of the market design), made the following recommendation to the MDC: "Proceeds for the auction would be fed back to the internal customers by using them to contribute to the fixed costs of the embedded transmission system." See Appendix 4 of the Market Design Committee's Final Report, particularly p. 38, available at http://www.theimo.com/imoweb/historical_devel/Mdc/Reports/FinalReport/Vol3/Appendix%204%20-%20TD%20Tech%20Panel%20Report.pdf

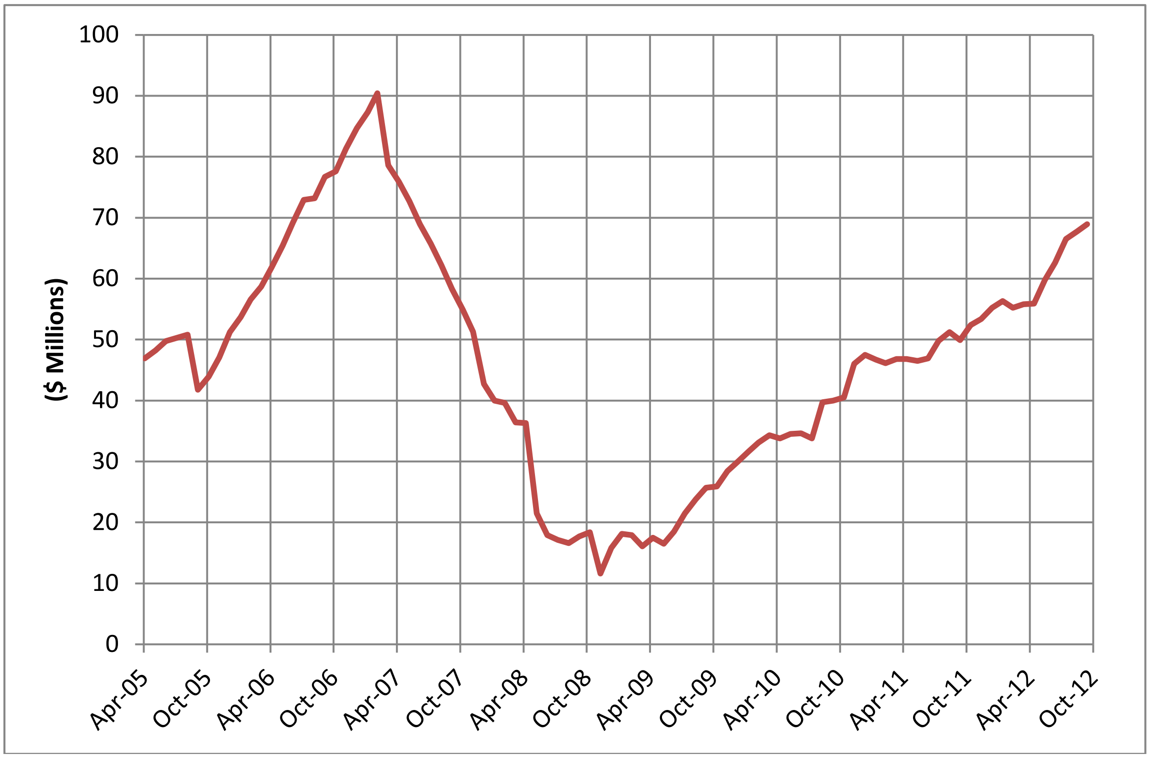
[127] See section 4.6.1 of Chapter 8 of the Market Rules, referred to above. If TR payouts were to exceed congestion rent collected then, on an aggregate basis, the financial rights would compensate a TR holder beyond what was necessary to fully hedge an intertie transaction.

the IESO Board of Directors to debit the TR Clearing Account for the purposes of offsetting "transmission services charges",[128] which are defined by the Market Rules as "all charges administered by the IESO to recover the costs of transmission services".[129] One such payment occurred in 2007 when the IESO Board of Directors approved a $57 million disbursement of TR Clearing Account funds to wholesale customers (12 payments totaling $4.75 million each, beginning in April 2007).[130]

Figure 3-3 displays the TR Clearing Account balance from April 2005 to October 2012. The account balance has grown steadily since the $57 million payment authorized by the IESO Board of Directors in 2007. As of October 31, 2012, the balance in the TR Clearing Account was $69.3 million, substantially above the $20 million Reserve Threshold established by the IESO Board of Directors and almost at the level at which it was when the last disbursement was made by the IESO.

[128] See section 4.18.1.5 of Chapter 8 of the Market Rules, available at http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter8.pdf. The other authorized bases for debiting the TR Clearing Account are for TR payouts (section 4.18.1.3) and TR resale market transactions (section 4.18.1.4 – not implemented).
[129] See Chapter 11 of the Market Rules, available at http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter11.pdf
[130] See IESO "Participant News" dated May 10, 2007, available at http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3453 .

Figure 3-3: TR Clearing Account Balance
April 2005 to October 2012



Source: IESO monthly reports available at http://www.ieso.ca/imoweb/marketdata/marketSummary.asp

Recommendation 3-2 above calls for the IESO to take steps to restore the balance between TR payouts and congestion rents collected. If implemented, that recommendation will result in a larger TR Clearing Account balance that can be periodically used to offset transmission charges. In the meantime, the Panel is not aware of any reason why an amount in excess of the $20 million Reserve Threshold set by the IESO Board should be retained. The Panel therefore makes the following recommendation:

Recommendation 3-3:

> ***(A) The IESO Board of Directors should authorize the disbursement of the portion of the Transmission Rights Clearing Account balance that currently exceeds the Reserve Threshold to reduce the transmission charges payable by loads.***

(B) In the future, the IESO Board of Directors should authorize disbursements of Transmission Rights Clearing Account balances in excess of the Reserve Threshold after each year end.

4.3 Transmission Rights Issues at the Minnesota Interface

In this section the Panel discusses the congestion rent shortfall observed in respect of imports on the Minnesota intertie as a result of a series of outages experienced during the Winter 2012 Period (the period from November 2011 to April 2012). Further to that analysis, the Panel makes a recommendation aimed at mitigating overselling and congestion rent shortfalls that could be applied to the IESO's TR auction policies prior to any changes that may arise as a result of any broader reassessment of the design of Ontario's TR market by the IESO.

4.3.1 Congestion

The Minnesota interface represents roughly 2% of Ontario's total intertie transfer capability.[131] In its August 2010 report, the Panel found that: [132]

(i) The Minnesota interface accounted for 17% ($20 million) of the total congestion rent shortfall from May 2003 to April 2010, of which 61% ($12 million) was due to the overselling of TRs and the remainder was due to the two-schedule market design.

(ii) Congestion rent shortfall in the import direction accounted for 63% ($13 million) of the total Minnesota shortfall, of which 46% ($6 million) was due to the overselling of TRs and 54% ($7 million) was due to the two-schedule market design.

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[131] The normal Minnesota intertie transfer capability is 140 MW in the export direction, and 90 MW in the import direction.

[132] See the Panel's August 2010 Monitoring Report (at pp. 161-163), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf.

Since 2010, the Minnesota interface has frequently been import-congested in the unconstrained schedule, even though exports are often flowing the other way. Table 3-3 lists the total number of import congestion hours at the Minnesota interface from May 2010 to April 2012, as well as the average ICP during congested hours. In October 2011, and again in January, March and April 2012 (the "four months of interest"), the interface was import-congested during 30% of the operating hours, often with a highly negative ICP. During the four months of interest, the weighted average hourly ICP during import congested hours was -$78.39/MWh compared with a weighted average hourly ICP of -$10.32/MWh during all other months over this two-year period.[133]

[133] The weighted average hourly ICP during all months in the two-year period was -$24.41/MWh, and reflects the distortive effects of the ICPs in the four months of interest.

Table 3-3: Import Congestion and Average Intertie Congestion Price at the Minnesota Interface May 2010 to April 2012 (number of hours and $/MWh)

Month	No. of Hours with Import Congestion	Average ICP in Congestion Hours ($/MWh)
May-10	404	-7.76
Jun-10	429	-8.21
Jul-10	448	-12.81
Aug-10	461	-14.02
Sep-10	292	-9.22
Oct-10	342	-8.13
Nov-10	419	-11.14
Dec-10	307	-5.70
Jan-11	157	-5.70
Feb-11	303	-19.50
Mar-11	405	-11.71
Apr-11	292	-8.60
May-11	273	-9.29
Jun-11	90	-18.89
Jul-11	150	-11.47
Aug-11	113	-4.42
Sep-11	216	-13.44
Oct-11	230	-43.17
Nov-11	181	-4.77
Dec-11	66	-3.59
Jan-12	291	-68.32
Feb-12	72	-8.94
Mar-12	205	-145.08
Apr-12	155	-60.15
Total	**6,301**	**-24.41**

An intertie may experience import congestion for a variety of reasons, including but not limited to: a large difference between the Ontario MCP and external market prices; forced outages or de-ratings at the interface; or the offer strategy of intertie traders. Upon further review of the congestion events identified in Table 3-3 above, the Panel determined that multiple de-ratings on the intertie caused the quantity of outstanding TRs to significantly exceed the real-time Scheduling Limit for extended periods of time.

4.3.2 Congestion Rent Shortfall

The import congestion hours identified in Table 3-3 caused significant congestion rent shortfall at the Minnesota interface. As shown in Table 3-4, the total payouts to import TR holders at the Minnesota interface from May 2010 to April 2012 were over $9.4 million, while the net congestion rent collected by the IESO was only $73,000 — a shortfall of over $9.3 million. Of that shortfall, $3.7 million (39%) was accrued during the four months of interest.

Table 3-4: TR Payouts and Congestion Rent Collected for Imports at the Minnesota Interface May 2010 to April 2012 ($ thousands)

Month	TR Payouts ($000)	Congestion Rent* ($000)	Congestion Rent Shortfall ($000)
May-10	282	-64	346
Jun-10	317	-54	371
Jul-10	373	-86	459
Aug-10	421	-208	629
Sep-10	175	-23	198
Oct-10	249	-22	271
Nov-10	420	-52	472
Dec-10	206	0	206
Jan-11	81	13	68
Feb-11	532	56	476
Mar-11	427	-208	635
Apr-11	226	-142	368
May-11	228	-110	338
Jun-11	153	-74	227
Jul-11	155	-175	330
Aug-11	45	8	37
Sep-11	261	89	172
Oct-11	897	150	747
Nov-11	78	36	42
Dec-11	21	4	17
Jan-12	1,300	281	1,019
Feb-12	42	18	24
Mar-12	1,938	524	1,414
Apr-12	606	112	494
Total	**9,434**	**73**	**9,361**

* Congestion rent collected will be negative when there is import congestion in the pre-dispatch unconstrained schedule (where the congestion price is determined), but there are net exports flowing in the real-time constrained schedule. This is typically a result of low shadow prices resulting in constrained-off imports, constrained-on exports or both.

4.3.3 Reductions of the Import Scheduling Limit

During the four months of interest, the transmission line that links the Minnesota border with a major transformer station in the northwest region of Ontario (the K24F transmission line) was out of service on the following dates:

- October 13 to October 20, 2011;
- October 24 to November 4, 2011;
- January 9 to January 29, 2012; and
- March 19 to April 23, 2012.

