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 2007- April 2008

PUBLIC

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Neil Campbell
Chair, Market Surveillance Panel

Président, Comité de surveillance du marché

July 21, 2008

The Honourable Howard I. Wetston, Q.C.
Chair & Chief Executive Officer
Ontario Energy Board
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Mr. Wetston:

Re: Market Surveillance Panel Report

On behalf of my colleagues on the Market Surveillance Panel, Don McFetridge and Tom Rusnov, I am pleased to provide you with the Panel's 12th semi-annual Monitoring Report of Ontario's wholesale electricity market, the IESO-administered markets.

This report, covering the period November 1, 2007 to April 30, 2008, is submitted pursuant to Article 7.1.1 of Ontario Energy Board By-law #3.

Best Regards,

Neil Campbell
Chair, Market Surveillance Panel

Enclosure

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Overall Assessment

Ontario's IESO-administered wholesale electricity market once again performed reasonably well according to its design over the six-month period November 2007 to April 2008. Spot market prices generally reflected demand and supply conditions. The Market Surveillance Panel (MSP) found no evidence of gaming, abuse of market power or other inappropriate conduct by market participants or the system operator, the Independent Electricity System Operator (IESO). However, as in previous reports, the MSP identified several potential opportunities to improve the efficiency of the market which are reflected in the 11 recommendations summarized below.

Market Prices and Uplift

For just over two years now, energy prices have being been relatively stable, as downward pressure from the modest amount of new supply has been accompanied by an upward pressure on prices induced by higher fuel costs. The average Hourly Ontario Energy Price (HOEP) for the period November 2007 through April 2008 was $49.16/MWh, 0.5 percent higher than the same period a year ago, with on peak HOEP being 1.8 percent higher and off peak HOEP 1.0 percent lower. The effective load-weighted HOEP, which provides a more accurate reflection of what Ontario load pays for energy after accounting for the Global Adjustment and the OPG Rebate, increased by $1.95/MWh or 3.7 percent this winter compared to the previous winter period. Total hourly uplift payments charged to market participants increased by $30 million or 18 percent during the current period compared to the same period the previous winter. This was primarily due to higher congestion management payments associated with bottled energy in the Northwest and more transmission or energy supply limitations in southern Ontario which led to constraining on imports or constraining off exports.

In terms of the distribution of the HOEP, there was some shifting of energy prices from the $20 to $40/MWh range to the $40 to $60/MWh range, corresponding to higher fuel prices. The period also saw a greater incidence of prices below \$20/MWh, 261 hours this year versus 189 hour last year. There were 2 hours when the HOEP was above \$200/MWh, compared with 1 hour during the period a year ago.

Demand and Supply Conditions

Ontario total energy demand was almost unchanged this winter compared with last, due to colder temperatures and higher demand early in the period being offset by lower demand later in the period. The major component, demand from local distribution companies (LDCs), has been fairly constant year-over-year, but we observe a continuing decline in wholesale load consumption. Total market demand (Ontario Demand plus exports) increased by 3.1 TWh. It was driven by a substantial rise in exports, to 8.5 TWh this year representing an increase of more than 60 percent. Total net exports (exports minus imports) increased by 1.8 TWh or 80 percent during the winter 2007/2008 months relative to 2006/2007, with about half the increase in each of the on-peak and off-peak hours.

The above export amounts exclude 1.8 TWh of exports which were part of 'linked wheels' (simultaneous import and export by a market participant for the purpose of moving power between two other markets through Ontario). Since the import offsets the export in a linked wheel there is no net effect on HOEP. Such transactions had been uncommon, but during this winter period grew by a factor of approximately 150 times relative to last year. This phenomenon appears to have arisen in response to features in certain U.S. markets that are being reviewed by the relevant authorities.

Planned outage rates over the recent winter period were generally in line with historical rates and seasonality, although the planned outage rate in April 2008 was lower than any other April since 2003. Forced outage rates during this winter period were comparable to monthly rates seen since the end of 2005. The exception was again April 2008, when nuclear units spiked to a monthly outage rate of almost 22 percent and drove the overall outage rate to 16 percent.

High and Low HOEP

We assessed the two hours during the November 2007 through April 2008 period when the HOEP was greater than $200/MWh and five hours when the HOEP was negative. The highest priced hour occurred on February 1, 2008 in hour ending (HE) 11 when the HOEP reached $563.62/MWh. The lowest priced hour this period occurred on February 18, 2008 in HE 3 when the HOEP dropped to minus $2.72/MWh, with the lowest interval price since market opening, minus $31.00/MWh, occurring two hours later in HE 5. While these outcomes are mostly explainable by reference to supply and demand conditions existing at the particular time, some of these outcomes were also influenced by elements of the market design that the Panel recommends be re-examined.

Operational Issues & Recommendations

The Panel has made several suggestions for potential changes to the present IESO-administered markets based on its analysis of observed market outcomes over the past six months.

Recommendation 2-1 (Chapter 2, Section 2.2.1)

The Net Interchange Scheduling Limit (NISL) is a conservative proxy for the ability of domestic generation to ramp up or down in response to abrupt import or export changes at the start of an hour. The upper limit was initially set at 700 MW after IESO discussions with participants prior to market opening. This approximated the ability of slower moving fossil generators to ramp, as it was presumed these would be the typical marginal resources. However, fossil generation may not be at the margin, for example in extremely high demand periods when peaking hydroelectric could be marginal, or in low demand periods when baseload hydroelectric could be marginal.

The IESO has an explicit control action allowing it to increase NISL during high demand periods to maximise net imports, but not during low load periods to maximise net exports.

A higher NISL could have avoided the situation observed this winter where exports were failing during a low load period, which limited net exports the next hour and induced more imports to be scheduled. These additional imports were more costly than the Ontario generation they replaced.

The MSP reiterates the recommendation in its June 2007 report that the IESO should review the 700 MW Net Interchange Scheduling Limit (NISL). This review should take into account the effects on potential efficient exports from Ontario in addition to the import issues raised in the MSP's prior report.

Recommendation 2-2 (Chapter 2, Section 2.2.4)

Following the forced outage of two nuclear units and the loss of 1,700 MW of generation, the IESO took a series of control actions needed to sustain reliability. These control actions included the Shared Activation of Reserve (SAR), the activation of Regional Reserve Sharing (RRS), the curtailment of exports for adequacy and Operating Reserve Activation (ORA). IESO procedures with respect to the first three treat these as a reduction in energy demand and ORA is accompanied by an equivalent reduction in operating reserve demand. Such reductions in the demand levels used in the unconstrained sequence do not correspond to any actual decrease in economic demand in the market. As a result, the HOEP was significantly and artificially lower.

The MSP reiterates the recommendations in its December 2006 and June 2007 reports, respectively, regarding Shared Activation of Reserve (SAR), and prompt replenishment of the Operating Reserve requirement levels. In addition, the MSP recommends the IESO review the application of Regional Reserve Sharing (RRS) because the current treatment of RRS in the unconstrained sequence also induces counter-intuitive prices.

Recommendation 3-1 (Chapter 3, Section 2.2.4)

In recent years, an increasing fraction of real-time IOG payments have been paid during periods of excess domestic supply, implying that these payments may not be buying much in the way of additional reliability for the Ontario market. In fact, during the period May 2006 to April 2008, the majority of IOG payments in on-peak hours were paid in hours when Ontario was a net exporter, and even more so in off-peak hours. The high IOG payments in such hours warrant a more detailed study on whether IOG payments continue to bring corresponding reliability benefits to Ontario.

As market supply conditions have improved, an increasing fraction of Intertie Offer Guarantee (IOG) payments is being paid in hours when there appear to be negligible reliability concerns. The MSP recommends the IESO review the real-time IOG program and determine if it is providing commensurate improvements in reliability.

Recommendation 3-2 (Chapter 3, Section 3.1)

Competitive wholesale energy markets utilize offers and bids to match electricity supply with demand. Unlike other markets reviewed, the IESO does not publish any form of offer or bid data. In general, publication of market information enhances market efficiency by equipping market participants to respond effectively. The traditional concern with the release of offer and bid data, in particular, is that it may facilitate implicit or overt collusion. However, the Panel believes that a multi-month lag is an adequate safeguard to prevent coordinated changes to offer/bid behaviour by market participants and still produce a favourable impact. The primary benefits from releasing bid/offer data with a lag relate to longer term decision-making by market participants (e.g. investment decisions) as well as opportunities for increased external scrutiny of the market.

The MSP recommends that the IESO publish masked bid and offer data on a four-month time lag.

Recommendation 3-3 (Chapter 3, Section 3.1)

When the market opened in 2002, some generators were concerned that releasing production information by unit could lead to inappropriate market behaviour. The Panel recommended that unit production data be released, but with a two-hour time lag due to concerns by a participant that more timely release of this information could lead to withholding by other generators. To date, the MAU has not observed any inappropriate behaviour resulting from publication of output data. In fact, one major generator in the province releases its own production information by fuel type on a 15-minute basis.

The MSP recommends that the IESO publish generating unit output using a one-hour lag rather than the current two-hour lag.

Recommendation 3-4 (Chapter 3, Section 3.1)

Forced outages of generating units are an inevitable occurrence from time to time. The impact on the market can be dramatic when large units are suddenly taken out of service. Information on the generation type is important because it suggests the probable duration of an outage to knowledgeable observers. Releasing information on the type of generating unit experiencing an outage in the IESO's System Status Reports (SSR) will facilitate a more widespread understanding of its implications for future market prices in Ontario and allow market participants to respond in an effective manner. It would also mitigate the present asymmetry of information with the largest generator having a much greater knowledge of the type and the extent of outages indicated.

The MSP recommends that when the System Status Reports indicate that a generating unit of greater than 250 MW has been forced from service, the IESO should also disclose the fuel type of the unit in order to increase the information available to all market participants regarding future market conditions.

Recommendation 3-5 (Chapter 3, Section 3.1)

The supply cushion is an important market and reliability measure that represents the amount of excess supply available for dispatch in a given hour. In the Panel's view it is a simple yet powerful indicator of supply and demand conditions in the province and its publication would be beneficial to market participants. If published in advance of the hour using forecast demand and expected available supply, this indicator could increase the ability of market participants and others to understand price movements and to make more efficient production/import and consumption/export decisions. The Panel understands that the IESO intends to begin publishing a supply cushion. However, the way in which this statistic is currently calculated by the IESO does not accurately reflect actual supply availability.

The IESO is planning to publish the supply cushion on an hourly basis. Its current calculation, however, does not represent actual supply capability. The MSP recommends that the IESO refine its formula to take into account forced outages, deratings, and import capabilities at the interties.

Recommendation 3-6 (Chapter 3, Section 3.3)

In Chapter 2, the Panel discussed some anomalous outcomes of intertie failures that resulted from the use of different reason codes by the IESO. In particular:

- a failed import in the constrained sequence can increase imports in the unconstrained sequence and thus decrease the real-time price; and
- a failed export in the constrained sequence can increase exports in the unconstrained sequence and thus increase the real-time price.

The anomalous outcomes are a result of the two-sequence dispatch algorithm and the way the IESO assigns a reason code to a failed transaction.

We understand that it is important for the IESO to separate transaction failures by reasons as this process can help the IESO to find the exact causes and improve system operation in the future. However, the modification of the unconstrained schedule that occurs when some of these reason codes are applied interferes with the operation of the market, and can lead to both distorted price signals and reduced market efficiency.

1. ***For inter-jurisdictional transactions that fail because of market participants' ('OTH') or external system operators' actions ('TLRe' and 'MrNh'), the MSP recommends the IESO revise its procedures to avoid distorting the unconstrained schedule. This would prevent counter-intuitive pricing results (and would allow traders in those instances to receive the Congestion Management Settlement Credit payment consistent with other situations where such payments are currently available).***

2. ***The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy ('ADQh') should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted.***

Recommendation 3-7 (Chapter 3, Section 4.1)

Between August and October 2003 in an effort to reduce the instances of counter-intuitive prices, 400 MW of out-of-market Operating Reserve was introduced into the market as Control Action Operating Reserve (CAOR).[1] When scheduled in pre-dispatch, this CAOR is backed by the IESO designating an equivalent amount of exports as recallable. This measure (along with others) appears to have lessened counter-intuitive effects of control actions on market prices. We now observe, however, that CAOR scheduled in pre-dispatch has itself become associated with counter-intuitive prices following a change in procedure by the New York Independent System Operator and

[1] The IESO's market rule amendment MR-00235-R00-R05, was effective on August 6, 2003. Another 400 MW of CAOR was introduced in November 2005.

more recently by the Midwest Independent Transmission System Operator which will no longer accept recallable exports.

The MSP recommends that the IESO explore a solution to the emerging problem posed by recallable exports that are designated for Control Action Operating Reserve (CAOR), which induce counter-intuitive prices when rejected by the New York Independent System Operator and the Midwest Independent Transmission System Operator.

Recommendation 3-8 (Chapter 3, Section 4.2)

As shown in our December 2007 report and in Chapter 1 of this report, both the frequency and the magnitude of operating reserve activations (ORA) have been increasing. An operating reserve activation is: "selected based on an 'unoptimized' simple stacking of the lowest to highest energy costs (offers) for the facilities with an operating reserve schedule".[2] The major purposes of an ORA are to:

- deal with a sudden loss of a large generator or a main transmission line;
- restore Area Control Error (ACE)[3] from a large negative (above 200 MW) to zero;[4] and
- rarely, to activate OR for Shared Activation of Reserve or Regional Reserve Sharing at the request of external markets or jurisdictions.

The Panel has explored reasons for the increase in both frequency and magnitude of operating reserve activations, most of which can be attributed to restoring ACE. There were two major changes in May 2006 that appear to have led to increases in ACE deviations:

[2] See IESO's discussion paper titled: "Operating Reserve Activations (ORA) vs. One Time Energy Dispatch (OTD)", April 4, 2007.
[3] ACE is a function of generation output deviation from their schedule, frequency deviation, and a small term adjusted for operational metering error. ACE is mainly affected by internal generation off-dispatch and forced outages, as well as ACE deviation in adjacent markets.
[4] See "Market and System Operations Part 2.4: Real-Time Operating Procedures, Section 2: Assess Impact on Routine Operations". When ACE is positive by a large number, the IESO will manually dispatch down generators, based on generators' preference when the IESO verbally communicates with the generators.

- On May 4, 2006, the IESO lowered the minimum Automatic Generation Control requirement from 150 MW to 100 MW, in an effort to reduce the AGC cost. The 50 MW reduction in AGC capacity had some effect of increasing the use of ORA as well as One-Time Dispatches (OTD).[5]

- On May 8, 2006, the IESO increased the compliance deadband from 10 MW to 15 MW (i.e., the actual output of a unit is allowed to deviate by 15 MW from its received dispatch instruction without any compliance consequences). However, at times an OTD or ORA may be needed when many units deviate in the same direction. This is especially true in periods of increasing or decreasing load where typically fossil generators, which have a limited ramp capability, are moving in the same direction.

In response to increases in ACE deviation and the IESO exceeding the NERC Control Performance Standard (CPS) by lesser margins, the IESO changed its operating policy regarding the monitoring of CPS obligations in late September 2006. The Panel does not question the IESO's objective of recovering ACE deviations as required by NERC. However, it is not clear that the IESO's goal of having a higher performance standard than required by NERC is bringing benefits to the Ontario market that are greater than the costs involved in achieving it. The Panel believes, however, that the IESO can achieve its objectives in a way that is more compatible with market efficiency.

1. ***To avoid distorting market prices, the MSP recommends that the IESO maintain the Operating Reserve requirement when Operating Reserve is activated in response to Area Control Error (ACE);***

2. ***If the IESO believes that it must maintain a higher standard than the NERC Control Performance Standard, the MSP recommends that the IESO conduct a cost-benefit analysis comparing alternatives for responding to Area Control Error (ACE) deviations, that is: providing more Automatic Generation Control (AGC);***

[5] See the IESO's study "DIWG – AGC Requirement", December 12, 2006 and "Proposal for Minimum Scheduling of AGC", February 16, 2007.

using One-Time Dispatch (OTD); using Operating Reserve Activation (ORA); and establishing a capability to re-run the dispatch algorithm on demand.

3. ***In the interim, until a cost-benefit study of the alternatives for handling ACE deviations is completed, in accordance with Recommendation 3-8(2), and assuming the IESO adopts Recommendation 3-8(1) regarding the maintenance of the Operating Reserve requirement level when Operating Reserve is activated for ACE, the MSP recommends that the IESO should use ORA instead of One-Time Dispatch to deal with negative ACE whenever possible.***

<u>Recommendation 3-9 (Chapter 3, Section 5)</u>

The Panel has long questioned what benefits the market receives from constrained-off payments. One of the major explanations for this market design feature was that, in a uniform-priced market, providing constrained-off payments encouraged market participants to follow their dispatch instructions. It has been argued that without these payments generators might continue to supply above their dispatch in order to avoid losing profit associated with production at higher prices.

We are now observing that there are fairly regular large dispatch deviations by generators which result in the need for the IESO to activate operating reserve or use one-time dispatches to correct for shortfalls in generation (see Chapter 3). There have been more than $550 million in constrained off CMSC payments since the market opened, on average about $7.6 million per month.

The Panel continues to hold the view that constrained off CMSC payments cannot be justified by the assumption that these encourage resources to comply with dispatch instructions. In spite of these payments, we have seen an increase in deviations from dispatch, and have seen deviations induce CMSC payments. Also, about one-quarter of the constrained off CMSC payments are to imports and exports for which there is no possibility of deviations, because of scheduling protocols between markets.

The MSP recommends that the IESO review the benefits of constrained off payments with a view to their discontinuation.

In response to a suggestion of the IESO's Stakeholder Advisory Committee, we have identified relative priorities among these recommendations. We have grouped the recommendations under four categories – price fidelity, dispatch, transparency, and hourly uplift payments – and ranked them as follows:

PRICE FIDELITY	***DISPATCH***	***TRANSPARENCY***	***HOURLY UPLIFT PAYMENTS***
3-7	***2-1***	***3-5***	***3-9***
3-6(2)	***3-8(2)***	***3-3***	***3-1***
3-8(1)	***3-8(3)***	***3-4***	
3-6(1)		***3-2***	
2-2			

The Panel regards each recommendation as important to improving the operation of the market. In particular, changes that may individually not be regarded as large can have a substantial cumulative effect, as well as spillover benefits in improving the confidence that market participants have in the operation of the Ontario market. Many of the recommendations do not appear to involve significant implementation costs; however, it remains the task of the IESO and stakeholders to identify costs and benefits from a broader perspective and establish final priorities and implementation schedules.

Chapter 1: Market Outcomes November 2007 – April 2008

1. *Highlights of Market Indicators*

This Chapter provides an overview of the results of the IESO-administered markets over the period November 1, 2007 to April 30, 2008, with comparisons to the same period a year earlier and in many instances a review of trends over several years. For ease of reference, the November through April period is sometimes referred to as the 'winter period'. There are four substantive sections summarizing the data on prices, demand, supply and trade. Highlights of each of these are summarized in the subsections that follow.

1.1 Pricing

The average monthly HOEP this winter period was slightly higher (by 0.5 percent) at $49.16/MWh than the HOEP corresponding to the period a year ago. This reflected a combination of on-peak HOEP being 1.8 percent higher and off-peak HOEP 1.0 percent lower. For just over two years now, prices have been relatively stable, consistent with only small amounts of new supply coming into service over this time-frame and relatively stable demand. However, even this modest amount of new supply would have had a downward pressure on prices, but this likely has been masked by an upward pressure on prices induced by higher fuel costs.

1.2 Demand

Ontario total energy demand was almost unchanged this winter compared with last, due to colder temperatures and higher demand early in the period being offset by lower demands later in the period. The major component, LDC (Local Distribution Company) demand, has been fairly constant year-over-year, but we observe a continued decline in wholesale load consumption. Total market demand (Ontario demand plus exports) has increased, driven by a substantial rise in exports to 8.5 TWh this year, which is 60 percent more than total exports a year ago.

1.3 Supply

Generating capacity remained relatively constant over the last winter period. Only 76 MW of new wind generation has been added to the Ontario market in the last 6 months although several large gas-fired units are under construction. Some smaller renewable generation embedded within LDCs, has also been added but these would be observed as reductions on LDC demand.[6] Somewhat lower planned outage rates to nuclear and coal units was offset by slightly higher forced outage rates

1.4 Imports and Exports

Total net exports increased to 4.1 TWh, an increase of 1.8 TWh or 80 percent, during the winter 2007/2008 months relative to 2006/2007. The increase was shared evenly between the on-peak and off-peak hours. The largest monthly increases were observed in January and March. There was a significant change in the pattern of imports and exports this winter with a dramatic rise in linked wheel transactions (simultaneous imports and exports by a market participant for the purpose of moving power across multiple markets). Such transactions had been uncommon, but during this winter period grew by a factor of approximately 150 times relative to last year.

2. *Pricing*

2.1 Ontario Energy Price

The Hourly Ontario Energy Price (HOEP) averaged $49.16/MWh over the winter 2007/2008 months, which was $0.25/MWh (or 0.5 percent) higher than that average price during the previous winter months as shown in Table 1-1. The six-month average on-

[6] A total of 34.3 MW of renewable generation has reached commercial operation as of April 30, 2008. For more details, see the OPA April 2008 Progress Report on Renewable Energy Standard Offer Program at: http://www.powerauthority.on.ca/Storage/69/6462_RESOP_April_2008_report.pdf.

peak HOEP was higher by $1.07/MWh (1.8 percent) while the off-peak HOEP was somewhat lower, by $0.33/MWh or 1.0 percent.[7]

Although the average changes in HOEP for the period were small, there were more visible differences on a monthly basis. There was a noticeable increase in the average HOEP of 25 percent in December 2007 relative to 2006, with on-peak prices having increased by almost 20 percent while off-peak prices increased by over 32 percent. Lower average temperatures in December 2007 compared to 2006 placed upward pressure on Ontario Demand, which rose from 12.92 TWh in December 2006 to 13.45 TWh in December 2007. However, this change was largely offset by lower prices in November, January, and February relative to the year previous which is consistent with improved baseload supply levels as presented in Table 1-31.

Table 1-1: Average HOEP, On-peak and Off-peak, November – April 2006/2007 & 2007/2008 ($/MWh)

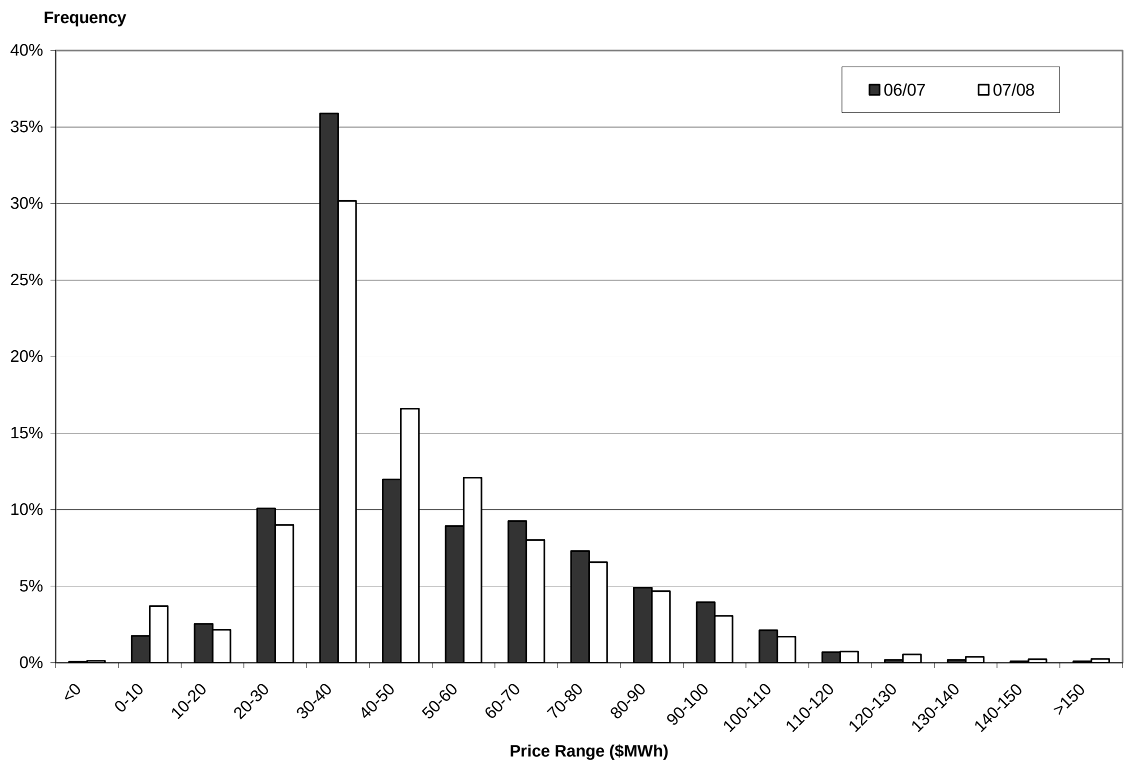
	Average HOEP			Average On-Peak HOEP			Average Off-Peak HOEP		
	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
November	49.71	46.95	(5.6)	60.13	56.35	(6.3)	39.75	37.96	(4.5)
December	39.25	49.08	25.0	53.06	62.96	18.7	29.71	39.48	32.9
January	44.48	40.74	(8.4)	53.44	50.89	(4.8)	36.43	31.62	(13.2)
February	59.12	52.38	(11.4)	70.93	67.48	(4.9)	48.39	39.52	(18.3)
March	54.85	56.84	3.6	68.31	68.60	0.4	42.76	48.72	13.9
April	46.05	48.98	6.4	57.58	63.61	10.5	37.63	34.99	(7.0)
Average	48.91	49.16	0.5	60.58	61.65	1.8	39.11	38.72	(1.0)

Figure 1-1 plots the frequency of price outcomes over the last two winter periods. The distribution shows that there were fewer hours when the HOEP fell between $20/MWh and $40/MWh (falling from 46 percent to 39 percent) while there were more instances when the HOEP fell between $40/MWh and $60/MWh (increasing from 21 percent to 29 percent). The greater incidence of higher prices in this range is associated with the increased cost of the underlying fuel. Finally, the number of hours above $100/MWh

[7] For the current winter period, which included a Leap day, there were a total of 4,368 hours, of which the on-peak period represented 45.4 percent and off-peak 54.6 percent. For the previous winter there were 4,344 hours, with peak hours accounting for 45.7 percent and off-peak 54.3 percent.

increased slightly from 3.4 percent (146 hours) during winter 2006/2007 to 3.8 percent (168 hours) during winter 2007/2008.

Figure 1-1: Frequency Distribution of HOEP, November – April 2006/2007 & 2007/2008 (% of total hours in $10/MWh price ranges)



2.1.1 Load-weighted HOEP

Monthly average HOEP in Section 2.1 was calculated as the simple average of the hourly values. Another measure of price is the load-weighted average, reflecting the annual average price per unit of Ontario consumption. Table 1-2 presents the annual figures for different groups of consumers, for the winter of 2006/2007 and 2007/2008 along with revenues paid to dispatchable loads providing Operating Reserve (OR), expressed per unit of energy consumption. The table shows for all Ontario loads that the average price for consumption increased marginally to $51.09/MWh, about 0.4 percent higher than the previous winter. The larger loads, both dispatchable load and other wholesale load, consume a larger portion of their energy off-peak and consequently the annual load-weighted averages continue to be a few percent lower than the average for all loads. The weighted price for dispatchable load dropped this winter by about 1.2 percent while for the other wholesale load group, the weighted price increased 0.8 percent. Given that unweighted average hourly HOEPs were seen to have higher on-peak prices this winter and lower off-peak, the changes in weighted prices suggest that wholesale loads may have shifted consumption marginally to on-peak periods. Dispatchable loads may have shifted marginally to off-peak and may have been marginally more successful avoiding high prices on-peak. Revenues paid to dispatchable loads providing OR have increased by approximately 37 percent, which was primarily driven by the high OR prices during April 2008.

Table 1-2: Load-Weighted Average HOEP and Dispatchable Load OR Revenue, November – April 2006/2007 & 2007/2008 ($/MWh)

Year	Unweighted HOEP	Load-weighted HOEP[8]			Dispatchable Load OR Revenue
		All Loads	Dispatchable Load	Other Wholesale Loads	
2006/2007	48.91	50.89	48.25	48.83	1.53
2007/2008	49.16	51.09	47.67	49.20	2.09
Difference	0.25	0.20	(0.58)	0.37	0.56
% Change	0.5	0.4	(1.2)	0.8	36.6

2.1.2 Impact of the Global Adjustment and the OPG Rebate on the Effective Price

Figure 1-2 plots the monthly average HOEP, Global Adjustment (GA), and OPG Rebate between April 2005 and April 2008.[9] These components are used to calculate the monthly average effective HOEP. In months when the HOEP is relatively high, the GA and OPG Rebate offset the net payments to generators and vice versa. Therefore, the effective HOEP has remained relatively stable within the $50-$57/MWh range since January 2006. The Panel expects that the effective HOEP should remain relatively stable

[8] Unadjusted – like the unweighted HOEP, the load-weighted HOEP does not include the impact of the Global Adjustment or the OPG Rebate.

[9] April 2005 represents the beginning of the Ontario Power Generation Non-Prescribed Asset Rebate, which was later renamed the OPG Rebate in May 2006.

moving forward assuming additional generation is signed to OPA contracts to meet the long-term supply requirements in Ontario.

Figure 1-2: Monthly Average HOEP Adjusted for OPG Rebate and Global Adjustment, April 2005 – April 2008 ($/MWh)

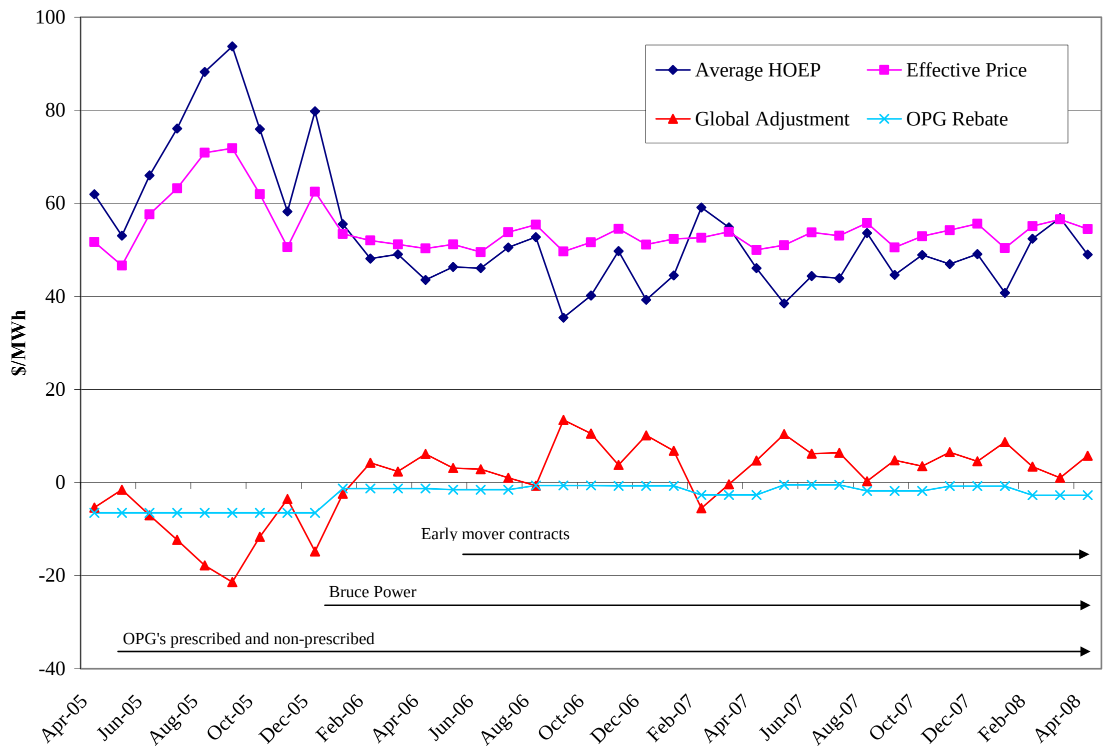


Table 1-3 reports the average six-month HOEP relative to the load-weighted HOEP with and without the Global Adjustment and OPG Rebate over the last two winter periods. The OPG Rebate plus Global Adjustment tend to offset increases in HOEP, with the result that monthly effective prices are fairly constant since the beginning of 2006. However, similar to the trend we noted in our December 2007 MSP report, the average OPG Rebate plus Global Adjustment increased marginally over the current six-month period, by $1.75/MWh, even though the average unweighted HOEP increased by $0.25/MWh and the load-weighted HOEP increased by $0.20/MWh. This highlights that the component of the Global Adjustment independent of HOEP is increasing as more resources with OPA contracts become active and demand response programs are implemented.

Table 1-3: Impact of Adjustments on Weighted HOEP, November – April 2006/2007 & 2007/2008 ($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate[10]	Effective Load-Weighted HOEP
2006/2007	48.91	50.89	(1.55)	52.44
2007/2008	49.16	51.09	(3.30)	54.39
Difference ($)	0.25	0.20	(1.75)	1.95
% Change	0.5	0.4	112.9	3.7

2.2 Price Setters

In this section we look at which resources were marginal and set the real-time and pre-dispatch prices. In real-time we are interested in the fuel types which set the price; in pre-dispatch we consider whether imports, exports or internal generation set the price.

2.2.1 Real-time Price Setters

Table 1-4 presents the percentage of hours that the real-time price is set by each resource type over the last two winter periods.[11] The share of coal generators setting the market clearing price (MCP) increased this winter relative to last winter by 6 percentage points, while the share of oil and gas generators setting the MCP fell by 7 percentage points.

Table 1-4: Average Share of Real-time MCP set by Resource Type, November – April 2006/2007 & 2007/2008 (% of Hours)

	2006/2007	2007/2008	Difference
Coal	53	59	6
Hydro	22	23	1
Oil/Gas	25	18	(7)

[10] A negative value represents a payment from consumers to generators

[11] The nuclear category is excluded from the price setting tables but is monitored for changes in price-setting behaviour. The Panel has observed that in recent reporting periods, it rarely set the price and its share is consistently 0 percent.

Tables 1-5 to 1-7 show the percentage of hours that the real-time price is set by each resource type divided by all hours, on-peak hours, and off-peak hours for the last two winter periods. Table 1-5 shows that coal's share of setting the real-time MCP increased in all months except December when it significantly declined from 62 percent to 47 percent. The decline in December, which is consistent with the observed higher demands and energy prices in December, was most prominent during the on-peak hours. The increase of the coal share in January to February is also consistent with reduced demand in those months. The tables also show that hydro's price setting share has remained relatively stable between the last two winter periods.

Table 1-5: Monthly Share of Real-Time MCP set by Resource Type, November – April 2006/2007 & 2007/2008 (% of Hours)

	Coal		Oil/Gas		Hydro	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	52	55	25	23	23	22
December	62	47	16	27	22	26
January	60	70	24	12	16	18
February	41	60	39	19	20	21
March	49	59	27	15	24	26
April	56	62	16	13	28	25
Average	53	59	25	18	22	23

As seen in Table 1-6, coal's on-peak share fell from 57 percent to 32 percent when comparing December 2007 with 2006, again related to the increased demand that month. The table shows that the oil-gas share tends to increase or decrease in fairly similar amounts to balance the changes seen in the portion of time coal sets the price. However, over the period coal increased from 39 percent to 44 percent and set the real-time MCP more often then oil/gas during on-peak hours.

Table 1-6: Monthly Share of Real-Time MCP set by Resource Type, On-Peak, November – April 2006/2007 & 2007/2008 (% of Hours)

	Coal		Oil/Gas		Hydro	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	37	33	41	40	22	27
December	57	32	30	45	13	23
January	44	60	41	23	15	17
February	25	42	59	36	16	22
March	26	39	44	29	29	32
April	45	59	25	22	30	19
Average	39	44	40	33	21	23

During the off-peak hours, coal units set the MCP most frequently. Table 1-7 shows that over the last winter period, coal units set the MCP 71 percent of the time, which is much higher than coal's share during the on-peak hours. However, monthly share movements are similar to on-peak movements except for November, where coal was more often the marginal resource with hydroelectric setting the price much less often.

Table 1-7: Monthly Share of Real-Time MCP set by Resource Type, Off-Peak, November – April 2006/2007 & 2007/2008 (% of Hours)

	Coal		Oil/Gas		Hydro	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	66	76	10	7	24	17
December	66	57	5	15	29	28
January	74	78	8	2	18	20
February	55	75	21	4	24	21
March	68	73	12	5	20	22
April	64	65	9	4	26	31
Average	66	71	11	6	24	23

2.2.2 Pre-dispatch Price Setters

Table 1-8 shows the percentage of hours that the one-hour pre-dispatch price was set by resource type on a monthly basis this winter compared to last winter. On average over the period there has been only a slight shift year-over-year change in the type of resource setting the pre-dispatch price. Imports and generation each now set price about

40 percent of the time, with exports doing so the remaining 20 percent of the time. On a monthly basis, generation set the one-hour ahead pre-dispatch price most often (almost half the time) in December and January, but was the price setter much less, about 36 percent of the time, in March and April.

Table 1-8: Monthly Share of Pre-dispatch Price set by Resource Type, November – April 2006/2007 & 2007/2008 (% of Hours)

	Imports		Exports		Generation	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
November	41	39	16	21	42	40
December	32	39	17	16	52	46
January	32	34	19	16	49	50
February	41	40	19	20	41	40
March	45	41	21	23	34	36
April	33	40	26	24	41	37
Average	37	39	20	20	43	41

Section 2.4.5 of this report contains a discussion of the implication of imports and exports setting the pre-dispatch price almost 60 percent of the time in total.

2.3 One-Hour and Three-Hour Ahead Pre-dispatch Prices and HOEP

The difference between pre-dispatch and real-time prices is an important market metric since accurate pre-dispatch price signals are important and necessary for efficient production and consumption decisions. The Panel regards the one-hour ahead pre-dispatch price as particularly important, but also examines the three-hour ahead pre-dispatch price as an indicator of the degree to which supply and demand levels can be predicted in advance.

2.3.1 One-hour Ahead Pre-dispatch Price

Table 1-9 shows the differences between the one-hour ahead pre-dispatch price and the HOEP for November 2007 through April 2008 relative to the same months a year ago. There was some improvement in the average difference as it declined to $9.15/MWh this winter compared to $9.91/MWh last winter. These are arithmetic averages which (based on Table 1-9) mean that in each month the average pre-dispatch price exceeded the average HOEP.[12] The average difference declined in all months relative to last winter with the exception of January 2008. Expressed as a percentage of HOEP, monthly changes year over year reflect the same pattern but the value in April this year seems relatively larger due to HOEP values which are close to zero. The other metrics in the tables indicate no significant changes over the period, although it is worth noting that the very low value of the minimum difference was observed in February 2008 as the result of the price spike on February 1, as explained in Chapter 2.[13]

Table 1-9: Measures of Differences between One-Hour Ahead Pre-Dispatch Prices and HOEP, November – April 2006/2007 & 2007/2008 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	8.34	7.50	59.00	56.65	(54.45)	(58.16)	14.52	12.91	24.82	20.87
December	8.77	7.37	91.68	52.08	(67.32)	(52.54)	13.50	13.32	22.68	28.86
January	7.69	9.41	40.71	64.78	(82.87)	(66.65)	12.08	13.52	23.88	34.39
February	14.00	11.28	80.63	107.12	(74.28)	(485.46)	16.26	25.08	32.21	32.04
March	11.06	10.87	87.12	77.36	(67.96)	(124.21)	16.30	18.68	28.46	23.08
April	9.57	8.46	95.48	77.91	(119.44)	(143.82)	17.18	21.38	31.65	68.30*
Average	9.91	9.15	75.77	72.65	(77.72)	(155.14)	14.97	17.48	27.28	34.59

* The large April percentage is driven by an outlier. In one hour, the average hourly difference as a percent of HOEP was 21,400 percent as the HOEP (denominator) was quite small at $0.02/MWh. Removing this outlier restates the average hourly difference to 38.59 percent and the average over six months to 29.64 percent.

2.3.2 Three-hour Ahead Pre-dispatch Price

Table 1-10 reports the differences between the three-hour ahead pre-dispatch price and the HOEP for November through April 2007/2008 compared to one year ago. Similar to the one-hour ahead comparison shown above, the average difference between the three-

[12] Typically HOEP is lower than the pre-dispatch price. In the recent 6 month period, HOEP was higher only 19 percent of the time.
[13] The minimum value is a large negative number since the HOEP was much larger than the pre-dispatch price in that hour.

hour ahead pre-dispatch price and HOEP decreased from $9.08/MWh in the 2006/2007 period to $8.14/MWh in the 2007/2008 period.

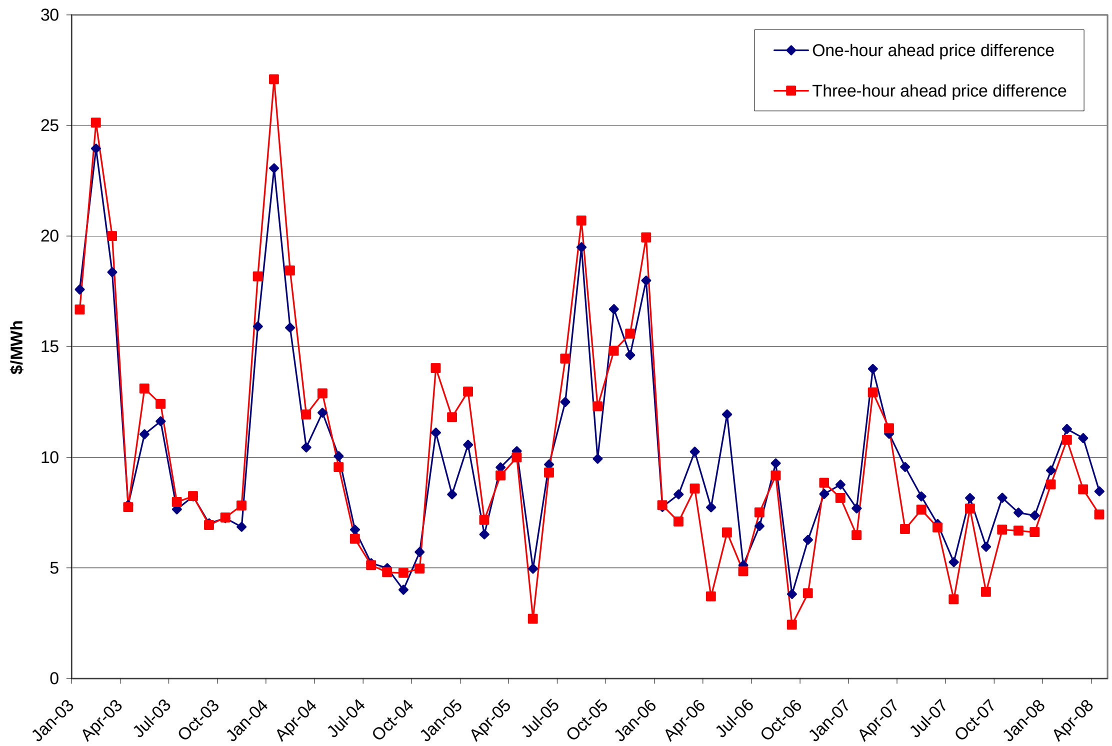
Table 1-10: Measures of Differences between Three-Hour Ahead Pre-Dispatch Prices and HOEP, November – April 2006/2007 & 2007/2008 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	8.85	6.68	62.20	50.18	(57.01)	(54.74)	14.87	13.48	25.36	18.56
December	8.16	6.62	83.82	48.05	(73.61)	(50.61)	14.21	14.24	15.19	28.43
January	6.48	8.78	46.19	63.38	(89.72)	(84.51)	13.18	14.28	20.38	30.31
February	12.93	10.79	73.34	68.85	(74.95)	(505.62)	17.30	25.50	29.42	23.44
March	11.31	8.55	88.29	77.36	(67.96)	(125.90)	16.83	20.29	28.05	19.54
April	6.76	7.42	81.19	82.12	(145.64)	(145.17)	18.26	22.34	24.35	19.39
Average	9.08	8.14	72.51	64.99	(84.82)	(161.09)	15.78	18.36	23.79	23.28

2.3.3 Reasons for Differences

Figure 1-3 displays the average monthly difference between the one and three-hour ahead pre-dispatch versus real-time prices since January 2003. First, we observe that, as for the comparison between HOEP to one-hour ahead pre-dispatch, the three-hour ahead pre-dispatch price to HOEP monthly differences are generally smaller this winter versus last winter. Second, it is worth noting that the three-hour ahead differences have typically been slightly lower than the one-hour difference each month since the beginning of 2006, a curiosity which the Panel is currently unable to explain. Prior to that time three-hour ahead differences tended to be slightly larger than the one-hour ahead differences.

Figure 1-3: Average Pre-dispatch to HOEP Price Differences
One and Three-Hour Ahead,
January 2003 – April 2008
($/MWh)



To date, the Panel has identified four main factors that lead to discrepancies between pre-dispatch and real-time prices:

- Demand forecast error;
- Performance of self-schedulers and intermittent (primarily wind) generators;
- Failure of scheduled imports and exports; and
- Frequency that imports (or exports) set the pre-dispatch price.

Table 1-11 presents the average and absolute average differences for each of the first three factors listed above for the November 2007 to April 2008 period. Clearly, the larger the MW the more the impact, but the averages mask the fact that in any given hour the discrepancy can be much larger. Each of these first 3 factors can have a significant impact, but the influence of demand forecast error followed by failed imports and exports tend to be greatest. On average, peak-to-peak demand forecast error is 25 MW higher in pre-dispatch relative to real-time on a net basis, but 174 MW higher in absolute terms.[14] The peak-to-average and absolute average demand forecast error differences are larger at 259 MW and 304 MW respectively. On the other hand, the magnitude of net export failures is on average 82 MW and 132 MW in absolute terms over the last winter period. The frequency that imports set the pre-dispatch price may also have a significant impact in any one hour, but on average the impact would likely be less.

Table 1-11: Average and Absolute Average Hourly Error by Discrepancy Factor, November 2007 – April 2008 (MW)

Discrepancy Factor	Average Error (MW)	Absolute Average Error (MW)	Average Error as % of Ontario Demand	Absolute Average Error as % of Ontario Demand
Peak-to-Peak Demand Forecast Error	25	174	0.14	0.99
Peak-to-Average Demand Forecast Error	259	304	1.47	1.73
Self-Scheduling and Intermittent Error	13	48	0.07	0.27
Net Export Failures	82	132	0.47	0.75

*Average hourly Ontario Demand for the six-month period was 17,603 MW

2.3.3.1 Demand Forecast Error

Table 1-12 reports the one-hour and three-hour ahead mean absolute demand forecast error on a monthly basis over the 2006/2007 and 2007/2008 winter months. The average monthly values this period are somewhat higher than in the last period, but the mean absolute difference, comparing peak versus peak, is still less than 1 percent.

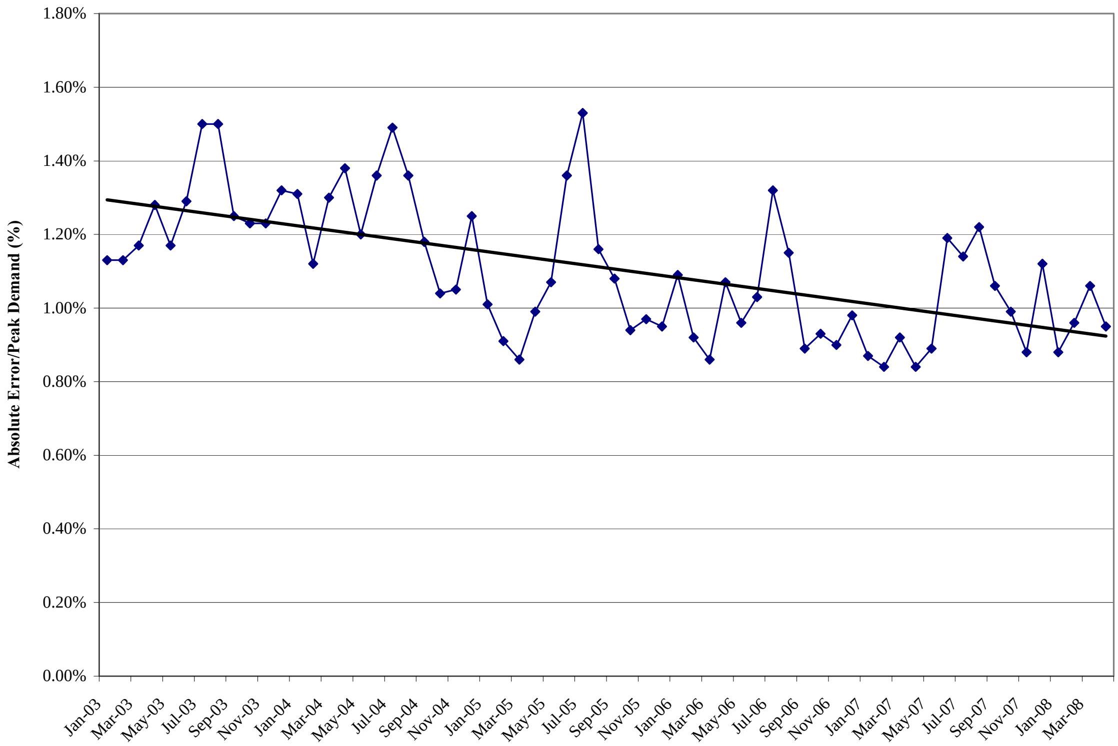
[14] Peak-to-peak demand forecast error compares the pre-dispatch peak demand forecast and the peak interval demand in real-time.

Table 1-12: Demand Forecast Error, November – April 2006/2007 & 2007/2008 (%)

	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			
	Three-Hour Ahead		One-Hour Ahead		Three-Hour Ahead		One-Hour Ahead	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	1.91	1.81	1.86	1.76	1.05	1.02	0.90	0.88
December	1.99	1.94	1.82	1.74	1.21	1.41	0.98	1.12
January	1.87	2.01	1.72	1.79	1.13	1.12	0.87	0.88
February	1.76	1.87	1.60	1.70	1.07	1.13	0.84	0.96
March	1.70	1.97	1.55	1.73	1.11	1.34	0.92	1.06
April	1.75	1.80	1.59	1.68	1.07	1.13	0.84	0.95
Average	1.83	1.90	1.69	1.73	1.11	1.19	0.89	0.98

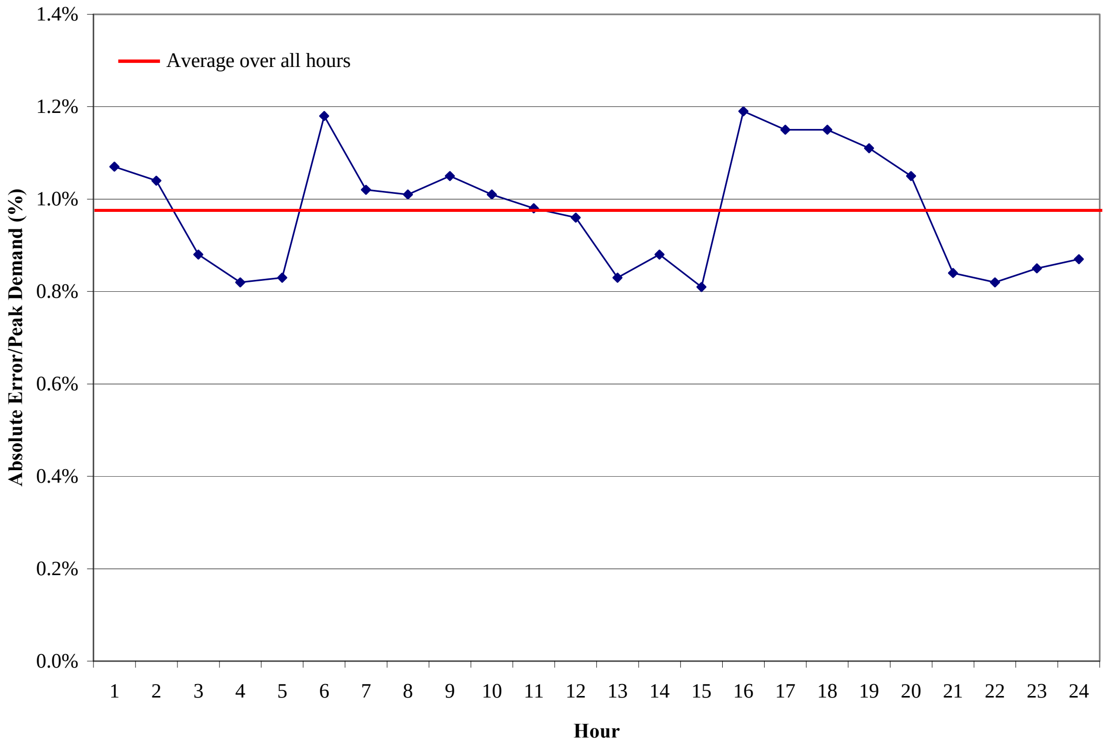
Figure 1-4 provides historical data on one-hour ahead absolute demand forecast errors since January 2003. The overall trend line continues to decline despite some recent increases.

Figure 1-4: Absolute Average One-Hour Ahead Forecast Error, January 2003 - April 2008 (% of Peak Demand)



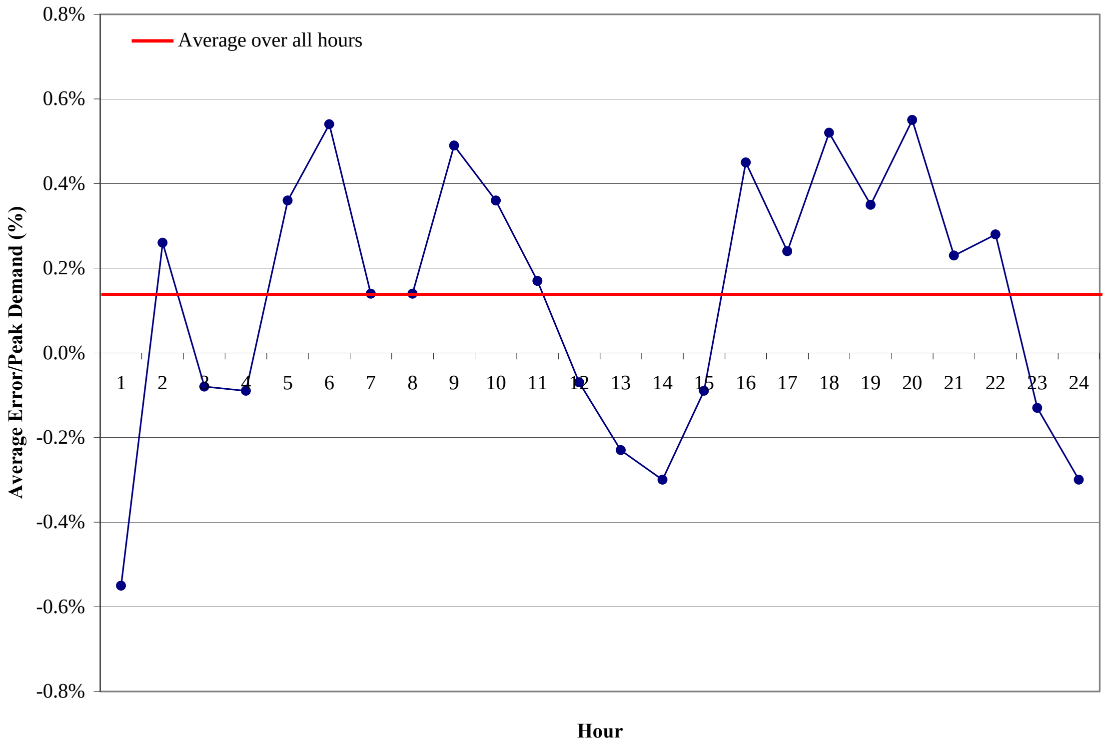
To observe the forecast error over the day, Figure 1-5 shows the average peak-to-peak absolute errors calculated by hour of the day, over the recent six month period. The horizontal line (red) in the figure reflects the average forecast error over all hours of the day. The figure shows poorer performance in HE 6 and HE 16 to 19 and better performance in HE 3 to 5, HE 12 to 14 and HE 21 to 24. To some extent this may be associated with greater load volatility in some hours versus relative stability in others.

Figure 1-5: Absolute Average One-Hour Ahead Forecast Error by Hour, November 2007 - April 2008 (% of Peak Demand)



In Figure 1-6 we present the arithmetic average of the normalized forecast errors (one-hour ahead and peak-to-peak), rather than the average absolute values. This shows that the errors tend to have a more positive bias just before and after morning load pickup and evening peak and load drop-off period.

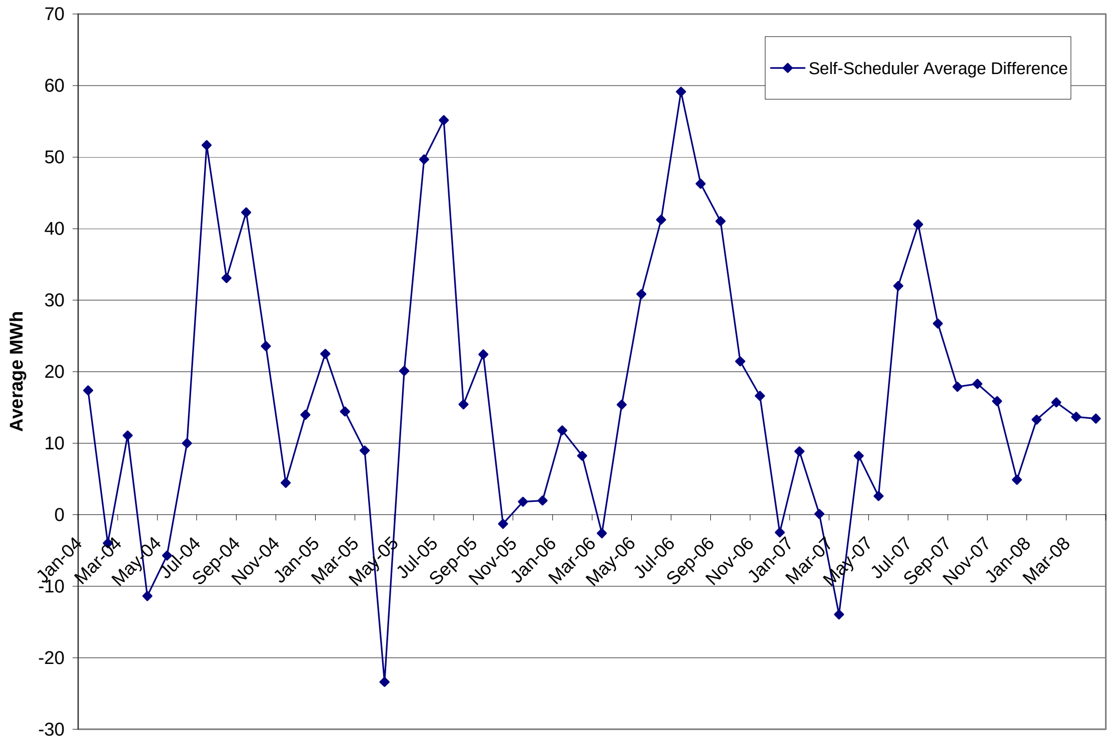
Figure 1-6: Arithmetic Average One-Hour Ahead Forecast Error by Hour, November 2007 - April 2008 (% of Peak Demand)



2.3.3.2 Performance of Self-Scheduling and Intermittent Generation

Figure 1-7 shows the monthly average difference between the amount of energy self-scheduling and intermittent generator’s forecast and the amount of energy they actually deliver in real-time. The peaks in the graph indicate large positive biases in summer forecast values. Monthly differences in the recent winter months were again lower than the previous summer values. They are somewhat higher than the previous winter values, but not out of line with earlier winter periods.

Figure 1-7: Average Difference between Self-Scheduling and Intermittent Generator's Offered and Delivered Energy, January 2004 - April 2008 (MWh)

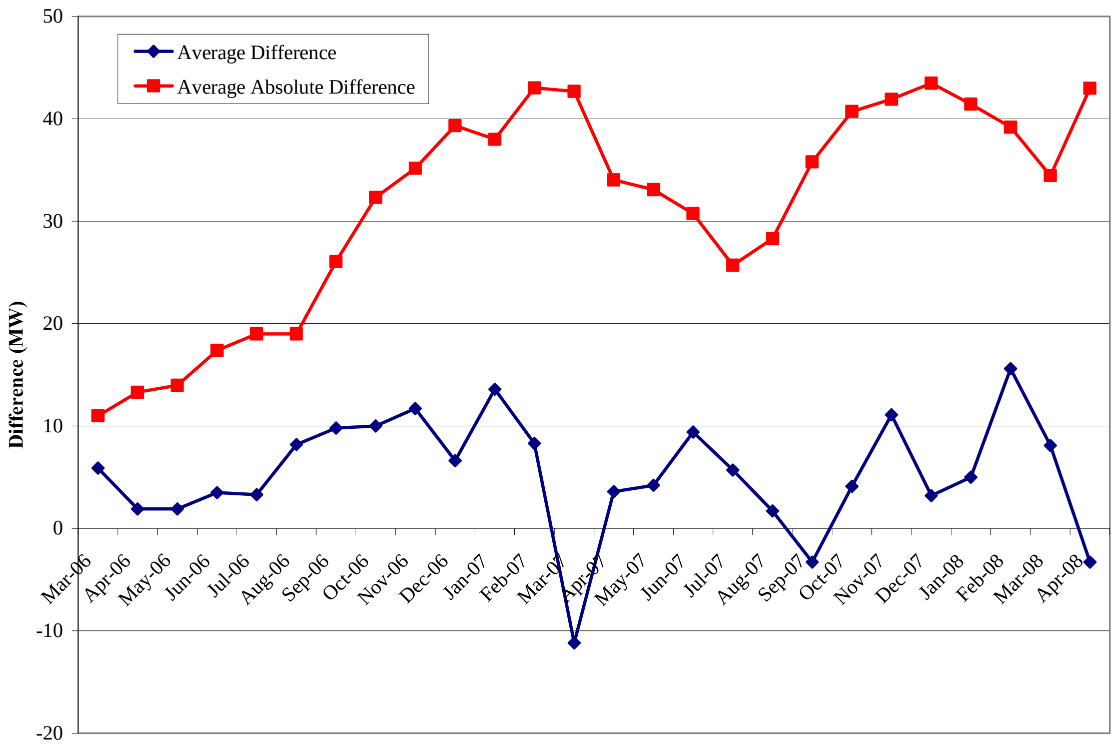


<u>Performance of Wind-Power Generation</u>

Wind generation accounts for the majority of intermittent generation in Ontario. In the last report, the Panel expressed a concern about the high level of forecast error attributable to wind generation and recommended that the IESO continue to review the forecasting process with wind generators in order to reduce forecast errors. Figure 1-8 plots the average and absolute average difference between wind generators' forecasted energy and actual energy produced. Over the recent six-month winter period, the average difference was 6.6 percent, which is up from 5.1 percent during the 2006/07 winter period. The average difference reached an all-time record of 15.6 MW in February 2008. The absolute average differences were generally higher this winter compared to last with the highest absolute average difference of 43.5 MW occurring in December 2007.

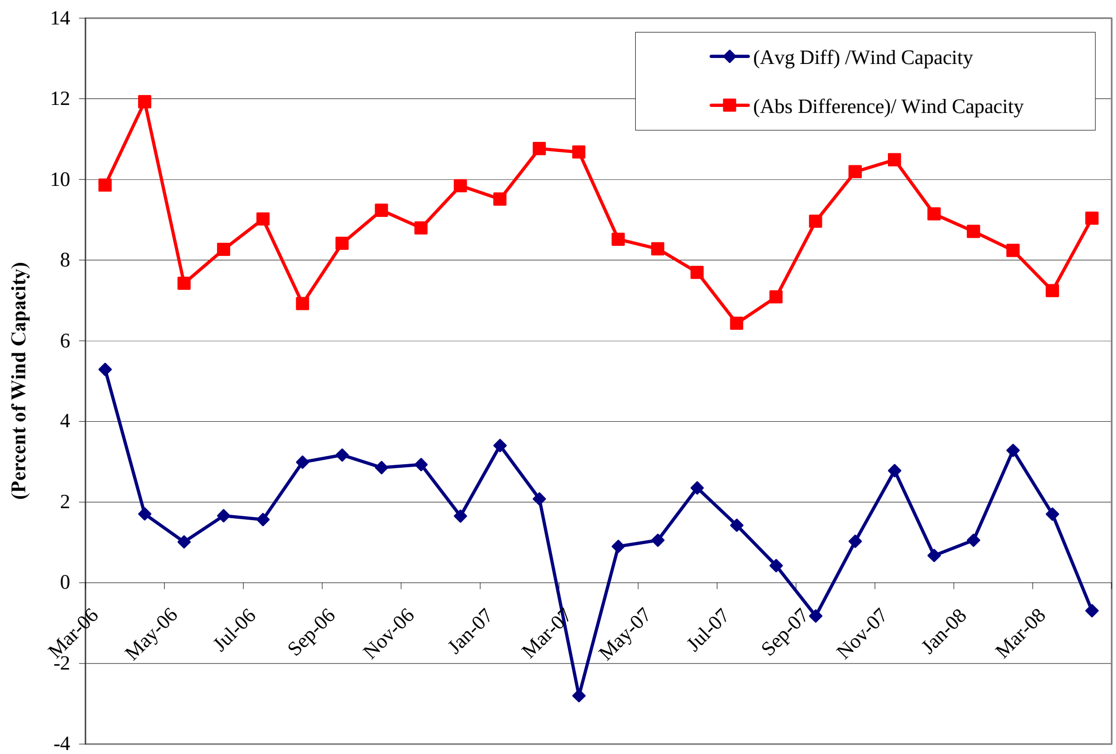
Overall, the absolute average difference increased from 38.7 percent last winter to 40.6 percent this winter.

Figure 1-8: Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy, March 2006 - April 2008 (MW)



Although average absolute differences have been growing, when error is normalized using total available wind capacity, little trend is apparent. Figure 1-9 plots the average and absolute average difference between wind generators' forecasted energy and actual energy produced normalized using monthly total wind capacity, since March 2006. With the exception of a few months, the normalized absolute average difference has fluctuated between 7 and 10 percent while the normalized average difference has fluctuated between 0 and 4 percent. With normalized absolute wind forecast error as high as 10 percent of capacity, absolute deviations will continue to increase as the future stock of wind generation increases. According to the OPA, 789 MW of new wind generating capacity is currently under development and construction and is expected to be in service by the end of 2008.[15] Furthermore, Ontario's Integrated Power System Plan (IPSP) states that by 2025, Ontario plans to have 3,039 MW of installed wind capacity.[16]

Figure 1-9: Normalized Average and Absolute Average Difference between Wind Generators' Forecasted and Delivered Energy, March 2006 - April 2008 (Difference/Wind Capacity)



2.3.3.3 Real-Time Failed Intertie Transactions

The Panel closely monitors both the frequency and magnitude of failed import and export transactions since they can contribute to differences between pre-dispatch prices and HOEP. In real-time, import failures represent a loss of supply while export failures represent a decline in demand, both of which result in discrepancies between pre-dispatch and real-time prices. For this recent winter period we have noticed a dramatic increase in

[15] See the OPA Wind Power Projects webpage for more details on the specific projects at: http://www.powerauthority.on.ca/Page.asp?PageID=924&SiteNodeID=234
[16] See the IPSP Exhibit B-1-1, October 19, 2007, page 10 at: http://www.powerauthority.on.ca/Storage/53/4857_B-1-1_corrected_071019.pdf

the level of failed imports and exports associated with the much higher volume of linked wheeling transactions.[17]

Tables 1-13 and 1-14 compare the number of hours when failures occur and rates of import and export failures over the 2006/2007 and 2007/2008 winter months respectively. In previous MSP Monitoring Reports, linked wheel failures were in a sense double counted. A failed linked wheel transaction was counted as both an import and an export failure. Linked wheel failures dramatically increased in early 2008. The tables have now been revised to exclude linked wheel failures since they have no influence on the difference between pre-dispatch and real-time prices.

Export Failures

Despite the linked wheel adjustment, the frequency of failed exports measured by the number of hours when export failures occurred increased this winter by 368 hours (15.7 percent) and increased in every month compared to last winter with the exception of March. The hourly magnitude of the failures increased as measured by the average export failure amount. The maximum hourly export failure amount increased by an average of 42 MW (27.6 percent) and 48 MW (5.4 percent), respectively, over the period. However, since the volume of scheduled exports increased substantially this period, the rate of export failures (the ratio of failed MWh to total scheduled MWh) fell this winter compared to last from 6.77 percent to 5.93 percent.

[17] See section 5.4.3 for a description of the linked wheel phenomenon.

Table 1-13: Frequency and Average Magnitude of Failed Exports from Ontario, November – April 2006/2007 & 2007/2008

	Number of Hours when Failed Exports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	315	363	766	876	157	171	8.53	6.10
December	384	431	865	857	169	186	8.89	5.87
January	415	508	801	1,142	152	207	7.48	5.62
February	373	498	1,220	1,150	129	265	3.88	8.20
March	403	401	671	774	142	154	5.94	4.83
April	454	511	1,028	843	160	179	5.89	4.96
Total	2,344	2,712	N/A	N/A	N/A	N/A	N/A	N/A
Average	391	452	892	940	152	194	6.77	5.93

* The incidents with less than 1 MW and linked wheel failures are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled exports MWh (less the export leg of linked wheels) in the unconstrained sequence in a month

Import Failures

Similar to export failures, the number of hours when import failures occurred increased this winter compared to the previous winter. In total, import failures increased by 234 hours, which represents a 22 percent increase relative to last winter. At the same time, the magnitude of import failures measured by the maximum hourly failure amount and the average hourly failure amount increased by 179 MW (37.9 percent) and 38 MW (36.9 percent) over the last two winter periods and increased in every month. Consistent with this trend, the import failure rate moderately increased from 3.59 percent to 4.33 percent as a result of significant rises in all months between January and April.

Table 1-14: Frequency and Average Magnitude of Failed Imports to Ontario, November – April 2006/2007 & 2007/2008

	Number of Hours when Failed Imports Occurred*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	240	210	595	677	114	136	3.44	2.80
December	132	170	384	597	102	129	3.03	2.19
January	135	261	553	843	111	156	3.31	5.86
February	224	233	502	550	92	139	4.87	4.97
March	215	221	550	786	112	155	3.58	6.10
April	105	190	250	450	89	132	3.29	4.07
Total	1,051	1,285	N/A	N/A	N/A	N/A	N/A	N/A
Average	175	214	472	651	103	141	3.59	4.33

* The incidents with less than 1 MW and linked wheel failures are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled imports MWh (less the import leg of linked wheels) in the unconstrained sequence in a month

<u>Causes of Failures</u>

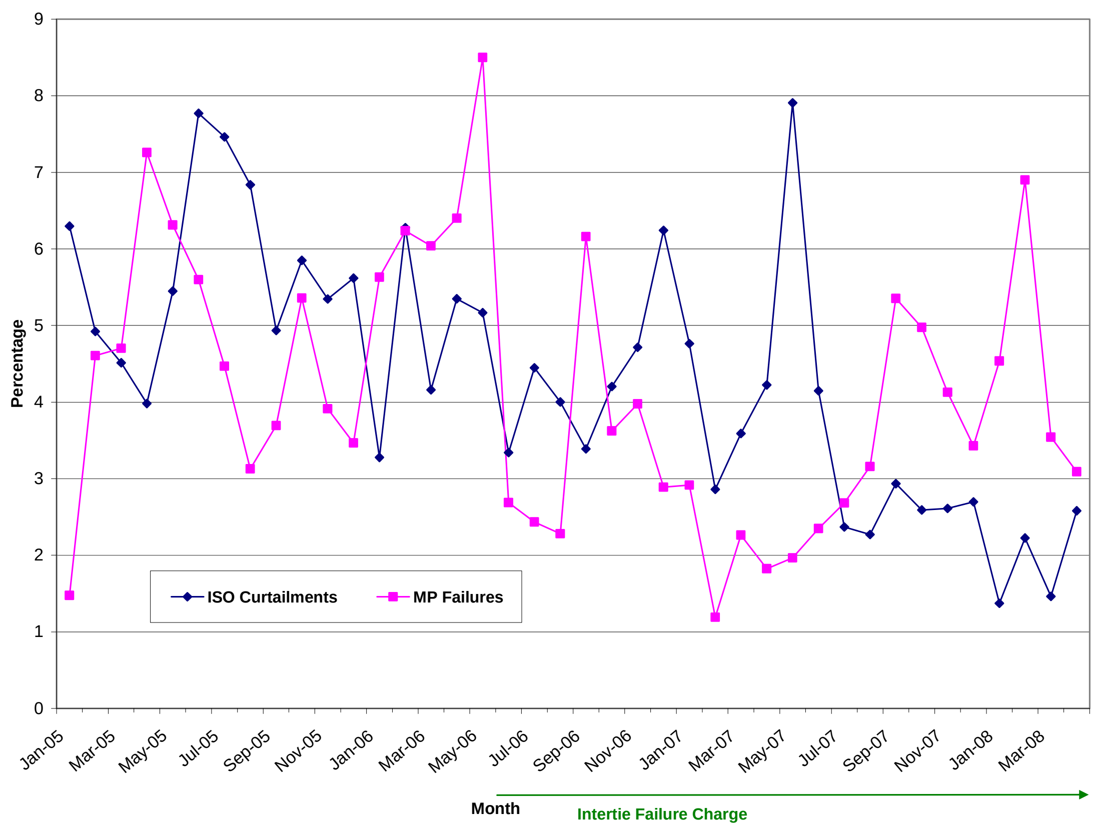
Figures 1-10 and 1-11 show failure rates since January 2005 for exports and imports for failures under the market participants' control (MP failures) and those under the control of an external ISO (ISO curtailments).[18] The failure rate is determined as a percentage of failed to total exports (or imports) in MWh per month. In these figures we have once again excluded the contributions from linked wheels (the majority of which have been under participant control).[19] These excluded failures represent about 2/3 of the total export failures this winter and about half of the total import failures.

The export failure rate, expressed as a percentage of export failures to total exports, did not significantly increase when linked wheel failures were removed. As can be seen from Figure 1-10, monthly total failure rates fluctuate; however, over the six winter months averages are about the same in the range of 6 percent to 7 percent. However, there has been a notable shift in export failures under market participant and ISO control since last

[18] Data prior to 2005 is not considered given the introduction of the intertie failure charge in June 2006 and market participant entries and departures.
[19] As explained in Chapter 3 there was a change in March 2008 by the IESO in the manner in which failed linked wheels were recorded. Until March 2008, these failures were recorded in the same manner as failures induced by external ISOs, even though the majority of these were under the control of the participant. We exclude linked wheeling transactions here to avoid the misleading implication that market participant failures increased substantially in March and April compared to earlier in the year.

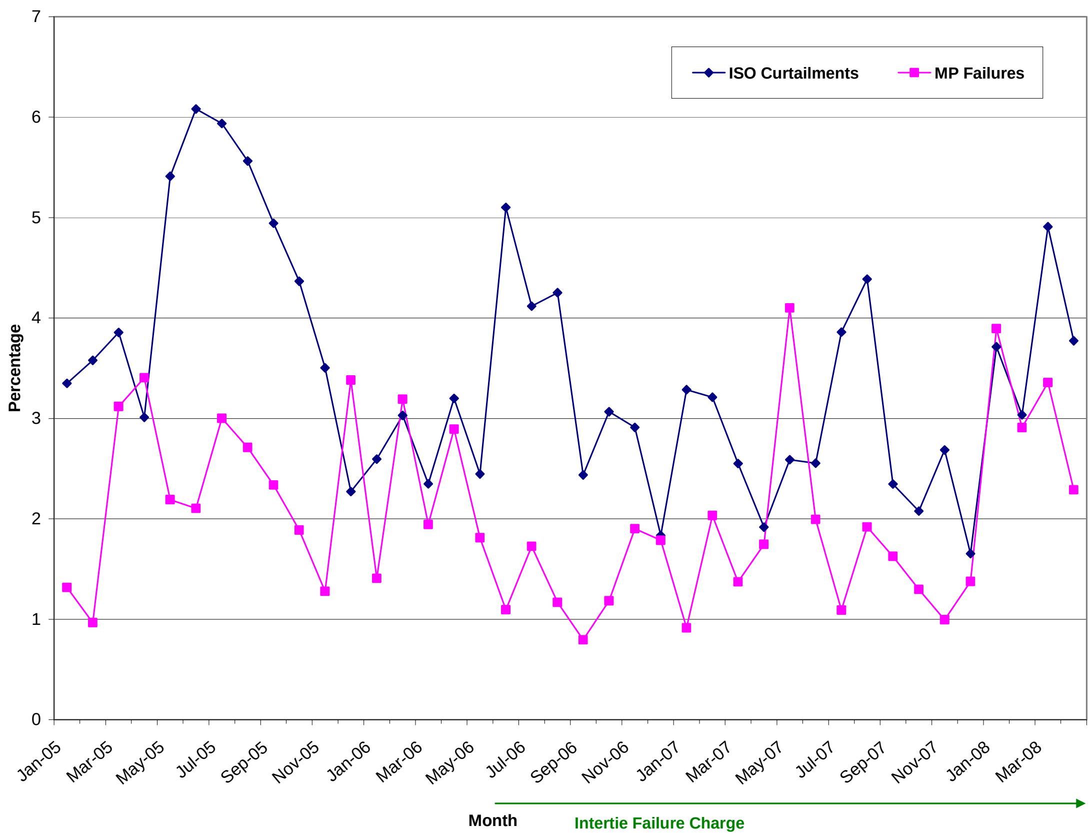
winter. Since reaching a low value in February 2007, the rate of failures controllable by participants has climbed significantly through February 2008. Similarly, over the same period the ISO curtailment rate has been trending lower. As of August 2007 the ISO curtailment rate has fallen below the market participant failure rate and now represents a minor part of the total failure rate. One factor that appears to have induced this shift was a procedural change by the NYISO in December of 2007, which led to identifying more failures as economic rather than security induced so they are reclassified as being failures within the participants' control.

Figure 1-10: Monthly Export Failures as a Percentage of Total Exports by Cause, January 2005 – April 2008 (%)



Failures under market participants' control dropped after the failure charge was introduced in June 2006, rising significantly above 2 percent in only one month through 2007. However, they have recently been moving in the 3 percent to 4 percent range. After rising in June 2006 the ISO curtailment failure rate appeared to have been trending downwards, but again in recent months this has turned around. As a consequence, failure rates this winter are noticeably higher than last winter as the result of the four most recent months, January to April.

Figure 1-11: Monthly Import Failures as a Percentage of Total Imports by Cause, January 2005 – April 2008
(%)



<u>Failures by Intertie Group</u>

Tables 1-15 and 1-16 show import and export totals and failures by cause and intertie group for the last six months. Similar to above, linked wheel failures have been removed. The percent column represents the total of all failures of that type which occurred at the intertie group. Table 1-15 demonstrates that the vast majority of exports fail in the New York market (where the largest portion of exports occurs). Table 1-16 shows that the majority of import failures which are participant controlled have occurred in the New York market, while most of the ISO controlled import failures have occurred in the

Michigan market. This latter observation implies it is somewhat more difficult for traders to bring imports from MISO because of system limitations there.

Table 1-15: Average Monthly Export Failures by Intertie Group and Cause, November 2007 – April 2008 (GWh and % Failures)

	Average Monthly Exports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
NYISO	1,000	23.9	77.2	59.3	94.9	2.4	5.9
MISO	312	2.8	9.2	2.8	4.5	0.9	0.9
Manitoba	12	0.3	1.0	0.0	0.1	2.5	0.0
Minnesota	47	0.8	2.5	0.2	0.3	1.7	0.4
Quebec	82	3.1	10.1	0.2	0.3	3.8	0.2
Total	1,453	31.0	100.0	62.5	100.0	2.1	4.3

Table 1-16: Average Monthly Import Failures by Intertie Group and Cause, November 2007 – April 2008 (GWh and % Failures)

	Average Monthly Imports	Failures - ISO Controlled		Failures - Participant Controlled		Failure Rate	
						ISO Controlled	Participant Controlled
	GWh	GWh	%	GWh	%	%	%
NYISO	162	1.4	6.0	10.9	64.9	0.9	6.7
MISO	472	17.8	77.3	5.7	34.0	3.8	1.2
Manitoba	24	0.7	3.0	0.1	0.3	2.9	0.4
Minnesota	10	0.2	0.8	0.0	0.3	2.0	0.0
Quebec	73	3.0	12.9	0.1	0.4	4.1	0.1
Total	741	23.0	100.0	16.8	100.0	3.1	2.3

2.3.3.4 Imports or Exports Setting Pre-dispatch Price

When imports set the pre-dispatch market clearing price there should be a greater likelihood of discrepancies between pre-dispatch and real-time prices. Since imports are unable to set the MCP in real-time (they are moved to the bottom of the offer stack), some other lower or higher-priced resource must set the MCP when the pre-dispatch price is set by an import. Thus there is a greater potential for discrepancies between the two prices during hours when an import is the marginal resource in the pre-dispatch schedule.[20] When exports set the pre-dispatch price, there is a similar potential for the HOEP to be different because exports are available to be the marginal resource in pre-dispatch but like imports, are not an option to set the MCP in real-time. All else held constant, we expect that the higher incidence of imports or exports setting the pre-dispatch price, the more of a tendency for pre-dispatch and real-time prices to diverge.

Table 1-17 shows the monthly frequency of imports or exports setting the pre-dispatch price for the November to April 2006/2007 and 2007/2008 periods. Comparing the six month periods shows that the frequency of imports or exports setting the pre-dispatch price increased slightly from 57 percent during the 2006/2007 winter period to 59 percent during the 2007/2008 winter period. On a monthly basis, the largest year-over-year change occurred in December with 42 more hours where imports or exports set the price.

Table 1-17: Frequency of Imports or Exports Setting the Pre-Dispatch Price, November – April 2006/2007 & 2007/2008 (Number of Hours and % of Hours)

	2006/2007		2007/2008		Difference	
	Hours	%	Hours	%	Hours	% Change
November	398	58	416	60	18	2.2
December	346	48	388	54	42	5.7
January	368	51	354	50	(14)	-1.7
February	372	60	393	60	21	0.9
March	469	66	450	64	(19)	-2.2
April	410	59	428	63	18	3.9
Total	2,364	57	2,428	59	66	1.5

The increase by 1.5 percent of the observed frequency of imports or exports setting the price suggests a slight tendency for HOEP to diverge more from the pre-dispatch price (i.e. be less than the pre-dispatch price). However, this contrasts with the observed lowering by $0.76/MWh of the average differences between one-hour-ahead pre-dispatch price and HOEP noted in Table 1-9. Based on the monthly frequency and price

[20] For a detailed explanation about how imports set the pre-dispatch price, see pp. 30-33 of the Panel's July 2007 MSP Monitoring Report available at: http://www.oeb.gov.on.ca/documents/msp/msp_report_20070810.pdf

differences in the above table, there appears to be little correspondence between movements of the two quantities over the two winter periods.[21]

2.4 Analyzing Year-Over-Year Changes in the HOEP

The Panel introduced a simple reduced form econometric model in its June 2005 Monitoring Report and has continued to publish the results of the evolving model over larger sample sizes. The current model is estimated using 64 monthly observations between January 2003 and April 2008.

On-peak and off-peak estimation results are presented in Table 1-18. The dependant variable is the monthly average HOEP while the independent variables in the model include nuclear production, self-scheduler production, Ontario demand, the Henry Hub spot market price, New York load, and monthly fixed effects. Consistent with results published in previous reports, the explanatory variables are all significant and the signs of the coefficients are intuitive. The results suggest that the baseload supply variables measured by nuclear and self-scheduler output are negatively correlated to the HOEP while the Ontario and New York demand variables and the natural gas price are positively correlated to HOEP.

[21] For example, the largest year-over-year monthly increase in frequency occurred in December (6 percent) whereas year-over-year the pre-dispatch to HOEP price difference declined by 1.4 percent representing the second largest monthly decrease.

Table 1-18: Estimation Results of the Updated Econometric Model, January 2003 - April 2008

Variable	On-peak Model		Off-peak Model	
	Coefficient	P-value[22]	Coefficient	P-value
Constant	-27.23	0.00	-20.47	0.00
LOG(Nuclear Output)	-0.72	0.00	-0.67	0.00
LOG(Self Scheduler output)	-0.20	0.01	-0.22	0.17
LOG(Ontario Demand)	1.48	0.00	1.83	0.00
LOG(New York Demand)	2.35	0.00	1.33	0.03
LOG(Natural Gas Price)	0.61	0.00	0.52	0.00
R-squared	0.90		0.81	
Adjusted R-squared	0.86		0.74	
LM test of Serial Correlation	Absent		Absent	
JB test of normality of residuals	Normal		Normal	
Number of observations	64		64	

The results from the decomposition analysis are shown in Table 1-19. This analysis relies on the results of the reduced form econometric model presented above to quantify what the monthly average HOEP would have been in the 2006/2007 winter months if the explanatory variables observed in 2007/2008 were used in place of the corresponding 2006/2007 values. For example, if we replace the November 2006 nuclear supply with the observed November 2007 value, the November 2006 HOEP would have been $0.91/MWh lower in the case of all hours and all else held constant. The table also reports the actual average HOEP for each month during the 2006/2007 winter months along with the model's predicted price (referred to as the calibrated HOEP).

Natural gas prices appear to be influential to changes in the HOEP. The results in Table 1-19 show that there would have been an increase in the January, March and April 2007 HOEP values if the 2008 gas prices were observed. The estimates are larger during the on-peak hours of the day. Conversely, the 2006/2007 HOEP would have declined if the November, December, and February 2007/2008 gas prices were observed in 2006/2007.

[22] The P-Value (probability value) in the table indicates the probability, under the null hypothesis (that the coefficient equals zero) of obtaining a value for the test statistic (in absolute value) that exceeds the value of the statistic that is computed from the sample. A p-value close to zero leads to rejection of the null hypothesis implying that the coefficient is statistically significant in the model.

For example, the November 2006 HOEP would have been $6.30/MWh lower if the November 2007 gas price was observed in November 2006. The result is intuitive as the average monthly Henry Hub spot price decreased by almost 20 percent from November 2006 to 2007 as presented in Table 1-31.

Table 1-19: Price Effects of Setting 2006/2007 On-Peak and Off-Peak Factors at 2007/2008 Levels ($/MWh)

	Month	Nuclear	Natural Gas Price	NY Load	Self	Ontario Load	2006/2007 HOEP	
							Actual	Calibrated
All Hours	November	-0.91	-6.30	2.49	0.98	1.20	49.71	48.02
	December	-2.71	-2.22	3.89	0.54	2.67	39.25	41.16
	January	-6.04	2.16	1.24	1.17	-1.04	44.48	47.82
	February	-1.06	-3.92	-3.58	1.46	-4.76	59.12	62.00
	March	1.21	4.63	-1.28	1.90	-1.36	54.85	57.68
	April	1.15	5.91	-1.61	1.23	-2.38	46.05	50.05
	Average	**-1.39**	**0.04**	**0.19**	**1.21**	**-0.95**	**48.91**	**51.12**
Off-peak Hours	November	2.92	-3.53	2.50	0.64	0.24	39.70	32.64
	December	-1.78	-1.37	3.71	0.27	2.67	28.61	31.14
	January	-3.99	1.32	1.97	1.03	-0.99	35.45	36.19
	February	-0.77	-2.51	-1.53	1.03	-4.72	48.25	48.50
	March	0.89	2.99	0.82	1.70	-0.86	43.92	46.15
	April	0.65	3.26	-0.08	0.90	-2.07	32.83	34.33
	Average	**-0.35**	**0.03**	**1.24**	**0.93**	**-0.95**	**38.13**	**38.16**
On-peak Hours	November	-0.53	-7.15	1.86	1.61	-0.86	60.13	56.82
	December	-2.90	-2.41	3.69	0.95	2.39	46.86	46.69
	January	-6.35	2.30	-0.01	1.63	-0.96	50.92	53.23
	February	-1.05	-4.14	-6.13	2.29	-4.26	66.88	68.40
	March	1.19	4.85	-4.09	2.69	-1.57	62.66	63.25
	April	1.32	6.66	-3.87	1.88	-2.30	55.55	59.13
	Average	**-1.39**	**0.02**	**-1.43**	**1.84**	**-1.26**	**57.17**	**57.92**

2.5 Hourly Uplift and Components

Table 1-20 reports the monthly total hourly uplift charge for the last two winter periods. Total hourly uplift charges increased from $170.4 million in 2006/2007 to $200.8 million in 2007/2008 (or 18 percent) and increased in every month with the exception of November. Contributing to the increase in total hourly uplift charges were increases in

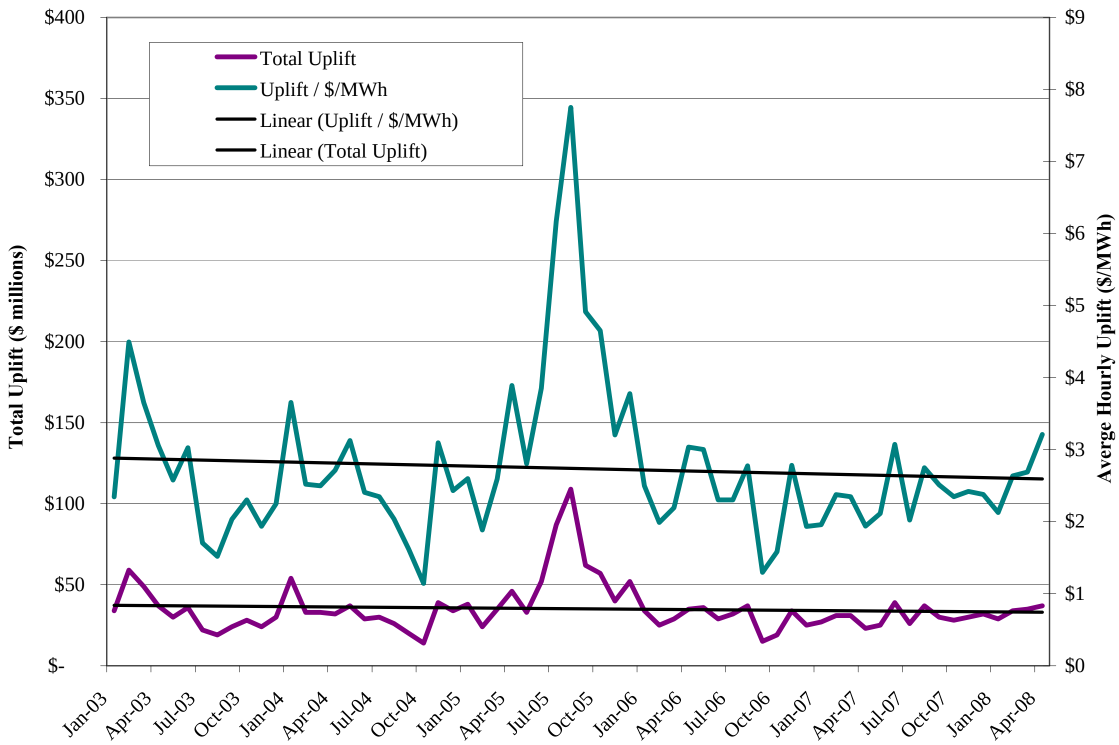
CMSC charges, operating reserve, and losses. CMSC charges increased from $49.5 million to $70.9 million, or 43 percent over the two periods and increased in every month relative to last year. Increases in CMSC were mainly due to more bottled energy in the Northwest and more resource restrictions in southern Ontario (transmission or energy supply limitations) which led to constraining on imports or constraining off exports. Losses increased from $84.2 million to $89.5 million (or 6 percent). Finally, operating reserve payments increased by $3.6 million (or 37 percent) as payments in April 2008 increased over threefold to $4.8 million relative to April 2007. April 2008 prices were higher as the result of the much greater availability of water this spring leading to hydroelectric plants providing more energy and reducing their ability to provide OR.