The loss of the K24F line caused the IESO to reduce the Scheduling Limit for imports at the Minnesota interface to 65 MW, from a normal transfer capability of 90 MW.[134] In addition to the outage of the K24F line, a generator in the area was also out of service for numerous planned and forced outages on the following trade dates:

- Planned for October 14 to October 24, 2011, and extended as a forced outage to November 9, 2011;
- December 23, 2011 to January 30, 2012; and
- February 27 to April 23, 2012.

With the generator out of service, the local system's ability to withstand a large and sudden drop in power supply brought about by a loss of imports from Minnesota was reduced. In order to mitigate this risk, the IESO limited the import transfer capability at the Minnesota interface to 15 MW during the period in which both the K24F line and the generator were on planned outages.[135]

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[134] While K24F is not the transmission line that traverses the Minnesota/Ontario border, the IESO's dispatch scheduling optimizer (DSO) must prepare for a potential contingency wherein an additional transmission line is forced out of service, causing imports to overload a nearby transmission line.

[135] The IESO has advised the Panel that if the generator in question is out of service but all other elements are in-service there is no impact on the transfer capability at the Minnesota interface.

4.3.4 Transmission Rights sold in Quantities Exceeding the Real-time Scheduling Limit

The IESO has various policies that govern the quantity of short-term and long-term TRs made available for sale in respect of a given intertie. The IESO establishes the quantity of TRs to be auctioned based in large part on the forecasted Scheduling Limit of the intertie for the trade dates covered by the TRs. The IESO uses the maximum achievable transfer capability as a starting point and adjusts downward based on anticipated conditions, such as equipment outages and security requirements. More specifically, when determining the quantity of TRs for sale the IESO considers individual outages longer than one month for long-term auctions, and individual outages exceeding one week for short-term auctions.[136] The composition of long-term versus short-term TRs is largely dependent on whether or not the intertie is a single-circuit or multi-circuit transmission line. For single-circuit interties, such as the Minnesota intertie, the IESO normally sells long-term TRs up to the Scheduling Limit forecasted for the intertie for the coming year (leaving no TRs for sale at short-term auctions).

Table 3-5 displays the quantity of outstanding TRs at the Minnesota interface by month, from May 2010 to April 2012. In accordance with the single-circuit TR policy noted above, all TRs sold in that two-year period were long-term TRs. As evidenced by the IESO's decision to sell TRs totaling the maximum transfer capability of the intertie (90 MW) for all months from October 2010 to December 2011, the IESO did not foresee any individual de-ratings longer than one month on the Minnesota intertie at the time the quarterly auctions were held. Table 3-5 also displays the average real-time Scheduling Limit by month. As a result of frequent de-ratings on the Minnesota intertie, the real-time Scheduling Limit was often much less than the number of outstanding TRs. This resulted in TRs being oversold relative to the average real-time Scheduling Limit in all but two months during the two-year period at issue. The average discrepancy was 28%.

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[136] Outages of shorter lengths may be considered on a case-by-case basis, but are not always reflected in the amount of TRs for sale. For more details, see IESO Market Manual 7, Part 11: Transmission Reliability Margin Implementation (at p. 8), available at http://www.ieso.ca/imoweb/pubs/tr/TRMID_IESO_PRO_0729.pdf

Table 3-5: Average Real Time Scheduling Limit and Transmission Rights Outstanding for Imports at the Minnesota Interface May 2010 to April 2012 (MW)

Month	Average Real-Time Scheduling Limit (MW)	TRs Outstanding (MW)	Difference	
			MW	%
May-10	75	90	15	16
Jun-10	79	90	11	12
Jul-10	68	65	-3	-4
Aug-10	62	65	3	5
Sep-10	76	65	-11	-17
Oct-10	64	90	26	29
Nov-10	62	90	28	31
Dec-10	81	90	9	10
Jan-11	77	90	13	14
Feb-11	35	90	55	61
Mar-11	39	90	51	57
Apr-11	40	90	50	55
May-11	57	90	33	36
Jun-11	18	90	72	80
Jul-11	67	90	23	25
Aug-11	78	90	12	13
Sep-11	75	90	15	17
Oct-11	53	90	37	41
Nov-11	77	90	13	15
Dec-11	81	90	9	10
Jan-12	38	65	27	42
Feb-12	49	65	16	24
Mar-12	36	65	29	45
Apr-12	21	65	44	68
Weighted Average	**59**	**83**	**24**	**28**

4.3.5 Proportion of TRs Sold in Short-Term Auctions

Outages and de-ratings can be broken down into known and unknown events, based on whether or not the IESO was aware of them at the time of the relevant auction. In the Panel's view, TR policies that maximize opportunities for the IESO to account for outages and de-ratings in determining the quantity of TRs to be sold would assist in mitigating the risk of congestion rent shortfalls.

Outages and de-ratings unknown by the IESO at the time of the relevant TR auction will often lead to considerable divergences between the quantity of outstanding TRs and the real-time Scheduling Limit. The likelihood of unknown outages or de-ratings occurring increases the further into the future the IESO sells TRs. At a long term auction, TRs are sold for trade dates up to 13.5 months into the future,[137] leaving a considerable period of time for additional planned or extended unplanned outages to arise. By selling TRs closer to the relevant trade dates, the IESO will have more accurate and complete information at its disposal on which to estimate the eventual real-time Scheduling Limit, helping to mitigate congestion rent shortfall.

One way in which the IESO could minimize its long-term TR commitments is by altering the composition of long-term versus short-term TRs for sale. Table 3-6 below displays the quantity of long-term import TRs sold for the Minnesota interface at each quarterly auction, and the quantity of outstanding TRs for quarterly trade periods in 2011 and 2012.

[137] Long-term TRs are auctioned every three months, and cover trade dates for the period of one year commencing in the month that is one and a half months from the date of the auction.

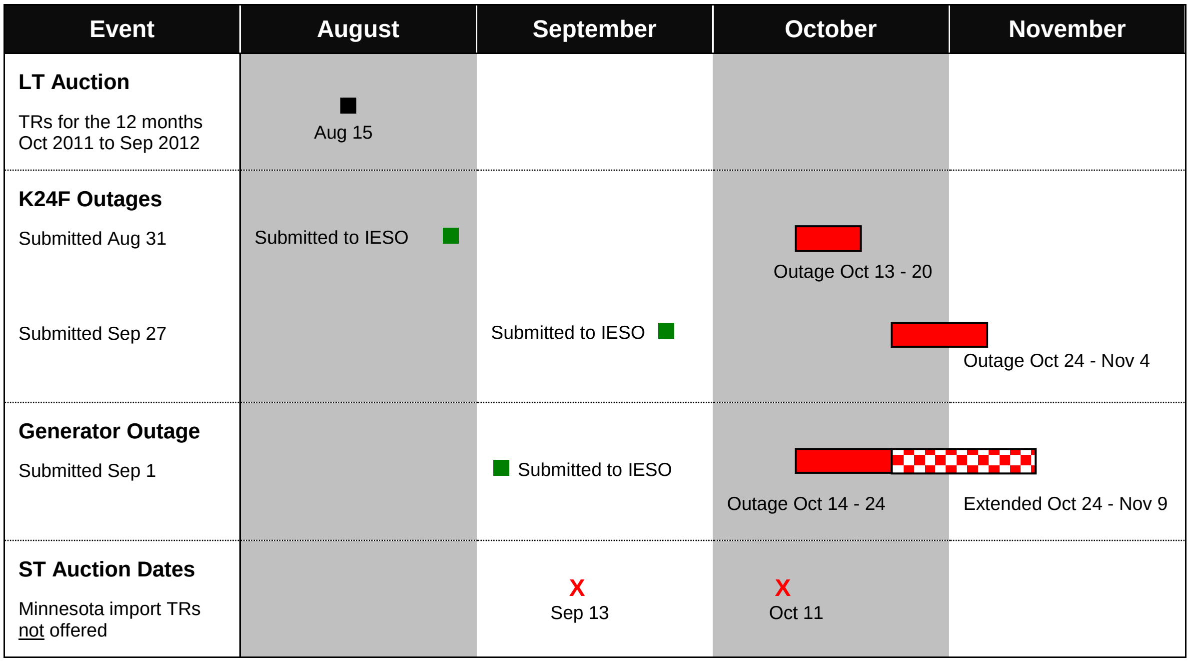
Table 3-6: Long-Term Import TRs Outstanding at the Minnesota Interface
January 2011 to December 2012
(MW)

Month in Which Long-Term TR Auction was Held	Trade Dates Covered by TRs						
	2011				2012		
	January - March	April - June	July - September	October - December	January - March	April - June	July - September
May 2010	10	10					
August 2010	55	55	55				
November 2010	25	25	25	25			
February 2011		0	0	0	0		
May 2011			10	10	10	10	
August 2011				55	55	55	55
November 2011					0	0	0
February 2012						0	0
May 2012							0
Total Outstanding	**90**	**90**	**90**	**90**	**65**	**65**	**55**

Between January 2011 and September 2012, all outstanding TRs for the Minnesota intertie were sold at long-term auctions. The Panel considers this practice unnecessarily risky, and notes that it has contributed to a significant amount of congestion rent shortfall. To illustrate the benefit of not selling all TRs at long-term auctions, the following analysis will focus on the October 2011 to December 2011 trade dates (specifically October and November) and the August 2011 long-term auction.

As noted in section 4.3.3, there were two outages to the K24F transmission line and one outage to a local generator that affected the Scheduling Limit at the Minnesota interface during October 2011 and November 2011. These outages led to a Scheduling Limit of 15 MW (down from a maximum transfer capability of 90 MW) for the majority of the time that the outages were in effect. The first K24F outage period lasted 8 days, from October 13 to 20, 2011, and according to the IESO was first submitted to it on August 31, 2011. The second K24F outage period lasted 12 days, from October 24 to November 4, 2011, and was first submitted to the IESO on September 27, 2011. The planned part of the generator outage lasted 11 days, from October 14 to 24, 2011, and was first submitted to the IESO on September 1, 2011. On October 24, 2011 the generator was forced out-of-service, extending the outage until November 9, 2011. Figure 3-4 provides a visual representation of the relevant auction dates, outage notifications, and outages.

Figure 3-4: Auction Dates, Outage Notifications Dates, and Outages Respecting the Minnesota Intertie
August to November, 2011



None of the outages were known to the IESO at the time of the August 2011 long-term auction. The IESO offered 55 MW of TRs for sale at the August 2011 long-term auction, all of which were bought bringing the outstanding TR position for the October 2011 to December 2011 trade dates to the maximum transfer capability of 90 MW. When the Minnesota intertie was later de-rated, large congestion rent shortfalls accrued (see Table 3-4).

Reserving a portion of TRs for single-circuit interfaces to be sold at short-term auctions would reduce the IESO's exposure (and by extension the exposure of loads) to events that could cause significant congestion rent shortfalls. If the IESO always reserved a portion of TRs for sale at short-term auctions, it could adjust the number of TRs sold to account for planned (or in some cases lengthy unplanned) outages of which it becomes aware closer to the TR auction date. To illustrate, when all available TRs are sold on a long-term basis, the IESO must select an auction quantity based on planned outages that are known 1.5 to 13.5 months in advance. However, when a portion of the maximum potential TRs are reserved for auction on a short-term basis, the IESO can adjust the auction quantities based on outages that are known as little as 0.5 to 1.5 months in advance.