Table 1-20: Monthly Total Hourly Uplift Charge by Component and Month, November – April 2006/2007 & 2007/2008 ($ millions and %)

	Total Hourly Uplift		IOG		CMSC		Operating Reserve		Losses	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	33.8	30.7	7.6	4.2	10.7	11.7	1.3	1.5	14.2	13.4
December	25.0	32.9	3.6	4.2	7.2	11.4	1.5	1.1	12.6	16.2
January	26.7	30.0	3.0	4.1	7.3	9.4	2.1	2.3	14.3	14.2
February	31.0	34.1	4.4	6.0	8.5	11.3	2.2	2.3	15.9	14.6
March	31.0	35.6	5.9	4.2	8.6	12.8	1.0	1.4	15.5	17.2
April	22.8	37.4	2.5	4.3	7.1	14.3	1.5	4.8	11.7	14.0
Total	170.4	200.8	26.9	27.0	49.5	70.9	9.7	13.3	84.2	89.5
% of Total	100.0	100.0	15.8	13.4	29.0	35.3	5.7	6.6	49.4	44.6

Figure 1-12 plots hourly uplift charges, as the hourly total and average $/MWh, since the beginning of 2003. Aside from large uplift payments in the second half of 2005, total uplift payments have remained relatively stable since the beginning of 2003 although the last winter period suggests they may be beginning to increase. In April 2008, total uplift charges on a $/MWh basis were $3.21/MWh, which is the highest monthly total since the end of 2005.

Figure 1-12: Total Hourly Market Uplift and Average Hourly Market Uplift, January 2003 - April 2008 ($ millions and $/MWh)



2.6 Internal Zone Prices and CMSC Payments

Table 1-21 presents average nodal prices for the 10 internal Ontario zones for each six month period for the last three 6-month periods.[23] Figure 1-13 shows the same average nodal prices graphically for each zone for the recent winter period. The average nodal price for a zone, also referred to here as the internal zonal price, is calculated as the average of the nodal prices for generators in the zone.[24]

[23] See the IESO's "Ontario Transmission System" publication for a detailed description of the IESO's ten zone division of Ontario at http://www.ieso.ca/imoweb/pubs/marketreports/OntTxSystem_2005jun.pdf

[24] All nodal and zonal prices have been modified to +$2,000 (or -$2,000) when the raw hourly value was higher (or lower). This hourly adjustment is an approximation that yields a different result for the Richview nodal price than in section 2.8 and Appendix A-6.

Table 1-21: Internal Zonal Prices, November 2006 – April 2008 ($/MWh and %)

Zone	Nov 06-Apr 07	May 07-Oct 07	Nov 07-Apr 08	% Change from Nov 06–Apr 07 to Nov 07–Apr 08
Bruce	55.37	53.80	56.82	2.6
East	55.49	54.42	58.36	5.2
Essa	52.71	52.16	57.06	8.3
Northeast	47.67	42.38	49.18	3.2
Niagara	55.41	52.29	56.01	1.1
Northwest	36.98	(136.65)	(43.86)	(218.6)
Ottawa	57.01	56.03	60.51	6.1
Southwest	56.04	54.50	57.22	2.1
Toronto	57.22	56.36	58.55	2.3
Western	56.54	55.23	57.53	1.8
Average	51.02	23.30	39.84	(21.9)
Richview*	56.63	56.04	59.01	4.2

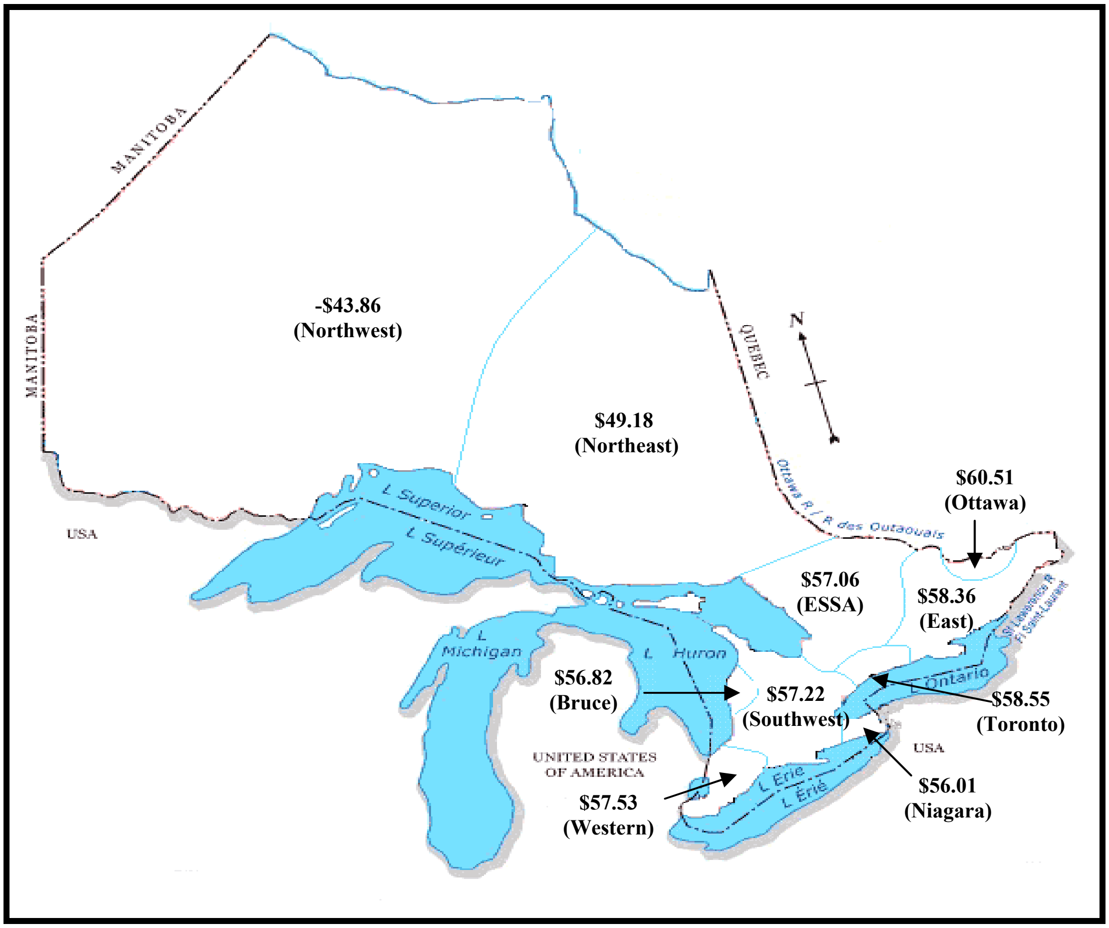
*Prices are limited to a maximum of $2,000/MWh or a minimum of minus $2,000/MWh on an hourly basis

For most zones other than the Northwest and Northeast, the table shows that current internal zonal prices are marginally higher than those of the previous year, between 1 to 10 percent above the earlier values. These price movements in the southern zones are largely related to generally higher supply costs in southern Ontario, which is also seen as an increase in the Richview nodal prices. The average Richview nodal price was $59.01/MWh over the recent winter which is $2.38/MWh and $2.97/MWh higher than the 2006/2007 winter and 2007 summer periods respectively. Adjusting for the change in Richview prices, the current period averages prices in the southern zones were within $2.00/MWh of the averages in the two earlier periods. Similar prices across these zones suggest that both congestion and losses are relatively small factors.[25] Upon further review of the price differences, congestion has been observed during less than 5 percent of the hours in the current period for each of the southern zones. This may appear somewhat low for transmission in the Niagara and Western zones given the levels of Lake Erie Circulation (LEC) that are briefly discussed in the section on linked-wheel transactions in Chapter 3. However, much of the problem induced by those loop flows

[25] Each nodal price is calculated from its three components: the Richview reference bus nodal price, the loss component and the congestion component. Once the Richview nodal price change has been considered, only the loss and congestion components remain to explain differences.

affects the interties at New York and Michigan. Changes to imports and exports, or manual re-dispatch of generation by the IESO relieve those constraints to a large extent, in which case they are not seen by the DSO as limiting internally in real-time.

Figure 1-13: Average Internal Zonal Prices
November 2007 - April 2008
($/MWh)



For the Northwest and Northeast, higher levels of losses and more frequent congestion in the zone (either at the interface with the rest of the system, or in more remote locations for example in the far Northeast area near James Bay) continue to drive the nodal prices significantly below prices in the south. As observed for the last summer period, congestion in the Northwest is the primary reason for average prices there to be quite low, at -$43.86 this last winter, which is lower than $36.98 (the average price the previous winter) but not as low as -$136.56 (the average price last summer). The abundant supply of very low-priced water in the Northwest, including energy available from imports, coupled with the decreasing demand in the area continues to induce flows near the limits of transmission through the area and to the rest of the province. These factors induced congestion in some part of the zone about 45 percent of the time this winter. The Northeast also has a large amount of hydroelectric supply but experiences less congestion, about 25 percent of the time this winter, within the zone or at the interface with the rest of Ontario. Prices in the Northeast were not as divergent from Richview prices this winter compared with the previous summer.

Figure 1-14 provides a comparable summary of congestion payments (CMSC) across the same 10 zones for the last winter period. For each zone, there is a total for CMSC paid for constraining off generation or imports (into the zone) or constraining on exports from the zone. A second figure shows the total CMSC for constrained on generation or imports, or constrained off exports. The data has been aggregated in this manner since constraining on exports is an alternative to constraining off supply when supply is bottled (oversupply in zone), and so the figure is to some degree a measure of the bottling of supply in the zone. Similarly, the second sub-total is a measure of the need for additional or out-of merit supply in a zone (undersupply in zone).[26] However, not all CMSC is induced by transmission or security (e.g. the 3-times ramp rate or slow ramping of fossil units can induce CMSC) so the total CMSC is not entirely a measure of congestion or losses.

[26] CMSC paid to dispatchable load is omitted here since the largest portion of those payments are self-induced.

Figure 1-14: Total CMSC Payments by Internal Zone, November 2007 - April 2008 ($ millions)

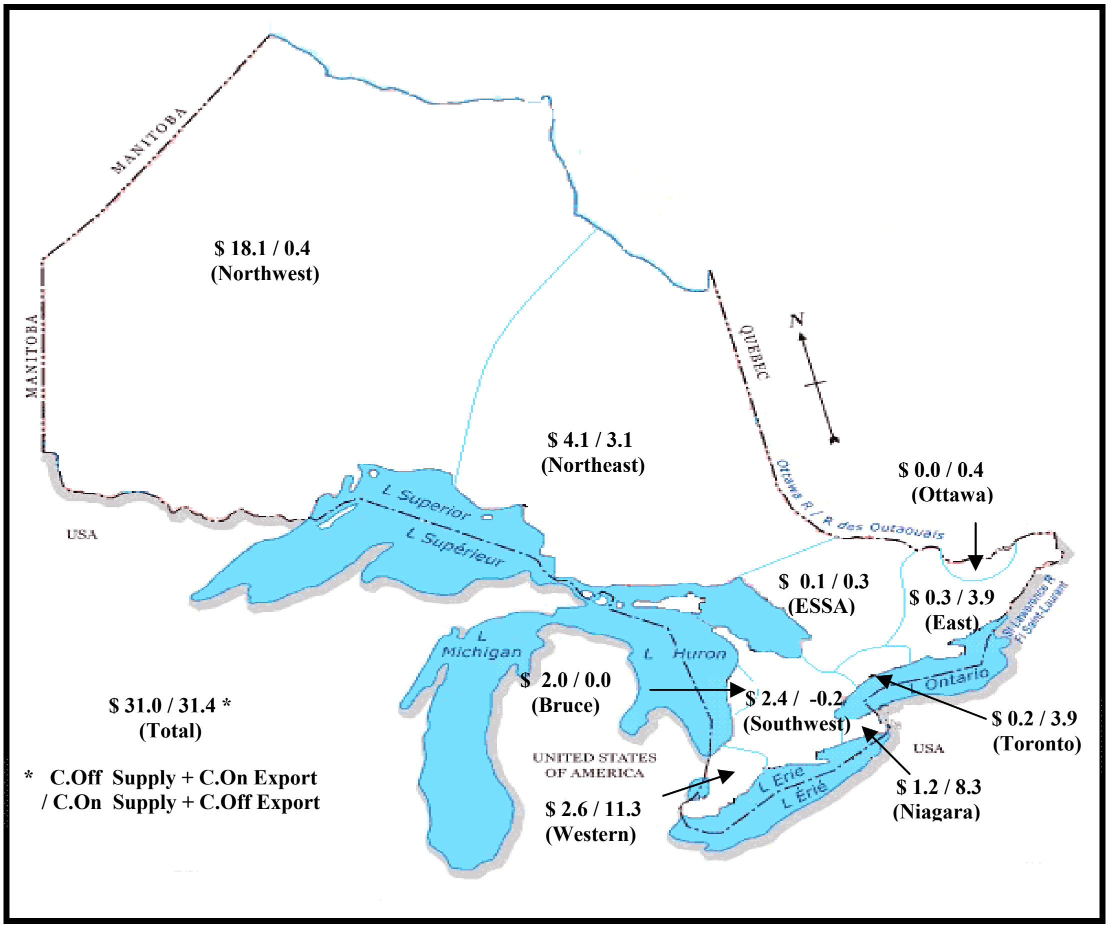


Table 1-22 presents the CMSC payments by internal zone over the 2006/2007 and 2007/2008 winter periods. Total CMSC payments were much larger this winter than for the same period a year ago, but somewhat less than the payments last summer. CMSC payments for constrained-off supply plus constrained-on exports have increased to $31 million, representing a year-over-year increase of $15 million (or 95 percent). Total CMSC for constrained-on supply plus constrained-off exports was also $31 million this winter, about $7 million or 30 percent higher than last winter.

Table 1-22: Total CMSC Payments by Internal Zone, November – April 2006/2007 & 2007/2008

($ millions)

Zone	Constrained-off Supply plus Constrained-on Exports			Constrained-on Supply plus Constrained-off Exports		
	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
Bruce	0.9	2.0	122	0.0	0.0	0
East	-0.1	0.3	(400)	4.6	3.9	(15)
Essa	0.2	0.1	(50)	0.1	0.3	200
Northeast	3.4	4.1	21	2.7	3.1	15
Niagara	1.9	1.2	(37)	4.4	8.3	89
Northwest	3.5	18.1	417	2.6	0.4	(85)
Ottawa	0.0	0.0	0	0.0	0.4	n/a
Southwest	2.4	2.4	0	0.2	-0.2	(200)
Toronto	0.3	0.2	(33)	2.2	3.9	77
Western	3.4	2.6	(24)	7.4	11.3	53
Total	15.9	31.0	95	24.2	31.4	30

The largest change in CMSC payments for constrained off supply or constrained on exports have been induced for much the same reasons as the changes in nodal prices, i.e. changing conditions in the Northwest. Compared with last winter, the increased supply and decreased load resulted in more congestion and bottled energy in the Northwest and led to an increase of just under $15 million (or 417 percent) in Northwest CMSC payments. This almost equalled the overall change for Ontario. Almost 80 percent of this increase was associated with CMSC payments to imports and exports. It is also notable that CMSC payments for constrained-off supply in the Bruce zone grew to $2 million (a 122 percent increase), as the result of several days when flow limits from the zone were reduced.

The largest changes in CMSC payments for constrained on supply or constrained off exports have occurred in the Western and Niagara zones, the connection points for the MISO and NYISO intertie zones. For each there was an increase of $4 million (53 percent increase in Western zone and 89 percent increase in Niagara zone) in CMSC payments compared to the previous winter. For the MISO intertie, this was the result of increased payments to imports and exports, which were increasing over the period as linked wheels increased, primarily from NYISO to MISO. For the NYISO intertie, increases were mostly due to constrained off exports, and to a lesser extent imports.

2.7 A Comparison of HOEP and Richview Nodal Price

This section reports summary statistics for comparing the HOEP and Richview nodal prices. Table 1-23 shows for the current and previous winter period average and median prices for each, and the number of hours these prices fell below $20/MWh or exceeded $200/MWh.[27]

Table 1-23: HOEP and Richview Price Summary Statistics, November – April 2006/2007 & 2007/2008 ($/MWh and Hours)

	HOEP		Richview Price		Richview - HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
Average ($/MWh)	48.91	49.16	55.66	57.96	6.75	8.8
Median ($/MWh)	39.90	42.32	44.30	45.49	4.40	3.17
Number of Hours Price < $20/MWh	189	261	246	286	57	25
Number of Hours Price > $200/MWh	1	2	47	66	46	64

The average Richview nodal price this winter of $57.96/MWh exceeded the HOEP by $8.80/MWh. This was larger than the $6.75/MWh difference relative to last winter, since HOEP increased $0.25/MWh for the period year-over-year, while the average Richview nodal price increased by $2.30/MWh. When comparing median prices for HOEP and the hourly Richview nodal price, we observe that all median values are much lower – ranging from approximately $7/MWh to $12/MWh lower than the corresponding averages. The table also shows that there is a smaller difference between the median values of the Richview nodal price and HOEP, and that this difference decreased from $4.40/MWh last winter to $3.17/MWh in the current period.

The greater difference in the average values is indicative of the greater volatility (potential for high prices) of Richview nodal prices compared with HOEP. Table 1-23

[27] As for the MCP in each interval, the Richview nodal price has been modified to +$2,000/MWh (or -$2,000/MWh) when the raw interval value was higher (or lower). Interval values were averaged to provide an hourly Richview price for comparison with the HOEP.

also shows the number of hours of high HOEP or Richview nodal prices (above $200/MWh). There were 1 or 2 high-priced HOEP hours in each winter period whereas Richview nodal prices exceeded $200/MWh for about 47 hours last winter and 66 hours this winter. (Corresponding to these, there were about 28 intervals with Richview prices of $2,000/MWh each winter, compared to no intervals of MCP at this level in either year.) The greater frequency of high Richview prices relative to high HOEP continues to reflect the greater sensitivity of the constrained schedule to disturbances, as the result of less energy available to the constrained schedule with the resulting steeper slope of the supply curve, and the one times versus three times ramp rates used in the corresponding constrained and unconstrained scheduling processes.

The number of hours with a low HOEP (<$20/MWh) increased from 189 hours last year to 261 hours this year. There were more hours with low Richview nodal prices each year, with these also increasing, from 246 hours last year to 286 hours this year. The higher incidence of low Richview prices demonstrates somewhat greater sensitivity of the constrained scheduling process to changes compared with the unconstrained process, most likely due to the one times versus three times ramp assumptions. However, with the low slope of the supply curve in this price range, the differences are not as significant as in the high price ranges.

2.8 Operating Reserve Prices

Table 1-24 presents average monthly operating reserve (OR) prices during the on-peak hours over the last two winter periods. Average on-peak prices were somewhat lower in the early part of the period, but rose later in the period to levels higher than the corresponding months in winter 2007. This was particularly so for April where prices rose to more than three times the previous year's averages for each class of operating reserve. Overall, the on-peak 10-minute spinning reserve (10S) price increased 21 percent, while the 10-minute non-spinning (10N) and 30 minute total reserve (30R) prices were about 50 percent higher, primarily because of the April results.

Table 1-24: Operating Reserve Prices On-Peak, November – April 2006/2007 & 2007/2008 ($/MWh)

	10S			10N			30R		
	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
November	3.99	2.15	(46.1)	1.86	1.96	5.4	1.86	1.74	(6.5)
December	2.83	2.21	(21.9)	2.32	1.77	(23.7)	2.32	1.77	(23.7)
January	4.72	4.77	1.1	3.9	4.59	17.7	3.88	4.49	15.7
February	6.07	5.97	(1.6)	4.75	5.28	11.2	4.61	5.08	10.2
March	2.61	3.96	51.7	1.78	3.35	88.2	1.73	3.18	83.8
April	2.99	9.01	201.3	2.44	8.96	267.2	2.41	8.44	250.2
Average	3.87	4.68	20.9	2.84	4.32	52.1	2.8	4.12	47.0

Table 1-25 provides similar data for off-peak hours. Overall off-peak reserve prices were 30 percent lower for 10S but 60 percent to 90 percent higher for 10N and 30R prices. Off-peak prices were lower in all months except April when 10S prices rose 57 percent and 10N and 30R prices were several times higher in the current period.

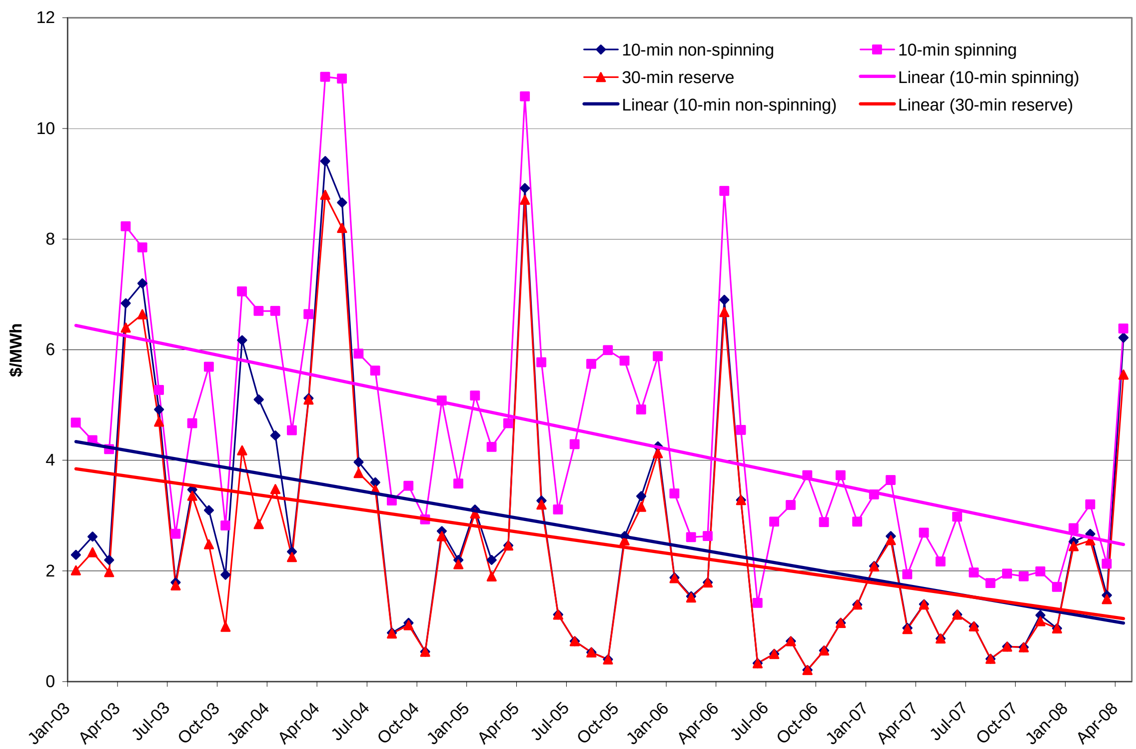
Table 1-25: Operating Reserve Prices Off-Peak, November – April 2006/2007 & 2007/2008 ($/MWh)

	10S			10N			30R		
	2006 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
November	3.48	1.84	(47.1)	0.29	0.48	65.5	0.29	0.47	62.1
December	2.93	1.37	(53.2)	0.76	0.40	(47.4)	0.76	0.40	(47.4)
January	2.18	0.98	(55.0)	0.47	0.69	46.8	0.47	0.62	31.9
February	1.43	0.84	(41.3)	0.69	0.44	(36.2)	0.69	0.40	(42.0)
March	1.34	0.87	(35.1)	0.25	0.33	32.0	0.25	0.33	32.0
April	2.47	3.87	56.7	0.65	3.61	455.4	0.65	2.78	327.7
Average	2.31	1.63	(29.5)	0.52	0.99	90.7	0.52	0.83	60.3

For all classes of reserve, both on-peak and off-peak, April prices were considerably higher this year. This was the result of the much greater availability of water during this current spring's runoff; with more water, hydroelectric plants provide energy reducing their ability to provide OR. Excluding April prices, 10S prices were little changed on average on-peak but dropped almost 50 percent off-peak, while 10N and 30R prices were on average about 15 percent higher on-peak but dropped nearly 10 percent off-peak.

Figure 1-15 shows monthly average OR prices since January 2003 by category of OR reserve. The long-term trend continues to indicate declining OR price levels since 2003, although OR prices have levelled off since the summer of 2006 and appear to be beginning to move back upwards in the most recent period.

Figure 1-15: Monthly Operating Reserve Prices by Class, January 2003 - April 2008 ($/MWh)



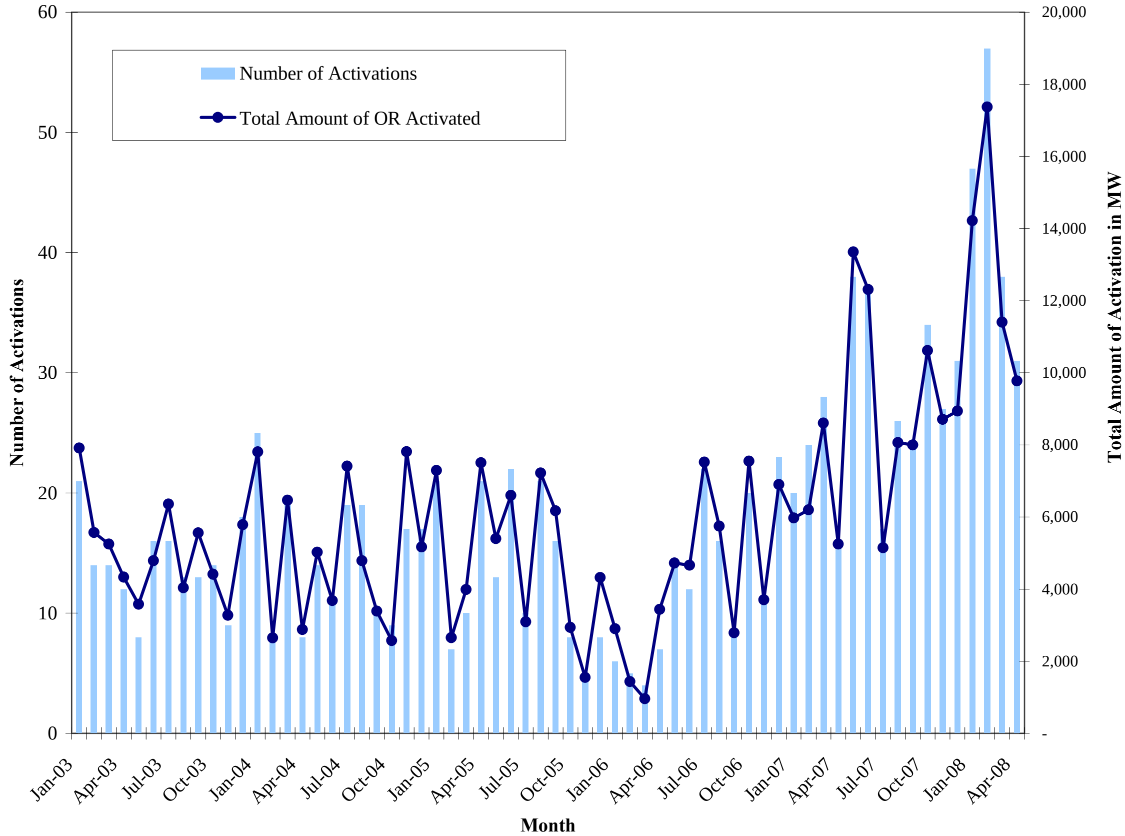
In the last report, the Panel identified an increasing trend in the frequency and magnitude of OR activations, specifically in the 2007 summer months.[28] Figure 1-16 plots the monthly frequency (in number of activations) and cumulative magnitude (in MW) of OR activations since January 2003. There appears to be a stark change in the level of activations between the 2003 to 2005 period and the subsequent period from 2006 to the present. In those first three years activations were relatively stable, with moderate monthly fluctuations. Since then activations have been trending upward with levels now more than double those in the 2003-2005 period.

[28]See the Panel's December 2007 Monitoring Report, pages 14-15.

The frequency and magnitude of OR activations have continued to increase during the 2007/2008 winter months. The previous monthly record total was 38 activations set in May 2007. It was surpassed in January and February 2008 by 47 and 57 activations respectively. Furthermore, the cumulative magnitude of OR activations reached a new monthly high in February 2008 at 17,374 MW, over 4,000 MW above the previous record set in May 2007.

The reasons behind the increasing trend in OR activations are discussed in Chapter 3. It appears the IESO modified its practices in late 2006 to activate OR in response to more frequent Area Control Error (ACE) deviations. ACE deviations might otherwise be dealt with by having more AGC available to respond or with one-time dispatches to increase generation from units not providing OR. These alternatives and their implications are further discussed in Chapter 3.

Figure 1-16: Monthly Operating Reserve Activations, January 2003 - April 2008 (Frequency and Cumulative MW)[29]



3. *Demand*

3.1 Aggregate Consumption

Table 1-26 compares total monthly energy demand and exports for the winter 2006/2007 and 2007/2008 months. In this table we have excluded exports which are part of a linked wheel since the level of linked wheels does not have a direct influence on market prices.[30]

Between November 2007 and April 2008, Ontario energy demand totalled 12.82 TWh per month, which represents a slight decrease of 0.02 TWh, or 0.2 percent compared to

[29] Cumulative MW represents the sum for a given month of amount of the capacity (MW) initially activated from operating reserve. The period of time for any activated MW is not captured in this measure.

[30] Since linked wheels are comprised of equal imports and exports, these net to zero for real-time scheduling, so have no influence on price. However, to the extent that linked wheels congest an interface and limit other imports or exports there could be an indirect impact on market price, potentially increasing or decreasing the final price.

the same period one year earlier. This was the result of colder temperatures and higher demand early this winter being offset by lower demand later in the period. As mentioned earlier, Ontario Demand increased by over 4 percent in December 2007 relative to 2006 with average temperature in the month being approximately 4 degrees lower in December 2007.

Table 1-26: Monthly Energy Demand, Market Schedule, November – April 2006/2007 & 2007/2008 (TWh)

	Ontario Demand*			Exports (excluding Linked Wheels)			Total Market Demand (excluding Linked Wheels)		
	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
November	12.22	12.39	1.4	0.53	0.96	81.1	12.75	13.35	4.7
December	12.92	13.45	4.1	0.66	1.29	95.5	13.58	14.74	8.5
January	13.79	13.63	(1.2)	0.78	1.77	126.9	14.57	15.40	5.7
February	13.04	12.90	(1.1)	1.19	1.48	24.4	14.23	14.38	1.1
March	13.21	13.01	(1.5)	0.91	1.22	34.1	14.12	14.23	0.8
April	11.86	11.52	(2.9)	1.16	1.75	50.9	13.02	13.27	1.9
Total	77.04	76.90	(0.2)	5.23	8.47	62	82.27	85.37	3.8
Average	12.84	12.82	(0.2)	0.87	1.41	62	13.71	14.23	3.8

* non-dispatchable loads plus dispatchable loads

Total exports (excluding linked wheels) increased 62 percent compared to last winter. Over the period, exports grew from 5.2 TWh last winter to 8.5 TWh this winter (excluding about 1.8 TWh of linked wheels this year). The largest monthly change was increase by 0.99 TWh or 127 percent in January 2008 relative to January 2007. The total market demand (excluding linked wheels) increased 3.1 TWh for the period relative to the previous winter, almost entirely the result of the change in exports.

3.2 Wholesale and LDC Consumption

Figure 1-17 plots the monthly total energy consumption separated by wholesale load and Local Distribution Companies (LDC's) since January 2003. Monthly total LDC consumption during the current winter period is very similar to totals observed in the previous winter months. The long-term trend in LDC consumption has been relatively flat since 2003. On the other hand, total monthly wholesale load continues to show a declining trend as was first noted in the Panel's December 2006 report.[31] Wholesale load was lower during the current winter period relative to any other winter period since 2003.

Figure 1-17: Monthly Total Energy Consumption, LDC vs. Wholesale Loads, January 2003 – April 2008 (GWh)

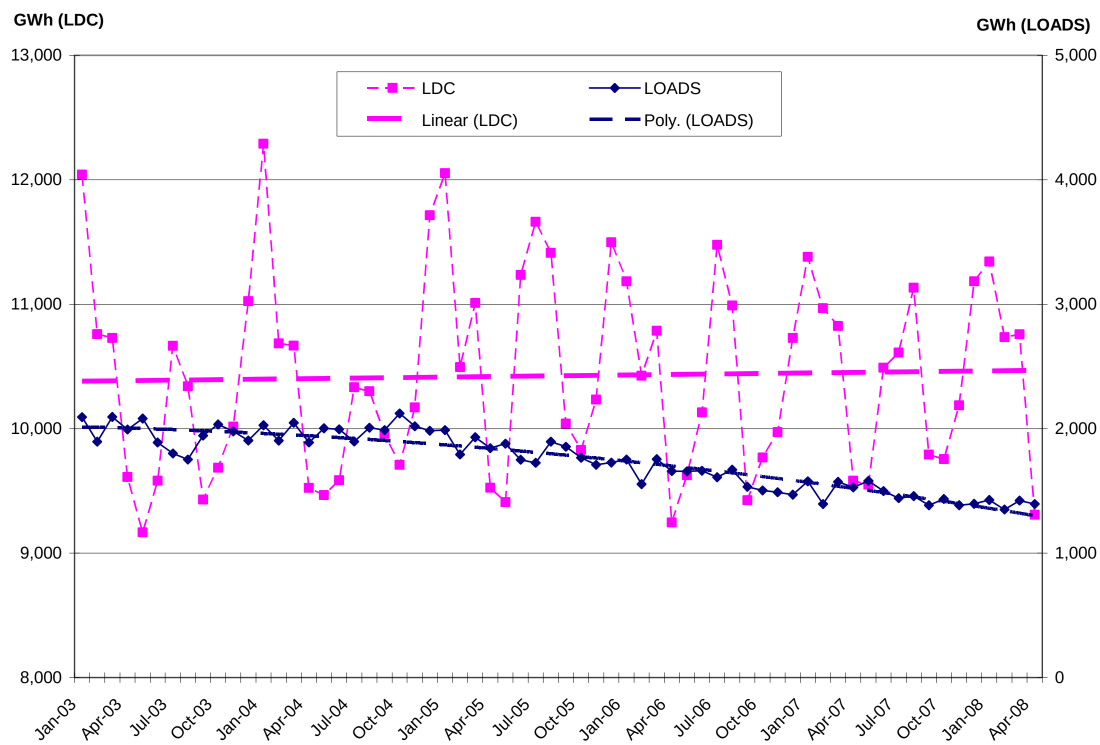
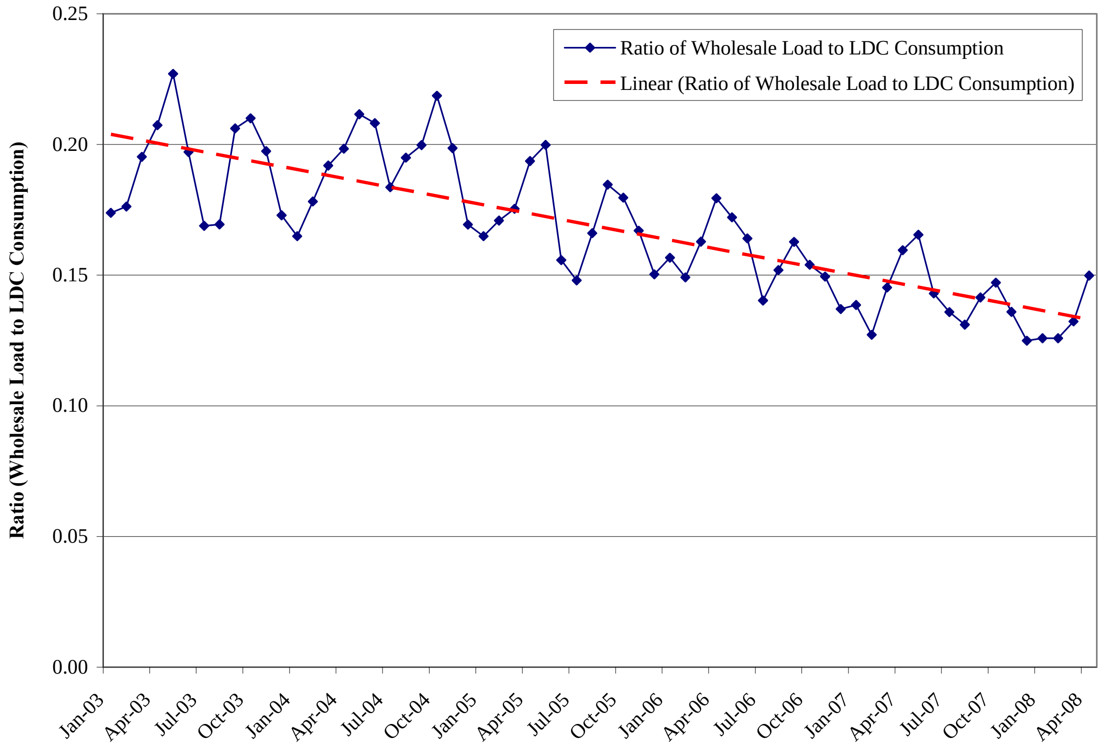


Figure 1-18 presents the wholesale load to LDC consumption as a ratio since January 2003 and reinforces the trend in declining wholesale load levels in Ontario. The ratio fell below 0.15:1 in all months during the current winter period, which is the lowest level since the market opened.

[31] See page 11 of the December 2006 MSP Monitoring Report available at: http://www.oeb.gov.on.ca/documents/msp/msp_report_final_20061222.pdf

Figure 1-18: Ratio of Wholesale Load to LDC Consumption, January 2003 – April 2008 (%)



4. *Supply*

4.1 Supply Conditions and the Supply Cushion

The supply of generating capacity remained relatively constant over the last winter period. Only 76 MW of new wind generation has been added to the Ontario market in the last 6 months although several large gas-fired units are under construction. Some smaller renewable generation embedded within LDCs, has also been added but these would be observed as reductions on LDC demand.

Improvements in supply relative to demand are measured by the supply cushion. This represents an important metric that reflects the excess amount of generation over load in Ontario on an hourly basis. Instances when the supply cushion falls below 10 percent represent relatively tight supply conditions while hours with a negative supply cushion means there is not enough internal generation available in the hour to meet Ontario demand. Tables 1-27 and 1-28 report the pre-dispatch total and real-time domestic supply cushion statistics for all months between November and April 2006/2007 and 2007/2008. The pre-dispatch average supply cushion improved this winter from 13.1 percent to 16.5 percent while the real-time average domestic supply cushion improved by 2 percent from 14.1 percent to 16.1 percent.

The improved supply cushion was also reflected in fewer hours with a supply cushion less than 10 percent and fewer hours with a negative supply cushion in both pre-dispatch and real-time. In pre-dispatch, the number of hours where the supply cushion fell below 10 percent dropped dramatically from 1,888 hours last winter to 1,262 this winter while the real-time domestic supply cushion fell below 10 percent 267 fewer hours this winter compared to last winter.

Table 1-27: Pre-Dispatch Total Supply Cushion, November – April 2006/2007 & 2007/2008 (% and Number of Hours under Certain Levels)

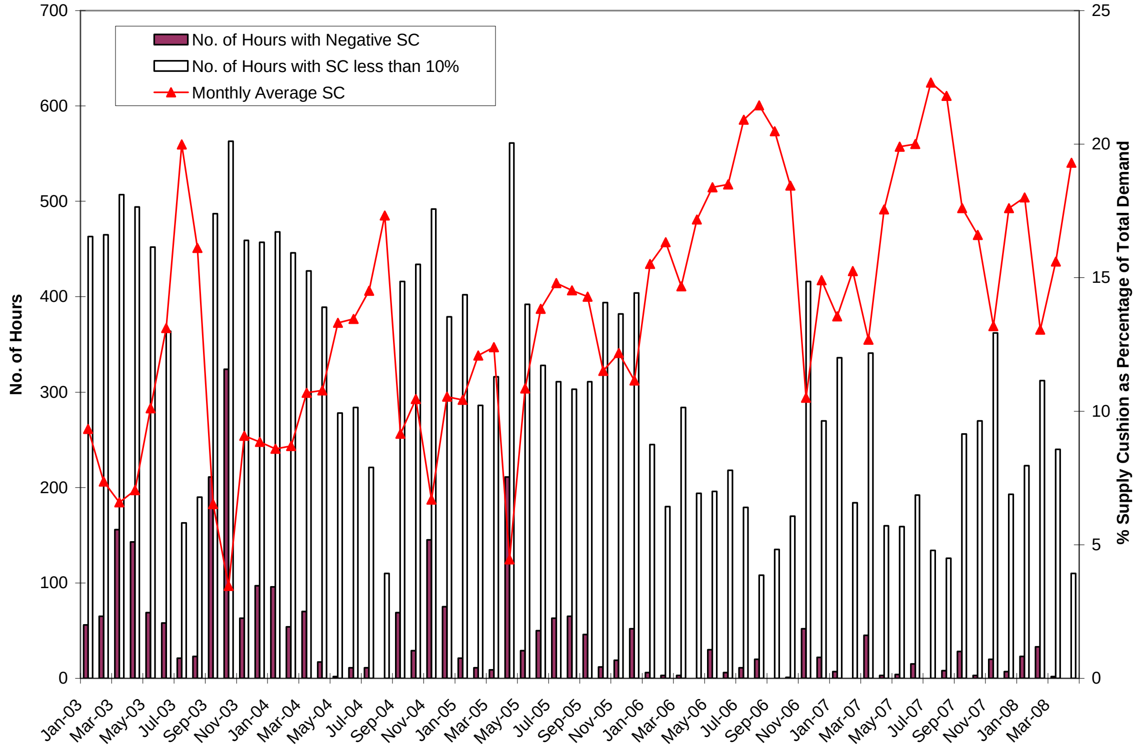
	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2006/ 2007	2007/ 2008	2006/ 2007	%	2007/ 2008	%	2006/ 2007	%	2007/ 2008	%
November	15.2	17.6	0	0.0	0	0.0	215	29.9	164	22.8
December	13.1	19.6	0	0.0	0	0.0	308	41.4	93	12.5
January	12.0	16.0	2	0.3	0	0.0	399	53.6	271	36.4
February	11.8	15.7	1	0.1	0	0.0	316	47.0	208	29.9
March	12.4	17.2	0	0.0	0	0.0	347	46.6	143	19.2
April	14.3	12.7	0	0.0	6	0.8	303	42.1	383	53.2
Total	13.1	16.5	3	0.1	6	0.1	1,888	43.5	1,262	28.9

Table 1-28: Real-time Domestic Supply Cushion,
November – April 2006/2007 & 2007/2008
(% and Number of Hours under Certain Levels)

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2006/ 2007	2007/ 2008	2006/ 2007	%	2007/ 2008	%	2006/ 2007	%	2007/ 2008	%
November	10.5	13.2	52	7.2	20	2.8	416	57.8	362	50.3
December	14.9	17.6	22	3.0	7	0.9	270	36.3	193	25.9
January	13.6	18	7	0.9	23	3.1	336	45.2	223	30.0
February	15.2	13.1	0	0.0	33	4.7	184	27.4	312	44.8
March	12.7	15.6	45	6.0	2	0.3	341	45.8	240	32.3
April	17.6	19.3	3	0.4	0	0.0	160	22.2	110	15.3
Total	14.1	16.1	129	2.97	85	1.9	1,707	39.3	1,440	33.0

Figure 1-19 plots the average monthly real-time domestic supply cushion along with the total number of hours with a supply cushion less than 10 percent and a negative supply cushion.

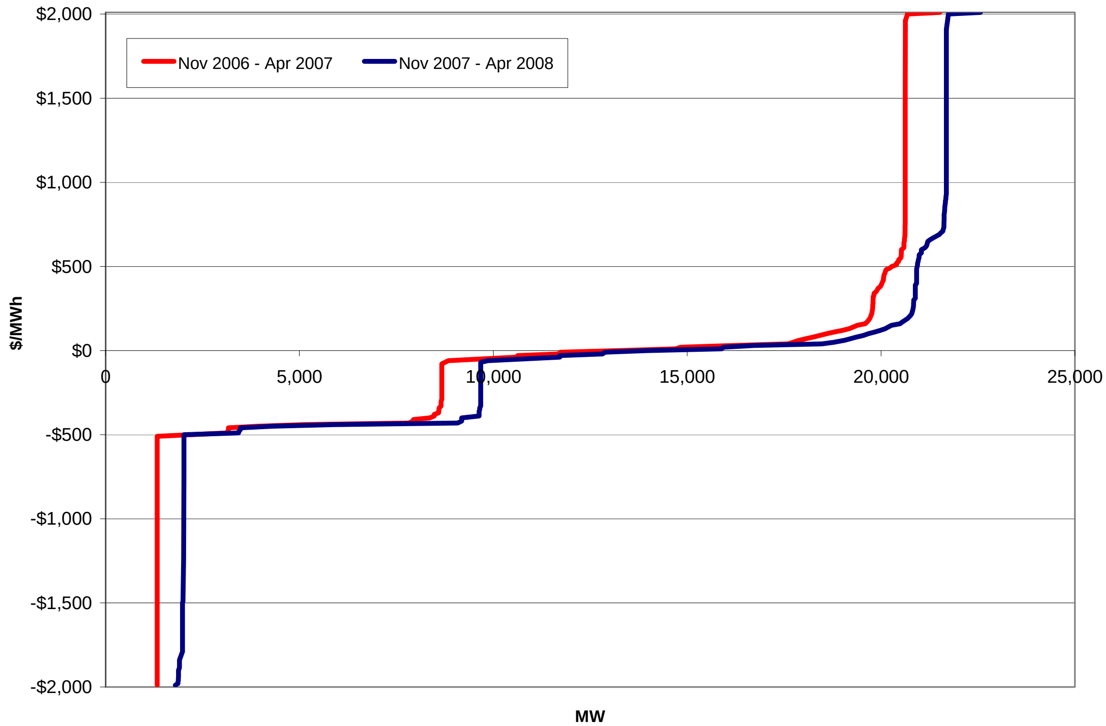
Figure 1-19: Monthly Real-time Domestic Supply Cushion Statistics, January 2003 – April 2008 (% and Number of Hours under Certain Levels)



4.2 Supply Curves

Figure 1-20 shows the average domestic offer curve for the last two November to April periods. The offer stack has shifted to the right in 2007/2008, which indicates improved baseload supply conditions.

Figure 1-20: Average Domestic Offer Curve, November – April 2006/2007 & 2007/2008 ($/MWh)



A large portion of Ontario's energy production is supplied by baseload generation. These include nuclear, baseload hydro, and self-scheduling generating units and these units are typically price-takers. Table 1-29 presents average monthly hourly market schedules by baseload generation category along with average hourly Ontario demand.[32] Overall, total average hourly baseload supply increased slightly from 12.3 GW last winter to 12.5 GW this winter (1.6 percent). Average hourly nuclear generation increased this winter compared to last winter by 0.4 GW (4.4 percent), which more than offsets small observed declines in baseload hydro by 0.1 GW (4.5 percent) and self scheduling supply by 0.1 MW (or 10 percent). Finally, baseload supply accounted for approximately 73 percent of Ontario Demand over the latest winter period as average hourly Ontario demand was 17.1 GW.

[32] See Appendix Tables A-13 and A-14 for average hourly supply separated by off-peak and on-peak hours respectively

Table 1-29: Average Hourly Market Schedules by Baseload Generation Type and Ontario Demand, November – April 2006/2007 & 2007/2008 (GW)

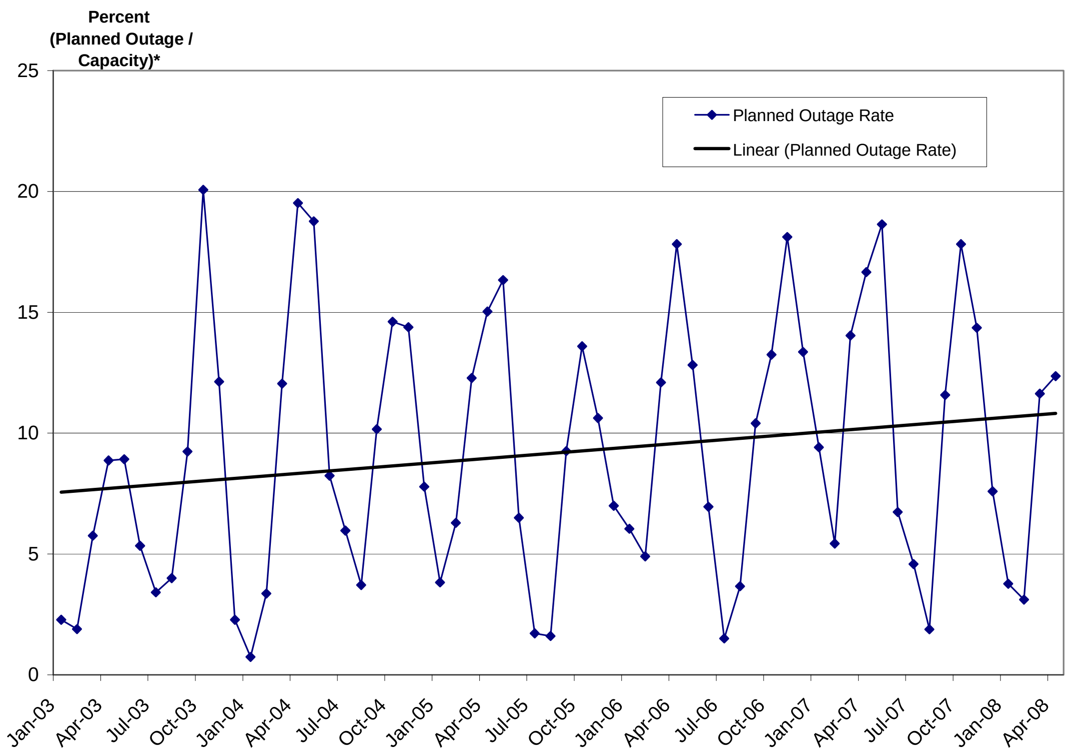
	Nuclear		Baseload Hydro		Self-Scheduling Supply		Total Baseload Supply		Ontario Demand (Non-Dispatchable Load)	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
November	8.2	8.5	2.1	2.1	1.0	0.9	11.3	11.5	16.4	16.7
December	9.5	10.3	2.3	1.9	1.0	0.9	12.8	13.1	16.9	17.6
January	9.2	11.0	2.2	1.9	1.0	0.9	12.4	13.8	18.0	17.8
February	9.7	10.0	2.2	2.1	1.0	0.9	12.9	13	18.9	18.0
March	9.0	8.7	2.2	2.3	1.0	0.8	12.2	11.8	17.2	16.9
April	8.9	8.6	2.2	2.3	0.9	0.8	12.0	11.7	15.9	15.4
Average	9.1	9.5	2.2	2.1	1.0	0.9	12.3	12.5	17.2	17.1

4.3 Outages

4.3.1 Planned Outages

Figure 1-21 plots the monthly planned outages as a percentage of capacity. Planned outage rates are highly seasonal as Ontario generators typically take outages during low demand periods in the spring and fall months. Planned outage rates over the recent winter period appear in line with historical rates although the planned outage rate in April 2008 was lower than any other April since 2003. There has been a small upward trend since 2003 which is consistent with the gradual ageing of the fleet.

Figure 1-21: Planned Outages Relative to Capacity, January 2003 – April 2008 (% of Capacity)

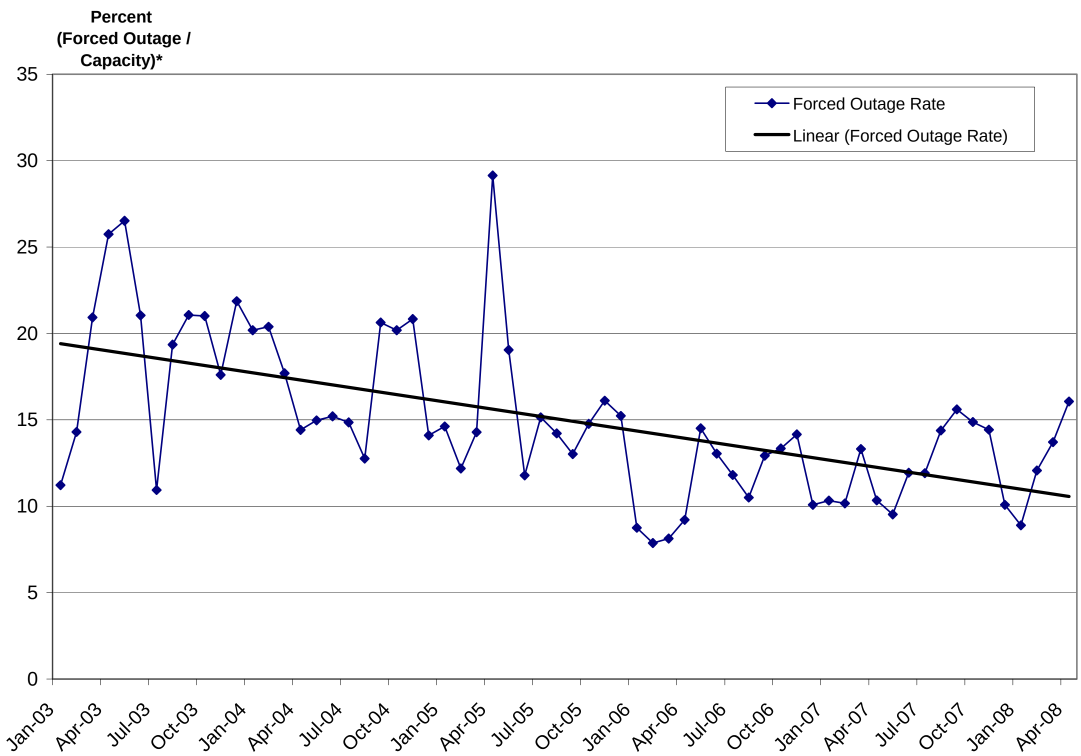


**Includes Nuclear, Coal, and Oil/Gas units.*

4.3.2 Forced Outages

Given that forced outages are unexpected, they do not exhibit the same level of seasonality as planned outage rates. Figure 1-22 plots monthly forced outage rates since January 2003. Since the end of 2005, forced outage rates have fluctuated between 10 percent and 15 percent with some exceptions including April 2008 where the forced outage rate climbed above 16 percent which represents the highest level since November 2005.

Figure 1-22: Forced Outages Relative to Capacity,*
January 2003 – April 2008
(% of Capacity)

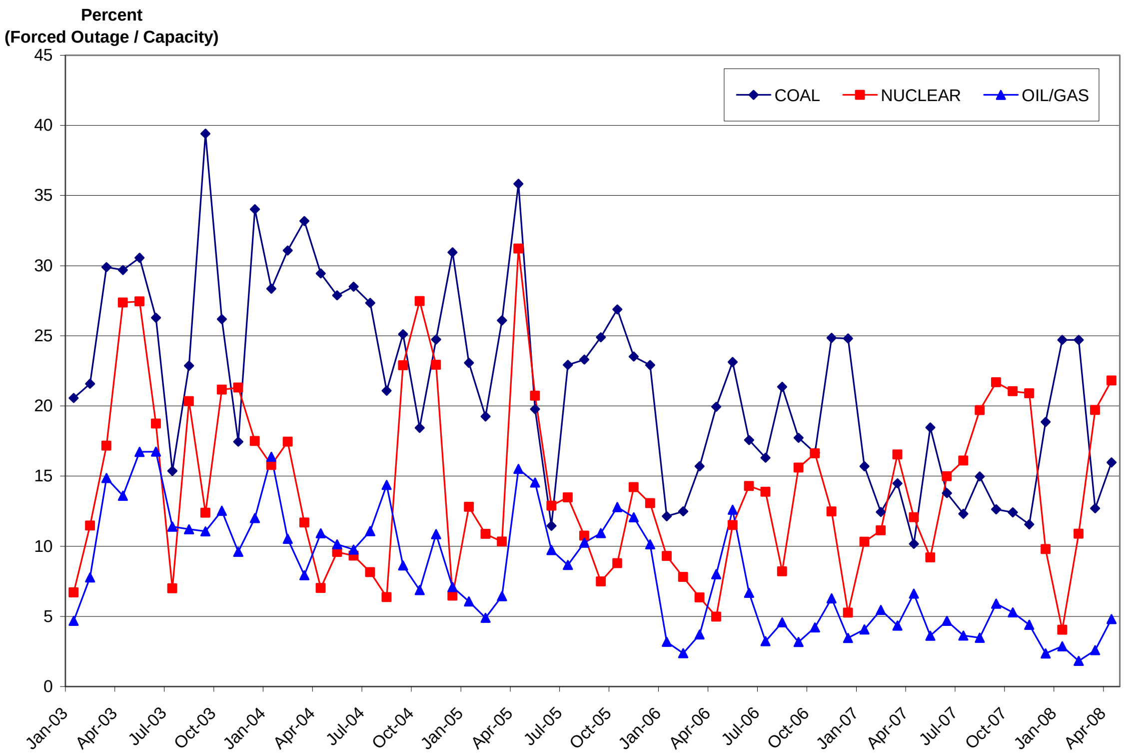


** Includes Nuclear, Coal, and Oil/Gas units.*

Figure 1-23 separates nuclear, coal, and oil and gas forced outage rates since January 2003. It is apparent that the high April 2008 forced outage rate was driven by forced outages to nuclear generators. The nuclear forced outage rate was 21.8 percent in April representing the highest monthly rate since April 2005. The monthly forced outage rate for coal was relatively high in January and February at slightly less than 25 percent but remained relatively low at less than 16 percent for the remaining 2007/2008 winter months. The long-term trend in coal forced outages appears to be improving since 2003 while the trend in nuclear forced outages is relatively flat.[33] Finally, oil and gas forced outage rates have fluctuated around 5 percent of capacity since the middle of 2006.

[33] Only part of which is due to shutting down the Lakeview plant in April 2005.

Figure 1-23: Forced Outages Relative to Total Capacity by Fuel Type, January 2003 – April 2008 (% of Capacity)



4.4 Changes in Fuel Prices

Tables 1-30 and 1-31 present the average monthly coal and natural gas prices for the last two winter periods. In general, coal prices continuously increased during the 2007/2008 winter months while gas prices trended upward during the period but on average remained unchanged relative to a year ago. When generators face higher fuel prices, the cost is factored into their offers and market clearing prices tend to increase, holding all else constant.

4.4.1 <u>Coal Prices</u>

Coal prices, represented by the NYMEX OTC Central Appalachian (CAPP) and the Powder River Basin (PRB) price have been steadily increasing in 2007 and 2008. Table 1-30 shows that over the latest winter period, the monthly average Central Appalachian coal price increased from $2.08/MMBtu in November 2007 to

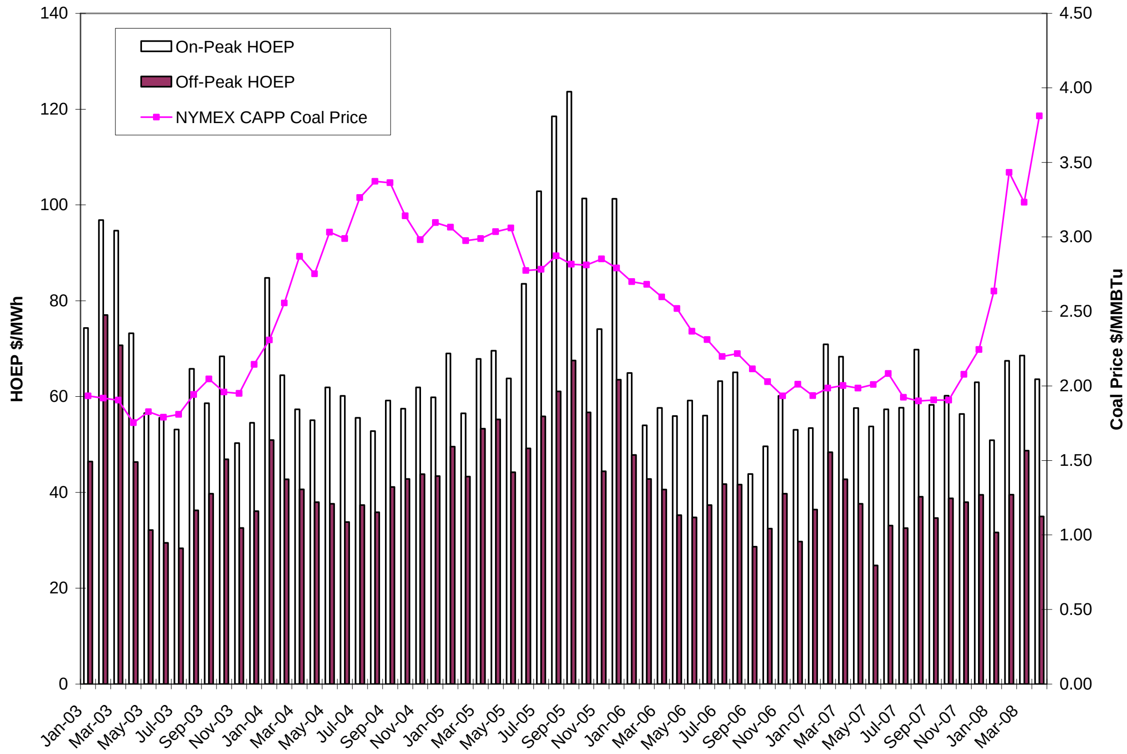
$3.81/MMBtu in April 2008, which represents an increase of 83 percent. Additionally, the average CAPP coal price increased by 47 percent this winter period relative to last winter. Similarly, PRB coal prices also appreciated during the latest winter period and relative to last winter although not as dramatically. Between November 2007 and April 2008, the PRB spot price increased from $0.60/MMBtu to $0.81/MMBtu (or 35 percent) and increased by 16.3 percent relative to last winter. Driving the coal prices higher is a global shortage of utility coal that has led to increased U.S. coal exports (made more attractive by a weaker US dollar compared with foreign currencies) and a severe winter in China that caused it to halt its coal exports.

Table 1-30: Average Monthly Coal Prices by Type, November – April 2006/2007 & 2007/2008 ($CDN/MMBtu)

	NYMEX OTC Central Appalachian			Powder River Basin		
	2006/ 2007	2006/ 2007	2006/ 2007	2006/ 2007	2007/ 2008	% Increase
November	1.93	2.08	7.8	0.66	0.60	(9.1)
December	2.01	2.24	11.4	0.65	0.64	(1.5)
January	1.93	2.64	36.8	0.61	0.68	11.5
February	1.99	3.43	72.4	0.59	0.75	27.1
March	2.00	3.23	61.5	0.59	0.80	35.6
April	1.98	3.81	92.4	0.58	0.81	39.7
Average	1.98	2.91	47.0	0.61	0.71	16.3

Figure 1-24 plots the monthly average CAPP coal price along with the on-peak and off-peak HOEP prices. Movements in the coal prices do not appear to coincide with movements in the HOEP. This is especially apparent given the dramatic increase in the price of Central Appalachian coal during the recent winter period and little increase in the HOEP.

Figure 1-24: NYMEX OTC Central Appalachian Coal Price and HOEP, January 2003 – April 2008 ($/MWh and $/MMBtu)



4.4.2 Natural Gas Prices

Natural gas prices, measured by the Henry Hub Spot and Dawn Daily Gas prices are presented in Table 1-31. For both types, prices trended upward during the latest winter but on average remained steady. Over the 2007/2008 winter months, the Henry Hub price significantly increased from $6.76/MMBtu in November 2007 to $10.28/MMBtu in April 2008, an increase of more than 50 percent during the period. Relative to the same months one year ago, the monthly average Henry price was lower for three of the six months and the average price over the period was $8.35/MMBtu, the same as the previous year. Gas prices have been rising recently as the result of pressures from increasing world oil prices, a drop-off in LNG imports to the U.S. and the drawdown in storage to the lowest levels in 4 years.[34]

[34] Energy Information Administration, US DOE; EIA Short-Term Energy and Summer Fuels Outlook, April 8, 2008 Release, http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr08.pdf p.8. "The Henry Hub spot price averaged $9.74 Mcf in March, nearly $1.00 per Mcf more than the average spot price in February. This was the first month since December 2005 that Henry Hub spot

In general, monthly Dawn prices are only slightly above the reported Henry Hub prices, small differences are reflective of transportation constraints. The Dawn gas price for the recent winter period was $8.75/MMBtu, which is roughly unchanged from the average price in the previous winter period. However, prices have increased during the recent winter period climbed from $7.21/MMBtu to $10.84/MMBtu, an increase of 50 percent.

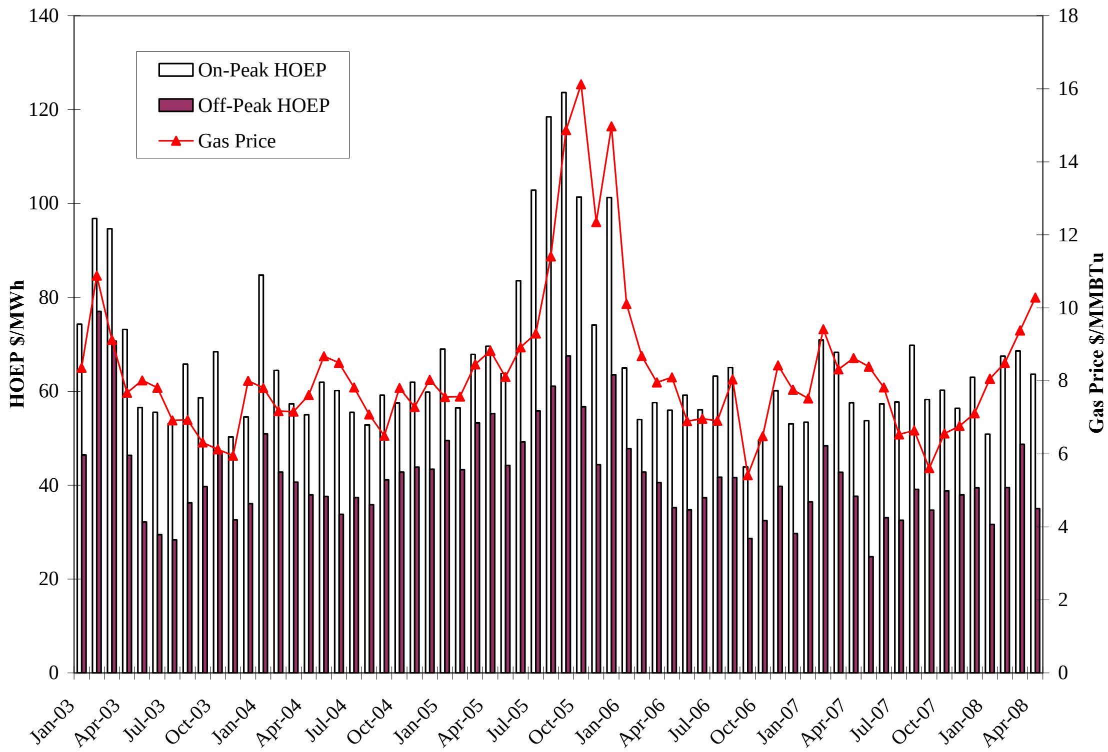
Table 1-31: Average Monthly Natural Gas Prices by Type, November – April 2006/2007 & 2007/2008 ($CDN/MMBtu)

	Henry Hub Spot Price			Dawn Daily Gas Price		
	2006/ 2007	2007/ 2008	% Increase	2006/ 2007	2007/ 2008	% Increase
November	8.43	6.76	(19.8)	8.79	7.21	(18.0)
December	7.76	7.11	(8.4)	8.16	7.56	(7.4)
January	7.52	8.06	7.2	7.72	8.25	6.9
February	9.42	8.50	(9.8)	9.05	8.73	(3.5)
March	8.31	9.38	12.9	8.68	9.89	13.9
April	8.63	10.28	19.1	8.98	10.84	20.7
Average	8.35	8.35	0.0	8.56	8.75	2.2

Figure 1-25 plots the monthly average Henry Hub spot price along with the on-peak and off-peak HOEP prices. Movements in the gas price appear to roughly coincide with movements in the HOEP, which contrasts the relationship between coal prices and HOEP.

prices averaged more than $9 per Mcf. The recent upward price shift reflects a number of factors, including the drop off in LNG imports compared to year-ago levels, high oil prices, and the drawdown in storage to the lowest levels in 4 years. As seasonal demand wanes, spot prices are expected to decline before they begin to rise again toward a winter peak. On an annual basis, the Henry Hub spot price is expected to average about $8.59 per Mcf in 2008 and $8.32 per Mcf in 2009."

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP, January 2003 – April 2008 ($/MWh and $/MMBtu)

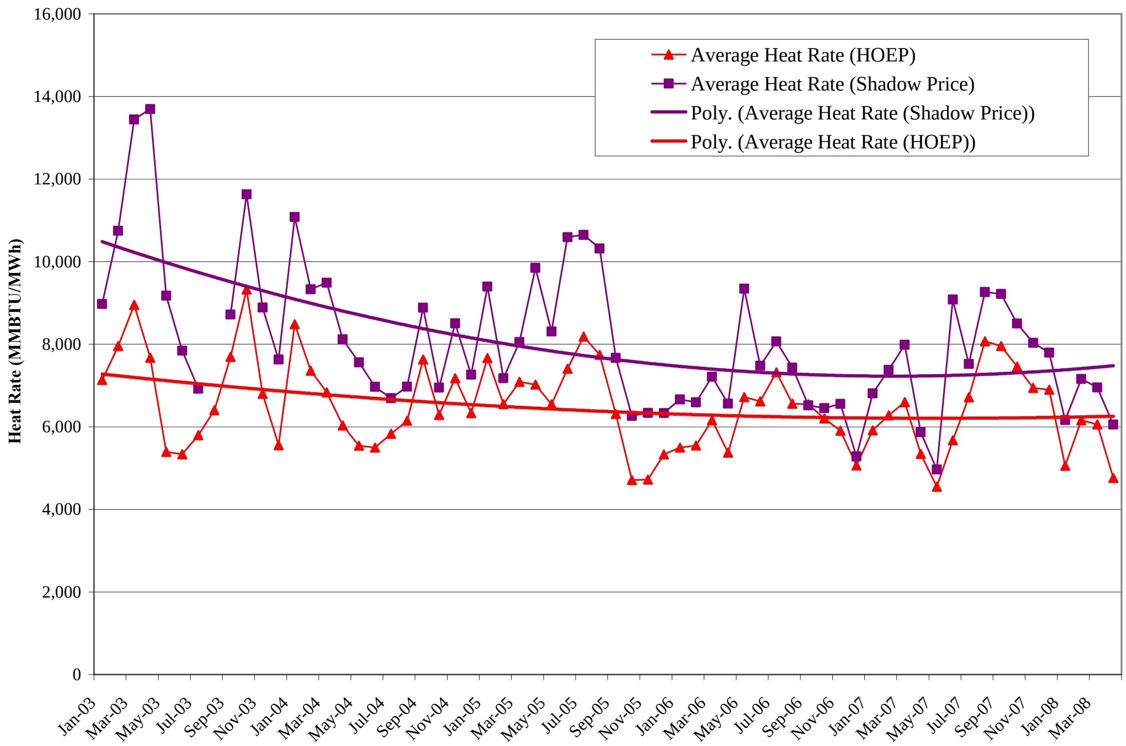


4.4.3 <u>Heat Rate</u>

Figure 1-26 plots the estimated system heat rate since January 2003. As described in the previous MSP Monitoring Report, the system heat rate is calculated by taking the average HOEP or Richview Shadow Price in a month divided by the average natural gas price measured by the Henry Hub spot price converted to Canadian dollars.[35] The system heat rate analysis assumes that gas-fired generators are always marginal.[36] Aside from 2003, the HOEP levels have been too low to allow a typical gas-fired generator with a standard heat rate of 7,000 MMBtu to recover its costs without a contract with the exception of three months in 2007 (August, September, and October).

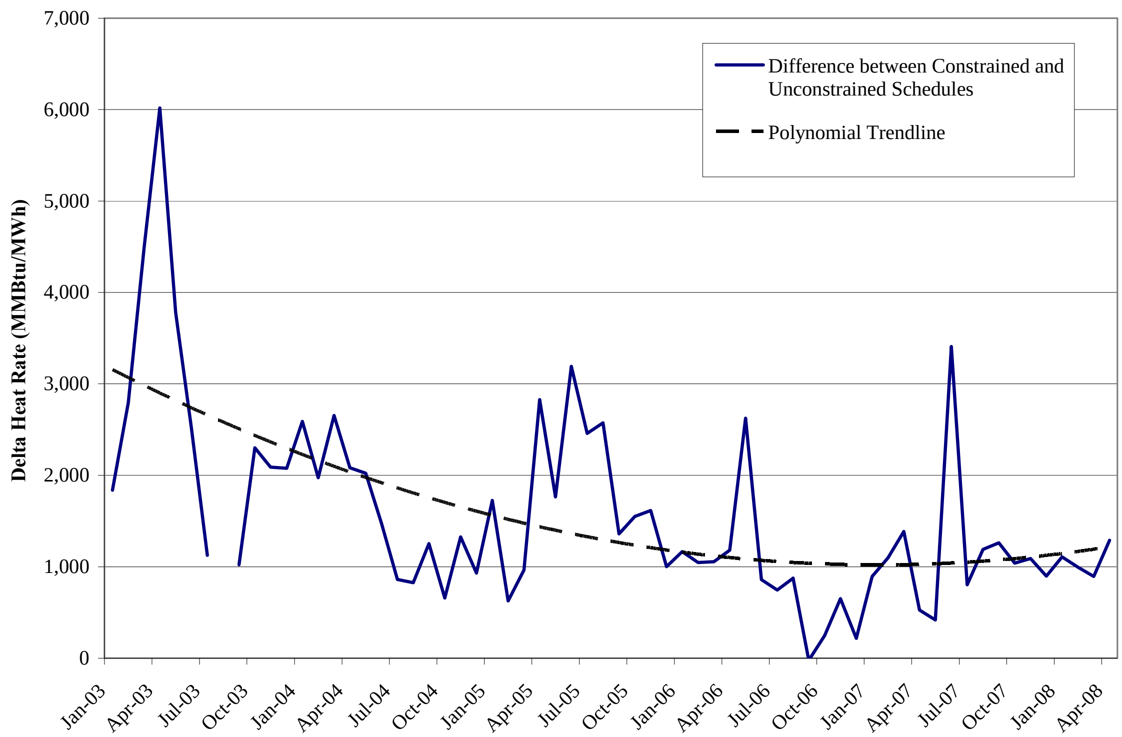
[35] See the Panel's December 2007 MSP Monitoring Report, page 59-61.
[36] See the Panel's December 2007 MSP Monitoring Report, page 59 for further explanation on this assumption.

Figure 1-26: Estimated Monthly Average System Heat Rate using HOEP and Shadow Price, January 2003 – April 2008 (MMBtu/MWh)



Generally, the system heat rate using the Richview shadow price is higher than when using the HOEP. Figure 1-27 presents the gap (or delta) between the monthly estimated heat rate using both prices. Over the last winter period, the delta remained relatively constant at around 1,000 MMBtu.

Figure 1-27: Heat Rate Differential Between Constrained less Unconstrained Schedules, January 2003 - April 2008 (MMBtu/MWh)



4.5 Net Revenue Analysis

Similar to previous MSP reports, we use a standardized model developed by the Federal Energy Regulatory Commission of the United States (FERC) to help assess whether there are sufficient revenues for a new gas-fired generator in Ontario to make an adequate rate of return on an investment with typical characteristics.[37, 38]

Table 1-32 reports net revenue estimates for the past five annual May to April periods. Estimated net revenues for the more efficient combined-cycle generator have fluctuated between $47,000/MWh and $73,000/MWh with average net revenue for the last five annual periods of $63,291/MWh. Net revenues for the less efficient combustion turbine

[37] See the Panel's December 2007 MSP Monitoring Report, page 62-63 for the most recent annual results based on the November-October periods.
[38] For details, see FERC 2004 State of the Markets Report, Docket MO05-4-000.

generator are much lower on average at $15,392/MWh. However, FERC estimates that a combined cycle generator would require approximately $US80,000-90,000/MW-year and a combustion turbine unit $US60,000-70,000/MW-year in order to meet debt and equity requirements.

Table 1-32: Yearly Estimated Net Revenue Analysis for Two Generator Types, May 2003 – April 2008 ($/MWh)

Generator Type	7,000 Btu/KWh of Combined-cycle with variable O&M cost of $1.10/MWh	10,500 Btu/KWh of Combustion turbine with variable O&M cost of $3.30/MWh
May 2003 – Apr 2004	73,349	17,609
May 2004 – Apr 2005	47,628	8,584
May 2005 – Apr 2006	83,252	24,827
May 2006 – Apr 2007	49,992	9,844
May 2007 – Apr 2008	62,236	16,098
Average	63,291	15,392

The results indicate that on average, market revenues derived from the HOEP continue to be insufficient to attract new gas-fired generation from entering the Ontario electricity market. Recent net revenue estimates suggest that subsidies and guarantees remain a requirement to increase generating capacity in the province.

5. *Imports and Exports*

5.1 Overview

Ontario has gradually evolved from being a net importer in the early years after market opening to a net exporter of energy, especially during the off-peak hours. Table 1-33 shows monthly net exports for the November – April 2006/2007 and 2007/2008 periods divided into off-peak, on-peak, and all hours. Total net exports increased by 1,819 GWh or 80 percent during the winter 2007/2008 months relative to 2006/2007 with about half the increase in each of the on-peak and off-peak hours. The rise in net exports was most noticeably higher in January and March 2008. In those two months, total net exports were 1.2 TWh higher, representing a tripling of net exports compared with the same two months one year ago. The increase in total net exports was the result of total exports for the period increasing by 5.1 TWh relative to last winter (from 5.2 to 10.3 TWh), which is larger than the year over year increase of 3.2 TWh in total imports (from 3.0 to 6.2 TWh). About 1.8 TWh of both the import and export increases is due to linked wheels (see section 5.4.3).

Table 1-33: Net Exports (Imports) from Ontario On-peak and Off-peak, November – April 2006/2007 & 2007/2008 (GWh)

	Off-Peak			On-Peak			Total		
	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
November	(35.0)	79.7	327.7	(200.4)	(114.5)	42.9	(235.4)	(34.8)	85.2
December	263.8	241.4	(8.5)	(32.2)	69.7	316.5	231.6	311.1	34.3
January	224.7	672.4	199.2	117.6	424.6	261.1	342.3	1,097.0	220.5
February	475.6	541.0	13.8	309.1	319.1	3.2	784.7	860.2	9.6
March	251.0	478.2	90.5	2.2	209.9	9,440.9	253.2	688.1	171.8
April	532.3	614.6	15.5	355.2	546.8	53.9	887.4	1,161.4	30.9
Total	1,712.4	2,627.3	53.4	551.5	1,455.6	164.0	2,263.9	4,083.0	80.4
Average	285.4	437.9	53.4	91.9	242.6	164.0	377.3	680.5	80.4

Figure 1-28 shows monthly total net exports from Ontario since January 2003. The trend has been toward increasing net exports, with the recent January quantity being the largest recorded both off-peak and on-peak.

Figure 1-28: Net Exports (Imports) from Ontario, On-peak and Off-peak, January 2003 – April 2008 (GWh)

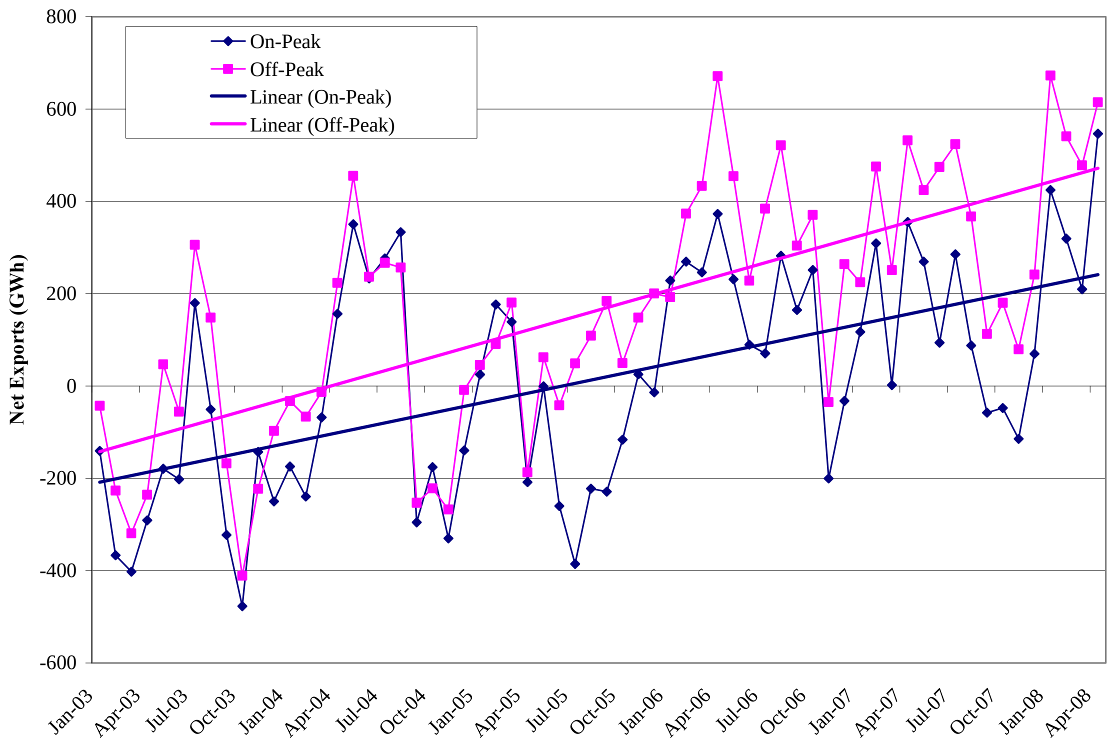


Table 1-34 presents monthly total net exports by neighbouring jurisdiction for the last two winter periods. The rise in net exports was accompanied by a shift from MISO (at the Michigan intertie) being a net importer to Ontario during the 2007 winter months to being a net exporter in 2008. The shift first appeared in January 2008 and has persisted in each subsequent month as net exports at Michigan totaled 1,303 GWh over the latest winter period compared to net exports of -808 GWh one year earlier. This is related to the large increase in this period in linked wheels that flow in from New York and out to Michigan. For the winter period, if the 1,750 GWh of linked wheels exported at Michigan were removed, the period would have exhibited a net exports of -500 GWh at the Michigan intertie, comparable with a net exports of -808 GWh last winter.

Table 1-34: Net Exports (Imports) from Ontario by Neighbouring Jurisdiction November – April 2006/2007 & 2007/2008 (GWh)

	Manitoba		Michigan		Minnesota		New York		Quebec		Total	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	37	(117)	(578)	(624)	(28)	(16)	372	733	(38)	(11)	(235)	(35)
December	23	(107)	(119)	(442)	(17)	(17)	442	791	(97)	87	232	311
January	13	(79)	(167)	604	(24)	23	519	550	1	(1)	342	1,097
February	20	(61)	3	519	(16)	5	833	502	(56)	(105)	785	860
March	(28)	(90)	(264)	489	(33)	3	619	293	(42)	(6)	253	688
April	13	(87)	317	758	(6)	(8)	616	495	(54)	3	887	1,161
Total	78	(542)	(808)	1,303	(122)	(10)	3,402	3,364	(285)	(32)	2,264	4,083

The reason for the rise in total net exports is not simple to track and cannot be fully explained by changes in HOEP or changes in relative prices between Ontario and other markets (see section 5.4). We observe that exports to New York rose in most months (except February) both on-peak and off-peak, with the period total rising 2.2 TWh (60 percent), but after accounting for imports from New York, the net export to this neighbouring market was almost unchanged over the period (in November and December net exports to New York had increased year-over-year but this reversed as the result of the increased wheeling from New York to Michigan since January).[39] We do not have a good understanding why exports to New York increased from January onward while at the same time wheeling from New York also increased. However, we do note that some traders may be attracted to export to New York when Ontario prices are lower, and others at the same time may be attracted by price differences between New York and PJM, which can induce wheeling through Ontario and MISO.

5.2 Congestion

Increases in the volume of intertie transactions have resulted in increasing levels of congestion at the interties.[40] The higher levels of congestion this winter were largely the result of transmission limitations at the interties, coupled with loop flows and the higher

[39] Detailed import and export statistics by neighbouring jurisdiction are presented in Appendix Tables A-28 and A-29.
[40] In this section we focus on intertie congestion which occurs in the unconstrained schedule and leads to intertie prices diverging from the uniform price. This is different from congestion in the constrained schedule at interfaces internal to Ontario, which can lead to imports or exports being constrained on or off and receiving CMSC payments.

levels of imports and exports. Note that although a wheeling transaction does not change net exports, it can affect congestion on either the import or export leg.

5.2.1 Import Congestion

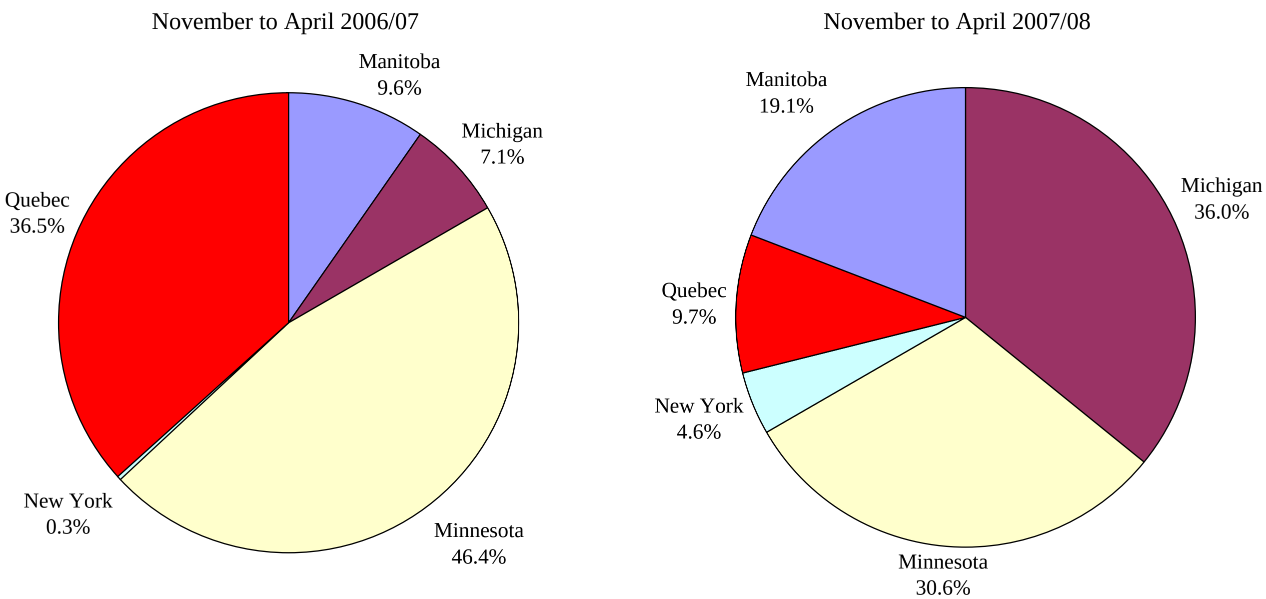
Tables 1-35 reports the number of occurrences of import congestion by month and intertie for the November to April 2006/2007 and 2007/2008 winter periods. Total import congestion frequency increased period to period from 364 hours in 2006/2007 to 393 hours in 2007/2008 representing an increase of almost 8 percent. The Michigan intertie experienced the largest increase in hours experiencing import congestion by 119 hours. However, this was offset by less import congestion at other interties, primarily Quebec and Minnesota.