Additionally, outages of shorter duration are more likely to be accounted for in determining the quantity of TRs for sale at short-term auctions than is the case with long-term auctions. As discussed earlier, when determining the quantity of TRs to sell the IESO, as a matter of policy, only considers outages of one month or longer for long-term auctions, and outages of one week or longer for short-term auctions. As a result, a known planned outage of 29 days or less may not be accounted for in determining the number of long-term TRs for sale, whereas that same outage would be taken into account in determining the quantity of TRs for sale at a short-term auction (provided the outage is longer than 6 days).

Taking the example above, the October 13-20, 2011 K24F outage was submitted on August 31, 2011 and could have been taken into account for the short-term auction held on September 13, 2011 (for TRs valid in October 2011). Similarly, the October 24 to November 4, 2011 K24F outage was submitted on September 27, 2011 and could have been considered in setting the quantities for the short-term auction held on October 11, 2011 (for TRs valid in November 2011). The generator outage was submitted on September 1, 2011 and could also have been considered in setting the quantities for the September 13, 2011 short-term auction. In each of these cases, the IESO could have reduced the total quantity of TRs for sale,[138] thereby reducing the likelihood and magnitude of congestion rent shortfall.

Selling a combination of short and long-term TRs not only benefits the IESO, it also benefits the market participants who purchase TRs. The time period covered by a TR is a fundamental characteristic of the product. A short-term TR and a long-term TR cover different periods, which may be of greater or lesser interest (value) to particular physical traders or financial purchasers at various times depending on their business strategies.[139] Potential purchasers are

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[138] For example suppose the IESO offered only 10 MW of TRs for sale at the August 15, 2011 long-term auction, and withheld the remaining 45 MW for possible sale at the relevant short-term auctions (i.e. a 'reserve' of 50% of the normal Minnesota Import Scheduling Limit — meaning a total of 45 MW offered at long-term auctions, and 45 MW possibly offered at short-term auctions). When the IESO was informed of the October 2011 outages that would eventually result in an average intertie transfer capability of 53 MW for the month (see Table 3-5), the IESO could have restricted the quantity of short-term TRs sold in the September 13, 2011 auction to 8 MW, bringing the outstanding TR commitment to 53 MW for the month of October 2011.

[139] For example, market participants looking to hedge financial transactions have a much better sense of expected congestion and therefore their potential interest in purchasing a TR, at a short-term auction of two weeks before the

likely to be better off if there are at least some short-term TRs available for auction (on each interface in each direction) every month, in addition to the quarterly auctions of long-term TRs. In the worst case, where there is absolutely no demand (i.e., no purchaser places any value on short-term TRs and no bids are received) the TRs will remain unsold. In all other cases, purchasers will benefit by obtaining the financial protection against uncertainty provided by a TR at a price equal to (or less than) the value they place on that product at the time the auction occurs.

In determining a target mix for short-term and long-term TRs (either generally or on an intertie-by-intertie basis), the IESO may find it useful to look at historic planned and forced outage information. This would allow the IESO to estimate the number of TRs that should be reserved for short-term auctions, thus allowing the IESO to account for outages that are planned but notified with relatively short lead times and to provide for the contingency attributable to forced outages. In addition, the relative prices in historic auctions may provide the IESO with indications of the relative demand for long-term versus short-term TRs from purchasers, and this could inform the "demand side" assessment of a target reserve margin.

In summary, reserving some portion of TRs for sale at short-term auctions potentially offers significant benefits for TR holders and the IESO, while also reducing loads' exposure to the risks of congestion rent shortfalls (including the loss of offsets against transmission service charges they might otherwise have the benefit of). Accordingly, the Panel recommends the following:

Recommendation 3-4:

> ***The IESO policy of selling only long-term transmission rights on single-circuit interfaces should be replaced by a policy of reserving a significant portion of the available transmission rights for sale at short-term transmission right auctions.***

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beginning of a trading month relative to the time lags involved with purchasing long-term TRs. Market participants looking to make short-term investments or adjust their hedge position from month-to-month would also benefit from the sale of TRs at a short-term auction.

As this recommendation pertains to IESO operating policies, the Panel believes that it can be addressed promptly and need not await the broader reassessment of the TR market recommended earlier.

4.3.6 Spreading Out the Sale of Long-term TRs

Until recently, it had been the policy of the IESO to sell all available TRs at the earliest relevant long-term auction.

The experience on the Minnesota interface illustrates how this approach can restrict the IESO's flexibility, limit the opportunities for TR purchasers, and increase the risk of congestion rent shortfalls. The August 2011 auctioning of the maximum available TR quantity of 55 MW locked this quantity in until September 2012 and precluded downward adjustment of the outstanding TRs at the November and February quarterly auctions. None of the outages affecting the real-time Scheduling Limit were known to the IESO at the time they sold 55 MW of TRs at the August 2011 long-term auction. When the outages occurred, the real-time average intertie transfer capability dropped, and was exceeded by the number of MWs of TRs outstanding at the time. This contributed to considerable congestion rent shortfall. In addition, with respect to the April 2011 to June 2011 trade dates displayed in Table 3-6, the IESO sold TRs in May, August and November, 2010 which resulted in the outstanding TRs equaling the intertie's maximum transfer capability (90 MW). Accordingly, when the February 2011 long-term auction was held, the IESO was not able to offer any additional TRs. This meant that there were no TRs for sale in respect of the trade dates from April 2011 to March 2012, although there may have been demand for such a product.

The Panel understands that the IESO has recently adopted a proportional selling approach under which the TRs offered for sale at a given long-term auction will be approximately 25% of the forecasted intertie transfer capability.[140] The Panel supports this change in policy.

[140] See IESO Market Manual 7, Part 11: Transmission Reliability Margin Implementation (at p. 7), available at http://www.ieso.ca/imoweb/pubs/tr/TRMID_IESO_PRO_0729.pdf

Congestion rent shortfalls have been persistent since market opening. All of the above recommendations related to transmission rights in this report are directed at restoring balance by bringing the TR Clearing Account back to the level where congestion rent collected is approximately equal to TR payouts, as originally contemplated.

Congestion rent surpluses are conceptually possible, but they can only arise when the quantity of outstanding TRs is less than the intertie transfer capability, generally leading to congestion rent collected in excess of TR payouts when congestion occurs. The Panel does not believe that the recommendations set out in this report will result in the systematic underselling of TRs relative to the real-time intertie transfer capability, or in systematic congestion rent surpluses.

4.4 Issues at the Manitoba Interface

4.4.1 Introduction

As noted in Chapter 2, while no Intertie Offer Guarantee (IOG) payments exceeded the Panel's threshold for anomalous events, the Panel did identify an hour during the Winter 2012 Period with a large IOG payment.

The highest hourly IOG payment of the Winter 2012 Period occurred on March 5, 2012 in HE 23. During that hour one market participant ('Participant A') received $325,407 in IOG payments, of which $307,925 was paid in respect of imports at the Manitoba interface, with the remaining $17,482 paid in respect of imports at the Minnesota interface.

An IOG payment is intended to protect an import scheduled day-ahead or in the final pre-dispatch run from a drop in the real-time price relative to the price at which the import was scheduled. When the real-time price drops below the scheduled import offer price, an IOG payment is made equaling the difference between the real-time price and the offer price on each megawatt.[141]

There are two types of IOG payments: day-ahead IOG payments and real-time IOG payments. A day-ahead IOG payment is made when a market participant's import transaction is committed under the day-ahead commitment process (DACP)[142] and the real-time price clears below its day-ahead offer price. A real-time IOG payment is made when an import is scheduled in the final pre-dispatch run and the real-time price subsequently drops below the participant's offer price. Both types of IOG payments are intended to increase system reliability by providing compensation certainty to importers, thereby incenting them to import power into the province.[143]

All IOG payments associated with the March 5, 2012 event were day-ahead payments. Day-ahead, the import transactions were scheduled at positive prices, but in real-time the interface price dropped precipitously, triggering a large IOG payment. As discussed in greater detail below, two factors contributed to the highly negative real-time prices at the relevant interfaces, and thus to the high IOG payments: (i) an offer price reduction on the imports scheduled day-ahead, and (ii) additional imports offered at highly negative prices following the completion of the DACP.

The following sections examine the market conditions and participant behavior that resulted in the highly negative real-time price at the Manitoba interface, in respect of which the largest of the IOG payments occurred.

[141] When an intertie is uncongested, the real-time price is equal to the Ontario MCP. When an intertie is congested, the real-time price is equal to the external zonal price at the interface.
[142] This is the Enhanced DACP referred to in earlier sections of this Chapter. For ease of reference, this section refers more simply to DACP.
[143] In past reports, the Panel has questioned the appropriateness of off-peak real-time IOG payments, given that reliability concerns during off-peak hours are extremely infrequent. The Panel ultimately recommended that the IESO review the IOG program to determine whether or not it results in reliability improvements commensurate with its cost. For details, see the Panel's July 2008 Monitoring Report (at pp. 140-152), available at http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200807.pdf

4.4.2 Reduction in Offer Price for Imports Scheduled Day-ahead

Day-ahead, Participant A offered to import 150 MW at $34/MWh and an additional 55 MW at $44/MWh, all across the Manitoba interface. Of the imports offered, 152 MW were committed by the DACP (150 MW at $34/MWh and 2 MW at $44/MWh). Imports committed day-ahead are guaranteed to receive, at a minimum, the offer price at which they were committed—in this case, $34/MWh for 150 MW and $44/MWh for 2 MW. Following the completion of the DACP, Participant A reduced its offer price on all 152 MW of its committed imports to -$2,000/MWh. This action ensured that Participant A's committed import megawatts would be scheduled in the final pre-dispatch run, and that Participant A would receive its guaranteed day-ahead offer price while avoiding a potential failure charge.[144]

4.4.3 Incremental Imports Offered at a Highly Negative Price

With 152 MW of committed imports offered at -$2,000/MWh, but guaranteed to receive the respective day-ahead offer prices once energy and IOG payments are netted, Participant A entered a new import offer of 53 MW at approximately $25/MWh. This incremental offer was entered into the market at the same time that Participant A reduced the offer price on its day-ahead import transactions. The incremental import offered at $25/MWh was uneconomic during all pre-dispatch schedules.

With negative-priced imports offered totaling 152 MW, an additional 53 MW offered at $25/MWh but not scheduled, and an intertie Scheduling Limit of 205 MW, the interface was never congested during any of the pre-dispatch runs in advance of the two-hour ahead run. With no congestion the pre-dispatch interface price was the same as the Ontario MCP, which was consistently between $21/MWh and $24/MWh. In response to these price signals, another

[144] An import may not be scheduled due to system situations even though it is offered at -$2,000/MWh. However, the importer will be exempted from the failure charge if the importer has passed the Offer Price Test. An importer will pass the Test if it has offered its day-ahead schedule at -$2,000/MWh in real-time. For details, see the IESO's Charge Type and Equations, available at: http://www.ieso.ca/imoweb/pubs/settlements/IMO_Charge_Types_and_Equations.pdf.

participant offered to import 50 MW at $18.02/MWh two hours before the delivery hour. There were no other imports offered or exports bid at the interface during the hour in question.

In the meantime, following the final actionable price signal (the three-hour ahead pre-dispatch price) but before the deadline to submit final offers and bids, Participant A increased its offered quantity from 53 MW to 55 MW on the incremental portion of its import offer, and reduced the offer price on all incremental megawatts to -$1,999.99/MWh. The quantity increase made Participant A's final import position 207 MW, all offered at highly negative prices and displacing the other participant's 50 MWs offered at $18.02/MWh. With a final Ontario pre-dispatch price of $22.03/MWh, Participant A was alone in offering economic imports. These were in excess of the 205 MW intertie transfer capability, causing import congestion, a large drop in the intertie zonal price to -$1,999.99/MWh and a large IOG payment to all imports scheduled day-ahead.