Table 1-35: Import Congestion in the Market Schedule by Intertie, November – April 2006/2007 & 2007/2008 (Number of Hours)

	NY to ON		MI to ON		MB to ON		MN to ON		QC to ON		Total	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	0	0	26	80	0	5	52	25	52	9	130	119
December	1	0	0	56	0	38	0	6	13	6	14	106
January	0	12	0	0	7	0	0	19	1	9	8	40
February	0	2	0	9	7	17	61	55	16	4	84	87
March	0	4	0	0	19	9	56	12	33	3	108	28
April	0	0	0	0	2	6		3	18	4	20	13
Total	1	18	26	145	35	75	169	120	133	35	364	393

Figures 1-29 compares the percentage of import congested hours by intertie over the last two winter periods. As a percentage of all congested hours, import congestion from Michigan increased from 7.1 percent to 36.0 percent while congested hours at Quebec fell from 36.5 percent in 2006/2007 to 9.7 percent in 2007/2008.

Figure 1-29: Percentage of Import Congestion in the Market Schedule by Intertie, November 2006/2007 – April 2007/2008 (Percentage of Congested Hours)



5.2.2 Export Congestion

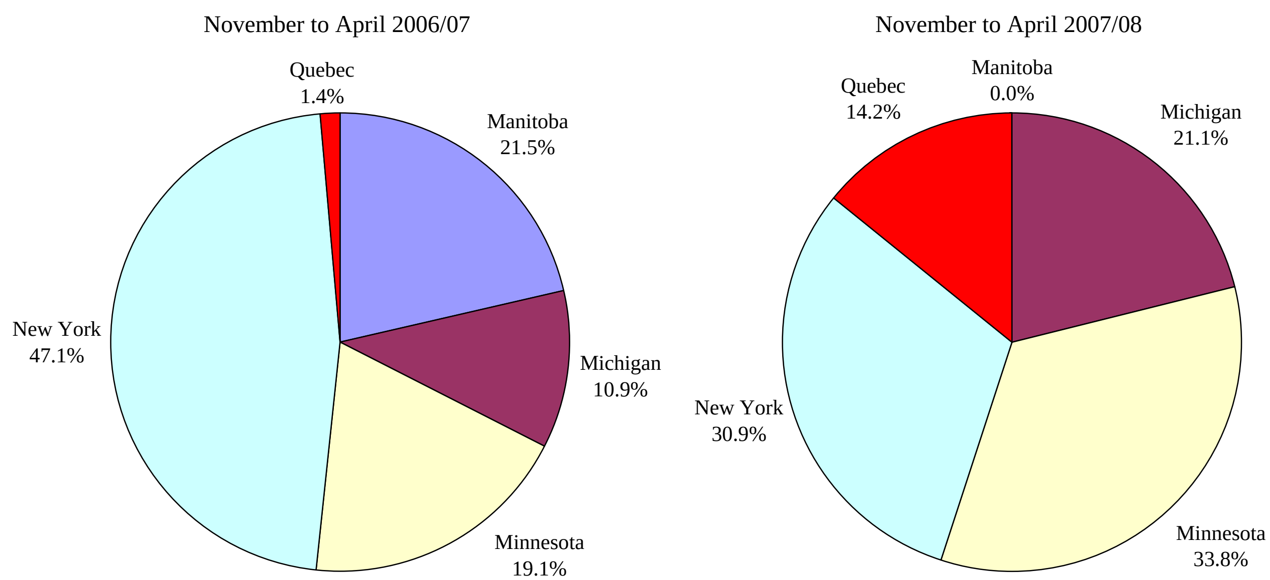
Table 1-36 summarizes the frequency of export congestion by month by intertie for November to April 2006/2007 and 2007/2008. Export congestion hours increased dramatically from 293 hours in 2006/2007 to 1,960 in 2007/2008, a six-fold increase. The largest increase in export congestion was seen at Minnesota, with other interties except Manitoba also experiencing significantly more congestion.

Table 1-36: Export Congestion in the Market Schedule by Intertie, November – April 2006/2007 & 2007/2008 (Number of Hours)

	ON to NY		ON to MI		ON to MB		ON to MN		ON to QC		Total	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	0	62	0	0	23	0	2	21	4	0	29	83
December	0	141	0	1	28	0	12	47	0	0	40	189
January	2	34	0	175		0	0	193	0	94	2	496
February	68	111	12	23	10	0	32	238	0	14	122	386
March	32	29	0	90	2	0	7	146	0	131	41	396
April	36	229	20	127		0	3	17	0	37	59	410
Total	138	606	32	416	63	0	56	662	4	276	293	1,960

Figure 1-30 compares the percentage export congested hours by intertie over the last two winter periods. As a share of all export congested hours, decreases at Manitoba and New York were offset by increases at Quebec, Michigan, and Minnesota over the last two winter periods.

Figure 1-30: Percentage of Export Congestion in the Market Schedule by Intertie, November 2006/2007 – April 2007/2008 (Percentage of Congested Hours)



5.2.3 Congestion Rents

Tables 1-37 and 1-38 report the congestion rents for the same periods and interties, as an indication of the impact on the market. Congestion rent is calculated as the MW of import or export that actually flows multiplied by the price difference between the congested intertie zone in Ontario and the uniform price. This represents a cost to traders, either in the form of a congestion price premium paid for exports or the reduction in the payment for imports. When a trader has a transaction in the opposite direction to the congested flow (i.e. an import on an export congested interface), that trader receives more (or pays less) for the transaction because of the congestion. This can induce negative components in the congestion rents presented below.

Table 1-37: Import Congestion Rent in the Market Schedule by Intertie, November – April 2006/2007 & 2007/2008 ($ thousands)

	NY to ON		MI to ON		MB to ON		MN to ON		QC to ON		Total	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	0	0	278	731	0	15	30	(13)	2,639	10	2,946	744
December	11	0	0	829	0	0	0	(1)	15	1	26	828
January	0	29	0	0	(9)	0	0	(10)	0	20	(9)	38
February	0	(1)	0	86	(3)	0	20	(45)	28	1,203	45	1,243
March	0	3	0	0	(5)	-3	32	(5)	127	1,346	154	1,340
April	0	0	0	0	2	2	0	(4)	19	82	21	80
Total	11	31	278	1,646	(15)	13	82	(78)	2,828	2,662	3,184	4,274

Table 1-38: Export Congestion Rent in the Market Schedule by Intertie, November – April 2006/2007 & 2007/2008 ($ thousands)

	ON to NY		ON to MI		ON to MB		ON to MN		ON to QC		Total	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	0	654	0	0	12	0	0	27	0	0	12	681
December	0	2,680	0	18	0	0	2	58	0	0	2	2,756
January	5	498	0	2,844	0	0	0	518	0	79	5	3,938
February	1,195	1,622	364	435	1	0	26	437	0	7	1,586	2,501
March	504	508	0	1,419	0	0	8	473	0	78	513	2,477
April	399	3,485	611	3,631	0	0	2	17	0	46	1,013	7,180
Total	2,104	9,447	976	8,346	13	0	38	1,531	0	210	3,132	19,533

Total congestion rent for exports ($19.5 million) was much larger than for imports ($4.3 million) this past winter period, whereas the congestion rents in the previous winter were similar for exports and imports, and both were lower than the current period amounts, at just over $3.1 million for each. Note, as would be expected the relative magnitudes of these total rents corresponds to the relative magnitudes of the total numbers of hours of congestion in the two previous tables.

Import congestion on the Quebec interties induced the largest congestion rents for importers, $2.7 million this winter and $2.8 million last winter. However, the year-over-year increase in total import congestion rents was the result of about $1.4 million increase this winter at the Michigan to Ontario interface. Export congestion at New York and Michigan account for the bulk of export congestion rents, rising from a total of $3.1 million last year to $17.8 million this year, with roughly equal amounts this year at each intertie.

Table 1-39 summarizes the average size of congestion payments per hour of congestion, by interie. Congestion rent can increase as the result of the number of hours, the magnitude of the transaction or the zonal to uniform price difference. These represent monetary transfers between various participants in the market, as opposed to the efficiency impact of congestion. Because of the smaller import or export capability at Quebec, Minnesota and Manitoba interfaces the sometimes large numbers of hours of congestion at those interties translates into much smaller congestion rents. For example, there were more hours of export congestion at Minnesota this winter (660 hours) than any other intertie, but the congestion rent ($1.53 million) was about 1/6 the rent at New York or Michigan.

Table 1-39
Average Congestion Rents per hour of Congestion by Intertie
($ thousands/hour)

	Import Congestion Rent (per hour of import congestion)			Export Congestion Rent (per hour of export congestion)		
	2006/2007	2007/2008	% Change	2006/2007	2007/2008	% Change
New York	11.0	1.7	(84.3)	14.9	15.6	4.5
Michigan	10.7	11.4	6.3	30.5	20.1	(34.2)
Manitoba	-0.4	0.2	140.7	0.2	0.0	(100.0)
Minnesota	0.5	-0.6	(234.7)	0.7	2.3	238.0
Quebec	20.8	76.1	265.8	0.1	0.8	587.3
Average	8.5	17.7	108.4	9.3	7.7	(16.6)

5.3 Analysis of the Determinants of Exports from Ontario to New York

To analyse the determinants of exports to New York, the IESO developed a reduced form structural model and the results were initially published in the June 2007 MSP report. The model tests whether average hourly export volumes from Ontario to New York are an increasing function of the monthly average energy price differential between the two jurisdictions. The model also incorporates monthly fixed effects and a time trend.[41]

In this report, the model is estimated using monthly data between January 2003 and April 2008 (64 observations). Table 1-40 presents the estimated results which are presented for all hours, on-peak hours, and off-peak hours. Both the HOEP and the New York price coefficients are significant and have the intuitive signs. That is, as the HOEP increases, exports to New York tend to decline and as the New York energy price increases, export volumes from Ontario to New York tend to rise. More specifically the estimated coefficients suggest that a one percent increase in the HOEP leads to a 4.16 percent decline in exports to New York (and vice versa), all other things held constant. Alternatively, a one percent increase in the New York price will lead to a 4.58 percent increase in exports destined for New York, only slightly lower than the 4.74 percent estimated in the last report. The elasticity estimate remained relatively unchanged when we added the six most recent observations. In the last report, the elasticity of exports

[41] The model is estimated using the two-stage least squares method and in logarithmic form. First stage instruments include Ontario non-dispatchable demand, nuclear output, self-scheduler output, New York load and the Henry Hub spot price for natural gas.

with respect to the HOEP was -4.27, which is only slightly higher in magnitude than the most recent estimate of -4.16.

Table 1-40: New York Export Model Estimation Results, January 2003 – April 2008

Variable	All Hours		On-peak		Off-peak	
	Coef.	Std. Error	Coef.	Std. Error	Coef.	Std. Error
Constant	4.20	0.94	2.25	1.16	5.07	1.12
Log(HOEP)	-4.16	1.20	-6.64	1.10	-2.15	1.10
Log(New York Price)	4.58	1.18	7.45	1.17	2.43	1.00
January	0.22	0.11	0.32	0.19	0.03	0.11
February	0.13	0.16	0.19	0.33	0.24	0.13
March	0.07	0.11	0.04	0.21	0.09	0.14
April	-0.13	0.11	0.01	0.24	-0.13	0.14
May	0.14	0.19	0.17	0.28	0.13	0.22
June	0.26	0.18	0.58	0.23	0.03	0.20
July	0.03	0.14	0.33	0.24	-0.17	0.26
August	-0.18	0.23	-0.14	0.29	-0.22	0.28
September	-0.14	0.14	-0.07	0.32	-0.18	0.14
October	-0.36	0.21	-0.18	0.26	-0.53	0.26
November	-0.03	0.12	0.09	0.17	-0.07	0.12
Time Trend	0.01	0.00	0.01	0.01	0.01	0.00
Model Diagnostics						
Correlation between actual and fitted values	0.79		0.78		0.74	
Number of observations	64		64		64	

5.4 Wholesale Electricity Prices in Neighbouring Markets

5.4.1 Price Comparisons

In the last two Panel reports we observed that prices in Ontario were below those of all neighbouring markets, although marginal costs (as represented by the Richview shadow price) suggested that Ontario production costs were not the lowest.[42]

In Table 1-41, we observe that the six-month average HOEP prices for the IESO are lower than market prices in the 4 main nearby markets, in both off-peak and on-peak

[42] For more details, see page 74 of the December 2007 Monitoring Report

periods and in aggregate.[43] MISO (Michigan Hub), which has traditionally been the lowest price jurisdiction, produced the next lowest prices, with the on-peak average $2.85/MWh higher than HOEP and off-peak only $0.58/MWh higher than HOEP. NYISO (Zone OH) had on-peak prices averaging just above the MISO price while off-peak it was almost $5/MWh higher. PJM (West) which borders both New York and MISO, saw on-peak prices more than $9/MWh above NYISO, and $13/MWh higher off-peak in the most recent period.

The average price of the five jurisdictions increased slightly from $58.92/MWh in 2006/2007 to $59.73/MWh (1.4 percent) in 2007/2008. Similar increases in the average price under 2 percent were observed during the on-peak and off-peak hours. Michigan Hub prices showed the largest percentage year-over-year decline as prices over all hours in Michigan fell 4.9 percent. On the other hand, the jurisdiction exhibiting the largest percentage increase this winter compared to last was New England where the average New England Internal Hub price increased by $4.79/MWh (or 6.3 percent) over all hours.

Table 1-41: Average HOEP Relative to Neighbouring Market Prices, November – April 2006/2007 & 2007/2008 ($CDN/MWh)

($CDN/ MWh)	All Hours			Off-peak Hours			On-peak Hours		
	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change	2006/ 2007	2007/ 2008	% Change
Ontario - HOEP	48.91	49.16	0.5	39.11	38.72	(1.0)	60.58	61.65	1.8
MISO – Michigan Hub	53.05	50.44	(4.9)	40.91	39.15	(4.3)	67.40	63.90	(5.2)
New England – Internal Hub	75.73	80.52	6.3	68.56	72.98	6.5	84.38	89.59	6.2
NYISO – Zone OH	54.43	53.58	(1.6)	45.70	44.56	(2.5)	64.75	64.56	(0.3)
PJM – West	62.50	64.93	3.9	54.13	57.45	6.1	72.54	73.80	1.7
Average	58.92	59.73	1.4	49.68	50.57	1.8	69.93	70.70	1.1

In Figures 1-31 to 1-33, we compare average prices for the same markets on a monthly basis between November 2007 and April 2008, for all hours, on-peak hours, and off-peak hours respectively. From these figures it can be seen that in the first three months of the

[43] All prices are expressed in Canadian dollars. The US market prices have been converted to Canadian dollars based on the Bank of Canada's daily noon spot rate available at http://www.bank-banque-canada.ca/en/rates/exchange.html.

current winter period, IESO prices were the 2nd lowest in each month with the exception of January 2008 off-peak where the HOEP was the lowest price relative to the other jurisdictions. The average monthly Michigan Hub price was lower than the HOEP in November and December while the average monthly New York Zone OH price was lower than HOEP in January during the on-peak hours and in all hours.

The figures also include the average monthly Richview nodal price for comparison with prices in other jurisdictions over all hours, on-peak hours, and off-peak hours. The Richview nodal price is more indicative of the actual cost of energy production in Southern Ontario. As we had noted in the previous report, based on the comparison with Richview prices, marginal costs in Southern Ontario tend to be higher on average than both MISO and NYISO prices in almost all months.[44, 45] For the six month period the on-peak average Richview price was $73.28/MWh, with the off-peak average $45.12/MWh and overall $57.96/MWh.

[44] Please add MSP report reference and page number(s)

[45] Hourly Richview prices in this data do not exceed +$2000/MWh or -$2000/MWh therefore no adjustments to the minimum and maximum caps have been made.

Figure 1-31: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, November 2007 – April 2008 ($CDN/MWh)

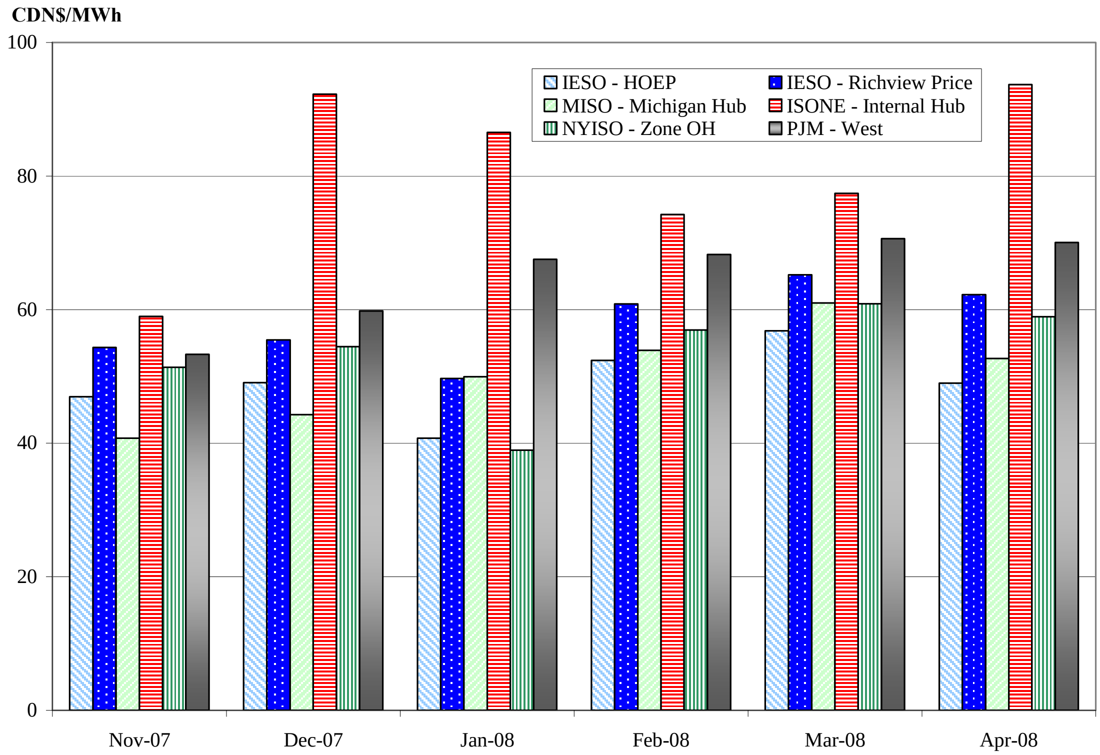


Figure 1-32: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, On-Peak, November 2007 - April 2008 ($CDN/MWh)

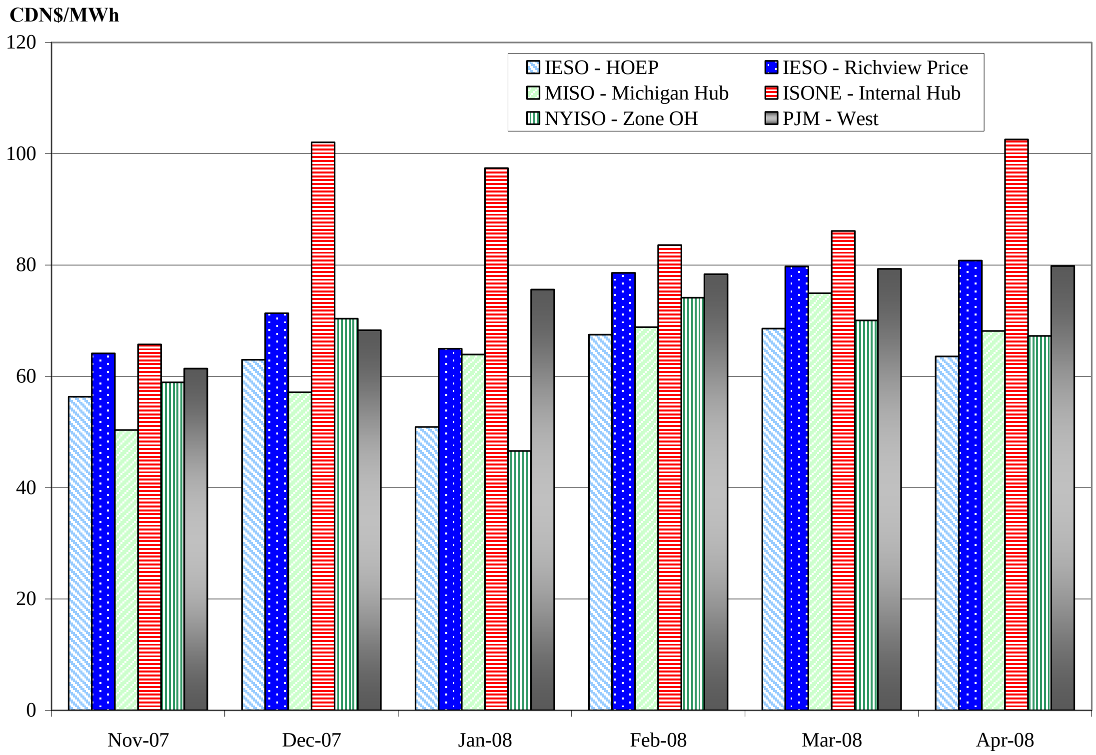
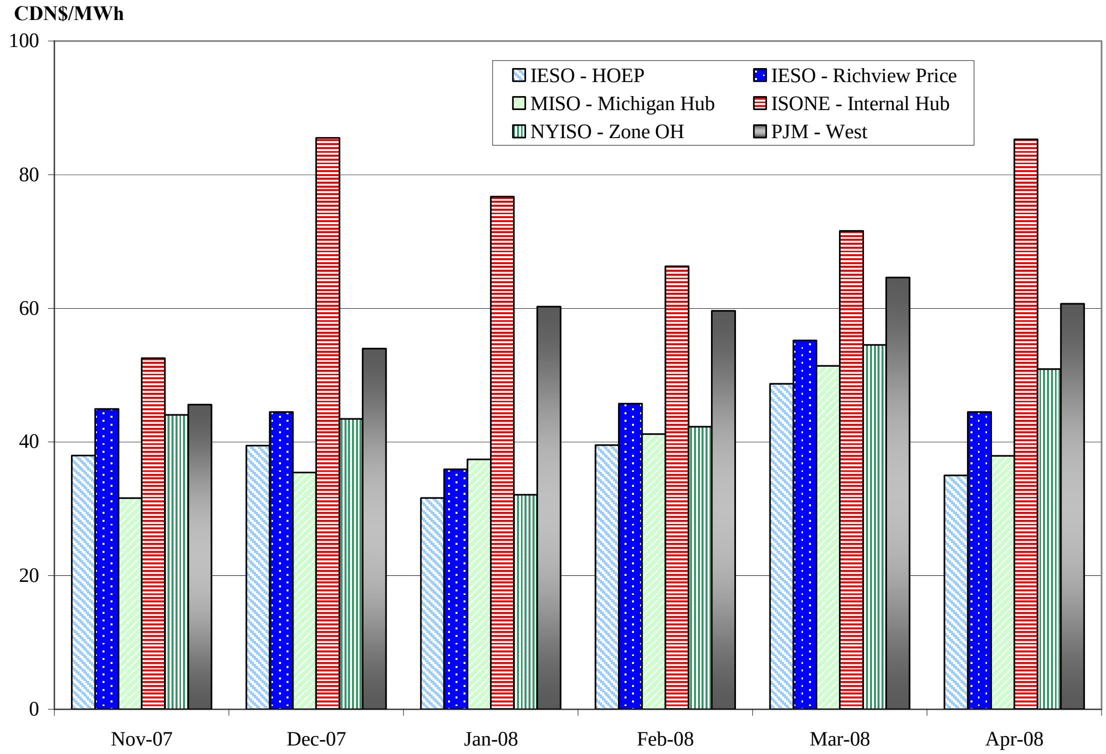


Figure 1-33: Average Monthly HOEP and Richview Shadow Price Relative to Neighbouring Market Prices, Off-Peak, November 2007 – April 2008 ($CDN/MWh)



These price differences provide some indication of the trade opportunities between jurisdictions. Based on the relativity of average prices and subject to congestion encountered, exports should have tended to flow most from Ontario to New York in almost all months on-peak and off-peak, and to MISO from January through April over on-peak, off-peak, and all hours. Both New York and MISO would appear to have had export opportunities to PJM (West) over the entire six-month time-frame, with the possible exception of on-peak in November.

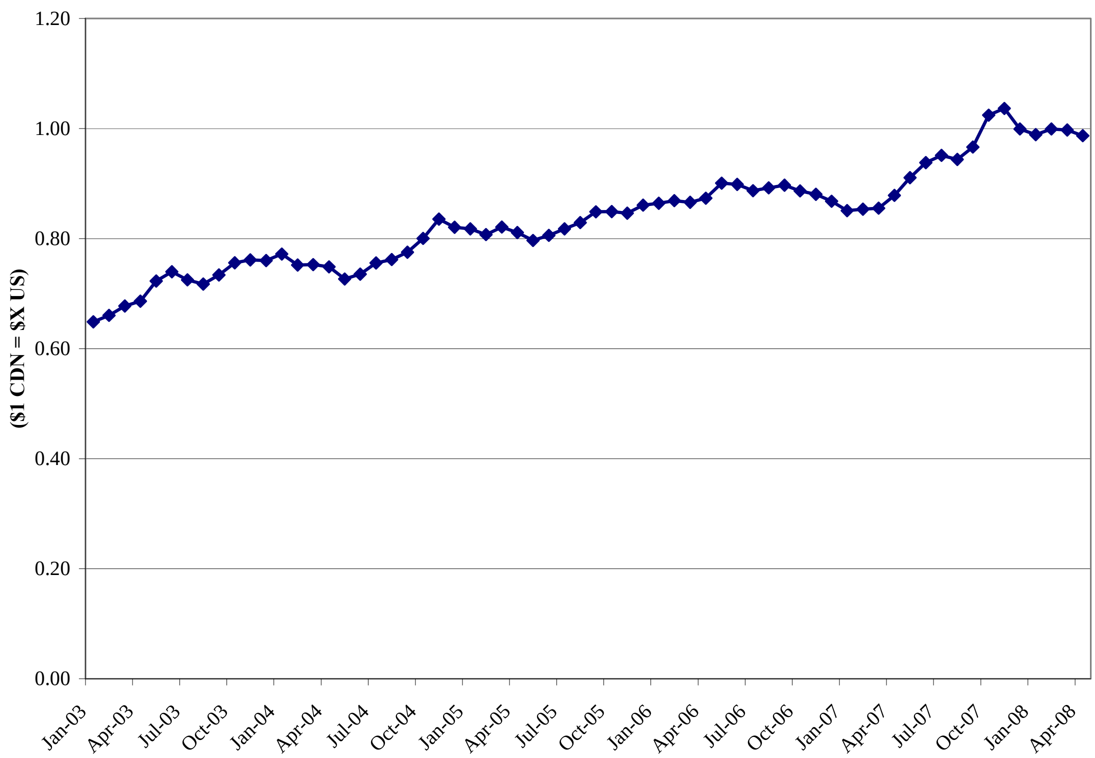
5.4.2 Exchange Rate Effects and Trade Flows

Figure 1-34 illustrates the increase in the monthly average Canadian/US dollar exchange rate since January 2004.[46] There has been a substantial appreciation in the Canadian

[46] The monthly exchange rate is calculated by averaging the Bank of Canada's daily noon spot rate available at http://www.bank-banque-canada.ca/en/rates/exchange.html.

dollar relative to the US dollar during the summer and fall of 2007. The figure shows a gradual appreciation of the Canadian dollar since early 2003 and the rapid movement in the second half of 2007. On a monthly basis, a peak appears to have been reached in November 2007 with the monthly average exchange rate of $1 CDN = $1.04 US. Since then the exchange rate has moderated and the $CDN appears to have found a more stable level at close to par with the $US, from 0.99 to 1.00.

Figure 1-34: Monthly Average Exchange Rate,
January 2003 – April 2008
($1 CDN = $X US)



Although US fuel prices for both gas and coal have risen considerably, the effect of the exchange rate has been to mute these for generators in Canada. Thus while the Henry Hub spot market gas price in $US rose on average 16 percent for the latest winter period compared to the previous, in $CDN there was no change on average and consistent with the small observed change of 2.2 percent in the Dawn gas price (which is published in $CDN). Similarly the $US NYMEX OTC price for Central Appalachian coal grew by 70 percent on average this winter, in $CDN there was only a 47 percent increase.

As we stated in our last report, the rising exchange rate has two offsetting effects. It increases the US cost of purchasing Ontario energy (or increases the value of selling into Ontario), but it would also tend to reduce relative fuel costs in Ontario (and this should contribute to lower market prices relative to the US markets to the extent that Ontario generators are purchasing fuel in US dollars. Prices in electricity markets are influenced by factors beyond spot fuel price changes or exchange rate fluctuations. Nevertheless, the Panel continues to hold the view that the tendency for the exchange rate alone as a driver to increase imports and reduce exports would seem to be muted by the compensating impact on fuel prices and in turn on market prices.

5.4.3 Linked Wheel Transactions

In the Ontario market a trader can move energy through the province (wheel energy) by importing at one intertie and exporting at another. This can be accomplished through two entirely separate transactions (referred to as an 'implied wheel'), or through a market mechanism which designates the two transactions as interconnected (a 'linked wheel'). The import and export legs of an implied wheel are treated quite separately (except for IOG payments). However, the two parts of a linked wheel must always be matched – they will both be either successful, or if one is cut for some reason, the other part of the transaction must also be cut. It is possible that both parts of an implied wheel are successfully scheduled by the IESO's pre-dispatch, but the wheel may fail during the checkout just before the hour. Being unsuccessful scheduling the import portion because of economics or for other reasons in the external source market, also leads to the cutting (failing) of the export leg of the transaction.

Figure 1-35 presents monthly levels of linked wheels since May 2005. It shows only minor levels of transactions, until a sudden surge in their use in January 2008. In the current six-month period, there have been a total of 1,859 GWh of linked wheel transactions, which is about 150 times (or 15,000 percent) more than in the previous winter period. Additionally, the quantity of linked-wheels in May 2008 is shown in

Figure 1-35 and is represented by the red bar. In May, linked wheels increased to almost 1,100 GWh representing an increase of over 60 percent relative to the March and April 2008 monthly totals of 670 GWh.

Figure 1-35: Quantity of Linked Wheel-through Transactions, May 2005 - May 2008 (GWh)

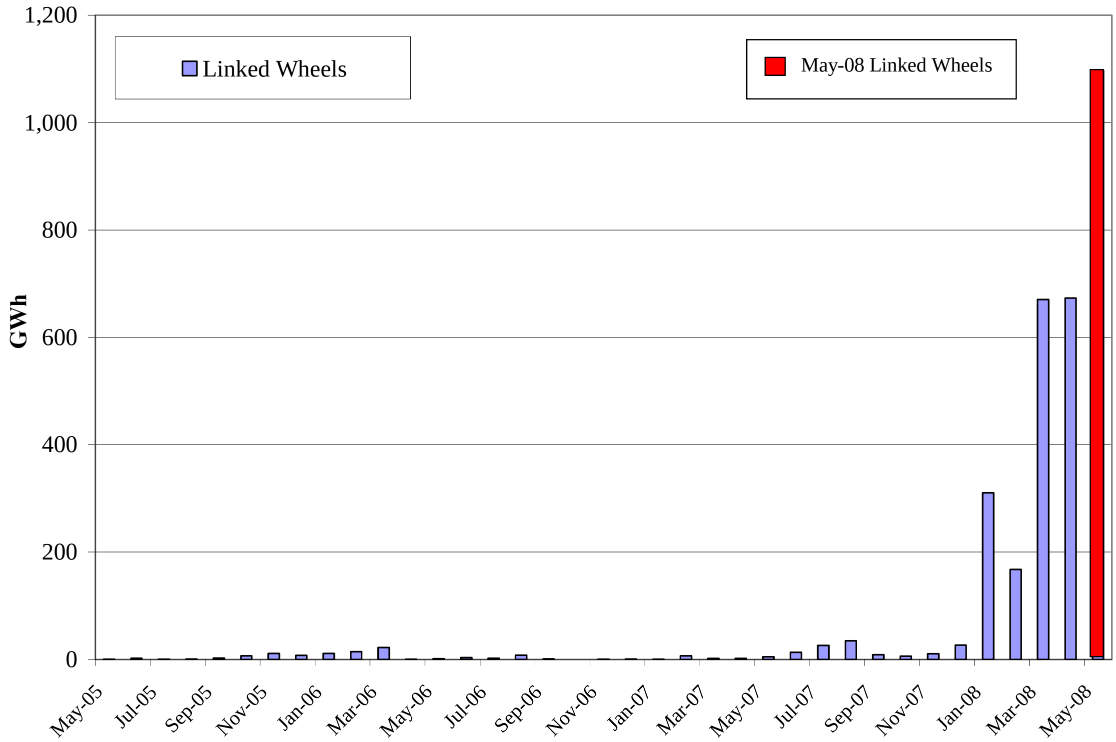
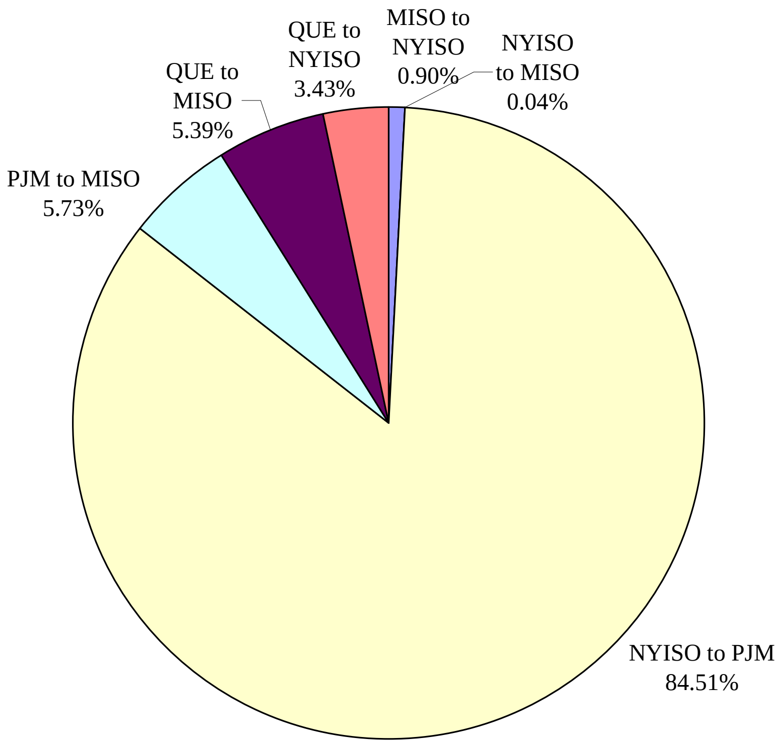


Figure 1-36 shows the proportion of linked wheels by origin and destination. Approximately 85 percent of the volume of linked wheels originated in New York and were destined for PJM through Ontario. The remaining 15 percent of linked wheels that flowed through Ontario were from PJM to Michigan, Quebec to Michigan and New York, Michigan to New York, and New York to Michigan.

Figure 1-36: Percentage of Linked-Wheels through Ontario by Origin and Destination, November 2007 – April 2008 (%)



Coincident with the rise in their usage, the volume of failures of linked wheels has also been growing. Table 1-42 compares the total quantity of linked wheels along with the amount of linked wheel failures on a monthly basis over the last two winter periods. The failure rate gradually increased and hit 31 percent in February 2008. During March 2008, the linked wheel failure rate declined significantly (although the volume of linked wheels continued to climb). The reason for the sudden decline in failures was due to the introduction of the Intertie Failure Charge (IFC) and the associated communications by the IESO to traders of the impact of these failures on operations.[47] The implications of the higher volume of linked wheels are discussed in Chapter 3.

[47] As of March 18, 2008, the Intertie Failure Charge was applied to linked-wheel failures.

Table 1-42: Quantity of Linked-Wheels and Incidents of Linked-Wheel Failures, November – April 2006/2007 & 2007/2008 (GWh and %)

	Total Linked Wheels (GWh)		Linked Wheel Failures (GWh)		Failure Rate (%)	
	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008	2006/ 2007	2007/ 2008
November	0.5	10.6	0.3	0.8	37.5	7.0
December	0.9	26.8	0.5	0.9	35.7	3.2
January	0.5	310.3	0.1	50.7	16.7	14.0
February	6.8	167.6	0.5	74.8	6.8	30.9
March	1.7	670.7	0.1	130.0	5.6	16.2
April	1.8	673.1	0.0	22.4	0.0	3.2
Total	12.2	1,859.1	1.5	279.6	10.9	13.1

Chapter 2: Analysis of Market Outcomes

1. *Introduction*

The Market Assessment Unit (MAU), under the direction of the Market Surveillance Panel (MSP), monitors the market for anomalous events and behaviours. Anomalous behaviours are actions by market participants (or the IESO) that may lead to market outcomes that fall outside of predicted patterns or norms.

Both high and low priced hours are monitored as well any other events that appear to be anomalous, even though they may not meet bright-line price tests. These events are reported to the Panel. The Panel believes the explanation of these events provides transparency on why certain outcomes occur in the market and leads to learning by all market participants. On occasion as a result of this monitoring the MSP may recommend changes to market rules or the tools that the IESO employs.

During the current reporting period, the Panel's review and analysis of high-priced and low-priced hours and other anomalous events did not suggest that there was gaming or abuse of market power by any market participant. However, it has led the Panel to make recommendations to the IESO to take certain actions to improve market efficiency.

Daily, the MAU reviews the previous day, not only to discern anomalous events but also to review:

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

This daily review leads to identifying anomalous events that may be discussed with the relevant market participants and/or the IESO.

The MAU reviews all high priced hours to identify the critical factors leading to the high prices and reports its findings to the Panel. In this report, high priced hours are defined as all hours in which the HOEP was greater than $200/MWh. In addition, the MAU reviews all low priced hours and reports its findings to the Panel. In this report, a low priced hour is defined as any hour in which the HOEP was less than $20/MWh.[48]

There were 2 hours during the review period November 2007 through April 2008 where the HOEP was greater than $200/MWh. Section 2.1 of this Chapter examines the factors contributing to the relatively high HOEP in each instance.

In this review period there were 261 hours in which the HOEP was less than $20/MWh including 5 hours where the HOEP was negative. A negative price implies generators are paying loads and export customers to consume energy. Section 2.2 of this Chapter reviews the factors typically driving prices to low levels in these hours.

In additional to high and low priced hours, the Panel examines and seeks to explain other hours that appear anomalous where prices do not reflect underlying demand and supply conditions. An event of this nature occurred during the current review period when a large nuclear unit was forced out of service. Under normal conditions, when a large nuclear unit is forced out of service, the market price should increase immediately to reflect ramp rate limitations or scarcity of resources. However, in one incident over 1,700 MW of nuclear generation was lost in a 90 minute period while the HOEP remained below $200/MWh due to a series of IESO control actions executed for reliability and resource adequacy concerns.

[48] $200/MWh is typically an upper bound for the cost of a fossil generation unit while $20/MWh is a lower bound for the cost of a fossil unit.

The Panel also provides examples of ongoing counter-intuitive market outcomes that are artifacts of the interaction between the constrained and unconstrained schedules. These include:

- The failure of an import to Ontario causing the Ontario price to fall; and
- The failure of an export from Ontario causing the Ontario price to rise.

In previous reports, the Panel reviewed the hours where uplift was greater than the HOEP. We noticed that in many cases, uplift greater than the HOEP was simply a result of a low or negative HOEP and as such, provided little worthwhile information. As a result, the Panel asked the MAU to explore the possibility of developing a more useful indicator of anomalous uplifts. The MAU has initiated an analysis to discern which uplift events can be considered anomalous. It has focused on those types of uplifts that, if understood and anticipated by participants, could potentially be avoided. These may include IOG, CMSC and OR payments. Thresholds of $500,000/hour for CMSC or IOG payments and $100,000/hour for OR (plus an OR shortage price) have been identified as reasonable metrics for discerning anomalous uplifts. A further threshold of $1,000,000 dollars per day may be an important threshold in the intertie zones. In future reports the MSP will be reporting the methodology of establishing the thresholds and anomalous events that trigger such thresholds.

2. *Anomalous HOEP*

2.1 Analysis of High Priced Hours

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

Table 2-1 depicts the total number of hours with a HOEP greater than $200/MWh between November 2007 and April 2008. The number of high-priced hours totaled 2 hours, representing less than 0.02 percent of total hours during the six-month period reviewed.

Table 2-1: Number of Hours with a High HOEP November – April 2005/06, 2006/07 and 2007/08 (Number of Hours)

	Number of Hours with HOEP >$200/MWh		
	2005/ 2006	**2006/ 2007**	**2007/ 2008**
November	0	0	0
December	2	0	0
January	0	0	0
February	0	0	1
March	0	0	0
April	4	1	1
Total	6	1	2

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

- real-time demand is much higher than the pre-dispatch forecasts of demand;
- one or more imports fail real-time delivery; and/or
- one or more generating units that appear to be available in pre-dispatch become unavailable in real-time as a result of a forced outage or derating.

Each of these factors has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. Instances when the HOEP rises above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent. There is nothing definitive about the 10 percent point, but from our observations, the offer curve is much steeper when the supply cushion is below 10 percent than it is when the supply cushion is above 10 percent.[49]

[49] The Panel's October 2002 Monitoring Report, page 53-60, and March 2003 Report, page 11-16.

2.1.1 February 01, 2008 HE 11 – HE 13

Prices and Demand

The HOEP reached $563.62/MWh in HE 12 although the pre-dispatch run projected a price of $78.16/MWh. Table 2-2 depicts the interval prices and demand for February 1, 2008 HE 11 through HE 13. The highest interval MCP in HE 12 was $654.65/MWh, which occurred in three intervals. The largest increase in MCP occurred between intervals 2 and 3 of HE 12 rising from $214.03/MWh in interval 2 to $654.65/MWh in interval 3. This sharp increase in MCP was associated with only a 60 MW increase in demand (from 21,288 MW in interval 2 to 21,348 MW in interval 3), indicating other significant factors that could have led to the price increase.

Table 2-2: The Real-Time and Pre-Dispatch Prices and Demand for HE 11 – HE 13 February 1, 2008

Delivery Hour	Interval	Price			Ontario Demand			Net Exports (MW)
		RT MCP ($/MWh)	PD MCP ($/MWh)	Difference (RT-PD) ($/MWh)	RT (MW)	PD (MW)	Difference (RT-PD) (MW)	
11	1	68.62	56.41	12.21	20,953	20,747	206	1,589
11	2	67.68	56.41	11.27	21,075	20,747	328	1,589
11	3	63.94	56.41	7.53	21,099	20,747	352	1,589
11	4	57.09	56.41	0.68	21,116	20,747	369	1,589
11	5	68.62	56.41	12.21	21,110	20,747	363	1,589
11	6	89.67	56.41	33.26	21,166	20,747	419	1,589
11	7	89.57	56.41	33.16	21,179	20,747	432	1,589
11	8	89.57	56.41	33.16	21,208	20,747	461	1,589
11	9	89.67	56.41	33.26	21,256	20,747	509	1,589
11	10	95.01	56.41	38.60	21,292	20,747	545	1,589
11	11	96.44	56.41	40.03	21,223	20,747	476	1,589
11	12	105.94	56.41	49.53	21,268	20,747	521	1,589
	Average	**81.82**	**56.41**	**25.41**	**21,162**	**20,747**	**415**	**1,589**
12	1	346.81	78.16	268.65	21,309	21,016	293	1,730
12	2	214.03	78.16	135.87	21,288	21,016	272	1,730
12	3	654.65	78.16	576.49	21,348	21,016	332	1,730
12	4	609.75	78.16	531.59	21,289	21,016	273	1,730
12	5	654.65	78.16	576.49	21,347	21,016	331	1,730
12	6	609.75	78.16	531.59	21,250	21,016	234	1,730
12	7	609.75	78.16	531.59	21,278	21,016	262	1,730
12	8	609.75	78.16	531.59	21,304	21,016	288	1,730
12	9	609.75	78.16	531.59	21,291	21,016	275	1,730
12	10	609.75	78.16	531.59	21,249	21,016	233	1,730
12	11	654.65	78.16	576.49	21,297	21,016	281	1,730
12	12	580.10	78.16	501.94	21,178	21,016	162	1,730
	Average	**563.62**	**78.16**	**485.46**	**21,285**	**21,016**	**269**	**1,730**
13	1	125.24	90.00	35.24	21,310	20,875	435	1,049
13	2	141.37	90.00	51.37	21,349	20,875	474	1,049
13	3	125.01	90.00	35.01	21,231	20,875	356	1,049
13	4	125.01	90.00	35.01	21,219	20,875	344	1,049
13	5	125.01	90.00	35.01	21,201	20,875	326	1,049
13	6	120.01	90.00	30.01	21,170	20,875	295	1,049
13	7	125.01	90.00	35.01	21,177	20,875	302	1,049
13	8	130.00	90.00	40.00	21,249	20,875	374	1,049
13	9	120.01	90.00	30.01	21,153	20,875	278	1,049
13	10	120.01	90.00	30.01	21,122	20,875	247	1,049
13	11	115.45	90.00	25.45	21,077	20,875	202	1,049
13	12	60.01	90.00	-29.99	20,649	20,875	-226	1,049
	Average	**119.35**	**90.00**	**29.35**	**21,159**	**20,875**	**284**	**1,049**

The HOEP in HE 11 and HE 13 were well below $200/MWh, but they are listed in order to show the behaviour of the MCP before and after the price spike. Market demand came in heavier in all three hours than forecast in pre-dispatch and the real-time MCP was greater than the pre-dispatch price. For example, the average market demand in HE 12 was 269 MW (1.3 percent) heavier than forecast and peaked at 332 MW (1.6 percent) above forecast in interval 3.

Despite demand rising by 132 MW between interval 12 of HE 12 and interval 1 of HE 13, the MCP dropped from $580.10/MWh to $125.24/MWh. The primary reason for the drop is that a large amount of exports were curtailed by the IESO for adequacy, which had the effect of suppressing the MCP and the HOEP. We will analyze the impact of IESO control actions in later sections.

Day-Ahead Conditions

The day-ahead Ontario demand forecast for HE 12 was 20,932 MW, with a day-ahead supply cushion of 24.1 percent.[50] The Day-Ahead Commitment Process (DACP) scheduled 16 fossil-fired dispatchable generators online, with a schedule of 4,100 MW.

There were no imports scheduled day-ahead, as there appeared to be sufficient economic internal supply to meet the Ontario demand. The DACP does not take exports into account.

Final Pre-dispatch (1 Hour-ahead) Conditions for HE 12

After the DACP ran, there was little change in either the generator availability or offers, except that one fossil-fired generator (with a capacity of about 500 MW) became

[50] The day-ahead supply cushion is a similar metric to the supply cushions measured in pre-dispatch and real-time. It measures the total DACP offers from internal generators plus imports scheduled in the DACP minus total Ontario demand (energy plus the OR requirement) relative to the total Ontario demand. For each hour all offers and schedules are measured at the time of the last DACP run, which is typically in HE 15 day-ahead.

available five hours ahead of real time. The unit returned from a forced outage two days earlier than originally anticipated.

Table 2-3 lists the sequential changes in Ontario demand and import/export schedules after the DACP run. Imports and exports started to be scheduled in the first pre-dispatch run after the DACP. Although both imports and exports increased over time, the largest hour-to-hour change occurred from three hours ahead to two hours ahead when significant volumes of imports and exports were offered immediately before the two-hour ahead offer/bid window was closed.[51] Between the three-hour ahead and two-hour ahead pre-dispatch runs, scheduled exports increased from around 2,700 MWh to 3,700 MWh and imports from 1,200 MWh to 1,800 MWh. The change between the two-hour ahead and one-hour ahead schedules was relatively small. This increase in net exports from day-ahead to the final one-hour ahead pre-dispatch run contributed to the reduction in the supply cushion.

Table 2-3: Ontario Demand and Intertie Schedules in Sequence for February 1, 2008 HE 12

Pre-dispatch Sequence (hours ahead)	PD Price ($/MWh)	Ontario Demand (MW)	Imports (MW)	Exports (MW)	Net Exports (MW)	Important Events
21 (DACP)	33.43	20,932	0	0	0	
20	49.38	20,854	328	(1,030)	(702)	
10	58.00	21,033	1,194	(1,737)	(543)	
5	46.97	20,969	910	(1,737)	(827)	a fossil-fired generator became available
4	57.09	21,102	950	(1,859)	(909)	
3	58.00	20,735	1,241	(2,754)	(1,513)	
2	73.00	20,784	1,820	(3,718)	(1,898)	
1	78.16	21,016	1,795	(3,543)	(1,748)	

In the final pre-dispatch run for HE 12, the forecast one-hour ahead Ontario Demand was 21,016 MW, which was only 84 MW (0.40 percent) greater than the day-ahead forecast. The one-hour ahead projected price was $78.16/MWh. There were 1,795 MW of imports and 3,543 MW of exports scheduled. About 950 MW of domestic generation was offered

[51] The IESO market requires all participants to offer or bid two hours prior to the real time dispatch. The two-hour ahead deadline is traditionally called the “two hour window”.

between $78/MWh and $650/MWh, of which 300 MW was between $210/MWh (the lowest MCP in HE 12) and $650/MWh (the highest MCP in HE 12).

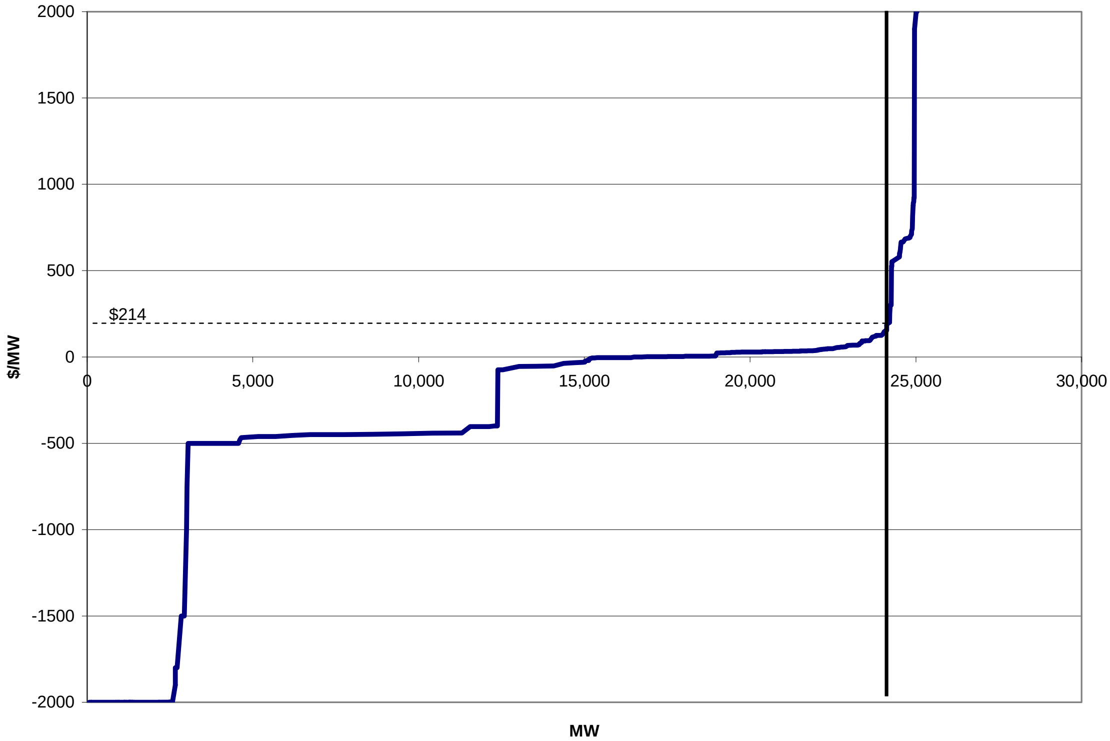
The pre-dispatch supply cushion was 5.7 percent compared to 24.1 percent in the DACP. The significant decrease in the supply cushion was primarily caused by:

- The 1,748 MW (3,543 MW-1,795 MW) of net exports not accounted for day ahead;
- A fossil-fired generating station's offer (about 2,000 MW) was included in the day-ahead supply cushion but was not included in the final pre-dispatch supply cushion because it was offline at the time.[52] Its offer prices were too high relative to the pre-dispatch prices and it was never scheduled to be online.

Figure 2-1 depicts the pre-dispatch offer curve from all generators. One can see that once the MCP reached $214/MWh, it was very easy for the MCP to jump to above $500/MWh with a small increase in demand or a small derating/outage to inframarginal generators.

[52] All fossil generators are included in the day-ahead supply cushion because they can be online anytime during the day after warming up for two to four hours. However, the final one-hour ahead pre-dispatch and real-time supply cushion does not include fossil generators that are offline, recognizing the ramp limitation.

Figure 2-1: One Hour Ahead Pre-dispatch Offer Curve, February 1, 2008 HE 12



Real-time Conditions

Real-time Ontario demand came in heavier than expected. The average Ontario demand in HE 12 was 21,285 MW, and the peak Ontario demand in the hour which occurred in interval 3 was 21,348 MW (332 MW or 1.6 percent greater than had been expected).

In HE 11, two units at one fossil-fired station were derated, representing a loss of 455 MW in real-time:

1. One unit was derated by 355 MW (from 445 MW to 90 MW) from HE 11 interval 3 to HE 14 interval 1 due to thermal stresses. At the time of the derating, the unit was actually producing slightly above 100 MW (in the constrained sequence) but was scheduled at 445 MW in the unconstrained sequence due to the 3 times ramp rate assumption. When the derating was applied, the unconstrained sequence immediately lowered the scheduled

output for the unit from 445 MW to 90 MW in one interval, while the constrained sequence was only reduced from about 100 MW to 90 MW.

2. The other unit was derated by 100 MW (from 495 MW to 395 MW) between HE 11 interval 7 and HE 15 interval 4 due to fuel supply problems.

In HE 12, three more generators were derated in real-time from interval 3 onwards.

1. One hydroelectric generator was derated by 58 MW for cooling down the base that bears the generation units between HE 12 interval 3 and HE 13 interval 2.
2. One fossil-fired generator was derated by 120 MW due to fuel supply problems from HE 12 interval 3 to HE 15 interval 4.
3. Another fossil-fired generator was forced to derate from 435 MW to 375 MW in HE 12 interval 10 due to fuel transportation problems. This forced derating continued until HE 14 interval 2.

There was only 18 MW of (net) export failures, which had a very limited offsetting effect on prices.

In summary, the factors that led to the price spike include:

1. a 332 MW increase in peak Ontario demand relative to one-hour ahead;
2. a 455 MW derating of two fossil-fired units after the final pre-dispatch run; and
3. a further 238 MW of generation was unavailable in real-time.

In other words, demand increased by 332 MW and supply declined by 693 MW for a net change of 1,025 MW. The increased demand and lost supply reduced the real-time supply cushion to minus 3.3 percent. As a consequence, the real-time MCP moved to above $500/MWh from interval 3 until the end of HE 12, after which changes in net exports and IESO control actions reduced it to the $120/MWh range.

IESO and Market Participants' Actions in HE 13 to14

In HE 13, the supply/demand situation appeared to be worse than in HE 12. Demand was running heavier than expected while 400 MW of imports from New York were cut by NYISO for internal security after the IESO's one-hour ahead pre-dispatch run.[53]

The sudden loss of 400 MW of imports had two consequences. First, the loss of imports threatened to overload the Ontario-New York interface as there were a large amount of scheduled exports destined for New York. In response, the IESO cut exports by 289 MW to relieve export congestion. It appears that the NYISO did not fully appreciate that the consequence of cutting 400 MW of exports would in turn lead to the cutting of 289 MW of imports as the circuit was overloaded. This 289 MW export curtailment by the IESO had no impact on the market price because the IESO used TLRi for the export curtailment and thus the unconstrained schedule was not changed. However, the IESO subsequently curtailed a further 438 MW of exports on the Michigan interface for resource adequacy, using the ADQh code.[54] The curtailment of exports for adequacy suppressed the HOEP because the curtailed exports were deducted from the market demand.

In HE 13, tighter real-time supply conditions led to a higher real-time price relative to the pre-dispatch price. But the real-time price did not reflect the full extent of the tight market conditions due to the price suppressing effect of the ADQh export curtailment. The Panel has recommended in its December 2007 Monitoring Report that the IESO should not remove exports reduced for adequacy from the unconstrained sequence as this action is not priced in the marketplace.[55] The removal of these exports from the market demand attenuates the scarcity signal, that there are economic export customers that would consume at a higher price if it were not for IESO procedures. The suppression of the real-time price also provides a false signal that encourages loads and exporters to

[53] 400 MW was the import reduction in the unconstrained sequence. In the constrained sequence, 597 MW were curtailed.
[54] Some of these exports were constrained-on exports. The actual curtailment in the constrained sequence was 375 MW.
[55] See the Panel's December 2007 Monitoring Report, pages 100-103, Recommendation 2-1.

consume and discourages generators and importers from offering greater supplies as soon as they are able to do so.

Due to the limitations of the current two-hour ahead bid window, importers and exporters could not change their offers or bids for HE 13 to HE 14 in response to the price spike in HE 12 and possible spikes in HE 13 and HE 14. However, during the middle of the price spike in HE 12 an additional 820 MW of imports were offered for HE 15, which appears to have been a response to the price spike. As the Panel noted in its December 2007 Monitoring Report, 15 minute dispatch associated with a shorter offer/bid window could significantly enhance the ability of market participants to respond to the price signals.[56]

Assessment

The MCP in HE 12 interval 1 jumped to $346.81/MWh from $105.94/MWh in HE 11 interval 12. This was due to an increase in net exports of 160 MW, an increase in Ontario demand of 40 MW, and a decrease in peaking hydro supply of 280 MW.[57] As the Panel discussed in its December 2007 Monitoring Report, imports and exports are scheduled hourly and peaking hydro is typically offered into or out of market as an hourly block. The effect of the abrupt change of this supply on the MCP is the highest in the first two intervals in each hour.[58]

The high MCP in the first two intervals of HE 12 reflected the tight supply conditions prevailing at the beginning of the hour. These tight supply conditions were caused by demand coming in 293 MW heavier than forecast, generators being derated due to technical problems prior to the real-time run, and the sudden change in net exports and peaking hydro supply on the hour.

[56] See the Panel's December 2007 Monitoring Report, pages 157-160, Recommendation 3-3.
[57] During the winter season, Ontario demand exhibits two peak load pickup periods: one in the morning and the other in afternoon. Peaking hydro units are usually offered and scheduled to help shave the two peaks. After the morning load pickup hours, some peaking hydro units are offered out of market to preserve energy for the afternoon peak hours.
[58] See the Panel's December 2007 Monitoring Report, pages 151-160.

Properly pricing exports curtailed for adequacy is an important issue. In a well functioning electricity market, an efficient price should allow consumers (including exporters) who have a higher valuation to consume and producers (including importers) who have a lower cost to supply. The use of the adequacy code by the IESO in essence assumes those curtailed exports have a zero value and thus can be removed from the demand curve without distorting it. The removal of exports from the unconstrained sequence has the serious consequence of biasing the market price downward so that it no longer reflects the scarcity conditions. We will discuss export curtailments further in Chapter 3.

As noted above, in HE 11 interval 3 a unit was derated by 355 MW (from 445 MW to 90 MW) in the unconstrained schedule, while only derated by 10 MW in the constrained schedule (from 100 MW to 90 MW). It is the Panel's understanding that this unit was incapable of achieving the 445 MW scheduled in the unconstrained sequence due to actual ramp rates of 2 MW/minute.

Intuitively it does not seem rational for generators to offer beyond their physical ramping capabilities. If generators ensured that their offers were reflective of their physical capability, this should go some ways to ensuring the supply in the unconstrained schedule is more reflective of actual market possibilities. The Panel has asked the MAU to study the issue of reflecting the physical generator capability in the unconstrained sequence.

2.1.2 <u>April 22, 2008, HE 12</u>

Prices and Demand

On April 22, 2008 HE 12, the HOEP reached a price of $204.56/MWh. Table 2-4 presents the pre-dispatch and real-time energy price and demand as well as the real-time net exports for all intervals in HE 11 and HE 12. In HE 11, the real-time MCP was lower than the final pre-dispatch MCP in all intervals, with a HOEP (average interval MCP) of $52.46/MWh. The highest MCP occurred in the first interval of HE 12 where the MCP rose to $569.95/MWh. It remained above $200/MWh in intervals 2 and 3, and then decreased to $81.66/MWh in interval 12.

Table 2-4: Pre-dispatch and Real-time Summary Information, April 22, 2008, HE 12 ($/MWh and MW)

Delivery Hour	Interval	Real-time MCP ($/MWh)	Pre-dispatch MCP ($/MWh)	Difference ($/MWh)	Real-time Demand (MW)	Pre-dispatch Demand (MW)	Difference (MW)	Real-time Net Export (MW)
11	1	59.55	74.99	(15.44)	17,770	17,771	(1)	1,122
11	2	42.55	74.99	(32.44)	17,754	17,771	(17)	1,122
11	3	74.37	74.99	(0.62)	17,926	17,771	155	1,122
11	4	44.52	74.99	(30.47)	17,889	17,771	118	1,122
11	5	44.52	74.99	(30.47)	17,889	17,771	118	1,122
11	6	52.26	74.99	(22.73)	17,939	17,771	168	1,122
11	7	43.39	74.99	(31.60)	17,884	17,771	113	1,122
11	8	43.70	74.99	(31.29)	17,896	17,771	125	1,122
11	9	42.55	74.99	(32.44)	17,825	17,771	54	1,122
11	10	95.00	74.99	20.01	18,013	17,771	242	1,122
11	11	42.97	74.99	(32.02)	17,862	17,771	91	1,122
11	12	44.11	74.99	(30.88)	17,917	17,771	146	1,122
	Average	52.46	74.99	(22.53)	17,880	17,771	109	1,122
12	1	569.95	83.14	486.81	17,914	17,736	178	1,688
12	2	230.22	83.14	147.08	17,914	17,736	178	1,688
12	3	230.22	83.14	147.08	17,952	17,736	216	1,688
12	4	180.02	83.14	96.88	17,870	17,736	134	1,688
12	5	177.49	83.14	94.35	17,808	17,736	72	1,688
12	6	180.02	83.14	96.88	17,853	17,736	117	1,688
12	7	170.22	83.14	87.08	17,843	17,736	107	1,688
12	8	180.02	83.14	96.88	17,932	17,736	196	1,688
12	9	170.22	83.14	87.08	17,848	17,736	112	1,688
12	10	128.56	83.14	45.42	17,800	17,736	64	1,688
12	11	156.13	83.14	72.99	17,854	17,736	118	1,688
12	12	81.66	83.14	(1.48)	17,785	17,736	49	1,688
	Average	204.56	83.14	121.42	17,864	17,736	128	1,688

Day-ahead Conditions

As is typically the case in the spring, many of Ontario's baseload generating units were taking planned outages for maintenance during a period when demand is normally light. Going into April 22, approximately 5,700 MW of baseload and intermediate generating capacity was either on planned or forced outage. Nevertheless, the day-ahead supply cushion was slightly above 25 percent and no imports were scheduled day-ahead as supply from Ontario generation appeared to be adequate.

Final Pre-dispatch Conditions

In the final pre-dispatch run, the peak Ontario Demand was forecast to be 17,736 MW and the pre-dispatch price was $83.14/MWh. The total supply cushion, which includes imports and exports, was -0.10 percent reflecting extremely tight supply conditions as scheduled net exports totalled 1,599 MW (3,234 MW of scheduled exports and 1,635 MW of scheduled imports). As a result, the DSO scheduled 400 MW of CAOR.

Real-time conditions

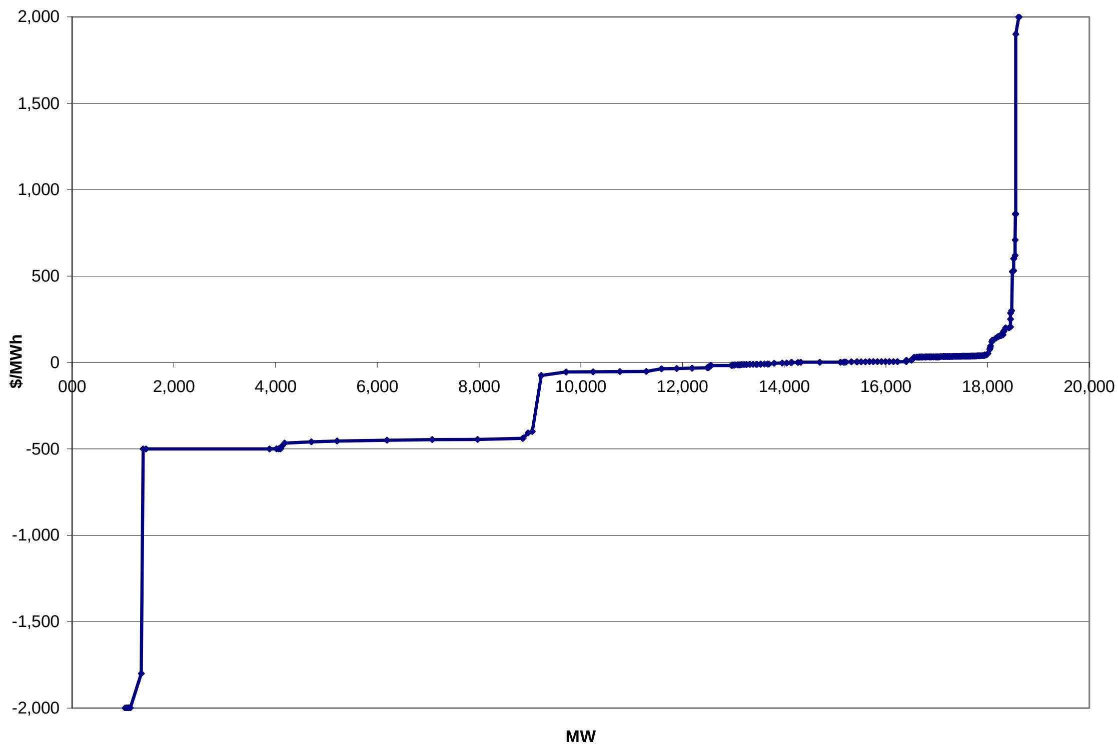
The HOEP reached a price of $204.56/MWh or 146 percent above the pre-dispatch price of $83.14/MWh, with the highest MCP at $569.95/MWh. The factors that led to the large discrepancy between the pre-dispatch and the real-time price were:

- Ontario Demand came in heavier than forecast. Average Ontario Demand in HE 12 was 17,864 MW while the peak demand was 17,952 in interval 3, or 216 MW (1.2 percent) higher than forecast one hour ahead.
- Self-scheduling generation produced 124 MW (10.1 percent) less than they forecast in pre-dispatch.
- There were 89 MW of failed net imports.
- There was a 45 MW derating to a fossil generator

The combined effect of these factors was to leave the real-time schedule 474 MW worse off than the pre-dispatch schedule and this placed upward pressure on real-time prices. Additional upward pressure on the MCP in the first interval of HE 12 was caused by an increase in net exports of 566 MW (from 1,122 MW in HE 11 to 1,688 MW in HE 12) which had to be accommodated in the first interval of HE 12.

Figure 2-2 plots the feasible offer curve for HE 12 interval 1 after taking into account the ramp rate capability.[59] The MCP was $569.95/MWh and the offer curve was extremely steep around this price. Although all offers are fixed for an hour, the availability of an offer can be different between intervals due to ramp rate limitations. For example, a fossil unit producing 54 MW in interval 12 of HE 11 offered 485 MW into the market for HE 12, but it could only move to 84 MW in interval 1 of HE 12.[60] In interval 2, its output could increase by a further 30 MW to 114 MW. Given the extremely steep offer curve around $569.95/MWh, the increase of 30 MW in baseload supply immediately pushed the MCP down to $230.22/MWh in interval 2.

Figure 2-2: Feasible Offer Curve, April 22, 2008, Hour 12, Interval 1



Assessment

As can be seen in Table 2-4 above, significantly higher prices were observed in interval 1 compared to the rest of the hour. As discussed in the Panel's December 2007 Monitoring

[59] The feasible offer curve is the maximum capable offers in the unconstrained sequence, taking into account the effect of the three times ramp rate assumption.
[60] The unit was scheduled 238 MW in the constrained sequence.

Report, high prices in interval 1 can be caused by a large increase in net exports on the hour combined with a sudden decrease in the amount of peaking hydroelectric generation scheduled relative to the preceding hour.[61] While net exports increased by 566 MW there was no significant change in hydroelectric resources as freshet was underway and most hydroelectric resources in the east were baseloaded.

To accommodate the combined 474 MW increase in demand and decrease in supply in Ontario and the 566 MW increase in net exports in interval 1, 1,040 MW of generation had to be ramped-up in that interval. With an already tight supply cushion it was necessary to turn to generators on the steep portion of the offer curve.

As noted above, one fossil-fired unit was scheduled to produce 54 MW in HE 11, interval 12. In the following interval (HE 12, interval 1), the unit was scheduled to ramp up further. With an upward ramping capability of 2 MW/minute, the unit was only able to increase by 30 MW/interval (after accounting for the 3x ramp rate) in the unconstrained schedule.[62] In interval 2, it was again able to increase by 30 MW and so on. While interval 1 had a price of $569.95/MWh, the MCP promptly declined to $230.22/MWh in interval 2 given an extremely steep supply curve. By interval 4, sufficient generation had ramped to push the MCP down to the vicinity of $180/MWh where it remained for six intervals before falling further.[63]

With respect to the 400 MW of CAOR scheduled in pre-dispatch, 284 MW of exports were designated as recallable on the Michigan interface by the IESO. The remaining 116 MW was supposed to be designated as recallable exports on the New York interface but was overlooked. If normal IESO procedures were followed, the New York interface would have had 116 MW more recallable exports, and in turn the NYISO would have cut

[61] See Panel's December 2007 Monitoring Report, pages 151-160.
[62] Physically the unit can only increase output by 10MW per interval, which is reflected by the constrained schedules.
[63] The constrained sequence appeared to have no problems because (1) it could look one hour ahead and schedule units with a slow ramp rate ahead of time; and (2) the Ontario demand in the constrained sequence decreased more than in the unconstrained sequence and the net export increased fewer in the constrained sequence than in the unconstrained sequence. In particular, the constrained sequence scheduled the slow ramping unit to about 250 MW in interval 1 of HE 12 in contrast to only 84 MW in the unconstrained sequence. The forecast Ontario demand was decreasing from 18,143 MW in HE 11 interval 12 to 17,841 MW in HE 12 interval 1, in contrast to only a 3 MW decrease in the unconstrained sequence (as showed in Table 2-4). And the increase in net exports was only 388 MW in the constrained sequence, compared to 566 MW in the unconstrained sequence.

these exports.[64] The cutting of these exports would have placed additional downward pressure on the HOEP because no imports/exports can respond to the suppressed price. However, the Panel believes the curtailment of recallable exports is a seam issue and should be properly dealt with as it leads to counter-intuitive prices. We will discuss the issue in details in Chapter 3.

2.2 *Analysis of Low Priced Hours*

Table 2-5 shows that the total number of winter hours with a low HOEP has been increasing period over period since 2005/2006. This is consistent with the observation that the number of hours with a high HOEP was smaller in 2006/07 and 2007/08 as a result of better supply/demand conditions. The higher number of low priced hours and the lower number of high priced hours reflects the shift in price distribution as illustrated in Figure 1-1 of Chapter 1.

Table 2-5: Number of Hours with a Low HOEP, November - April 2002/2003 to 2007/2008 (Number of Hours)

	Number of Hours with HOEP <$20/MWh					
	2002/ 2003	2003/ 2004	2004/ 2005	2005/ 2006	2006/ 2007	2007/ 2008
November	0	0	0	4	25	10
December	0	13	0	2	103	78
January	3	1	4	3	18	59
February	0	0	0	6	0	30
March	0	1	0	1	0	0
April	0	2	0	94	43	84
Total	3	17	4	110	189	261
% Change	n/a	467	(76)	2,650	72	38

The primary factors generally leading to low priced hours are:

- Low market demand. This typically occurs in the overnight hours, on holidays or during the spring/fall seasons.
- Abundant baseload supply from hydro-electric generators. This occurs most frequently during the spring-time months of April and May when even peaking

[64] New York's procedure since June 2007 is to decline any export to New York which is designated as recallable.

hydroelectric plants have abundant water from spring snow melt and increased rainfall, but it can occur at other times.

While these are the primary factors that contribute to a HOEP less than $20/MWh, demand forecast errors and failed export transactions can also place additional downward pressure on the HOEP.

All 5 hours with a negative HOEP occurred in early morning off-peak hours, HE 2 through HE 5 on February 18, 2008 and in HE 4 on April 25, 2008.

The MAU's review of these low priced hours between November 2007 and April 2008 indicates that they were mainly a result of low Ontario demand in combination with failed exports and over-forecasts of demand. When real-time demand is low, baseload generation may be sufficient to meet it, leading to very low prices.

Table 2-6 summarises the average monthly data on low priced hours by month and Table A-53 in the Statistical Appendix has detailed hourly statistics on these hours.[65]

Table 2-6: Average Monthly Summary Data for Low Priced Hours November 2007 –April 2008 ($/MWh and MW)

Delivery Month	Number of Low-Priced Hours	Failed Net Exports (MW)	Real Time Ontario Demand (MW)	Pre-dispatch Ontario Demand (MW)	Demand Over-forecast (MW)	HOEP $/MWh	Pre-dispatch Price $/MWh	Difference (RT-Pre-dispatch) $/MWh
November	10	297	14,188	14,320	132	9.51	25.64	(16.13)
December	78	202	14,875	15,053	178	10.94	21.18	(10.24)
January	59	139	15,074	15,365	291	9.48	20.13	(10.65)
February	30	558	15,452	15,741	289	7.56	25.18	(17.62)
April	84	103	13,079	13,335	256	7.54	19.82	(12.28)
Average /Total	261	201	14,382	14,621	239	9.07	21.13	(12.06)

[65] March 2008 is missing from the summary table since there were no low priced hours during the month.

2.2.1 Negative Prices: February 18, 2008 HE 2 - HE 5

The HOEP was negative in four hours from HE 2 through HE 5 on February 18, 2008. The minus $2.72/MWh in HE 3 was the second lowest HOEP since market opening (the lowest HOEP was minus $3.10/MWh in HE 5 on September 3, 2006).

Prices

Table 2-7 lists the interval MCP and HOEP for HE 2 to HE 5. The lowest MCP was minus $31.00/MWh which occurred in HE 5 interval 1 and is the lowest MCP since market opening.

Table 2-7: MCP and HOEP, February 18, 2008, HE 2 to HE 5 ($/MWh)

Hour	Interval												HOEP
	1	2	3	4	5	6	7	8	9	10	11	12	
2	1.70	0.00	0.00	(4.08)	(3.81)	(4.08)	(4.08)	(4.08)	1.70	(3.81)	(4.08)	1.70	(1.91)
3	(0.06)	(0.06)	(4.08)	(0.06)	(4.08)	(4.08)	(3.81)	(0.06)	(4.08)	(4.13)	(4.08)	(4.08)	(2.72)
4	(1.00)	(0.17)	(1.00)	(0.06)	(1.00)	(4.08)	(3.81)	(1.00)	(4.08)	(0.17)	(0.17)	(0.17)	(1.39)
5	(31.00)	0.00	(1.00)	1.70	1.80	1.70	1.80	3.75	1.80	3.75	3.85	4.00	(0.65)

Compared to external markets, the Ontario price was much lower, implying a significant profit opportunity to export from Ontario if an exporter could anticipate the low prices. Table 2-8 shows the real-time price in Ontario and neighbouring markets. The HOEP was consistently lower than the prices in New York, New England, PJM and Michigan. However, Ontario still imported more than 1,000 MW in each hour, which is in the opposite of what the price differential would have predicted. A large portion of the imports were induced by a binding Net Interchange Scheduling Limit (NISL), which is simply the maximum allowed net intertie change between hours. In Ontario this is usually set at 700 MW. We will discuss the NISL in more detail in later sections.

Table 2-8: HOEP and External Prices in Neighbouring Markets, February 18, 2008, HE 2 to5 (CDN$/MWh)[66]

Hour	HOEP	NYISO Zone OH	NYISO Zone HQ	ISONE Internal Hub	PJM West HUB	MISO-Michigan Hub
2	(1.9)	8.28	13.96	69.87	25.85	25.23
3	(2.71)	11.28	19.04	42.54	25.49	24.99
4	(1.39)	3.99	2.16	5.56	24.83	24.87
5	(0.63)	24.72	27.44	40.46	26.71	26.54

Day-Ahead Conditions

The day-ahead Ontario forecast demand for HE 2 to HE 5 was around 15,000 MW, with a price of $0/MWh for all hours. The DACP scheduled 11 large fossil-fired generating units online, with all units scheduled at their respective preferred minimum output level. No generator was eligible for Day-Ahead Generation Cost Guarantee (DAGCG) for these hours. The total generation scheduled from these units was 1,128 MW. No imports were scheduled.

The day-ahead supply cushion for these hours was about 74 percent.

Pre-dispatch Conditions

The two hour-ahead forecast Ontario demand varied from a high of 15,035 in HE 2 to a low of 14,309 MW in HE 4. The two hour ahead pre-dispatch price were between $13.05/MWh and $24.20/MWh.

The one-hour ahead forecast Ontario demand was very close to the two-hour ahead forecast, with a supply cushion above 35 percent in all hours. The one-hour ahead pre-dispatch prices were between $4.40/MWh and $7.55/MWh, which was much lower than the two-hour ahead pre-dispatch price. Table 2-9 lists the summary information for the two-hour and one-hour ahead pre-dispatch runs.

[66] The U.S. market prices were converted at the February (18) exchange rate of $1USD=$1.0075CDN

The lower one-hour ahead price was a result of export failures in the previous hour which led to a binding NISL for the dispatch of the coming hour. When the NISL is binding, imports and exports are scheduled independently of the Ontario price although they still affect the Ontario price. In other words, when scheduling imports and exports, the DSO looks at import and export offers only and schedule imports and exports until the NISL limit is reached. However, the reduced (net) export capability resulting from a binding NISL has the effect of reducing the pre-dispatch price for the coming hour. We will discuss the impact of NISL further in the Assessment section.

Table 2-9: Two and One Hour Ahead Pre-dispatch Conditions February 18, 2008, HE 2 to 5

Hour	2 Hour-Ahead		One Hour-Ahead				
	Ontario Demand (MW)	PD Price ($/MWh)	Ontario Demand (MW)	PD Price ($/MWh)	Supply Cushion (%)	Import (MW)	Export (MW)
2	15,035	24.20	15,224	7.55	35.2	1,226	1,971
3	14,792	20.78	14,637	4.80	41.1	1,332	1,927
4	14,309	13.05	14,294	4.40	43.2	1,141	1,753
5	14,375	13.05	14,556	4.50	40.5	1,102	1,789

Real-time Conditions

Real-time Ontario demand came in lighter than expected in all hours except HE 4. Table 2-10 shows the forecast peak demand, real-time peak demand and hourly average demand. The peak market demand was over-forecast by 468 MW in HE 2, 137 MW in HE 3 and 89 MW in HE 5. In HE 4, however, the peak market demand came in slightly higher than forecast.

Table 2-10: Pre-dispatch and Real-time Ontario Demand, February 18, 2008, HE 2 to5 (MW)

	Final PD Demand	RT Peak Demand	RT Average Demand	Peak vs peak (PD-RT)	Peak vs Average (PD-RT)
2	15,224	14,756	14,628	468	596
3	14,637	14,500	14,389	137	248
4	14,294	14,335	14,276	(41)	18
5	14,556	14,467	14,372	89	184

After the final pre-dispatch run and before the real-time dispatch run for each hour, large amounts of exports were failed on the New York interface. Import and export failures are shown in Table 2-11. These exports were scheduled by the pre-dispatch sequence in Ontario, but failed to be scheduled by the New York hour-ahead sequence because they were offered at too high a price in New York. These export failures place significant downward pressure on the HOEP in the hour.

Table 2-11: Pre-dispatch and Real-time Imports and Exports, February 18, 2008, HE 2 to5 (MW)

	Imports			Exports		
	PD	**RT**	**Failure**	**PD**	**RT**	**Failure**
2	1,226	1,226	0	1971	1,121	850
3	1,332	1,305	27	1927	1,217	710
4	1,141	1,141	0	1753	1,128	625
5	1,102	1,102	0	1789	1,186	603

All dispatchable, self scheduling and intermittent generators were performing as expected in these hours and thus did not contribute to the fall in HOEP compared to the pre-dispatch price.

As illustrated above, there are two factors that contributed to the low HOEP in these hours; export failure and demand overforecast, with export failure having a much greater impact. However, further downward pressure on the HOEP was largely mitigated by the derating of the six fossil-fired units by 550 MW which will be discussed later.

Export Failures

Table 2-12 lists the scheduled net exports (PD Net Exports), realized net exports (RT Net Exports), NISL, net export failures, and indicator of a binding NISL. In HE 1, failed exports amounted to 890 MW, which directly led to a binding NISL for HE 2. Failed net exports exceeded 600 MW from HE 2 to HE 5. The large amount of export failures easily led to a binding NISL. For example, the net exports were only 45 MW in HE 1 when 890 MW of exports failed. Because of the NISL, maximum net exports allowed were only 745 MW for HE 2, and the DSO scheduled net exports up to the maximum allowed level. In fact, from HE 2 to 10, net exports scheduled in pre-dispatch were at the maximum allowed by the NISL in every hour.

Table 2-12: Pre-dispatch and Real-time Net Exports and Net Interchange Scheduling Limits, February 18, 2008, HE 1 to 10

Delivery Hour	PD Net Exports	RT Net Exports	Net Export Failure	NISL	Is NISL Binding?	Maximum Net Exports Allowed
1	935	45	890	700	N/A	N/A
2	745	(105)	850	700	Yes	745
3	595	-88	683	700	Yes	595
4	612	(13)	625	700	Yes	612
5	687	84	603	700	Yes	687
6	784	534	250	700	Yes	784
7	1,234	1,092	142	700	Yes	1,234
8	1,792	1,367	425	700	Yes	1,792
9	2,067	1,502	565	700	Yes	2,067
10	2,202	2,152	50	700	Yes	2,202

If exports had not failed in such high volumes, the NISL would not have been binding and real-time prices would have been closer to the pre-dispatch prices. Table 2-13 and Table 2-14 show the comparison of actual and simulated outcomes and the efficiency loss due to export failure, respectively. If all exports had flowed successfully, the pre-dispatch price would have been above $22/MWh in all hours and the HOEP would be similar to the pre-dispatch price. The binding NISL resulted in more imports scheduled at offer prices above the pre-dispatch price, but had no impact on exports.[67] The importers did not suffer from a lower pre-dispatch and HOEP as they were paid an IOG. The total cost of the extra imports in the four hours was $97,000, and the avoided production cost (due to more imports) was $33,000.[68] The net efficiency loss due to export failure was $64K in the four hours.

Table 2-13: Comparison of Actual and Simulated Results
February 18, 2008, HE 2 to 5

Hour	PD Price ($/MWh)	Simulated PD Without Export Failure ($/MWh)	HOEP[69] ($/MWh)	Simulated HOEP Without Export Failure ($/MWh)	Import (MW)	Simulated Import Without Export Failure (MW)	Export (MW)	Simulated Export Without Export Failure (MW)	Net Export Difference (Simulated – Actual) (MW)
2	7.55	27.70	(1.91)	23.45	1,226	535	1,971	1,971	691
3	4.80	22.50	(2.72)	21.07	1,332	677	1,927	1,927	655
4	4.40	23.35	(1.39)	22.07	1,141	458	1,753	1,753	683
5	4.50	22.49	(0.65)	25.35	1,102	477	1,789	1,789	625
Total					4,801	2,147	7,440	7,440	2,654

Table 2-14: Estimates of the Efficiency Loss
due to Export Failure and the Binding NISL,
February 18, 2008, HE 2 to 5

Hour	Cost to Additional Imports ($'000)	Production Cost Savings ($'000)	Efficiency Loss Due to Export Failure ($'000)
2	22	10	12
3	21	6	15
4	26	8	18
5	28	9	19
Total	97	33	64

[67] This implies that no exports that were offered between $4/MWh and $23/MWh were dispatched even though the pre-dispatch price was about $4/MWh. This is rational because scheduling additional 1 MW export needs to schedule additional 1 MW imports (because of a binding NISL), which has a higher offer price than the export bid. The DSO then finds that not scheduling the export is more efficient.
[68] The cost estimation is based on the simulation of the unconstrained sequence.
[69] We report actual HOEP instead of "simulated actual" HOEP here because our simulation tool generates a HOEP around $4/MWh, much greater than the actual. The price difference appears to be related to the difference in convergence methodology between the simulation tool and the IESO's DSO. However, the simulation tool and the DSO produce the same schedule in the majority of intervals. Therefore, the difference in price does not materially affect the efficiency calculation because efficiency estimation is based on the schedules and their respective offer, rather than the simulated price.

Exports that induce imports and then fail tend to reduce the HOEP because the imports are scheduled for demand (the exports) that no longer exists. Directionally, increased supply (imports) and reduced demand (failed exports) should drive price down. The inducement for the exporter not to fail is the real-time Intertie Failure Charge (IFC). However, due to the small price difference between pre-dispatch and real-time, the penalty is low during these hours.[70] Potentially, a market participant could have an inducement to fail an export transaction if, the benefit from a lower HOEP on remaining exports would more than offset the failure charge. Monitoring and assessing such behaviour is part of the MAU's daily routine activity. In the four hours concerned, the market participant accounting for the vast majority of failed exports was charged about $8,000 of IFC. Because this market participant did not have a large amount of other exports at the same time, the reduction in its export cost due to a lower price was estimated at only $7,000. That is, in these hours, this market participant did not receive a net gain from its export transaction failures.

The NISL of 700 MW was instituted by IESO after discussions with market participants prior to market opening and was primarily intended to be reflective of the ability of domestic generation to ramp up or down in response to abrupt import/ export changes on the hour. Other considerations include potential impacts on the market price and the volume of intertie trades. The primary focus was on ramp-limited fossil generators because they were presumed to be the marginal resource most of the time. But at times fossil generation is not at the margin, those times typically being:

- In extremely high demand periods where hydroelectric generation may be on the margin (indeed an explicit IESO control action during high demand periods is to expand NISL to maximize net imports).[71]
- In low demand periods where hydroelectric generation may be on the margin and can ramp up quickly to handle much larger changes in NISL (hydroelectric

[70] The IFC will adjust for a factor of about $2/MWh in these hours. For example, the PD price is $4.5/MWh and the HOEP is -$1.5/MWh. The penalty to an exporter is $4/MWh (i.e. $4.5/MWh-(-$1.5/MWh)-$2/MWh). For a full detail on IFC, check the IESO's website: http://www.ieso.ca/imoweb/settlement/se-itf.asp

[71] According to IESO's Operational Manual 2: Market and System Operations, Part 2.4: Real-time Market Operating Procedure, the NISL can be expanded to 1,000MW during EEA level 1 and 1,200MW during EEA level 2 and above. In the period, from May 2007 to April 2008, the IESO increased the NISL in five incidents for a total of 42 hours.

generation is typically not ramp-limited and can ramp from minimum to full within one interval.