Table 3-7 displays Participant A's import offer structure in the lead up to real-time.

Table 3-7: Participant A's Import Offer Structure over Time
March 5, 2012, HE 23
(MW & $/MWh)

Time	Offer #1		Offer #2		Offer #3		Total MW
	MW	$/MWh	MW	$/MWh	MW	$/MWh	MW
March 4 before DACP run	150	$34	55	$44	0	N/A	205
Scheduled in DACP	*150*	*$34*	*2*	*$44*	*0*	*N/A*	*152*
March 4 following DACP	150	-$2,000	2	-$2,000	53	$25	205
March 5 following PD-3 publication but before deadline for HE 23 offers	150	-$2,000	2	-$2,000	55	-$1,999.99	207
Scheduled in final pre-dispatch run	*150*	*-$2,000*	*2*	*-$2,000*	*53*	*-$1,999.99*	*205*

4.4.4 Interplay between TR Payouts and IOG Payments

With a final pre-dispatch Ontario MCP of $22.03/MWh and a Manitoba intertie zonal price of -$1,999.99/MWh, the ICP was set at -$2,022.02/MWh. The import congestion caused by the last-minute offer change by Participant A resulted in large payouts to all import TR holders. For the month of March 2012, Participant A owned 190 MW of import TRs, while six other market participants owned a combined 15 MW. Import TR owners are paid the absolute value of the ICP for each megawatt of TRs they hold when the intertie is import-congested in the final pre-dispatch run; in this case $2,022.02 per MW of TRs owned.

Table 3-8 lists all estimated payments associated with the Manitoba interface made during the hour in question. All payments considered, importers at the Manitoba interface realized combined profits of nearly $310,000 for the hour, of which approximately $279,515 was made by Participant A. On a profit-per-MWh delivered basis, Participant A made approximately $1,363/MWh for that hour.

***Table 3-8: Estimated* Gross Profits Associated with the Manitoba Interface
March 5, 2012, HE 23
(MW, $/MWh & $)***

Payment Type	Participant A			All Other Participants		
	Total MW subject to Payment (MW)	**Relevant Price ($/MWh)**	**Total Payment Amount ($)**	**Total MW subject to Payment (MW)**	**Relevant Price (S/MWh)**	**Total Payment Amount ($)**
Energy Market	205	-1,999.99	(409,998)	0	N/A	0
Cost of Power in External Market	205	18.82**	(3,858)	0	N/A	0
Day-ahead Intertie Offer Guarantee	150 2	2,033.99 2,043.99	305,099 4,088	0	N/A	0
Transmission Rights Payout	190	2,022.02	384,184	15	2,022.02	30,330
Estimated Gross Profit***	**$279,515**			**$30,330**		
Estimated Gross Profit per MWh Delivered	**$1,363/MWh**			**N/A**		

* Payment amounts are estimated. Final settlement amounts vary minimally due to nuances in the various settlement equations.

** Based on a Midwest Independent Transmission System Operator - Manitoba nodal price of $13.82/MWh, plus assumed transaction costs of $5.00/MWh.
*** The cost of purchasing TRs is not included in the gross profit calculation, as the purchasing cost is sunk and not linked to an individual transaction. Allocating the sunk cost incurred by Participant A of purchasing TRs for the month of March 2012 across all hours in March results in an hourly cost of $859.95 per 190 MW of TRs purchased.

Had Participant A not increased the import offer quantity on the incremental portion of its import transaction (from 53 MW to 55 MW) or not reduced its import offer price (from $25/MWh to -$1,999.99/MWh), there would have been no congestion at the interface (based on the final pre-dispatch MCP of $22.03/MWh, the final schedule would have been 152 MW of imports at -$2,000/MWh from Participant A and 50 MW of imports at $18.02/MWh from the other participant). No TR payments would have been made, and IOG payments would have been limited to the difference between Participant A's day-ahead committed offer prices ($34/MWh and $44/MWh) and the real-time intertie price had there been no congestion ($22.03/MWh).

Participant A's offer structure was profitable because of the overlapping protection provided by the IOG payment and the TR payout. As noted earlier in this Chapter, TRs are intended to provide a financial hedge against congestion-related price differences at an intertie. A TR payment ensures that an importer is paid the Ontario MCP for all megawatts that flow up to the megawatt quantity of TRs owned. This is achieved by compensating the participant for any discrepancy between the Ontario MCP and the intertie zonal price resulting from congestion at the intertie. Accordingly, import megawatts covered by TRs are fully protected from the lower price that arises when the intertie is congested.

Day-ahead IOG payments also compensate importers for a drop in the intertie zonal price caused by congestion. When a participant has an import committed day-ahead, those megawatts are guaranteed to receive at least their day-ahead offer price, and are thus protected from a drop in the real-time intertie zonal price. Changes in the intertie zonal price from day-ahead to real-time can occur for two reasons: namely; a drop in the Ontario MCP, and/or congestion at the intertie. Intertie zonal price changes due to a drop in the Ontario MCP occur when the global supply and demand conditions change, and tend to result in modest discrepancies between the real-time Ontario MCP and day-ahead pre-dispatch prices. Changes in the intertie zonal price caused by intertie congestion can occur when offers or bids are added, removed, or altered following the

DACP, or from a reduction in the intertie Scheduling Limit. These changes can result in heavy congestion and large discrepancies between day-ahead and real-time intertie zonal prices.

With both IOG payments and TR payouts compensating importers for low prices induced by intertie congestion, a participant will be more than kept whole when the sum of its day-ahead committed megawatts and its megawatts of TRs owned is greater than the amount of megawatts they flow in real-time.[145] Taking the March 5, 2012 HE 23 events to illustrate, Participant A had 152 MW committed day-ahead, and owned 190 MW of TRs, totaling 342 MW of protection against a congestion-induced price drop. With an intertie limit and final schedule of 205 MW, Participant A effectively had protection on 137 MW of imports above what was necessary. When the market settled, Participant A had to pay the -$1,999.99 intertie zonal price on the 205 MWs of energy that flowed, but was compensated for this price drop based on its 342 MW of protection. Participant A realized a gross profit of $279,515.

Generally, if the sum of a participant's day-ahead committed megawatts and megawatts of TRs owned is greater than the intertie transfer capability, offering highly negative-priced imports in excess of the import Scheduling Limit presents no financial risk to the participant. Using the circumstances at issue to illustrate, all megawatts scheduled under the DACP (152 MW) were guaranteed the moderately positive price they were scheduled at, insulating Participant A from loss due to a reduction in the real-time price. While not directly protected under a program or guarantee, all megawatts offered by Participant A at -$1,999.99/MWh (55 MW) following the DACP were also protected against the significant downside risk suggested by the participant's offer price via the TRs held by Participant A. When congestion occurred, the highly negative energy price paid to imported power (205 MW) was more than offset by the IOG payment (covering 152 MW) and TR payouts (covering 190 MW) received. Had an offsetting export

[145] There is no double protection for imports covered by a real-time IOG and TRs. Real-time IOG payments compensate imports for a drop in the real-time zonal price relative to the one-hour-ahead pre-dispatch zonal price. Because the congestion price is calculated based on the one-hour-ahead pre-dispatch price and locked in at that level for real-time, all changes in the intertie zonal price from pre-dispatch to real-time must be a result of a change in the Ontario MCP. Accordingly, the real-time IOG only compensates for a drop in the Ontario MCP, while TRs only compensate for a price drop induced by intertie congestion. In such circumstances, there is no double protection.

been scheduled and there had been no congestion, then Participant A's import would have received the Ontario MCP.

The Panel notes that Participant A has also routinely offered imports in excess of the intertie transfer capability at the Minnesota interface, causing import congestion in a large number of hours. Much like the Manitoba situation described above, on a net basis Participant A profited from the congestion due to its position in the TR market.

Recommendation 3-5:

> ***As part of the IESO's planned review of the Enhanced Day-Ahead Commitment Process, the Panel recommends that the IESO examine the interplay between the day-ahead intertie offer guarantee program and the transmission rights market.***

Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is the Panel's 20th semi-annual monitoring report on the IESO-administered markets. It covers the winter period November 2011 to April 2012, and also reports on market outcomes for the period May 2011 to April 2012. As in previous reports, the Panel has concluded that the energy 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.

During the winter period, the Panel completed two investigations in which it concluded that neither of the market participants engaged in gaming in respect of infeasible import transactions. The Panel currently has six investigations in progress. These investigations relate to possible gaming issues involving Congestion Management Settlement Credit and other payments. As each of these investigations is completed, the Panel will submit its investigation report to the Chair of the OEB and the report will be published on the OEB's website.[146]

2. Future Development of the Market

The Panel understands that the IESO has work programs under way to assist address various issues identified in the 2011 report of the Electricity Market Forum,[147] and has retained external advisors to assist it in that regard. The Panel believes that this work is important to the future development of the Ontario wholesale electricity markets.

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[146] The submission and posting of Panel investigation reports is addressed in Article 7 of the OEB's By-law #3 (Market Surveillance Panel), available at http://www.ontarioenergyboard.ca/OEB/_Documents/About the OEB/OEB_bylaw_3.pdf.

[147] George Vegh, "Reconnecting Supply and Demand: How Improving Electricity Pricing Can Help Integrate A Changing Supply Mix, Increase Efficiency and Empower Customers (Report of the Chair of the Electricity Market Forum)" (December 2011), available at: http://www.ieso.ca/imoweb/pubs/consult/Market_Forum_Report.pdf .

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 the release of each of the Panel's monitoring reports, the IESO posts the recommendations and its responses to those recommendations on its public web site.[148] The IESO also discusses the recommendations and its responses with its Stakeholder Advisory Committee (SAC) and with the IESO Board of Directors.

The Panel's April 2012 Report contained five recommendations, four of which were directed to the IESO and one of which was directed to the OPA and the Government of Ontario.

3.1 Recommendations to the IESO from the Prior Report

The relevant IESO responses to the four recommendations in the Panel's April 2012 Report are reproduced in Table 4-1.[149]

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

Recommendation	IESO Response
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.*	"The IESO agrees with this recommendation and is pursuing this within the requirements of NPCC's Regional Reliability Reference Directory #6. Directory #6 contains NPCC's set of requirements regarding participation in Reserve Sharing Groups (RSG). These requirements outline who can participate in an RSG, the obligations of the RSG once formed (for example each RSG will have an RSG Agreement), and the Reserve Sharing Implementation requirements within the RSG Agreement."
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.*	"The MSP monitoring document which provides guidance to generators regarding offer prices used to signal an intention to come offline has resulted in a substantial reduction in CMSC payments to ramping down generators. The IESO's judgement is that the remaining CMSC amount of $3-4M of the original $12M may well be consistent with the cost of efficiency losses that generators incur when ramping down and that removing ramping down CMSC from generator revenues would require an alternate mechanism to allow for generators to recover legitimate losses.

[148] The IESO's responses to recommendations set out in Panel reports dating back several years are available at: http://www.ieso.ca/imoweb/pubs/marketSurv/ms_mspReports-20120621.pdf .
[149] *Ibid.*

Recommendation	IESO Response
	The IESO will conduct a review of the real-time and day-ahead guarantee programs commencing this fall and plans to have recommendations related to issues requiring consideration by Q1 2013. Ramping down CMSC will be considered in the context of this broader review to ensure that generators are compensated for only legitimate costs incurred during ramp down."
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.*	"The IESO agrees with this recommendation. Since the event referenced in the MSP Report, the IESO has and will continue to implement new processes with the neighbouring jurisdictions to improve communication of outage plans, allowing this information to be considered in the sales of Transmission Rights."
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.*	"The IESO agrees with this recommendation. The IESO currently has market rules in place to allow for the recovery of Transmission Rights payouts when the trader fails its intertie transactions, and intends to adjust settlement amounts paid or payable to traders in situations where the trader has failed to schedule the transaction with the appropriate scheduling entity other than for bona fide and legitimate reasons. Refer to the Market Rules Chapter 3, section 6.6.10A and Chapter 7, sections 7.5.8A and 7.5.8B."
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.*	"The IESO agrees with this recommendation. The IESO is initiating work based on the Electricity Market Forum's recommendations aimed at improving market efficiency, including reviews of HOEP, Global Adjustment (GA), the two-schedule system and intertie trading. Requests for Proposals (RFP's) related to the HOEP and GA recommendations have been posted. Work on the two-schedule structure will be influenced by the results of the HOEP effort and we anticipate initiating this work by the end of the year. The IESO has begun work on the recommendations related to improved trading processes."

3.2 Other Recommendations from the Prior Report

The Panel made the following recommendation directed toward the OPA and the Government of Ontario in its April 2012 Report:

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.

Through a consultant, the OPA analysed the interplay between the OPA's Demand Response 3 program and the Global Adjustment allocation methodology as part of the OPA's regular evaluation of its demand response programs. The OPA has provided relevant excerpts from the consultant's report to the Panel for its review.[150] The Panel plans to meet with the OPA to discuss the issues noted in the consultant's report.

4. Summary of Recommendations

The Panel groups its recommendations into four categories: price fidelity, efficiency, transparency and hourly uplift payments. Some recommendations may have impacts in more than one category (e.g., a scheduling change could affect prices as well as uplift). In such cases the recommendation is included in the category of its primary effect.[151] Within each category, the recommendations in this report have been prioritized based on the Panel's view of their relative importance.

All of the recommendations contained in this report pertain to the TR market. Four of those recommendations speak to issues associated with the design and operation of that market, and are directed at restoring balance by bringing the TR Clearing Account back to the level where congestion rent collected is approximately equal to TR payouts. The fifth recommendation relates to the interplay between the TR market and the day-ahead Intertie Offer Guarantee program.

4.1 Efficiency

Efficient dispatch is one of the IESO's primary objectives in operating the wholesale market.

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[150] The OPA's response and the excerpt from the consultant's report are available at http://www.ontarioenergyboard.ca/OEB/Industry/About%20the%20OEB/Electricity%20Market%20Surveillance/Market%20Surveillance%20Panel%20Reports.

[151] The Panel does not have any recommendations in this report relating to transparency or price fidelity, but many of the efficiency and uplift recommendations would also have positive implications in these areas.

Recommendation 3-1:

The IESO should reassess the design of the Ontario transmission rights market to determine whether it is achieving its intended purpose.

4.1 Uplift and Other Payments

The Panel examines uplift and other payments[152] both as they contribute to the effective price paid by customers and as they impact the efficient operation of the market.

Recommendation 3-2:

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 3-3:

(A) The IESO Board of Directors should authorize the disbursement of the portion of the Transmission Rights Clearing Account balance that currently exceeds the Reserve Threshold to reduce the transmission charges payable by loads.
(B) In the future, the IESO Board of Directors should authorize disbursements of Transmission Rights Clearing Account balances in excess of the Reserve Threshold after each year end.

Recommendation 3-4:

The IESO policy of selling only long-term transmission rights on single-circuit interfaces should be replaced by a policy of reserving a significant portion of the available transmission rights for sale at short-term transmission right auctions.

[152] Uplift charges are collected from customers in the wholesale market to pay for Operating Reserve; for Congestion Management Settlement Credit, Intertie Offer Guarantee and cost guarantee program payments; and other costs such as energy losses on the IESO-controlled grid. See section 2.3.1 of chapter 1.

Recommendation 3-5:

As part of the IESO's planned review of the Enhanced Day-Ahead Commitment Process, the Panel recommends that the IESO examine the interplay between the day-ahead intertie offer guarantee program and the transmission rights market.

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

Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2011 – April 2012

List of Tables

Table A-1: Outages, May 2010 - April 2012 (TWh)*

	Total Outage		Planned Outage**		Forced Outage	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	5.58	4.65	2.79	2.32	2.79	2.33
Jun	4.07	3.80	1.01	1.33	3.06	2.47
Jul	3.88	3.04	0.74	0.80	3.14	2.24
Aug	3.61	3.18	0.81	0.59	2.80	2.59
Sep	4.17	4.08	2.17	1.93	2.00	2.15
Oct	5.62	5.82	3.27	3.39	2.35	2.43
Nov	4.47	5.77	2.20	3.03	2.27	2.74
Dec	2.57	3.97	1.49	1.54	1.08	2.43
Jan	1.32	3.26	0.28	0.98	1.04	2.28
Feb	3.59	3.42	1.49	1.31	2.10	2.11
Mar	4.23	3.62	1.80	1.15	2.43	2.47
Apr	6.24	5.50	3.65	2.35	2.59	3.15
May – Oct	26.93	24.57	10.79	10.36	16.14	14.21
Nov - Apr	22.42	25.54	10.91	10.36	11.51	15.18
May - Apr	49.35	50.11	21.70	20.72	27.65	29.39

* There are two sets of data that reflect outages information. The 2010/2011 columns relies on information from the outage information that is actually input to the DSO to determine price. The 2011/2012 column relies on information used to forecast supply. The MAU has reconciled the difference between the two sets of data by applying outage types from the IESO's outage database to the DSO outage information.
** CO_2 Outages are recorded as forced outages by the IESO but are classified as planned outages for purposes of our statistics.

Table A-2: Ontario Consumption by Type of Usage
May 2010 – April 2012
(TWh)

	LDC's*		Wholesale Loads		Generators		Metered Energy Consumption**		Transmission Losses		Total Energy Consumption***	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	9.57	9.08	1.35	1.31	0.11	0.11	11.03	10.50	0.33	0.28	11.36	10.78
Jun	9.87	9.56	1.36	1.23	0.09	0.10	11.32	10.90	0.24	0.34	11.56	11.24
Jul	11.50	11.51	1.40	1.33	0.08	0.09	12.98	12.93	0.32	0.37	13.31	13.30
Aug	11.09	10.75	1.44	1.39	0.11	0.08	12.64	12.22	0.28	0.31	12.92	12.53
Sep	9.40	9.38	1.42	1.38	0.12	0.07	10.93	10.84	0.12	0.31	11.05	11.14
Oct	9.31	9.36	1.46	1.38	0.09	0.07	10.86	10.82	0.07	0.19	10.93	11.01
Nov	9.82	9.48	1.37	1.31	0.10	0.07	11.29	10.86	0.01	0.26	11.30	11.12
Dec	11.11	10.42	1.37	1.32	0.10	0.07	12.59	11.82	0.12	0.32	12.71	12.13
Jan	11.44	10.98	1.44	1.38	0.11	0.08	12.99	12.44	0.31	0.27	13.30	12.72
Feb	10.18	9.93	1.32	1.30	0.11	0.06	11.61	11.29	0.16	0.32	11.78	11.61
Mar	10.54	9.66	1.47	1.41	0.11	0.10	12.12	11.17	0.23	0.32	12.35	11.49
Apr	9.17	8.88	1.34	1.36	0.11	0.09	10.63	10.34	0.16	0.31	10.79	10.64
May –Oct	60.73	59.65	8.43	8.02	0.65	0.54	69.76	68.21	1.36	1.80	71.12	70.01
Nov - Apr	62.27	59.35	8.31	8.09	0.65	0.47	71.23	67.91	1.00	1.79	72.23	69.70
May -Apr	123.00	119.01	16.74	16.11	1.30	1.01	140.99	136.12	2.36	3.59	143.35	139.71

* LDC's is net of any local generation within the LDC
** Metered Energy Consumption = LDC's + Wholesale Loads + Generators
*** Transmission Losses = Total Energy Consumption - Metered Energy Consumption

Table A-3: Total Hourly Uplift Charge by Component, May 2010 – April 2012 ($ Millions)

	Total Hourly Uplift*		RT IOG**/IOG***		DA IOG***		CMSC****		Operating Reserve		Losses	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	19.89	32.76	0.16	0.35	0.34	0.02	9.57	13.01	0.35	12.20	9.47	7.17
Jun	21.30	33.66	0.12	0.72	0.02	0.04	11.22	18.36	1.14	4.74	8.8	9.81
Jul	30.11	22.74	0.37	0.33	0.13	0.03	13.68	9.55	1.46	1.51	14.47	11.32
Aug	25.28	17.53	0.23	0.17	0.03	0.20	10.28	6.95	2.12	2.45	12.62	7.77
Sep	20.49	15.71	0.45	0.21	0.08	0.92	8.45	6.56	3.25	0.71	8.27	7.31
Oct	14.14	13.09	0.23	0.25	0.04	0.14	5.54	5.58	1.28	0.45	7.05	6.65
Nov	14.76	15.01	0.10	0.54	0.04	n/a	6.58	9.13	1.08	0.60	6.96	4.74
Dec	23.00	12.28	0.33	0.67	0.03	n/a	8.48	3.48	3.72	1.17	10.44	6.96
Jan	18.72	11.09	0.46	0.77	0.04	n/a	5.94	2.75	2.21	1.28	10.07	6.29
Feb	14.21	10.49	0.43	1.16	0.03	n/a	4.99	3.77	1.30	0.58	7.46	4.98
Mar	17.01	15.64	0.42	1.46	0.02	n/a	7.09	6.19	1.10	3.99	8.38	3.99
Apr	20.19	9.32	0.40	0.40	0.04	n/a	7.71	3.52	4.70	1.25	7.34	4.15
May- Oct	131.21	135.50	1.56	2.03	0.64	1.34	58.74	60.02	9.60	22.06	60.68	50.04
Nov - Apr	107.89	73.83	2.14	5.00	0.20	n/a	40.79	28.85	14.11	8.87	50.65	31.11
May -Apr	239.11	209.33	3.70	7.04	0.84	1.34	99.53	88.87	23.71	30.93	111.33	81.15

* Total Hourly Uplift = RT IOG + DA IOG + CMSC + Operating Reserve + Losses

** The IOG numbers are not adjusted for IOG offsets, which was implemented in July 2002. IOG offsets are reported in Table A-19. All IOG Reversals have been applied to RT IOG.