Recommendation 2-1:

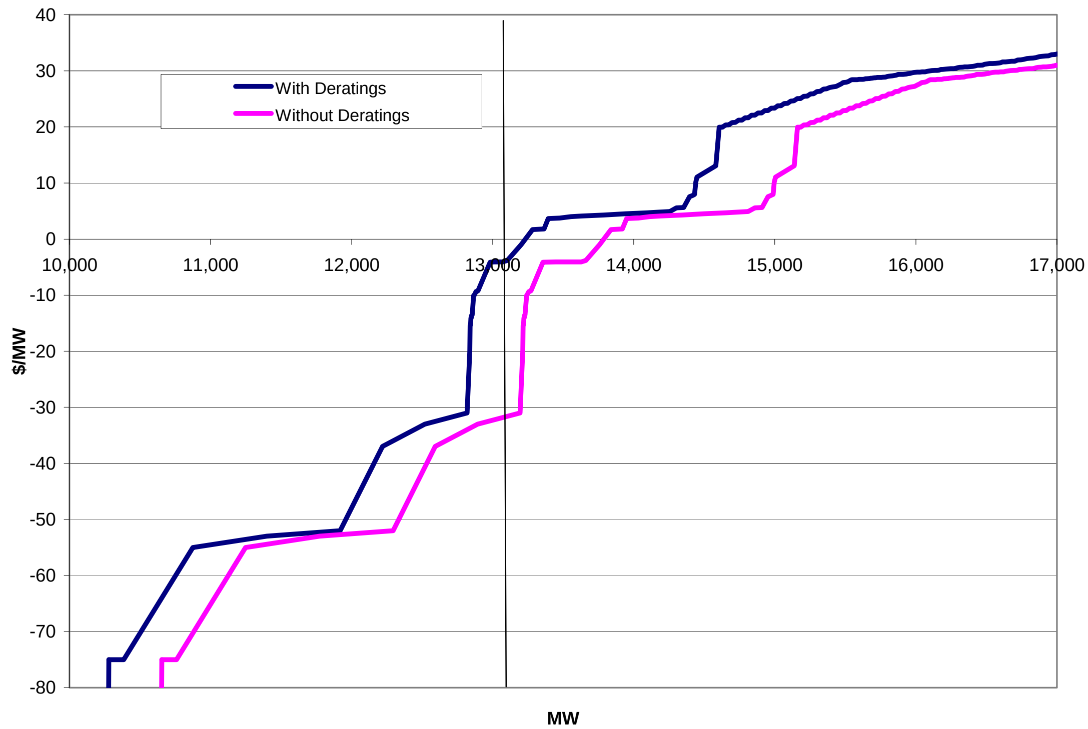
The MSP reiterates the recommendation in its June 2007 report that the IESO should review the 700 MW Net Interchange Scheduling Limit (NISL). This review should take into account the effects on potential efficient exports from Ontario in addition to the import issues raised in the MSP's prior report.

Derating of Several Fossil Units

A few minutes before the final pre-dispatch run for HE 2, a market participant derated several units at a fossil-fired station, thus removing a total of 550 MW of offers from the market schedule. The deratings were applied up to the end of HE 7. The participant derated these units to their minimum operating levels in anticipation of "excess baseload generation" so that baseload hydroelectric generators would not spill water.

The deratings of the baseload generating units had the effect of significantly increasing the HOEP. Take HE 3 as an example. Had the units not been derated, there would have been an additional 550 MW baseload supply, implying an even lower HOEP. Figure 2-3 compares the generation offer curve with and without the deratings. The blue line is the offer curve with the deratings and the pink line without the deratings. Based on these curves, the HOEP would have been below minus $30.00/MWh had the units not been derated, compared to a graphically estimated HOEP of minus $4.00/MWh with the deratings.

Figure 2-3: Comparison of Supply Curves with and without the Fossil Unit Deratings, February 18, 2008, HE 3



The Panel understands the economic incentives for a generator to use more baseload hydroelectric resources. However, it believes that should be addressed through an appropriate offer structure. In other words, generators' offers should reflect their willingness to operate or not operate. With an appropriate offer structure the marketplace will provide both the economic dispatch signal the market participant desires and the correct price.

The MAU investigated and determined that the issue is the registration of a generator's minimum output. The IESO tools presently prevent generators from being dispatched below their Minimum Loading Point, unless the IESO manually intervenes in the process at the market participant's request or the participant derates the generator. The IESO's definition of *Minimum Loading Point* is "the minimum output of energy specified by the market participant that can be produced by a generation facility under stable conditions without ignition support".[72] In this particular case the generator for economic reasons wished to reduce its output below its defined Minimum Loading Point. The market participant submitted a derating in order to operate the unit at a level which was feasible. But with a minor definitional change by the IESO as to what minimum loading point is, the market participant could have offered at a price in the market to gain the desired output without having to resort to out of market actions such as deratings, which in turn created price impacts.

The IESO's Compliance group is undertaking an investigation to determine the appropriateness of a unit derating for what could be considered to be an economic issue as this has occurred on a repeated basis.

Assessment

The major causes of the negative price in HE 2 to 5 on February 18, 2008 were the large export failures and a binding NISL in each hour. The binding NISL also led to (1) fewer exports and (2) more imports than it should, both of which contributed to the negative prices in these hours. The export failure and the subsequent binding NISL in the four hours also resulted in a $64,000 efficiency loss to the market.

Persistently failing export or import transactions could be a form of gaming behaviour as this could lead to:

a. a binding NISL and thus counter-intuitively low price in both pre-dispatch and real-time.
b. a lower price for other exports. If a trader has many exports transactions, failing portion of them could induce a lower real-time price and thus reduce the price the trader pays for its other exports. This strategy would be profitable if the failure charge is smaller than the cost saving on the successful exports.

[72] IESO's Market Rules, Chapter 11: Definitions.

c. a lower price for its Ontario customers. When the trader also has obligations to serve its Ontario customers with whom it has a long term fixed price contract, a lower real-time price would appear to be profitable.

After a full study on the events in these hours, the MAU determined that the market participant who persistently failed its exports was not gaming. The MAU is monitoring such incidents of this nature on a daily basis.

2.2.2 April 25, 2008, Hour 4

In HE 4 on April 25, 2008, the HOEP fell to -$0.12/MWh. Table 2-15 presents real-time energy market clearing prices (MCP) over all intervals in this hour along with Ontario demand. The lowest MCP occurred in the first two intervals of the hour when the MCP was -$4.04/MWh. It remained negative or zero until interval 10.

Table 2-15 – Pre-dispatch and Real-time Energy Prices and Demand by Interval, April 25, 2008, HE 4

Hour	Interval	MCP ($/MWh)			Ontario Demand (MW)		
		Pre-dispatch	Real-time	Difference (RT-PD)	Pre-dispatch	Real-time	Difference (RT-PD)
4	**1**	3.00	(4.04)	(7.04)	13,049	12,702	(347)
4	**2**	3.00	(4.04)	(7.04)	13,049	12,677	(372)
4	**3**	3.00	(1.00)	(4.00)	13,049	12,721	(328)
4	**4**	3.00	(1.00)	(4.00)	13,049	12,743	(306)
4	**5**	3.00	(1.00)	(4.00)	13,049	12,736	(313)
4	**6**	3.00	(0.01)	(3.01)	13,049	12,756	(293)
4	**7**	3.00	0.00	(3.00)	13,049	12,791	(258)
4	**8**	3.00	0.00	(3.00)	13,049	12,778	(271)
4	**9**	3.00	0.00	(3.00)	13,049	12,778	(271)
4	**10**	3.00	3.21	0.21	13,049	12,850	(199)
4	**11**	3.00	3.12	0.12	13,049	12,803	(246)
4	**12**	3.00	3.30	0.30	13,049	12,883	(166)
Average		3.00	(0.12)	(3.12)	13,049	12,768	(281)

Day Ahead Market conditions

Going into April 25, 2008, there were over 25,000 MW of offers through the DACP to meet Ontario Demand, OR, and export demand requirements in HE 4 including 10 fossil units offering over 4,700 MW. The day-ahead supply cushion was 105 percent. There were no imports scheduled in DACP as there was more than sufficient and more economic generation available internally. The weather forecast indicated somewhat mild overnight temperatures, above 10 degrees in the Toronto area.

Pre-dispatch Market Conditions

Pre-dispatch Ontario Demand (one-hour ahead) was forecast to be relatively low at 13,049 MW in HE 4 with a pre-dispatch price of $3.00/MWh. The pre-dispatch total supply cushion was 32.1 percent, reflective of more than adequate supply to meet the demand conditions.

Although a pre-dispatch price of $3.00/MWh would appear attractive to exporters had they anticipated it, traders would have had to make their export decisions and submit offers into the market two-hours ahead. However, the three-hour ahead pre-dispatch price was $26.83/MWh, at the time similar to prices in other markets and hence offering little attractiveness to traders.

Increasing amounts of clockwise Lake Erie Circulation (LEC), or loop flow, led to the intertie export scheduling limits to New York being lowered by IESO from 850 MW to 0 MW in HE 2. The following is as an explanation as to why the IESO lowered the intertie limit to 0 MW. Before the final pre-dispatch run, the IESO checks the NERC Interchange Distribution Calculator (IDC) and determines the expected level of loop flow on both the New York and Michigan interface.[73] Based on the information from the IDC, the IESO determines how much loop flow is firm (i.e. induced by firm transactions) and how much is non-firm. The IESO then adjusts the import/export capability based on the firm loop flow expected on the interface. In the current case, the IESO determined the

[73] The IDC is an integrated system designed to assist reliability coordinators (system operators) in managing congestion in the interconnected grid. Use of the tool allows these operators to coordinate congestion relief procedures across markets, and control areas.[73] The IDC prioritizes the intertie transactions based on tag associated with each transaction and determines the transaction's impact upon each flow-gate. The tool also uses the tags to identify which transactions are firm and which are non-firm. Firm transactions are typically those transactions that have purchased firm transmission service, and have a higher priority of being scheduled between markets when congestion occurs.

firm loop flow would use up all export capacity and thus reduced the export capacity to zero on the New York interface.

The Panel understands that the IESO's policy is that firm transactions that induce loop flow should not be curtailed as they could lead to significant reliability problems in the Ontario market as well as a significant amount of changes in scheduling of intertie transaction between system operators.[74] As a result, the firm-transaction-induced loop flow is accounted for in setting intertie scheduling limits at the Ontario border. In other words, the IESO is willing to re-dispatch Ontario resources or forego imports or exports in order to allow firm loop flow.

While firm loop flow is taken into account in the IESO's determination of intertie scheduling limits in pre-dispatch, non-firm loop flow is not. If a transmission interface is operating above its limits due to non-firm loop flow, the IESO may issue a Transmission Loading Relief order (TLR3a) to cut non-firm transactions contributing to this overload condition. The NERC IDC process will identify those transactions contributing to an overload condition on a particular interface. The IESO can then order the portion of these non-firm transactions identified by IDC to be cut in order to get the flow on the limiting transmission circuit back within its operating limits. In the interim until this process works its way through the various markets and finds the transactions that contributing the congestion, the IESO will re-dispatch internal generation to meet the transmission limits on the interface.

If cutting non-firm transactions is not sufficient to get a circuit below its operating limits the IESO will issue a TLR5 and begin to cut firm transactions according to selections made by the IDC.

[74] These firm transactions are curtailable. But curtailing them could have a large impact on the Ontario system because we may have to curtail native contributions to the loopflow which is more difficult and can cause other adequacy issues.

Since there was little change in the three-hour ahead and one hour-ahead demand forecast, the abrupt 850 MW drop in export capability to New York was the primary reason for the drop in the pre-dispatch price from the 3 hour-ahead to the 1 hour-ahead.

Real-time Market conditions

Several factors contributed to the negative real-time price. Average real-time Ontario demand was 12,768 MW (281 MW or 2.2 percent lower than the forecast peak demand) for the hour and peak interval Ontario demand in the hour was 12,883 MW in interval 12, which is 166 MW (1.3 percent) lower than forecast in pre-dispatch. On an interval basis, the largest discrepancy between pre-dispatch and real-time demand occurred in interval 2 where the difference was over 370 MW. Self-scheduled generators produced 23 MW (0.2 percent) more than forecast which placed further downward pressure on real-time prices. There were no import failures or export failures in the hour so that cumulatively, real-time market demand was lower than pre-dispatch by slightly over 300 MW (2.3 percent).

When prices in Ontario are low, exporters tend to move energy to higher-priced neighbouring jurisdictions. Real-time New York Zone OH prices were above $60/MWh so there was a profitable opportunity for traders to move energy out of Ontario if they were charged the Ontario uniform price.[75] However in HE 4, the net export capability to New York was reduced to zero due to large amounts of clockwise LEC, which limited the maximum amount of exports to 845 MW as there were only 845 MW of imports scheduled. The reduction in the export capability led to a congestion price in pre-dispatch on the New York interface ($229/MWh in the New York zone and $3/MWh in the Ontario zone).

When the IESO set the net export limit to 0 MW due to loop flow, it does not mean exports cannot flow to New York. Rather, the net flow over the intertie must be 0 MW. In other words 1 MW can export if 1 MW is imported and the resultant net schedule on the tie is 0 MW. In this particular case the congested price of $229/MWh at the intertie

[75] New York Zone OH represents the New York/Ontario border price.

meant someone was bidding to buy energy at $229/MWh to export from Ontario. Since the net scheduling limit was 0 MW, to satisfy this export an import was offering to sell to Ontario from New York at a lower offer price and the IESO dispatch algorithm accepted both trades with the offsetting flows. With sufficient time one would expect that intertie prices would converge towards $60 which was the NYISO price, but due to the timing of the change in the scheduling limit from 850 MW to 0 MW there was insufficient time for importer/exporter response.

On Michigan, the other major exporting interface, the export limit was 1,800 MW. While the IESO accounted for 1,500 MW of clockwise loop flow in calculating the scheduling limit on the New York interface, it did not account for this clockwise loop flow in determining the Michigan export limit. In other words, the actually feasible export capability was higher than the IESO assigned in its dispatch tool. Although the 1,800 MW limit did not prevent exports to Michigan. In fact, while the actual schedule of net exports from Ontario to Michigan was 1,357 MW in HE 4, the actual power flow was -34 MW (from Michigan to Ontario), implying a clockwise loop flow of 1,391MW.

In these low demand/low priced overnight hours Ontario's baseload generators begin to be marginal (hydroelectric spill or manoeuvring nuclear generators may occur). By HE 2 a nuclear unit began to receive dispatches to lower its output as it became marginal in the constrained sequence and as a result its output was constrained down by a total of 300 MW.[76]

Derating of Several Fossil Units

A generator derated four baseload fossil units by a total of 280 MW beginning in HE 2 in order to avoid spill at a baseload hydro unit. The derating of the fossil units had the effect of increasing the real-time price. The MAU ran a simulation assuming the four

[76] Nuclear units can reduce output at a potentially high cost by simply condensing the steam from their reactors rather than manoeuvring the reactor. The potential cost is high because condensing the steam from the reactors might potentially force the reactors out of service. Nuclear generators thus usually are unwilling to adjust their output, unless the IESO instructs them to do so for system reliability.

units had not been derated, and found that the HOEP would have been -$5.95/MWh (ie. $5.83/MWh lower) had the four units not been derated. As in the previous section, the Panel recommends that participants should revise its offer to avoid such a derating that may be considered to be not legitimate reduction in its physical capability.

Assessment

In this hour, significant quantities of firm loop flow crowded out economic exports to other markets, such as New York. The abrupt reduction in export capability led to a negative HOEP and a nuclear generator being constrained down by 300 MW (which had no effect on the HOEP).

2.2.3 Counter-intuitive Pricing Due to Failed Intertie Transactions

The Panel has long observed that the failed intertie transactions are an important cause of the gap between the pre-dispatch and real-time price. In particular, a failed import results in less supply in real-time than projected in pre-dispatch and thus pushes up the real-time price relative to the pre-dispatch price. Similarly, a failed export leads to less demand in real-time and thus reduces the real-time price compared to the pre-dispatch price.

To deal with the price fidelity problem as well as reliability problems induced by failed intertie transactions, the IESO introduced an Intertie Failure Charge in June 2006. As illustrated in Chapter 1, it has significantly reduced the export failure rate and to a lesser extent the import failure rate. The failure charge requires an exporter to make a payment if there is a decrease in the real-time price and an importer to make a payment if there is an increase in the real-time price when its transaction fails. The benchmark price is the Ontario pre-dispatch price plus or minus an adjustment factor, which is based on the historical difference between the pre-dispatch and real-time price. Since June 2006 the Panel has observed a narrowing gap between the two prices.

It is not always the case, however, that a failed import leads to a higher real-time price and a failed export to a lower real-time price. To the contrary, in some cases, a failed import leads to a lower real-time price and a failed export to a higher real time price. This counter-intuitive change in the market price reduces market efficiency.

The above-noted price effects warrant discussion. The cause for such counter-intuitive results is the Ontario market design which has two separate sequences (the constrained and unconstrained sequence) and the way the IESO treats export/import failures in each sequence. In this section we are interested in the subset of cases in which counter-intuitive price changes in the unconstrained sequence can be traced back to an export/import transaction failure, as opposed to other causes.

An intertie transaction scheduled in the final pre-dispatch can fail for a variety of reasons.

- Internal transmission congestion or (rarely) IESO internal scheduling errors (e.g. as a result of computer software problems). In this case, the IESO uses the ‘TLRi’ code for the transaction failure.
- The IESO may curtail an export for internal adequacy by using ‘ADQh’ when internal resources are insufficient to meet the demand.
- External markets or operators may curtail a transaction for their own internal security. The IESO codes this failure with ‘TRLe’.
- An export may be cut for operating reserve activation. The code for this control action is ‘ORA’.
- A transaction may fail due to inability to acquire transmission service or ramping limitation in MISO or New York. This type of failure is coded with ‘MrNh’.
- A transaction may fail because of an incorrect e-tag or the corresponding transaction not being scheduled in the neighboring market. This type of transaction failure is coded with ‘OTH’.

OTH failures are regarded as the responsibility of the market participant involved and are subject to failure charges. The other types of failures are not regarded as controllable by the market participant and are not subject to failure charges.

Although 'TLRi' and 'ORA' do not affect the unconstrained sequence, all other codes do.[77] The IESO procedure is to carry over the scheduled import/export energy in the constrained sequence (after failure) to the unconstrained sequence when 'ADQh', 'OTH', 'TLRe' or 'MrNh' is used.[78] In doing so, the CMSC payment to the market participants involved is avoided (participants also avoid paying a negative CMSC in some cases).[79] But, at times, this practice has a perverse impact on the real-time price. We will have a full discussion on the codes and their implication in Chapter 3.

In its December 2007 Monitoring Report, the Panel observed that the curtailment of exports for adequacy ('ADQh') has led to counter-intuitive prices (prices that do not reflect actual demand and supply conditions) and market inefficiency. The Panel recommended that the IESO not remove exports curtailed for adequacy from the market schedule.[80]

The use of 'ADQh', 'OTH', 'TLRe' and 'MrNh' codes can also lead to other types of counter-intuitive price impacts:

- A failed import can increase the supply in the unconstrained sequence and thus decrease the real-time price (Example 1 below); and
- A failed export can increase the demand in the unconstrained sequence and thus increase the real-time price (Example 2 below).

The counter-intuitive effects of transaction failures on the real-time price are illustrated in the following two examples.

Example 1: April 14, 2008, HE20 – a failed import decreased the real-time price

On April 14, 2008 in HE 20, a market participant was scheduled to import 164 MW from New York in the pre-dispatch constrained sequence. The same transaction was not

[77] Note all these situations affect the constrained sequence.
[78] Procedure 2.4-7 "Interchange Operations' Appendix B: Summary of Instructions on the Application of Reason Codes and Market Manual 4 Appendix C: Application of Interchange Schedule Codes.
[79] A necessary condition for a CMSC payment is that the constrained schedule must be different from the unconstrained schedule. When the two schedules are the same, there will be no CMSC, negative or positive.
[80] The Panel's December 2007 Monitoring Report, page 100-103

scheduled in the unconstrained sequence (implying the import was constrained on). During the 30 minute check-out period, 66 MW was curtailed by the NY ISO due to security problems in New York. Thus the actual schedule was 98 MW in the constrained sequence. With the application of a TLRe code by the IESO, the real-time unconstrained sequence is adjusted from its original 0 MW to 98 MW**.** As a result, the real-time unconstrained sequence had 98 MW more imports than the pre-dispatch (0 MW), and the real-time price was suppressed by the import failure.[81] Had the 98 MW import not been inserted into the unconstrained sequence, a simulation indicates that the HOEP would have been $40.22/MWh, or $1.59/MWh (4.1 percent) higher than the actual HOEP of $38.63/MWh (see Table 2-16). This level would have more accurately reflected the marginal cost of the resources being used because an import failure logically should lead to an increase rather than a decrease in generation costs.

Table 2-16: Pre-dispatch and Real-Time Imports and Actual and Simulated Price, April 14, 2008, HE 20

	Constrained Sequence	Unconstrained Sequence	Simulated in the Unconstrained Sequence
Pre-dispatch Imports (MW)	164	0	
Real-Time Imports (MW)	98	98	0
Difference (RT-PD Imports) (MW)	(66)	98	
Difference in Imports as Percentage of Total Demand (%)	(0.36)	0.54	
Pre-dispatch Price ($/MWh)		87.00	87.00
Real-Time Price/HOEP ($/MWh)		38.63	40.22
Difference in Price (RT-PD) ($/MWh)		48.37	46.78
Difference as percentage of HOEP (%)		125	116

Example 2: April 8, 2008, HE14 – a failed export increased the real-time price

On April 8, 2008, HE 14, a market participant was scheduled to export 147 MW to Manitoba in the pre-dispatch constrained sequence. This was a constrained-on export and the transaction was not scheduled in the unconstrained sequence (0 MW). However, due to a transmission line limit in Manitoba (TLRe), the transaction was reduced to

[81] Note due to an import being unable to set the real-time price, the DSO subtracts the amount of import from the total demand and then allows internal generators and loads to calculate the price. A greater import implies a lower demand for internal generation and thus a lower real-time price.

121 MW. The TLRe code makes both the constrained and unconstrained schedule match the constrained amount. As a result, the real-time unconstrained sequence had 121 MW more exports than the pre-dispatch (0 MW), and the real-time price was increased by the export failure. Had the 121 MW not been inserted into the unconstrained sequence, a simulation indicates that the HOEP would have been $50.35/MWh, or $6.59/MWh (11.6 percent) lower than the simulated "actual" HOEP of $56.94/MWh (see Table 2-17 below). This level would have more accurately reflected the marginal cost of the resources being used because an export failure logically should lead to a decrease rather than an increase in generation costs.

Table 2-17: Pre-dispatch and Real-Time Imports and Actual and Simulated Price, April 8, 2008, HE 14

	Constrained Sequence	Unconstrained Sequence	Schedule in the Unconstrained Simulator
Pre-dispatch Exports (MW)	147	0	
Real-Time Exports (MW)	121	121	0
Difference (RT-PD Exports) (MW)	(36)	121	
Difference in Exports as Percentage of Total Demand (%)	(0.21)	0.69	
Pre-dispatch Price ($/MWh)		82.00	82.00
Real-Time Price/HOEP ($/MWh)		56.94	50.35
Difference in Price (RT-PD) ($/MWh)		25.06	31.65
Difference as percentage of HOEP (%)		44	63

The effect of the import/export failures in above two examples changes the HOEP in the opposite direction to that which would equilibrate supply and demand. In other words, a failed import can reduce the HOEP while a failed export can increase the HOEP.

Furthermore, the more a trader fails, the smaller impact the failure has on the HOEP. For example, in the two examples, if the whole transaction had failed, there would have been zero MW scheduled in both the constrained and unconstrained sequences and there would have been no impact on the HOEP.

The Panel's comments

In past reports, the Panel has recommended a full Locational Marginal Pricing (LMP) approach in Ontario.[82] This would eliminate the unconstrained schedule, thereby improving market efficiency and eliminating counter-intuitive pricing incidents of the type described above. Incidents of this nature occur roughly 2 percent of time and are illustrative of the problems associated with having two schedules.

The treatment of partially failed transactions described above has the effect of excluding the market participants involved from getting a CMSC payment. For example, suppose an exporter is constrained on 200 MW (200 MW in the constrained sequence and 0 MW in the unconstrained sequence). If the export is cut to 199 MW, the market participant then looses its entitlement to the constrained-on payment for the whole 199 MW transaction if the HOEP turns out to be greater than its offer price, while another exporter whose export is not cut will get the full constrained-on payment.

The IESO's treatment of some export/import transaction failures distorts the HOEP. This suggests it may be appropriate to handle such import/export transaction failures differently than they are now. In the Panel's view, the key factor should be the reason why the transaction is failed. We will explore this issue in more depth and provide our recommendations in Chapter 3.

2.2.4 April 28, 2008 HE 12 to 14 – The $200/MWh HOEP that wasn't

On April 28, 2008, the HOEP was $65.09/MWh in HE 12, $189.33/MWh in HE 13 and $54.62/MWh in HE 14. These prices are not outside the Panel's price thresholds of $200/MWh for high priced hours or $20/MWh for low priced hours. Nevertheless, they warrant discussion because they do not reflect the tight supply conditions that prevailed in the market after two large nuclear units were sequentially forced out of service within 90 minutes. If it had not been for price-suppressing control actions taken by the IESO,

[82] See the Panel's July 2006 and July 2007 Monitoring Reports.

the HOEP would have been over $200/MWh in all three hours and the Panel would have been reporting on a price reflective of scarcity at the time.

In HE 12 interval 4, one nuclear unit experienced control computer problems and was forced to shutdown within a few intervals. This represented a loss of 810 MW of baseload generation in less than 20 minutes.

Ninety minutes later in HE 13 interval 10, another nuclear unit which was producing 890 MW at the time, was forced to shutdown due to moderator problems.

The loss of 1,700 MW in baseload generation in 90 minutes resulted in very tight supply conditions. Normally, these tight supply conditions would have been reflected in the market price. As a result of a series of IESO's control actions, however, the HOEP remained quite low (especially in HE 12 and 14) and this conveyed a perverse signal (consume more, generate less) to market participants.

Day-Ahead Conditions

The forecast Ontario demand at the DACP run was about 18,000 MW for HE 12 to 14, with a day-ahead supply cushion of about 44 percent. Fourteen large fossil-fired generators were scheduled online, ten of which were guaranteed the DACP GCG in the one or two hours prior to HE 12. No imports were scheduled for HE 12 to 14.

Pre-dispatch Conditions

Table 2-18 shows that pre-dispatch Ontario Demand was between 18,300 MW and 18,500 MW in HE 12 to 14. The supply cushion was very low, varying from 2.4 percent to 6.0 percent. The pre-dispatch MCP was only $55/MWh to $80/MWh. This is lower than expected given the very low supply cushion and it implies a very steep supply curve above the pre-dispatch price. The steep supply curve indicates an increased probability of a price spike when there is a forced outage, imports fail, or the IESO under forecasts demand.

Table 2-18: One Hour Ahead Pre-dispatch Conditions, April 28, 2008, HE 12 to 14

Delivery Hour	MCP ($/MWh)	Forecast Demand (MW)	Net Exports in the Unconstrained Sequence (MW)	Net Exports in the Constrained Sequence (MW)	Supply Cushion (%)
12	55.00	18,320	1,851	1,181	2.7
13	66.07	18,507	1,697	1,399	2.4
14	80.00	18,299	1,285	775	6.0

Ontario was a net exporter in these hours, with more than 1,000 MW net exports in both the unconstrained and constrained sequence in each hour (except in the constrained sequence for HE 14).

Real-time Supply Conditions

Table 2-19 lists key real-time information for HE 12 to 14. Supply conditions were tight, which is reflected by the low supply cushion in each hour.

Table 2-19: Real-Time Conditions, April 28, 2008, HE 12 to 14

Delivery Hour	PD MCP ($/MWh)	PD Ontario Demand (MW)	RT HOEP ($/MWh)	RT Average Ontario Demand (MW)	RT Peak Ontario Demand (MW)	Net Exports (MW)	Cumulated Forced Outage (MW)	RT Supply Cushion at Beginning of the Hour (%)
12	55.00	18,320	65.09	17,982	18,216	1,590	810	5.0
13	66.07	18,507	189.33	17,968	18,187	1,177	1,700	2.1
14	80.00	18,299	54.62	17,868	17,992	448	1,700	2.1

HE 12

After the final pre-dispatch run, 325 MW of exports failed on the NY interface because these exports were made recallable for CAOR.[83, 84] Meanwhile, 64 MW of imports failed

[83] There was 150 MW failed in the constrained sequence. Because of the separation of the unconstrained and constrained sequence, the 150 MW failure was transferred into 325 MW failure in the unconstrained sequence.

at the MISO interface due to ramp limitations. The net export failure was 261 MW in the unconstrained sequence (325 MW minus 64 MW). In other words, market demand was 261 MW less than in pre-dispatch due to net export failures.

Average real-time Ontario Demand was 17,982 MW, with a peak demand of 18,216, which was 104 MW (0.6 percent) lower than expected. The real-time supply cushion increased to 5.0 percent at the beginning of the hour as a result of the net export failures and lower than expected demand.

In the middle of HE 12 interval 4, a nuclear generator reported a loss of control of one unit due to computer problems. The unit was taken offline in three intervals, representing a loss of baseload generation of 810 MW.

In response to the loss of the nuclear unit, the IESO requested 400 MW of SAR from New York. Meanwhile, the IESO activated 400 MW of OR in HE 12 interval 3 and then an additional 100 MW in interval 4 representing a total of 500 MW. The OR activation led to an equivalent reduction in the OR requirement. In HE 12 interval 9, all 500 MW of OR were deactivated and the OR requirement was restored. In HE 12 interval 10, the 400 MW of SAR was deactivated, 100 MW of Regional Reserve Sharing (RRS) was activated and kept until HE 13 interval 10. At that point the OR requirement was increased to 1,418 MW, reflective of the fact that no further RRS was available to Ontario as Operating Reserve when the IESO was using it.

HE 13

Prior to the HE 13 real-time sequence running, 570 MW of exports failed on the NY interface (300 MW failed for not being scheduled in the NY market and 270 MW were cut by NYISO after being designated as recallable by the IESO). At the same time, 50 MW of imports were cut on the New York interface because they were not scheduled

[84] Starting from June 2007, NYISO rejects all exports that are designed as recallable by the IESO. More details are in Chapter 3 section 4.1.

in New York. These failures resulted in a 520 MW (570 MW minus 50 MW) reduction in net exports in the unconstrained sequence.

At the end of HE 13 interval 10, another nuclear unit (890 MW) was forced to shutdown within two intervals due to moderator problems. In response to this contingency, the IESO requested 473 MW of SAR from NY and activated 500 MW of OR. The OR Requirement was correspondingly reduced by 500 MW from 1,418 MW to 918 MW. At the same time, the IESO recalled a fossil-fired generator, which was derated for a test at the time. The recall added an additional 100 MW to the system.

HE 14

The supply cushion at the beginning of HE 14 was 2.1 percent, or 3.9 percentage points lower than the pre-dispatch supply cushion.

Before the real-time sequence ran, 620 MW of exports failed on the NY interface, of which 100 MW failed for not being scheduled in NY and 520 MW for being designated as recallable by the IESO.[85]

The IESO also cut 267 MW of exports on the MISO interface for HE 14 intervals 4 to 12 for resource adequacy using the ADQh code.

Although 50 MW of imports were being curtailed due to ramp limitations on the MISO interface, the net export failure was 837 MW (620 MW plus 267 MW minus 50 MW).[86]

By HE 14 interval 3, all OR was deactivated and the OR requirement was restored to 1,318 MW. In HE 14 interval 4, the SAR was ended but 100 MW of RRS was activated and kept until HE 15 interval 4.

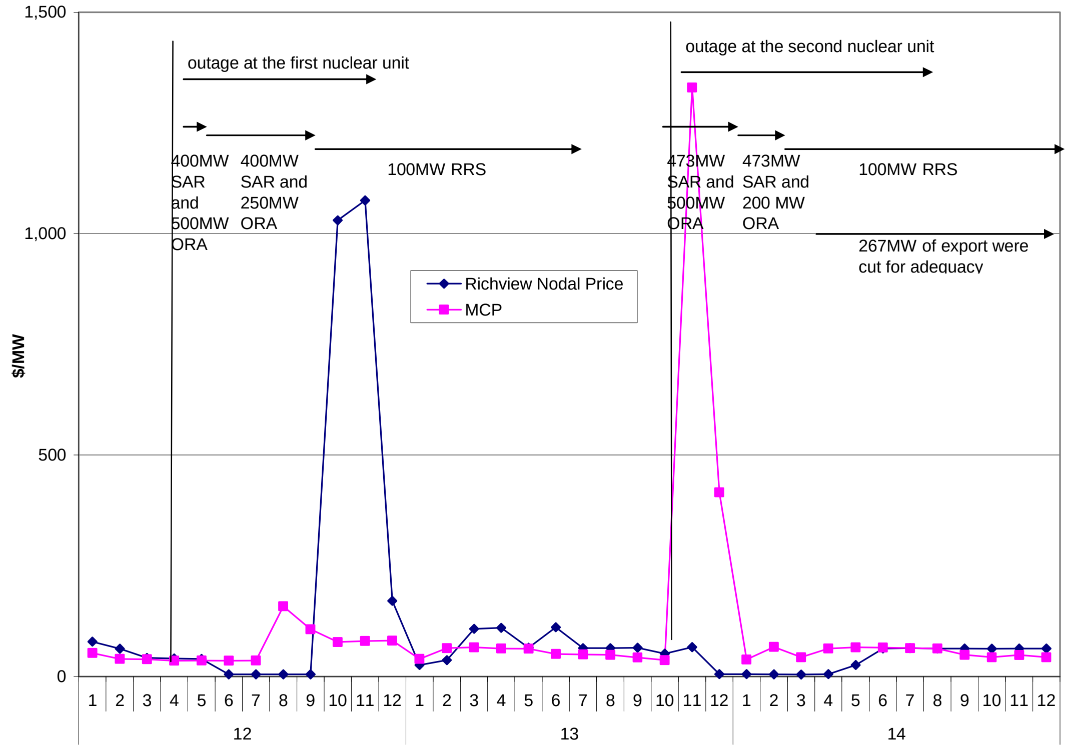
[85] In the constrained sequence, only 335 MW were designated as recallable. However, the 335 MW were transferred into 520 MW in the unconstrained sequence. As a result, when the 335 MW failed in the constrained sequence, there were 520 MW failed in the unconstrained sequence.
[86] The 50 MW in the unconstrained sequence corresponded to a 75 MW in the constrained sequence.

Assessment

Although the market was experiencing a very tight situation as a result of a loss of 1,700 MW of generation in 90 minutes, the MCP (and even the Richview shadow price, which generally reflects the supply/demand balance in the constrained sequence) did not reflect this tight situation.

Figure 2-4 displays the market price (real-time MCP and Richview shadow price) and the control actions that the IESO took during the event. The Richview price spiked in only two intervals following the first outage at one nuclear unit and the MCP spiked in only two intervals after the second outage at the other nuclear station. Most of the time, both the MCP and the Richview shadow price were in the range of $40/MWh to $60/MWh, with the Richview price even dropping to about $5/MWh in several intervals.

Figure 2-4: Real-Time MCP and Richview Price and Control Actions, April 28 2008, HE 12 to 14



These counter-intuitive prices were primarily the result of IESO actions that resulted in price-suppression: activation of SAR, ORA and RRS, the export curtailment for adequacy and the failure of exports that were designated as recallable on the New York interface due to the change of the NYISO procedure.[87] It should be pointed out that all the actions the IESO took were compliant both with the Market Rules and Market Manuals.

- SAR

  When SAR is activated, the actual Ontario demand is reduced by the same amount. This resource is treated as a free resource and has an effect of suppressing both the real-time MCP and the Richview shadow price. The Panel recommended eliminating the price impact of SAR in its December 2006 Monitoring Report.[88]

[87] The NYISO (June 2007) policy change is described in Chapter 1 and more in Chapter 3.
[88] The Panel' December 2006 report, page 75. The IESO is currently undertaking a detailed study on the impact of this recommendation.

- RRS (100 MW)

  As is the case with SAR, RRS is considered by the IESO as a free resource. When RRS is activated, the IESO subtracts this amount from Ontario demand thus suppressing the MCP. However, when RRS is activated, the IESO does increase the OR requirement by 100 MW because no further RRS can be utilized. The increase in the OR requirement partially offsets the price suppressing effect, but not by the full amount.

- ORA

  When OR is activated, the IESO reduces the OR requirement by an equivalent amount. This action suppresses the real-time energy and OR price. The Panel has recommended in the July 2007 report that the IESO review its practice of reducing the OR requirement after it has been activated.[89]

- Export curtailment for adequacy

  When an export is curtailed for adequacy ('ADQh'), the IESO removes the export from both the constrained and unconstrained sequence. The Panel in its December 2007 Monitoring Report observed that this action leads to counter-intuitive market prices and recommended that the IESO change this practice.[90]

- Export failure resulting from being recallable for CAOR

  CAOR was originally introduced to reduce incidents of counter-intuitive market prices. Since the implementation of the new operational procedure in New York in June of 2007, however, the designation of exports as recallable has itself become a major cause of counter-intuitive prices. CAOR will be discussed further in Chapter 3.

[89] The Panel's July 2007 Monitoring Report, pages 86-90.
[90] The Panel's December 2007 Monitoring Report, pages 96-103.

To assess the effects of these actions, except CAOR export curtailment, MAU ran a simulation of the unconstrained sequence.[91] Table 2-20 lists the comparison of simulation results, with and without the control actions affecting the real-time unconstrained sequence. It shows that if the SAR and RRS energy had been treated in the same way as an emergency energy purchase, if the OR requirement had been restored immediately and if the export curtailment for adequacy had not been used to alter the unconstrained sequence, the HOEP would have been $223.51/MWh, $418.32/MWh, and $362.53/MWh in these hours, 12 through 14 respectively.[92, 93] These simulated values of HOEP are, respectively, 258, 124, and 570 percent above the actual HOEP.

Table 2-20: Simulation of Impact of Control Actions on the Unconstrained Sequence, April 28, 2008, HE 12 to 14

Hour	Integrated Value (MW)*				Actual HOEP*** ($/MWh)	Simulated HOEP ($/MWh)	Difference in HOEP ($/MWh)
	RRS	SAR	OR Reduction	Export curtailed for Adequacy (MW)			
12	25	200	125	0	62.42	223.51	161.09
13	67	158	100	0	185.98	418.32	232.34
14	75	118	46	200	54.07	362.53	308.45

* A control action may be used for a few intervals. An integrated value is the average MW for the hour.
** The CAOR impact is not simulated
***Actual HOEP is the simulated "actual" HOEP. They may be slightly different from the actual HOEP in the market because of modeling differences between the DSO and our simulator.

All the control actions the IESO took were compliant both with the Market Rules and Market Manuals and the Panel is not questioning the IESO's need to undertake these actions to ensure reliability. Rather, the Panel is questioning whether these actions are correctly treated in the unconstrained pricing sequence; in other words, whether these actions are correctly priced and whether they result in market distortions or inefficiencies.

While the IESO's actions result in a market price that may reflect the marginal cost of generation in Ontario, these actions treat some of the other sources of supply required to

[91] The impact of the curtailment of exports that were recallable for CAOR was not simulated because its impact depends on what else the IESO might have done. We provide several alternatives to the designation of exports backed by CAOR as recallable in Chapter 3.
[92] The IESO's rule amendment MR-00296-R00 (August 2005) allows the IESO to adjust the market demand to offset the impact of the emergency purchase
[93] The IESO implemented a rule change (Rule Amendment MR-00296-R00) in August 2005, after the Panel's recommendation, not to reduce the Ontario demand by the amount of emergency energy purchase, thus eliminating such counter-intuitive price events in such situation.

meet demand as being costless. In essence, IESO control actions result in a market price that is well below the marginal opportunity cost of the energy involved. It is important to understand that under scarcity conditions, the market price is often determined by the offers of loads rather than generation cost. The Panel has for many years recommended that it is more efficient to allow the HOEP to reflect the opportunity cost of Ontario consumption and scarcity of supply. See Recommendation 3-6 for the recommended treatment of exports being curtailed for adequacy.

Recommendation 2-2:

The MSP reiterates the recommendations in its December 2006 and June 2007 reports, respectively, regarding Shared Activation of Reserve (SAR), and prompt replenishment of the Operating Reserve requirement levels. In addition, the MSP recommends the IESO review the application of Regional Reserve Sharing (RRS) because the current treatment of RRS in the unconstrained sequence also induces counter-intuitive prices.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

1. *Introduction*

This Chapter summarises changes since the Panel's last report which impact on the efficient operation of the markets monitored by the Panel. It also discusses new developments arising in the marketplace and issues that the Panel has identified.

Section 2 identifies material changes that have occurred in the market since our last report. This section includes two issues:

- The replacement of the twelve-times ramp rate assumption with a three-times ramp rate assumption in the unconstrained sequence, which was briefly discussed in our December 2007 report, and
- Developments related to the real-time IOG payments issues that were raised in past reports.

In section 3, we discuss a few issues which have been introduced in earlier reports:

- The Panel initially discussed transparency in its April 2003 report. In this report, we compare the current data release practices of system operators in several other jurisdictions and recommend changes in data release practices which would contribute to the more transparent and effective operation of the Ontario market.
- We examine the possible effects of the increase in linked wheeling transactions since January 2008.
- We analyse the IESO's coding practices for intertie transactions.

In section 4 the Panel comments on some new issues:

- We review how CAOR, which was initially introduced to deal with counter-intuitive real-time prices, has itself become a source of counter-intuitive prices since the implementation of a change in New York's operating procedure for recallable imports.

- We discuss the causes of increased operating reserve activations documented in our December 2007 report and in Chapter 1 of this report.

In section 5 we report on CMSC payments since market opening, and discuss their role in encouraging compliance with dispatch instructions.

2. *Material changes to the marketplace since the Panel's last report*

2.1 Three-Times Ramp Rate

In previous reports, we have described how the unconstrained sequence (i.e., the market schedule) derives dispatch schedules and the corresponding energy prices based on the assumptions that generation can ramp at twelve times its actual capability as specified in its offer and that potential transmission limits are not binding.[94] The Panel has noted how this has led to market prices that are inconsistent with actual generator capabilities and dispatches leading to inefficiencies in the marketplace. The Panel has previously recommended using the actual (one times) ramp rate in the market schedule.[95]

The IESO moved to a 3-times ramp multiplier in the market (real-time) schedule on September 12, 2007. In its December 2007 report, the Panel briefly discussed on the potential effect of this change on the HOEP, based on the limited number of observations then available (49 days of data from September 12 to October 31, 2007). As expected, we found that the interval MCP had become more volatile but more in line with the Richview nodal price, which is considered to be a good measure of the incremental cost of supply.

In this section, we provide further analysis for the period September 2007 to April 2008. In particular, we try to isolate the price impact of the change in ramp rate by simulating the real-time pricing algorithm under the respective assumptions that:

- there is no behavioural response by exports to potential price changes; and

[94] For details, see our December 2003 Monitoring Report, page 112, and December 2004 Monitoring Report, page 63.
[95] See our December 2003 Monitoring Report, page 112.

- exports respond to any price changes induced by the change in the assumed ramp rate.

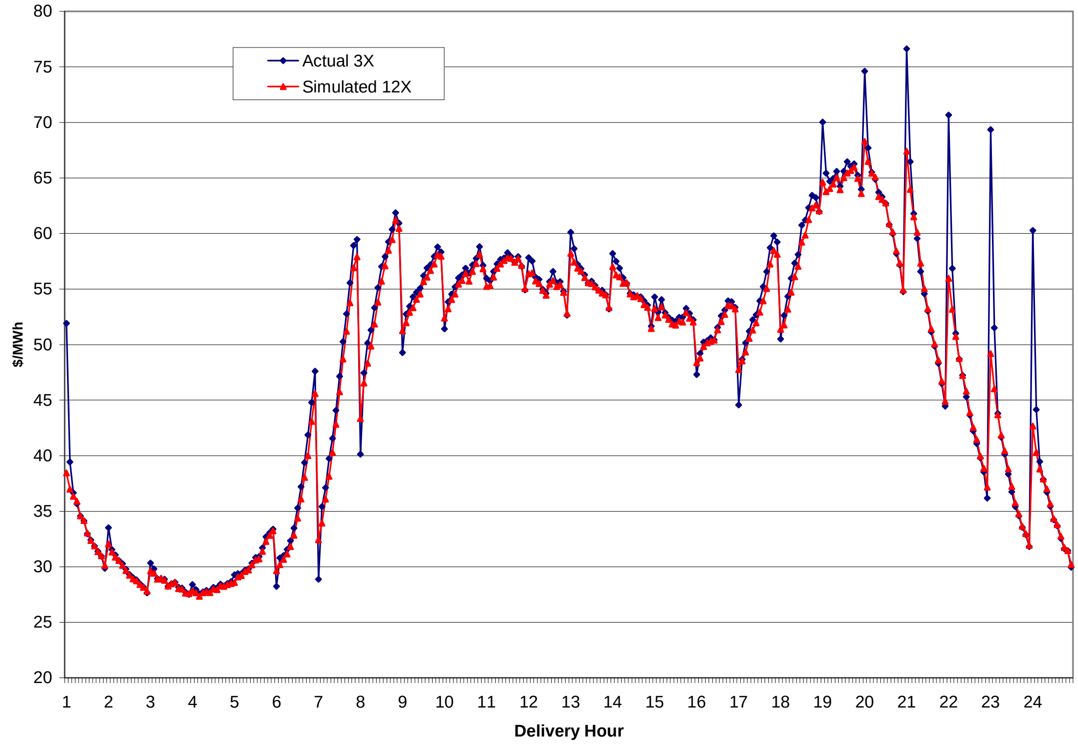
For each of these, to isolate the impact of the change in the assumed ramp rate, the real-time simulator was run twice: one ("actual") as the base case using the 3-times ramp rate (3X) assumption, and the other ("simulated") using the 12-times ramp rate (12X) assumption and assuming everything else unchanged. The comparison of the two simulations provides an estimate of the direct price impact of the change in the ramp rate multiplier, everything remaining unchanged. We then estimate the indirect price impact of the change in the assumed ramp rate by incorporating the export elasticity on the New York interface, which we have reported in Chapter 1 and also in previous reports.