***The DA IOG and RT IOG are billed as one charge as of October 13th, 2011.

**** Numbers are adjusted for Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments.

Table A-4: CMSC Payments, Energy and Operating Reserve, May 2010 – April 2012 ($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	5.73	5.87	3.13	3.46	8.86	9.33	0.30	2.76	9.16	12.09
Jun	6.87	9.24	3.46	3.41	10.33	12.66	0.59	1.67	10.92	14.32
Jul	8.87	5.55	3.93	2.69	12.79	8.23	0.58	0.40	13.37	8.63
Aug	7.23	3.64	3.08	3.00	10.32	6.64	0.99	0.82	11.31	7.46
Sep	5.27	2.83	3.43	3.00	8.70	5.84	1.07	1.06	9.77	6.90
Oct	3.66	3.09	1.67	1.51	5.33	4.61	1.45	0.52	6.78	5.12
Nov	3.77	6.15	2.02	4.06	5.79	10.21	1.31	0.45	7.10	10.66
Dec	5.67	2.34	1.59	1.84	7.25	4.17	1.37	0.34	8.62	4.51
Jan	3.15	2.12	2.37	1.39	5.52	3.51	0.62	0.39	6.14	3.90
Feb	3.12	1.91	1.73	1.72	4.85	3.63	0.33	0.17	5.18	3.80
Mar	4.56	3.75	1.84	2.75	6.40	6.50	0.55	1.01	6.95	7.51
Apr	3.86	3.60	2.33	1.31	6.19	4.91	1.21	0.54	7.40	5.45
May- Oct	37.63	30.23	18.7	17.07	56.33	47.30	4.98	7.23	61.31	54.53
Nov - Apr	24.13	19.87	11.88	13.06	36.00	32.93	5.39	2.90	41.39	35.83
May -Apr	61.76	50.10	30.58	30.13	92.33	80.23	10.37	10.13	102.70	90.36

* The sum for energy being constrained on and off does not equal the total CMSC for energy in some months. This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC amounts.
** The totals for CMSC payments do not equal the totals for CMSC payments in Table A-11: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months. Neither table includes Local Market Power adjustments.

Table A-5: Share of Constrained On Payments for Energy by Type of Supplier, May 2010 – April 2012 (%)

	Domestic Generators		Imports	
	2010 / 2011	2011 / 2012	2010 / 2011	2011 / 2012
May	99.9	99.6	0.1	0.4
Jun	99.7	97.9	0.3	2.1
Jul	100.9	99.7	(0.9)	0.3
Aug	100.0	99.8	0.0	0.2
Sep	99.8	99.8	0.2	0.2
Oct	100.3	100.1	(0.3)	(0.1)
Nov	100.0	99.9	0.0	0.1
Dec	98.1	100.0	1.9	0.0
Jan	99.6	99.7	0.4	0.3
Feb	98.9	100.0	1.1	0.0
Mar	99.7	99.9	0.3	0.1
Apr	100.4	99.6	(0.4)	0.4
May- Oct	100.1	99.5	(0.1)	0.5
Nov - Apr	99.4	99.8	0.6	0.2
May -Apr	99.8	99.7	0.2	0.3

Table A-6: Supply Cushion Statistics, On-Peak, May 2010 – April 2012 (% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	18.9	8.4	0	0	25	240	14.7	11.2	0	0	116	131
Jun	15.6	13.2	0	0	76	105	15.6	8.6	0	0	46	230
Jul	16.6	12.4	0	0	54	121	13.5	10.2	3	9	148	164
Aug	16.7	13.9	0	0	58	106	12.7	9.2	6	0	173	213
Sep	15.4	14.7	0	0	118	65	14.7	10.9	0	0	100	146
Oct	13.2	14.9	0	0	155	45	15.1	13.7	0	0	45	49
Nov	18.3	16.8	0	0	40	48	14.9	13.9	1	0	58	57
Dec	10.5	12.8	0	0	239	112	17.6	10.5	0	0	14	156
Jan	12.9	10.2	0	1	151	175	15.8	11.0	0	0	50	135
Feb	14.0	13.0	0	0	106	92	13.2	12.6	0	0	97	81
Mar	11.2	13.1	0	0	216	104	12.7	13.0	0	0	116	83
Apr	9.5	11.6	0	0	283	137	10.8	15.9	4	0	228	26
May- Oct	16.1	12.9	0	0	486	682	14.4	11.5	9	9	628	933
Nov - Apr	12.7	12.9	0	1	1035	668	14.2	12.8	5	0	563	538
May -Apr	14.4	12.9	0	1	1521	1350	14.3	12.1	14	9	1191	1471

* This category includes hours with a negative supply cushion
** The 2010-2011 figures have been revised from the previous report

Table A-7: Supply Cushion Statistics, Off-Peak, May 2010 – April 2012 (% and Number of Hours)

	One Hour-ahead Pre-dispatch Total						Real-time Domestic					
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*		Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion < 10% (# of Hours)*	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	35.3	12.2	0	0	0	162	26.6	23.5	0	0	0	16
Jun	30.4	19.1	0	0	0	24	26.2	20.8	1	0	2	42
Jul	34.4	22.3	0	0	0	40	24.6	19.7	0	0	0	34
Aug	32.1	20.8	0	0	1	30	20.9	19.4	0	0	7	31
Sep	25.2	22.5	0	0	8	6	22.4	19.6	1	0	5	14
Oct	22.6	21.9	0	0	14	4	27.4	21.5	0	0	3	13
Nov	31.2	26.5	0	0	2	4	25.2	23.8	0	0	1	11
Dec	23.3	21.9	0	0	2	31	28.5	19.0	0	1	0	51
Jan	21.5	20.4	0	0	7	50	24.4	20.8	0	0	0	22
Feb	21.6	21.5	0	0	1	31	20.1	20.4	0	0	1	18
Mar	18.9	18.0	0	0	30	69	22.1	21.5	0	0	4	40
Apr	17.1	17.7	0	0	39	83	23.6	22.5	0	0	13	10
May- Oct	30.0	19.8	0	0	23	266	24.7	20.7	2	0	17	150
Nov - Apr	22.3	21.0	0	0	81	268	24.0	21.3	0	1	19	152
May -Apr	26.1	20.4	0	0	104	534	24.3	21.0	2	1	36	302

* This category includes hours with a negative supply cushion
** The 2010-2011 figures have been revised from the previous report

Table A-8: Resources Selected in the Real-time Market Schedule, May 2010 – April 2012 (TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Wind		Domestic Generation*	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	0.51	0.32	0.55	1.63	1.28	0.11	1.53	1.06	2.47	3.67	5.74	6.91	0.21	0.28	11.23	12.04
Jun	0.52	0.38	1.18	1.07	1.73	0.22	1.4	1.43	2.14	3.38	6.55	6.62	0.16	0.21	11.98	11.87
Jul	0.77	0.71	1.32	1.29	2.07	1.35	2.08	1.99	2.15	2.99	7.04	7.30	0.14	0.14	13.48	13.77
Aug	0.70	0.55	1.25	1.08	1.75	0.64	2.06	1.85	2.04	2.50	7.14	7.81	0.16	0.16	13.15	12.97
Sep	0.79	0.39	1.71	0.85	0.51	0.27	1.31	1.46	2.34	2.20	7.23	7.41	0.26	0.23	11.65	11.58
Oct	0.51	0.30	1.44	1.05	0.12	0.20	1.25	1.69	2.70	2.34	7.15	7.09	0.28	0.34	11.50	11.67
Nov	0.48	0.29	1.26	0.89	0.49	0.42	1.38	1.63	2.64	2.60	6.82	6.36	0.33	0.55	11.66	11.56
Dec	0.47	0.27	2.14	0.75	0.64	0.35	1.64	1.39	3.13	2.96	8.19	7.27	0.36	0.47	13.96	12.45
Jan	0.41	0.33	1.56	1.12	0.54	0.40	1.76	2.21	3.16	3.10	8.2	7.06	0.28	0.58	13.94	13.36
Feb	0.38	0.31	1.00	1.05	0.32	0.47	1.61	1.79	2.79	3.09	6.77	6.37	0.39	0.45	11.88	12.18
Mar	0.37	0.33	1.03	1.33	0.26	0.41	1.4	1.22	3.1	3.27	7.4	6.92	0.30	0.52	12.46	12.34
Apr	0.34	0.50	1.06	1.58	0.12	0.22	0.93	1.42	3.03	3.21	6.76	6.32	0.36	0.43	11.20	11.60
May – Oct	3.8	2.65	7.45	6.97	7.46	2.79	9.63	9.49	13.84	17.09	40.85	43.15	1.21	1.37	72.99	73.90
Nov - Apr	2.45	2.02	8.05	6.72	2.37	2.27	8.72	9.66	17.85	18.24	44.14	40.31	2.02	3.00	75.10	73.48
May - Apr	6.25	4.68	15.5	13.69	9.83	5.07	18.35	19.15	31.69	35.33	84.99	83.46	3.23	4.37	148.09	147.38

* Domestic generation is the sum of Coal, Oil/Gas, Hydroelectric, and Nuclear.

Table A-9: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2010 – April 2012 (MW and %)

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	283	195	223	169	320	243	261	228	1.9	1.3	1.5	1.2	2.1	1.7	1.7	1.6
Jun	285	282	216	214	321	345	274	293	1.8	1.8	1.4	1.4	2.0	2.2	1.7	1.9
Jul	348	337	266	253	399	388	319	321	2.0	1.9	1.5	1.4	2.2	2.2	1.8	1.8
Aug	332	318	256	233	393	399	331	330	1.9	1.9	1.5	1.4	2.3	2.4	1.9	2.0
Sep	211	230	164	173	285	343	262	293	1.4	1.5	1.1	1.1	1.9	2.2	1.7	1.9
Oct	167	176	136	144	265	276	254	267	1.1	1.2	0.9	1.0	1.8	1.9	1.7	1.8
Nov	240	240	205	206	264	250	236	232	1.5	1.6	1.3	1.3	1.7	1.6	1.5	1.5
Dec	266	258	227	220	254	264	229	234	1.6	1.6	1.3	1.4	1.5	1.6	1.4	1.4
Jan	293	299	241	246	300	280	250	236	1.7	1.8	1.4	1.4	1.7	1.6	1.4	1.4
Feb	253	271	198	209	266	285	229	232	1.5	1.6	1.1	1.3	1.5	1.7	1.3	1.4
Mar	249	248	199	195	299	274	261	236	1.5	1.6	1.2	1.3	1.8	1.8	1.6	1.5
Apr	227	246	185	196	275	296	259	260	1.5	1.7	1.2	1.3	1.8	2.0	1.7	1.8
May – Oct	271	256	210	198	331	332	284	289	1.7	1.6	1.3	1.2	2.1	2.1	1.8	1.8
Nov – Apr	255	260	209	212	276	275	244	238	1.6	1.6	1.3	1.3	1.7	1.7	1.5	1.5
May - Apr	263	258	210	205	303	304	264	263	1.6	1.6	1.3	1.3	1.9	1.9	1.6	1.6

Table A-10: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2010 – April 2012 (%)*

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	2	0	8	6	7	5	10	13	17	15	15	19	29	31	13	10	27	25	74	75
Jun	0	1	10	8	6	6	10	11	14	13	15	14	29	29	15	18	26	26	73	74
Jul	3	2	9	8	7	6	9	7	11	12	13	14	30	31	19	19	28	24	73	76
Aug	2	1	9	9	6	5	8	6	10	13	14	11	30	34	22	21	25	21	76	79
Sep	1	1	5	5	6	6	11	9	15	14	17	14	31	36	14	16	23	20	77	80
Oct	0	0	4	6	4	5	11	10	16	14	19	16	33	35	13	13	19	22	81	78
Nov	0	1	8	10	8	9	13	13	15	15	18	16	27	26	12	9	29	33	72	67
Dec	1	1	8	11	9	10	15	15	15	16	14	12	29	26	9	10	33	37	67	63
Jan	2	3	11	13	8	11	12	13	15	16	15	12	26	24	10	7	33	41	66	59
Feb	1	1	8	12	7	9	13	13	17	15	16	14	29	28	9	7	29	35	71	65
Mar	1	2	5	9	6	8	11	11	16	17	14	17	34	28	13	8	23	30	77	70
Apr	1	1	8	9	8	9	12	11	14	14	15	12	28	31	14	12	29	30	71	70
May – Oct	1	1	8	7	6	6	10	9	14	14	16	15	30	33	16	16	25	23	76	77
Nov – Apr	1	1	8	11	8	9	13	13	15	15	15	14	29	27	11	9	29	34	71	66
May - Apr	1	1	8	9	7	8	11	11	15	14	15	14	30	30	14	12	27	29	73	71

* Data includes both dispatchable and non-dispatchable load.

Table A-11: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities,
May 2010 – April 2012
(MW and %)*

	Pre-Dispatch (MW)		Pre-Dispatch (MW)						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	783,768	915,174	390.2	450.6	(254.3)	(437.6)	49.6	34.2	4.9	3.5
Jun	839,507	883,235	312.8	382.6	(413.1)	(369.4)	49.7	61.6	4.5	5.5
Jul	875,636	839,723	410.3	424.1	(285.9)	(331.2)	70.7	106.2	6.1	9.5
Aug	823,801	820,450	414.8	400.1	(256.8)	(364.9)	58.2	99.2	5.5	9.3
Sep	792,001	680,730	302.1	485.2	(336.2)	(307.9)	23.2	66.8	2.4	7.5
Oct	959,747	994,553	328.6	345.5	(382.4)	(318.9)	43.3	58.0	3.7	5.1
Nov	1,030,041	1,213,412	472.0	585.5	(272.2)	(477.5)	82.6	39.5	6.2	2.6
Dec	1,140,816	1,170,263	458.2	556.6	(265.4)	(540.8)	86.9	57.0	6.1	4.2
Jan	1,033,636	1,318,597	453.3	600.5	(704.6)	(505.6)	84.2	18.3	6.2	1.2
Feb	1,068,883	1,142,862	376.4	576.1	(453.8)	(477.2)	(15.0)	16.0	(0.3)	1.7
Mar	1,020,602	1,248,420	458.5	593.9	(563.6)	(535.7)	(0.5)	3.7	0.4	0.7
Apr	998,323	1,081,747	669.2	566.4	(556.7)	(505.7)	8.9	24.3	1.2	1.9
May – Oct	845,743	855,644	359.8	414.7	(321.5)	(354.9)	49.1	71.0	4.5	6.7
Nov – Apr	1,048,717	1,195,884	481.3	579.8	(469.4)	(507.1)	41.2	26.5	3.3	2.0
May - Apr	947,230	1,025,764	420.5	497.2	(395.4)	(431.0)	45.2	48.7	3.9	4.4

* Self-scheduled generators comprise list as well as those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.
** Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-12: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2010 – April 2012

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	207,596	294,124	320.2	441.6	(320.1)	(488.1)	26.8	13.9	14.2	9.6
Jun	156,607	233,070	277.5	331.0	(416.4)	(377.1)	27.1	29.6	19.5	14.3
Jul	140,646	193,803	228.2	390.4	(296.4)	(395.2)	34.6	73.6	24.7	32.8
Aug	158,271	210,386	326.0	344.1	(275.2)	(400.5)	29.2	65.8	17.2	31.6
Sep	264,568	261,841	303.0	384.3	(307.8)	(331.2)	34.1	40.4	15.5	16.2
Oct	282,782	367,524	344.2	359.0	(293.1)	(344.7)	51.7	37.4	17.7	15.9
Nov	327,404	571,271	400.1	546.4	(273.7)	(480.2)	67.8	25.6	22.4	5.6
Dec	364,588	492,913	426.1	533.2	(189.6)	(622.6)	91.3	30.2	26.2	9.1
Jan	279,316	596,989	399.8	599.2	(488.0)	(488.4)	110.9	20.5	36.0	5.8
Feb	389,229	468,624	491.5	540.2	(188.2)	(488.7)	122.7	22.8	26.5	11.3
Mar	296,744	521,327	505.4	520.7	(360.9)	(497.8)	95.5	2.7	29.0	4.8
Apr	364,285	437,220	631.8	478.2	(326.7)	(523.4)	116	22.6	30.0	7.9
May – Oct	201,745	260,125	299.9	375.0	(318.2)	(389.5)	33.9	43.4	18.1	20.1
Nov – Apr	336,928	514,724	475.8	536.3	(304.5)	(516.8)	100.7	20.76	28.4	7.4
May - Apr	269,336	387,424	387.8	455.7	(311.3)	(453.2)	67.3	32.1	23.2	13.7

* Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-13: Failed Imports into Ontario, On-Peak, May 2010 – April 2012 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	120	95	380	467	67	89	4.2	4.4
Jun	142	81	600	595	71	137	4.1	4.7
Jul	170	124	679	550	96	109	5.4	3.1
Aug	165	167	650	621	85	82	6.4	3.6
Sep	76	108	475	250	130	71	1.8	3.4
Oct	78	118	249	350	114	98	2.2	6.3
Nov	95	91	289	441	78	101	2.7	4.7
Dec	99	76	329	417	63	118	4.1	5.4
Jan	103	130	360	640	59	97	4.9	5.2
Feb	90	67	514	470	78	116	3.5	3.4
Mar	80	114	614	538	118	122	2.8	6.6
Apr	85	59	388	200	84	79	3.0	2.3
May-Oct	751	693	505	472	94	98	4.0	4.2
Nov-Apr	552	537	416	451	80	105	3.5	4.6
May-Apr	1303	1230	460	461	87	101	3.8	4.4

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-14: Failed Imports into Ontario, Off-Peak, May 2010 – April 2012 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	207	119	857	349	131	126	9.8	14.1
Jun	189	116	517	581	97	157	7.1	14.5
Jul	180	141	730	633	153	119	6.8	7.6
Aug	192	154	1274	897	208	137	8.6	12.2
Sep	133	142	693	729	181	129	5.0	10.4
Oct	155	193	685	451	112	134	5.5	17.7
Nov	135	180	440	600	81	151	3.9	21.6
Dec	111	157	329	355	82	98	3.1	12.4
Jan	176	165	918	531	125	79	11.1	11.3
Feb	118	89	364	347	91	75	5.8	7.2
Mar	106	174	500	669	90	104	7.1	21.4
Apr	143	94	373	508	101	107	9.7	6.6
May-Oct	1056	865	793	607	147	134	7.1	12.8
Nov-Apr	789	859	723	502	95	102	6.8	13.4
May-Apr	1845	1724	692	554	121	118	7.0	13.1

* Excludes transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-15: Failed Exports from Ontario, On-Peak, May 2010 – April 2012 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	162	198	566	860	139	184.5	7.8	6
Jun	204	170	1524	1033	192	200.9	6.3	8.2
Jul	234	235	838	831	168	189.5	6.1	6.9
Aug	236	214	850	910	168	154	7.0	6.5
Sep	229	213	806	1231	156	155.1	4.1	8.9
Oct	226	168	545	638	156	102.4	5.5	3.8
Nov	151	165	350	469	86	101.3	2.0	3.8
Dec	226	132	788	1006	180	206.7	3.9	8.1
Jan	279	195	1298	1013	357	151.5	12.3	5.1
Feb	257	200	1251	954	256	228	11.7	7.9
Mar	295	221	943	1036	275	169.9	13.4	5.8
Apr	151	222	824	807	137	200.5	5.2	6.4
May-Oct	1291	1198	855	917	163	164	6.1	6.7
Nov-Apr	1359	1135	819	881	215	176	8.1	6.2
May-Apr	2650	2333	696	899	189	170	7.1	6.4

* Excludes transaction failures of less than 1 MW.

** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-16: Failed Exports from Ontario, Off-Peak, May 2010 – April 2012 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	135	237	806	720	135	141	6.1	3.2
Jun	156	171	1241	850	193	159	4.8	4.0
Jul	182	205	575	622	124	120	3.1	3.9
Aug	181	242	701	1229	122	170	3.0	6.8
Sep	180	192	950	567	133	103	2.7	3.8
Oct	243	201	683	533	136	89	3.8	2.9
Nov	108	143	431	429	71	109	1.2	3.2
Dec	257	126	800	671	189	82	4.1	2.3
Jan	349	259	1,030	708	312	95	11.4	4.2
Feb	244	210	1,064	1006	154	141	6.9	5.4
Mar	217	263	775	872	161	157	6.5	5.9
Apr	241	272	665	859	152	135	5.1	4.5
May-Oct	1,077	1248	826	753	141	130	3.9	4.1
Nov-Apr	1,416	1273	764	757	173	120	5.9	4.3
May-Apr	2,493	2521	690	755	157	125	4.9	4.2

* Excludes transaction failures of less than 1 MW.

** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-17: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2010 – April 2012

	Average Hourly Reserve (MW)		% of Total Requirements												Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import			
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	1,354	1,553	13.1	9.9	62.5	43.8	2.3	5.9	7.9	50.3	11.5	26.8	0.8	9.4	0.0	0.0
Jun	1,495	1,491	10.1	8.4	58.2	53.0	6.2	14.2	8.0	32.8	11.4	20.3	6.9	8.4	0.0	0.0
Jul	1,466	1,530	11.9	7.1	59.9	66.0	2.4	17.9	6.8	16.1	7.7	10.0	3.7	5.7	0.0	0.0
Aug	1,648	1,596	9.1	7.6	77.7	65.5	3.8	11.7	11.6	22.9	3.1	7.6	6.1	11.1	0.0	0.0
Sep	1,503	1,559	11.0	8.9	47.7	64.1	6.4	8.9	12.4	27.0	3.8	6.4	10.8	8.7	0.0	0.0
Oct	1,441	1,521	14.9	8.4	38.1	61.5	7.3	2.1	15.2	36.4	1.3	2.6	10.3	5.3	0.0	0.0
Nov	1,539	1,510	10.6	9.2	47.0	61.4	8.3	4.6	18.4	34.0	5.9	4.3	11.9	7.2	0.0	0.0
Dec	1,617	1,553	13.4	6.3	45.6	68.7	10.7	8.3	17.3	22.9	1.3	1.5	9.5	7.9	0.0	0.0
Jan	1,594	1,553	13.1	8.5	56.9	68.8	5.9	11.4	18.1	19.9	1.3	6.2	4.8	7.2	0.0	0.0
Feb	1,567	1,438	15.6	8.0	55.3	65.5	1.6	12.9	16.5	21.6	1.3	1.1	6.5	8.8	0.0	0.0
Mar	1,553	1,418	17.3	9.1	51.0	50.1	1.6	12.9	18.0	37.0	1.1	10.6	5.4	11.1	0.0	0.0
Apr	1,553	1,448	17.8	8.6	44.5	61.8	4.4	15.6	16.7	22.6	0.9	2.7	8.2	9.1	0.0	0.0
May-Oct	1,485	1,542	11.7	8.4	57.4	59.0	4.7	10.1	10.3	30.9	6.5	12.3	6.4	8.1	0.0	0.0
Nov-Apr	1,571	1,487	14.6	8.3	50.0	62.7	5.4	11.0	17.5	26.3	2.0	4.4	7.7	8.6	0.0	0.0
May-Apr	1,528	1,514	13.2	8.3	53.7	60.8	5.1	10.5	13.9	28.6	4.2	8.3	7.1	8.3	0.0	0.0

Table A-18: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2010 – April 2012

	Average Hourly Reserve (MW)		% of Total Requirements												Export	
			Dispatchable Load		Hydroelectric		Coal		Oil/Gas		CAOR		Import			
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	1,332	1,553	13.1	9.7	71.2	74.0	0.4	1.6	5.1	24.3	5.9	32.3	0.2	8.3	0.0	0.0
Jun	1,467	1,485	11.3	7.4	65.3	76.4	1.3	4.9	4.3	18.7	2.9	14.7	7.5	4.0	0.0	0.0
Jul	1,472	1,505	13.5	7.8	67.4	76.3	1.4	10.3	5.6	13.4	2.0	9.8	6.1	9.6	0.0	0.0
Aug	1,526	1,586	11.3	7.7	74.7	85.1	1.1	3.6	5.0	11.4	1.6	8.1	3.6	8.0	0.0	0.0
Sep	1,505	1,564	14.8	8.0	59.4	82.3	1.8	2.8	5.6	14.9	1.3	3.8	7.6	7.9	0.0	0.0
Oct	1,433	1,510	21.5	8.5	60.5	79.7	0.6	2.1	6.4	18.2	0.5	1.6	3.9	7.5	0.0	0.0
Nov	1,534	1,512	17.5	7.5	57.0	78.4	1.3	3.1	6.5	18.6	3.9	1.1	6.2	7.0	0.0	0.0
Dec	1,605	1,565	14.7	7.9	63.3	81.3	2.8	5.0	6.7	13.6	0.6	3.4	6.8	10.1	0.0	0.0
Jan	1,605	1,553	17.5	8.7	64.2	78.8	1.0	5.3	6.5	15.9	0.5	3.2	5.2	5.9	0.0	0.0
Feb	1,560	1,456	17.7	7.8	56.8	77.9	0.2	6.9	5.6	15.2	0.3	4.4	9.6	10.1	0.0	0.0
Mar	1,572	1,418	17.6	8.8	61.9	68.8	1.5	3.7	7.1	27.4	0.4	11.3	4.4	12.6	0.0	0.0
Apr	1,553	1,497	18.8	10.1	57.2	73.9	2.9	3.0	7.3	23.0	0.2	6.3	8.9	9.0	0.0	0.0
May-Oct	1,456	1,534	14.3	8.2	66.4	79.0	1.1	4.2	5.3	16.8	2.4	11.7	4.8	7.6	0.0	0.0
Nov-Apr	1,572	1,500	17.3	8.5	60.1	76.5	1.6	4.5	6.6	19.0	1.0	5.0	6.8	9.1	0.0	0.0
May-Apr	1,514	1,517	15.8	8.3	63.2	77.8	1.4	4.4	6.0	17.9	1.7	8.3	5.8	8.3	0.0	0.0

Table A-19: Monthly Payments for Reliability Programs, May 2010 – April 2012 ($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		Total	
	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012	2010/2011	2011/2012
May	0.34	0.02	0.15	0.29	0.35	12.20	4.12	2.68	3.99	5.50	8.94	20.70
Jun	0.02	0.04	0.12	0.70	1.14	4.74	9.58	3.40	2.74	6.56	13.60	15.44
Jul	0.13	0.03	0.34	0.27	1.46	1.51	6.76	5.12	7.16	7.23	15.85	14.16
Aug	0.03	0.20	0.22	0.22	2.12	2.45	7.74	9.39	4.52	3.99	14.63	16.25
Sep	0.08	0.92	0.40	0.20	3.25	0.71	7.71	8.22	5.13	6.80	16.57	16.85
Oct	0.04	0.14	0.20	0.25	1.28	0.45	3.98	8.95	5.34	3.84	10.84	13.63
Nov	0.04	n/a	0.10	0.54	1.08	0.60	4.84	7.92	6.07	5.06	12.14	14.11
Dec	0.03	n/a	0.26	0.67	3.72	1.17	2.80	5.85	8.58	6.95	15.40	14.64
Jan	0.04	n/a	0.43	0.77	2.21	1.28	2.44	4.80	9.59	5.03	14.71	11.88
Feb	0.03	n/a	0.37	1.16	1.30	0.58	3.39	6.52	10.08	7.25	15.16	15.50
Mar	0.02	n/a	0.36	1.46	1.10	3.99	4.13	3.52	7.47	10.04	13.09	19.01
Apr	0.04	n/a	0.38	0.40	4.70	1.25	3.32	2.93	3.78	7.60	12.23	12.18
May – Oct	0.65	1.34	1.42	1.94	9.59	22.06	39.88	37.77	28.88	33.92	80.43	97.02
Nov – Apr	0.20	0.00	1.90	5.00	14.12	8.87	20.93	31.52	45.57	41.92	82.72	87.32
May - Apr	0.85	1.34	3.32	6.94	23.70	30.93	60.81	69.29	74.46	75.84	163.15	184.34

* In certain situations, payments for the same import are made via the DA IOG and RT IOG programs but subsequently one of the payments is recovered through the IOG reversal. Since June 2006, approximately $3.45 million has been received through the IOG reversal. The data reported in this table does not account for the IOG reversal.

Table A-20: Summary Statistics for Hours when HOEP < $0/MWh, May 2011 – April 2012

Month	Number of Hours*	PD Demand (MW)**	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	% Change in Price	Minimum HOEP
May	31	12100	12016	(0.7)	43	-8.86	(53.27)	501.3	(128.1)
June	23	12102	11977	(1.0)	103	-4.89	(65.83)	1,246.6	(128.2)
July	4	11931	11843	(0.7)	66	8.02	(25.81)	(421.9)	(69.8)
August	17	12460	12443	(0.1)	369	-15.38	(80.80)	425.4	(128.6)
September	6	12914	12765	(1.2)	35	15.67	(17.03)	(208.6)	(42.4)
October	17	12243	12199	(0.4)	28	0.51	(34.78)	(6,904.1)	(128.1)
November	13	12731	12528	(1.6)	7	18.69	(62.07)	(432.1)	(119.3)
December	14	13779	13630	(1.1)	-58	15.78	(37.58)	(338.2)	(107.2)
January	9	13008	12886	(0.9)	197	11.79	(59.54)	(605.0)	(128.3)
February	2	13666	13572	(0.7)	-27	17.97	(53.45)	(397.5)	(71.5)
March	44	12720	12625	(0.7)	84	4.41	(55.62)	(1,360.8)	(128.2)
April	5	12625	12564	(0.5)	-53	13.17	(29.07)	(320.7)	(57.7)
Total	185	12563	12465	(0.8)	83	1.90	(53.5)	(794.3)	(128.64)

* Monthly figures reflect the average of hourly PD and RT Demand, Net Failed Exports, and PD and HOEP prices over all hours when HOEP was negative.

Table 1-21: Monthly Share of Real-Time MCP by Marginal Resource Type
May 2010 – April 2012
(% of intervals)

Month	Coal		Gas		Hydro		Nuclear		Load	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	41.8	2.2	36.8	38.5	18.7	56.1	0.0	1.7	2.7	1.5
June	49.2	14.0	37.0	46.6	11.8	35.9	0.0	1.7	1.9	1.7
July	47.2	40.8	32.4	34.7	18.2	22.0	0.0	0.1	2.1	2.5
August	50.6	28.5	31.5	38.7	15.3	28.3	0.0	1.5	2.7	3.0
September	31.7	16.5	32.6	45.3	30.8	32.9	0.1	0.2	4.8	5.1
October	15.3	11.5	43.7	53.2	35.0	31.4	0.1	0.9	5.9	3.0
November	34.1	20.5	44.9	59.3	17.7	19.1	0.0	1.1	3.2	0.0
December	34.7	17.3	41.4	45.8	21.5	33.1	0.4	0.7	2.0	3.1
January	33.7	29.8	45.1	45.8	17.2	21.6	0.8	0.6	3.3	2.1
February	29.9	39.2	49.6	41.7	17.6	16.1	0.0	0.1	2.9	2.9
March	28.9	23.2	47.6	20.8	20.2	52.2	0.1	2.2	3.2	1.7
April	15.9	15.0	32.9	41.7	48.0	41.3	1.8	0.2	1.4	1.8
Average	34.4	21.5	39.6	42.7	22.7	32.5	0.3	0.9	3.0	2.4

***Table 1-*22: Monthly Share of Real-Time MCP by Marginal Resource Type, On-Peak**
May 2010 – April 2012
(% of intervals)

Month	Coal		Gas		Hydro		Nuclear		Load	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	31.9	3.8	49.5	53.2	18.6	42.5	0.0	0.3	0.0	0.1
June	37.7	19.5	49.7	60.5	12.6	19.8	0.0	0.1	0.0	0.1
July	36.8	37.7	42.0	48.8	21.2	13.5	0.0	0.0	0.1	0.0
August	46.6	33.5	39.6	50.4	13.8	16.0	0.0	0.0	0.0	0.1
September	43.5	21.6	44.4	57.4	12.2	20.8	0.0	0.1	0.0	0.0
October	26.1	14.6	61.5	74.2	12.4	10.9	0.1	0.2	0.0	0.0
November	36.4	25.0	56.0	69.2	7.6	5.8	0.0	0.0	0.0	0.0
December	33.1	18.9	53.4	63.7	13.5	17.4	0.0	0.0	0.0	0.0
January	38.4	32.6	57.6	51.4	4.1	16.1	0.0	0.0	0.0	0.0
February	31.0	46.2	58.1	44.8	10.9	9.0	0.0	0.0	0.0	0.0
March	24.4	28.9	65.4	25.5	10.1	45.2	0.1	0.5	0.0	0.0
April	17.9	25.2	50.4	52.7	31.2	22.1	0.4	0.1	0.0	0.0
Average	33.7	25.6	52.3	54.3	14.0	19.9	0.1	0.1	0.0	0.0

***Table 1*-23: Monthly Share of Real-Time MCP by Marginal Resource Type, Off-Peak**
May 2010 – April 2012
(% of intervals)

Month	Coal		Gas		Hydro		Nuclear		Load	
	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012	2010/ 2011	2011/ 2012
May	49.3	0.9	27.2	26.3	18.8	67.2	0.0	2.9	4.7	2.7
June	60.2	8.8	25.0	33.3	11.1	51.4	0.0	3.3	3.6	3.2
July	55.9	43.1	24.6	24.0	15.8	28.4	0.0	0.2	3.7	4.3
August	53.8	24.0	24.8	28.2	16.5	39.3	0.0	2.9	4.8	5.7
September	21.3	12.0	22.2	34.8	47.1	43.5	0.2	0.2	9.1	9.5
October	7.2	9.0	30.2	35.8	52.1	48.3	0.2	1.4	10.3	5.5
November	31.9	16.2	34.3	49.9	27.4	31.9	0.0	2.0	6.4	0.0
December	36.0	16.0	31.5	32.3	28.1	44.9	0.7	1.2	3.7	5.5
January	30.1	27.6	35.6	41.2	27.1	26.2	1.4	1.1	5.7	3.9
February	29.0	33.1	42.5	39.1	23.1	22.2	0.0	0.2	5.3	5.3
March	33.3	18.1	30.2	16.5	30.1	58.6	0.1	3.7	6.2	3.1
April	14.5	7.5	20.1	33.7	60.3	55.4	2.8	0.3	2.3	3.1
Average	35.2	18.0	29.0	32.9	29.8	43.1	0.5	1.6	5.5	4.3