Price Impact in the Absence of Export Response

Figure 3-1 depicts the average interval MCP under the two ramp rate assumptions. Similar to what was shown in our December 2007 report, both scenarios show a sharp change in MCP at the beginning of an hour, especially during the load pick-up and drop-off period. For example, in the morning load pick-up period (HE 6-10), the MCP in the first interval of each hour is much lower than the MCP in interval 12 of the previous hour. In contrast, during the load drop-off period (HE 20-24), the MCP in the first interval of each hour is much greater than the MCP in interval 12 of the previous hour. The sharp change in price is a result of the sharp change in peaking hydro supply and intertie trades.[96] To mitigate this price and dispatch volatility and improve market efficiency, the Panel has recommended the IESO explore the feasibility of a 15 minute dispatch algorithm.[97]

[96] Peaking hydro units are offered either deep into the money or well out of it so that they will be scheduled to run or not run throughout a particular hour. Intertie transactions are scheduled hourly, leading to abrupt changes in supply (imports) or demand (exports) at the beginning of the hour. The aggregate changes in peaking hydro supply and imports/exports must be accommodated by the DSO in the first interval of the hour, which often leads to a sharp change in MCP due to the limitation of ramp capability. For more details, see our December 2007 Monitoring Report, pages 151-160.
[97] December 2007 Monitoring Report, pages 151-160, Recommendation 3-3.

Figure 3-1: Average MCP Under 3 and 12 Times Ramp Rate Assumption, September 12 2007 to April 30, 2008

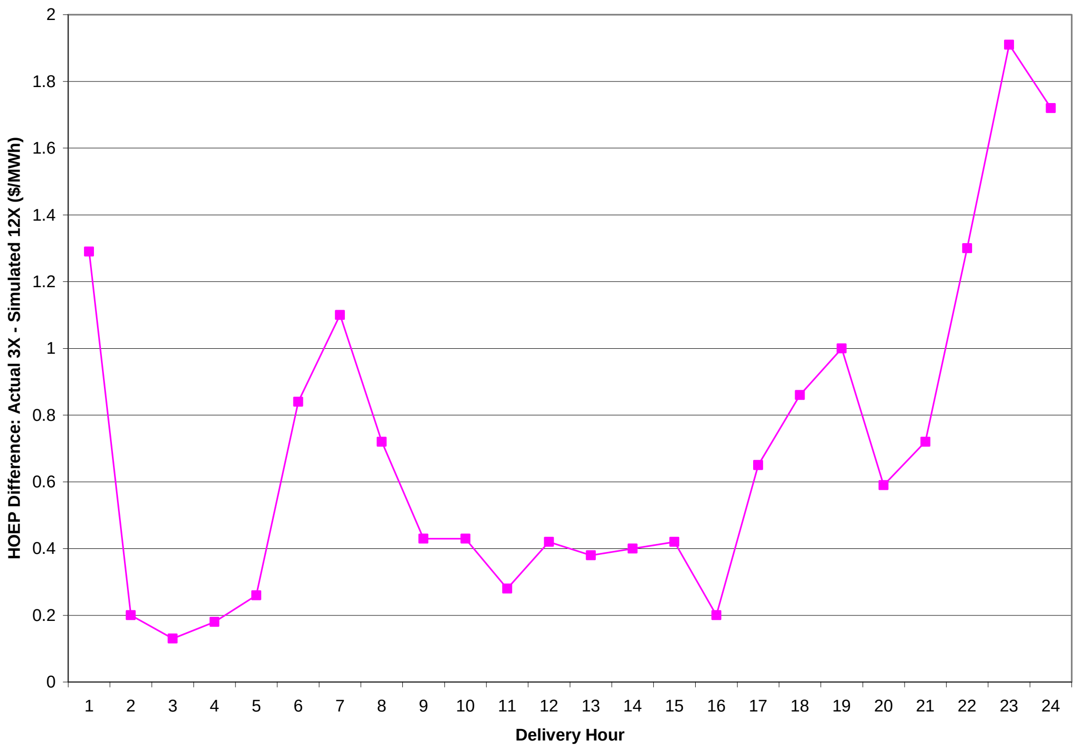


It can also be seen that during the load pick-up period, the MCP in the first interval is lower under the 3-times ramp rate assumption than under the 12-times ramp rate assumption, and then increases slightly above in the last few intervals. The reason for the large discrepancy in the first interval is that when Ontario demand picks up in the morning, exports decline and peaking hydro comes on line. Both these changes occur on the hour and this requires that other Ontario generators ramp down temporarily to accommodate this sudden change in the supply/demand balance. The lower is the ramp rate assumed, the less the assumed response is from some generators and the lower is the MCP in the first interval.

In contrast, during the load drop-off period, the MCP is much higher in the first interval under the 3-times ramp rate assumption and then quickly converges to the level of the 12-times ramp rate assumption. During load drop off, peaking hydro leaves the market, imports decline and exports increase and all of these changes occur on the hour. Ontario generation must ramp up temporarily to accommodate this sudden decrease in supply and increase in demand. The lower is the ramp rate assumed, the less the assumed response is from some generators and the higher is the MCP in the first interval.

Figure 3-2 compares the HOEP that would result under the two ramp rate assumptions, assuming no changes in other parameters. It appears that the HOEP under 12-times ramp rate would have been lower in all hours, everything else being equal. On average, the HOEP under the 12-times ramp rate assumption would have been $0.69/MWh lower than under the 3-times ramp rate assumption.[98]

Figure 3-2: HOEP Difference: Actual 3X minus Simulated 12X, September 12, 2007 to April 30 2008



Price Impact with Export Response

The realized price impact of the shift from 12X to 3X may be far smaller than the initial simulation reported above predicts because of the price responsiveness from importers,

[98] Prior to the implementation of the 3X ramp rate multiplier, the IESO had simulated that the price under 3-times ramp rate would have been $1.47/MWh higher than under 12-times ramp rate for the period November 2005 to April 2006. For more details, see the IESO's "Simulation Results", dated on August 15, 2006, as well as market rule amendment proposal (MR-00331-R00).

exporters and Ontario generation. Here we account for some of that potential market response, by estimating changes in exports to New York.[99] Since this does not capture all the market response possible, the actual price impact could still be less than the simulations below suggest.

In Chapter 1, we estimated from an econometric model that the price elasticity of exports on the New York interface is negative 4.16, implying that a 1 percent increase in the HOEP would, on average, lead to 4.16 percent decrease in exports on that interface. This export response implies that any tendency for a price increase in Ontario, due in this case to a change in policy, would be mitigated to some extent by a reduction in the demand for exports to New York. Ontario is currently also a large exporter to Michigan or to PJM through Michigan, and thus there should also be some price responsiveness of exports on the Michigan interface. We have not yet estimated the export demand elasticity on that interface, however, as Ontario has been a significant net exporter on that interface for a relatively short period of time.

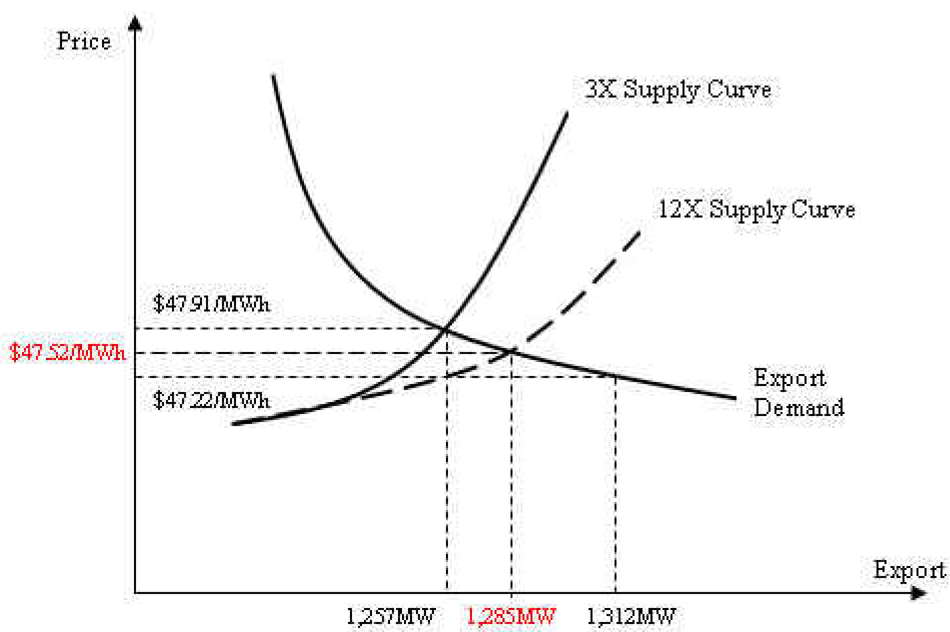
To estimate the price impact of the shift to 3-times ramp rate after allowing for the mitigating effect of reduced net exports on the New York interface, we incorporate an export demand curve with an elasticity of negative 4.16 in our simulation. The demand curve is anchored at the actual HOEP, assuming traders have perfectly foreseen this price.[100]

Figure 3-3 illustrates our simulation results. Average hourly exports during the period September 12, 2007 to April 2008 were 1,257 MWh.[101] The *3X Supply Curve* is the supply curve under the 3-times ramp rate assumption, and the *12X Supply Curve* the supply curve under the 12-times ramp rate. The *12X Supply Curve* is located to the right

[99] We focused on exports to New York since these represent the largest group of exports, and are the basis for the econometric model discussed in Chapter 1. There is no comparable econometric model for imports, although we anticipate the response of imports to HOEP would be more subdued since imports derive payments from IOG and constrained on CMSC as well. Although higher HOEP should also attract more Ontario generation response, the large number of contract or fixed price arrangements, in addition to CMSC and cost guarantees, reduce potential generator response to HOEP as well.
[100] This approach may overstate price responsiveness because the real-time simulator assumes exporters can respond to the MCP while they are actually responding to the HOEP, but it does provide some interesting results for us to better understand the potential impact of the change in the ramp rate assumption.
[101] Linked wheels are excluded as they are not responding to the Ontario price.

of the *3X Supply Curve* because there is more fictional supply under the 12-times ramp rate assumption. *Export Demand* is the export demand curve, which is downward sloping with an elasticity of -4.16. The 3-times ramp rate assumption results in a HOEP of $47.91/MWh, and the 12-times ramp rate assumption implies an average HOEP of $47.22/MWh ($0.69/MWh or 1.4 percent lower than actual) at the export level of 1,257 MW.[102] However, at $47.22/MWh, exports would be greater than 1,257 MW because that export level was realized when the HOEP was $47.91/MWh. Based on the estimated export elasticity, exports on the New York interface would be 1,312 MW, or 55 MW higher. A higher export level tends to push up the HOEP, which in turn discourages exports. In equilibrium, the market clears where the *12X Supply Curve* intersects *Export Demand*.

Figure 3-3: Price Impact of 3X Incorporating Export Response (Illustration – not to scale)



Our simulation shows that after taking into account the export response on the New York interface, average hourly exports would have been 1,285 MW or 28 MW (2.2 percent)

[102] The price under the 3-times ramp rate assumption is the simulated base case price, for consistency with the simulated 1-times ramp case. All outliers (i.e. intervals with a simulated MCP deviates from the actual MCP by more than $20/MWh), representing about 1 percent of all intervals, were removed, mitigating the potential distortion of the difference between the simulator and the DSO.

higher under 12-times ramp than they actually were (under 3-times ramp). The increased 28 MW is inefficient as it was induced by the fictional 12-times ramp rate. The average HOEP under 12-times ramp would have been $47.52/MWh or $0.39/MWh (0.8 percent) lower than the actual HOEP, in contrast to the estimated $0.69/MWh of assuming no export response. In other words, after controlling for the export response on the New York interface, the change from 12 to 3-times ramp rate in the unconstrained sequence led to an increase of only $0.39/MWh in the HOEP and a 28 MW reduction in (inefficient) exports.[103] While exporters would have experienced a $0.39/MWh increase in the HOEP, much of Ontario's load is hedged via various government contracts.

Although there are some limitations to using simulation analysis and caveats in interpreting the results, the simulation described here does provide some indication of how the change in the ramp rate assumption has impacted the market. It supports the Panel's historic view that the reduction in the fictitious ramp rate multiplier would better align the market price with the cost of supply and reduce inefficient exports.[104]

2.2 Real-Time IOG

The real-time IOG was implemented at market opening in order to guarantee that importers would "be kept financially whole by being settled at their offer as a minimum" (Market Rule Amendment MR-00177) and thus to help maintain the reliability of the IESO-controlled grid.[105] The Panel has always considered the apparent justification of IOG payments being the IESO's desire to attract additional imports in order to increase system reliability.

[103] This likely provides an upper bound of the price impact of the change in the ramp rate assumption, because export response on other interfaces (especially on the Michigan interface) and import response are not counted in.
[104] December 2004 Monitoring Report, pages 63-66.
[105] The IOG payment is only one of several mechanisms for maintaining the system reliability. Mechanisms for maintaining reliability can be generally grouped into three layers. The first layer is the market price. When the market is tight, the market price should reflect such a tight situation, thus inducing supply and demand responses to the extent feasible. The IOG payment is a hedge to importers against the drop in the real-time price due to reasons beyond the importers' control. The second layer includes the DACP program, OR activation (either internal or from external system operators), demand response programs (such as Emergency Load Reduction Program, Peak Saving Program, as well as OPA's Demand Response programs), export curtailment for transmission loading relief or internal adequacy, emergency energy purchase from external system operators, and even dispatchable load being constrained-down. The last layer is the voltage reduction (3 percent or 5 percent) and shedding a portion of non-dispatchable load, if the IESO has used up all other control actions.

In its June 2004 Monitoring Report, the Panel noted the persistently high IOG payments during the delivery hours from 22-24 and raised concerns that these IOG payments may not be buying much in the way of additional reliability.[106] In its June 2007 Monitoring Report, the Panel recommended that the IESO should consider reviewing and possibly discontinuing off-peak real-time IOG payments since it appeared that these payments might not provide commensurate reliability improvements.[107]

In this section, we provide further analyses regarding the causes of IOG payments, the impact of IOG payments on imports and exports, and the relationship between IOG payments and the domestic supply cushion (the domestic supply cushion reflects the level of spare generation relative to total Ontario demand plus the OR requirement, indicating the extent to which imports are required to meet Ontario demand).

2.2.1 The Causes of IOG Payments

The real-time IOG payment is the excess of the offer price of a scheduled import over the HOEP. The early rationale for the IOG was that by guaranteeing an importer a payment of at least his/her offer price, the IESO would encourage more imports and reduce import failures, both of which would help maintain system reliability in Ontario.

As explained in Chapter 1, there are many factors that could push the HOEP below the pre-dispatch price and trigger an IOG payment:

- *Differences between the pre-dispatch and real-time market solution algorithms:* For example, forecast hourly peak demand is used in pre-dispatch compared with actual demand in each interval, which is typically lower than the peak demand in the hour, and imports/exports are not allowed to set the real-time price;
- *Over-forecast of peak demand*. When demand is over-forecast, the IESO may over-commit imports (which has an effect of shifting the real-time supply curve to the right), thus leading to a lower HOEP.

[106] June 2004 Monitoring Report, pages 69-82.
[107] June 2007 Monitoring Report, pages 124-127, Recommendation 3-4.

- *Real-time control actions*. Some control actions have the effect of suppressing the real-time price (by artificially reducing demand). These include curtailing exports for adequacy, pricing external energy supplied to Ontario at a zero price (SAR and RRS), and delaying the replenishment of the OR Requirement following the activation of OR during a contingency.[108]
- *Export failure.* Export failure leads to less demand than projected in pre-dispatch and thus a lower real-time price. Exports can fail for a variety of reasons: internal or external reliability, participants' error, not being scheduled in external markets, or seams issues. A New York ISO operating procedure, which leads to all exports that are designated as recallable on the New York interface to be curtailed, has recently become an important factor. We will discuss this in more detail in section 4.2.
- *Deviation of self-scheduling and intermittent generators.* Traditionally, these generators have done a good job in projecting their output level because the majority of them were either fossil-fuelled or hydroelectric generators and they were largely in control of their own production decisions. Wind generators have greater forecast errors and this form of generation is increasing in importance. When this group of generators produces more than it projected one hour ahead, the HOEP will tend to be lower (because of over-commitment of imports in pre-dispatch). In its December 2007 report, the Panel recommended that the IESO explore a better forecast methodology with the wind generators.[109]

An Example: April 2, 2008 HE 20

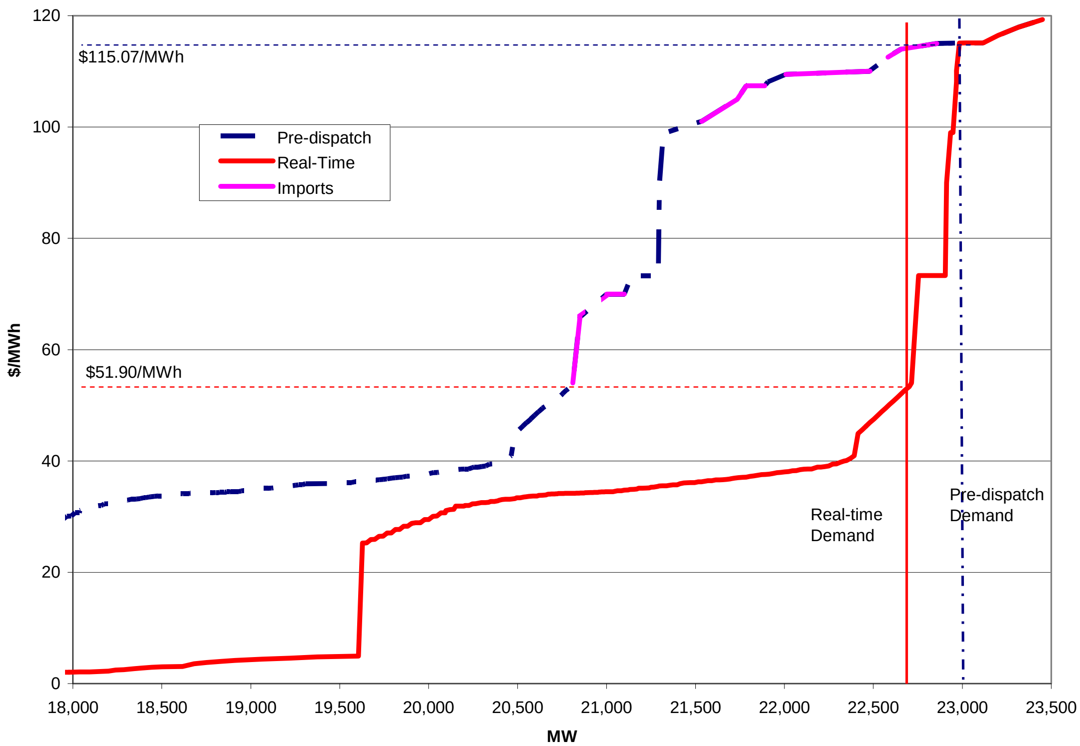
Figure 3-4 illustrates how differences between pre-dispatch and real-time scheduling can lead to an IOG payment. HE 20 of April 2, 2008 is chosen as an example of a case in which the HOEP was much lower than the pre-dispatch price although peak demand was only slightly over-forecast and there were no intertie failures and no control actions by the IESO. The final pre-dispatch run projected Ontario demand plus net export as

[108] The Panel recommended to eliminate the counter-intuitive price impact of export curtailment in the December 2007 Monitoring Report, pages 100-103, and to replenish the OR Requirements as soon as possible in its June 2007 Monitoring Report, pages 86-90.
[109] December 2007 Monitoring Report, pages 24-28, Recommendation 1-1.

19,719 MW (forecast Ontario demand of 19,247 MW plus scheduled net exports of 472 MW). The average real-time Ontario demand plus net export was 19,517 MW, with a peak of 19,602 MW which was only 117 MW (or 0.6 percent) lower than forecast.

The dotted blue curve in the figure with isolated pink lines is the pre-dispatch offer curve and the vertical dotted blue line is the pre-dispatch market demand (domestic demand plus exports). The pink lines on the offer curve represent imports which totalled 1,793 MW. The pre-dispatch price was $115.07/MWh. After the final pre-dispatch run, all imports were placed at the bottom of the supply stack as they are considered non-dispatchable and thus not allowed to set the real time price. This made the real-time supply curve much steeper and lower on the left side of the pre-dispatch demand.[110] The steeper and lower real-time supply curve largely explains why the HOEP can be lower and much more volatile than the pre-dispatch price thus triggering an IOG payment.

Figure 3-4: Comparison of Pre-dispatch and Real-time Supply Curves, April 2, 2008, HE 20



[110] Since import offers above the pre-dispatch price are not scheduled and these are also removed from the real-time supply curve, the curve is also steeper to the right of the pre-dispatch demand level.

The HOEP for the hour was $51.90/MWh, less than half of the pre-dispatch price. Because the HOEP was lower than the offer prices of some of the imports, a total of $90,714 IOG was paid to the 1,793 MW of imports for an average of $50.59/MWh.

The IOG payments were made while Ontario was a net exporter in the hour, with 1,995 MW of imports and 2,467 MW of exports navigating between Ontario and external markets.[111] Although the pre-dispatch price was $115.07/MWh and importers were paid at least their offer price, all exporters paid the HOEP of $51.90/MWh.[112] Exports were high as exporters expected a lower HOEP than the pre-dispatch price, which is often the consequence of the differences in the respective pricing algorithms for the pre-dispatch and real-time sequences. In other words, the high volume of imports that were guaranteed an IOG payment put a downward pressure on the HOEP, which in turn induced more exports. Given that Ontario was a net exporter in the hour and the real-time domestic supply cushion was 9 percent, the $90,714 of IOG payments to importers did not appear to be necessary to provide reliability in Ontario in this hour.

2.2.2 The Impact of IOG Payments on Imports and Exports

Although in the example above the majority of imports were paid an IOG payment, the MWh receiving an IOG payment usually account for a smaller percentage of total imports. Table 3-1 lists the total MWh that have received an IOG payment, the total IOG payments and the total amount of imports by period.[113] On average, about 26 percent of imports received the IOG payment in the past six years. Although both total imports and IOG payments have generally decreased over time, the percentage of imports that receive IOG payment has increased. For example, there were 10 TWh of imports between May 2002 and April 2003 and 18 percent of those imports received $259 million in IOG payments. In the past year, however, there were only 8 TWh of imports with 35 percent

[111] In addition, there were 1,158 MW of linked wheeling transactions. These transactions had no impact on either the pre-dispatch price or the HOEP as they did not cause any congestion.
[112] Before the urgent rule change in July 2002, a trader could receive IOG payment in addition to the HOEP for imports while paying only the HOEP for his exports (an 'implied' wheeling transaction). The trader could thus receive the IOG payment for doing nothing to help the Ontario reliability. The rule change eliminated such profit opportunity by clawing back the IOG payment.
[113] These are the market schedule quantities. Sometimes IOG can be offset by a negative CMSC. However, negative CMSC are typically small and thus does not materially affect our analysis.

(2.6 TWh) receiving $40 million in IOG payments. With the exception of the first year of the market, the average IOG payment has varied between $15 and $30/MWh.

Table 3-1: Imports that Receive IOG, Total IOG Payments, and Total Imports by Annual Period, May 2002 – April 2008*

Period	Imports Receiving IOG (GWh)	Total IOG ($ million)	Average IOG Payment ($/MWh)	Total Imports (GWh)	% of Imports Receiving IOG	% of Hours when Imports Set the PD MCP
May 2002 - April 2003	1,839	259	140.59	10,297	18	30
May 2003 - April 2004	2,202	55	25.00	9,760	23	31
May 2004 - April 2005	2,464	34	13.90	9,902	25	37
May 2005 - April 2006	2,738	81	29.55	9,693	28	36
May 2006 - April 2007	2,175	33	15.32	5,761	38	36
May 2007 - April 2008	2,598	40	15.40	7,967	33	35
Total/Average	13,818	502	35.82	53,379	26	34

* linked wheels are excluded

The increased percentage of imports receiving IOG suggests that importers may have shifted from being price-takers to price-setters, i.e. receiving their ‘pay-as-bid’ offer price. This shift can also be seen in the increased frequency of imports setting the pre-dispatch price, which is illustrated in the last column of Table 3-1. In the first two years after the market opened, imports set the pre-dispatch price approximately 30 percent of time. However over the past four years, imports set the pre-dispatch price approximately 36 percent of time.

It is expected that without the IOG payment, importers would increase their offer prices in anticipation of the possibility that the price they might actually be paid for their imports is less than their offer price. As a result some imports might not be chosen in pre-dispatch and this would drive up the HOEP in those situations. At the same time, the higher HOEP would reduce export demand placing offsetting downward pressure on the HOEP. While we cannot determine the net effect of these two opposing forces we expect that, in the new equilibrium, market supply and demand would both be lower and the HOEP might not change much. This outcome is suggested by the price responsiveness of exports on the New York interface modeled in Chapter 1.

In Chapter 1 of this report and in previous reports, the Panel has provided estimates of the price responsiveness of exports on the New York interface (the price elasticity of demand for exports). The export demand elasticity can be used to simulate the effect of various assumed reductions in imports on the demand for exports to New York in 2007.[114] We established three scenarios for simulation, taking into account the possible responsiveness of imports if IOG payments were eliminated:

- Scenario 1 assumes all IOG imports (i.e. the portion of total imports which received IOG payments) would disappear if there were no IOG payment.
- Scenario 2 assumes two-third of IOG imports would disappear and
- Scenario 3 assumes one-third of IOG imports would disappear.

Table 3-2 reports the simulation results for the 2007 calendar year. In Scenario 1, where all 2,129 GWh of IOG imports disappear, exports on the New York interface drop by 1,144 GWh, equivalent to 54 percent of the IOG imports. In other words, if the IOG payment increased imports to Ontario by 100 MW, 54 MW of these imports would simply be exported back to New York. In Scenario 2 where two-thirds of IOG imports would have disappeared, exports would decrease by 956 GWh, or 67 percent of reduced IOG imports. In Scenario 3 where only one-third of IOG imports disappear, exports on the New York interface would be reduced by 538 GWh or 76 percent of the reduction in imports. The simulation implies that a large portion of imports attracted by IOG payments simply flows back out to New York. The total outflow from Ontario would be greater if induced exports to Michigan were taken into account.

[114] The simulation tool is the real-time simulator. We established a real-time export curve based on the elasticity we estimated in Chapter 1, assuming exporters have perfectly forecast the actual real-time price (HOEP). We then incorporated the export demand curve into our real-time simulator to approximate the potential export reduction in response to a reduction in imports. It should be recognized that the estimated export elasticity is an average elasticity (for either peak or off-peak) for 2003-2008, while our simulator is an interval simulator. Thus the simulated reduction in exports can be reasonably approximated over a longer period, but there may be large prediction error in a given hour. To mitigate the effect of those large deviations, we removed all the hours in the simulation where the export reduction appeared to be greater than the import reduction. Thus the reported simulation results are for 4,100 hours, or about 80 percent the total 5,081 hours in which an IOG payment was paid.

Table 3-2: Simulated Export Reduction on the New York Interface in Response to IOG Elimination, January to December 2007

Month	IOG Imports (GWh)	Export Reduction					
		Scenario 1: all IOG imports disappear (GWh)	% of IOG Imports	Scenario 2: 2/3 IOG imports disappear (GWh)	% of 2/3 IOG Imports	Scenario 3: 1/3 IOG imports disappear (GWh)	% of 1/3 IOG Imports
Jan-07	178	88	49	68	57	34	57
Feb-07	197	117	60	107	82	59	90
Mar-07	267	132	50	110	61	61	68
Apr-07	129	75	58	63	73	35	81
May-07	161	62	39	59	55	35	65
Jun-07	104	42	40	45	65	29	84
Jul-07	88	54	62	46	78	27	94
Aug-07	142	59	42	49	52	33	69
Sep-07	142	78	55	66	70	38	80
Oct-07	201	116	58	91	68	51	76
Nov-07	237	133	56	104	66	53	67
Dec-07	283	187	66	148	78	83	88
Total/Average	2,129	1,144	54	956	67	538	76

2.2.3 IOG Payments and Reliability

One indicator of the reliability of the supply of electric power in Ontario is the domestic supply cushion which is the excess of available domestic generation over load, all expressed as a percentage of load. For the purpose of this discussion, we use the IESO's guideline that a domestic supply cushion below 5 percent is indicative of very tight supply conditions and thus of heightened reliability concerns.[115]

Figure 3-5 shows yearly IOG payments for various values of the domestic supply cushion. In the first year after market opening, 86 percent of the IOG was paid when the domestic supply cushion was negative. In the second year after market opening, 59 percent of the IOG was paid when the domestic supply cushion was below 5 percent, that is, during

[115] The IESO's study "Peak vs Average Demand in Pre-dispatch: Result of Analysis" dated May 13, 2008 stated that "the historical data provides some evidence that a supply cushion of less than 5 percent combined with other events increases the likelihood of having to use control actions." to deal with reliability concerns (page 5).
Note the IOG payment is not the only resource for maintaining the system reliability. In tight supply situations, the IESO can activate other reliability programs such as Emergency Load Reduction Program, Peak Saving Programs and Operating Reserves, or constraining down dispatchable load, or take control actions such as curtailing exports, purchase emergency energy, cut voltage by 3 or 5 percent, or shed some non-dispatchable loads.

times of heightened reliability concerns. In the past two years (May 2006 to April 2008), however, 75 percent of IOG was paid when the domestic supply cushion was above 5 percent, while only 5 to 8 percent of IOG payments was paid when the supply cushion was negative and the system was actually relying on imports. In this type of shortage situation, the HOEP would have been high enough to be set by dispatchable loads if procedures associated with various control actions taken by the IESO allowed price to reflect the shortage. In this case, IOG payments would not have been needed.

If we use a 10 percent supply cushion as a simple indicator that domestic supply is sufficient, we find that, over time, an increasing proportion of IOG is being paid when the supply cushion is above 10 percent. From May 2002 to April 2004 between 3 and 17 percent of the IOG was paid when the domestic supply cushion was above 10 percent while during the period May 2006 to April 2008 as much as 45 to 48 percent of the IOG was paid when the domestic supply cushion was above 10 percent. This implies that, over time, an increasing portion of IOG is being paid in hours when reliability concerns would appear to be minimal.

Figure 3-5: Distribution of IOG by Period and By Domestic Supply Cushion Level, May 2002 to April 2008 ($ millions)

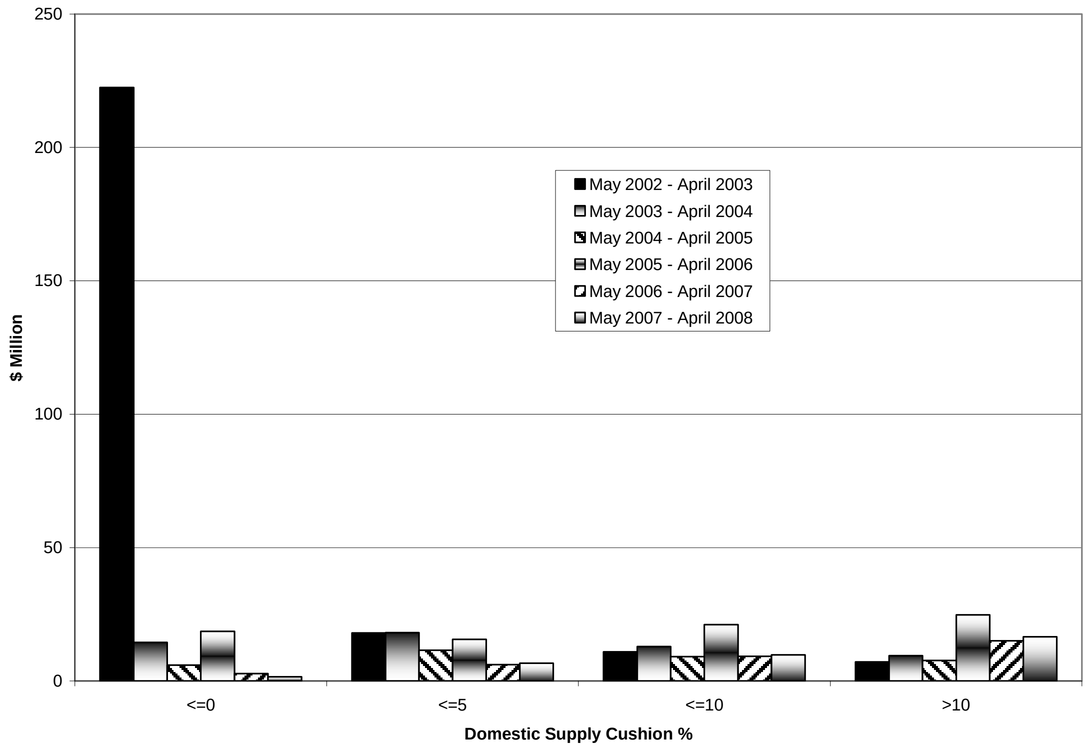


Table 3-3 lists total on-peak IOG payments by hourly net import or export range.[116] For example, the row of ">500" shows how much IOG was paid in all peak hours when Ontario was importing 500 MW or more than it was exporting in each period. The row for "<-500" shows how much IOG was paid in all peak hours when Ontario was exporting 500 MW or more than it was importing. The table shows that in the period May 2002 to April 2003, all on-peak IOG was paid in hours when Ontario was a large net importer. However, in the period May 2007 to April 2008, 62 percent of on-peak IOG was paid in hours when Ontario was a net exporter.

[116] The total payment in the two tables may be different from the total IOG payment in Table 3-1 because of rounding errors.

Table 3-3: IOG Payments by Level of Net Imports May 2002 to April 2008, On-Peak ($ millions)

Net Imports (MWh)	May 2002 - April 2003	May 2003 - April 2004	May 2004 - April 2005	May 2005 - April 2006	May 2006 - April 2007	May 2007 - April 2008
>500	242	29	13	35	8	5
500 ~ 400	0	1	1	2	1	1
400 ~ 300	0	1	1	2	1	1
300 ~ 200	0	1	1	2	1	1
200 ~ 100	0	1	1	2	1	1
100 ~ 0	0	0	1	2	1	1
0 ~ -100	0	0	1	1	1	1
-100 ~ -200	0	1	1	1	1	1
-200 ~ 300	0	0	1	1	1	1
-300 ~ 400	0	0	1	1	1	1
-400 ~ -500	0	0	0	1	1	1
<-500	0	1	3	4	6	11
Total	242	35	25	54	24	26
% of IOG paid when Ontario was a net exporter	0	6	28	17	46	62

Table 3-4 shows total off-peak IOG payments by hourly net import or export range. The percentage of off-peak IOG paid when Ontario was in a net export situation has been increasing over time. For example, in the period May 2002 to April 2003, all off-peak IOG was paid in hours when Ontario was a large net importer. However, in the period May 2007 to April 2008, 83 percent of off-peak IOG was paid in hours when Ontario was a net exporter. The substantial portion of off-peak IOG paid when Ontario was a net exporter highlights the possibility that the IOG payment is not contributing to the reliability of the Ontario system during these hours.

Table 3-4: IOG Payments by Level of Net Imports
May 2002 to April 2008, Off-Peak
($ millions)

Net Imports (MWh)	May 2002 - April 2003	May 2003 - April 2004	May 2004 - April 2005	May 2005 - April 2006	May 2006 - April 2007	May 2007 - April 2008
>500	12	12	6	9	3	1
500 ~ 400	0	1	0	1	0	0
400 ~ 300	0	1	0	1	0	0
300 ~ 200	0	1	1	1	1	0
200 ~ 100	0	1	1	2	1	0
100 ~ 0	0	1	0	1	1	1
0 ~ -100	0	0	0	1	0	1
-100 ~ -200	0	0	0	1	1	1
-200 ~ 300	0	0	0	1	1	1
-300 ~ 400	0	0	0	1	1	0
-400 ~ -500	0	0	0	1	1	1
<-500	0	1	1	5	5	6
Total	12	18	9	25	15	12
% of IOG paid when Ontario was a net exporter	0	6	11	40	60	83

2.2.4 The Panel's Comments

This analysis shows that any impact that IOG payments have on encouraging imports is significantly reduced by offsetting exports. In recent years, an increasing fraction of IOG payments have been paid during periods of excess domestic supply implying that these payments may not be buying much in the way of additional reliability. The analysis also demonstrates that as the market has evolved, an increasing portion of IOG payment is being paid when the system is unlikely to have reliability concerns (i.e. when Ontario is a net exporter). In fact, during the period May 2006 to April 2008, 54 percent of the IOG payments in on-peak hours were paid in hours when Ontario was a net exporter, and this fraction was even higher, 70 percent, in off-peak hours. The high IOG payments in such hours warrant a more detailed study on whether IOG payments continue to bring corresponding reliability benefits to Ontario.

In addition to improved supply conditions due to increased supply and reduced forced outage rates at fossil stations, there have been some changes since market opening that have improved reliability by increasing available resources. With this improved reliability there should be a reduced need for the IOG. These changes include:

- *Multi-Interval Optimizer (MIO).* In June 2004, the IESO introduced MIO, which can look 12 intervals ahead and schedule generators in optimal economic order based on changing market supply and demand conditions. By looking several intervals ahead MIO can begin ramping slow-moving fossil units earlier, increasing their availability in later intervals when needed.
- *Day-Ahead Commitment Process (DACP).* Introduced by the IESO in June 2006, the DACP allows generators and importers to receive a cost guarantee if they are scheduled in day ahead and meet certain conditions. This program reduces the real-time price risks to generators and importers and thus increases the likelihood of a generator being online and reduces import failures.
- *Dispatchable Load Program*. When the market opened, there were only two dispatchable loads with 40 MW being price-responsive. By April 2008, this had increased to 10 dispatchable loads with 416 MW being price responsive, providing additional resources that can be dispatched in the event of a shortfall in supply.[117]

After the Panel raised the IOG issue in its June 2004 Monitoring Report, the IESO initiated a discussion of the matter in its Market Pricing Working Group (MPWG). The Group has yet to commence a full study of the issue. The Panel understands that the Working Group will review the priority of this issue in its October 2008 meeting. In light of the dramatic increase in the portion of IOG paid during hours in which reliability does not appear to be a problem, we encourage the MPWG to view this issue as a priority.

Recommendation 3-1:

As market supply conditions have improved, an increasing fraction of Intertie Offer Guarantee (IOG) payments is being paid in hours when there appear to be negligible reliability concerns. The MSP recommends the IESO review the real-time IOG program and determine if it is providing commensurate improvements in reliability.

[117] We consider those MW bid at $2,000/MWh to consume are not price responsive and unwilling to be cut.

3. *New matters*

3.1 Data Transparency

In the past, the Panel has expressed the view that greater transparency can contribute to market efficiency by helping market participants in the price discovery process. In its March 2003 Monitoring Report, the Panel recommended that the IMO (now the IESO) expand its publication of market price data in order to allow market participants to improve their forecasts of real-time prices rather than simply relying on the IESO's pre-dispatch prices.[118] Although improvements have been made since market opening, opportunities for greater transparency continue to exist.

As a general principle, increased transparency in markets tends to result in the more efficient functioning of these markets by reducing uncertainty and facilitating more informed supply and demand responses. In addition to informing bid, offer and production decisions, market data can help market participants benchmark their performance and experiment with operational improvements as well as signaling competitive opportunities. Market data allow a potential entrant to assess both its competitiveness and its impact in the market. Masked or unmasked data permit more academic or other 3rd party review of the market to analyze what behaviour has occurred and this can add to the outside scrutiny of and public confidence in market activity.

Although the Panel focuses on efficiency benefits in the assessment below, it also recognizes that data release can reduce information asymmetry between larger market participants (who have more internal information on which to base forecasts of future conditions) and smaller participants. Typically reducing asymmetry means smaller market participants having more complete and timely information, which allows them to respond more quickly and with greater certainty to changing market conditions. For example, in Alberta, there was reluctance on the part of loads to contract with generators partially because of the asymmetry of information on outages reducing the opportunity

[118] March 2003 Monitoring Report, page 97.

for potentially efficient trades.[119] This situation seems to have been improved by the publishing of the outage data, shortly after the event (typically within 20 minutes).

With increased data release, there may also be a risk of potentially anti-competitive outcomes. For example, publishing bid and offer data could facilitate coordinated behaviour (collusion or tacit collusion) or reveal opportunities for a market participant to raise (or lower) market prices unilaterally when it recognizes instances in which it could have market power. The potential for negative outcomes appears to diminish, however, as the time delay before releasing the data increases. In the course of its regular monitoring activities, the Market Assessment Unit (MAU) has not found that current data publication practices have had any adverse effects on the market.

This section explores data release practices of various jurisdictions with a view to considering whether the publication of market data should be expanded in Ontario. We provide a detailed comparison of data release practices across seven jurisdictions (six of them being North American) with a discussion of some issues that have been noted regarding the release of specific types of information.

IESO Data Release Practices Relative to Other Markets

The section below compares data release practices with respect to:

(i) bid/offer data,
(ii) operational data,
(iii) supply cushion,
(iv) load data,
(v) price forecast data, and
(vi) pre-dispatch shadow prices.

[119] http://www.albertamsa.ca/files/MSAPositionPaper_InformationAsymmetry_February182004(1).pdf, page 2: "Trading in the forward market constitutes an important component of the energy market in the Province and the declining trend in market liquidity is of concern. The *potential* for and negative *perception* around the use of outage information is exacerbated by the level of information asymmetry that exists in the Alberta market, i.e., some market participants have a significantly greater view of unit availability than the market at large. The combination of these factors creates the *perception* amongst current and potential participants that the forward market is unfair, has a high level of uncertainty, and reduces the ability of most participants to manage risk, particularly among those who do not have access to the information. The MSA believes that information asymmetry and the *potential* for trading on outage information are contributors to poor market liquidity in the forward market."

We compare practices for the following jurisdictions:

- Ontario's IESO,
- ISO-New England (ISO-NE),
- New York ISO (NYISO),
- Midwest ISO (MISO),
- Pennsylvania, New Jersey, Maryland Power Pool (PJM),
- Alberta Electricity System Operator (AESO), and
- Australia's National Electricity Market Management Company Limited (NEMMCO).

Offer and Bid Data

Competitive wholesale energy markets utilize offers and bids to match electricity supply with demand. Table 3-5 summarizes offer and bid data release practices for the IESO and other jurisdictions. At this point, the IESO does not publish any form of offer or bid data. NEMMCO (Australia) is by far the most aggressive jurisdiction when publishing offer data. NEMMCO publishes unmasked, unit-specific offer data with a one-day lag, allowing participants the opportunity to understand generator offer behaviour almost immediately. Interestingly, NEMMCO does not publish any bid data information. In contrast, NYISO, PJM (offer data only), and MISO all publish unit-specific offer and bid data under a permanent fictitious ID with a six-month lag and ISO-NE has recently moved to a three month lag.[120]

[120] ISO-NE received approval in October 2007 to publish offer/bid data with a three month lag beginning March 1, 2008. The data is published monthly (on the first day of the month) three months afterwards. For example, April 1 to April 30, 2008 bid and offer data will be published on August 1, 2008. See FERC press release titled "Commission improves market transparency in New England", October 18, 2007 at: http://www.ferc.gov/news/news-releases/2007/2007-4/10-18-07-E-13.asp#skipnavsub.

Table 3-5: Offer/Bid Data Release Practices in Seven Jurisdictions

Jurisdiction	Bid Data		Offer Data	
	Format	Reporting Lag	Format	Reporting Lag
IESO	None	n/a	None	n/a
NYISO	Masked unit-specific (permanent fictitious ID's)	Six months	Masked unit-specific (permanent fictitious ID's)	Six months
ISO-NE	Masked unit-specific (permanent fictitious ID's)	Three months	Masked unit-specific (permanent fictitious ID's)	Three months
MISO	None	n/a	Masked unit-specific (permanent fictitious ID's)	Six months
PJM	Aggregated by zone	Six months	Masked unit-specific (permanent fictitious ID's)	Six months
AESO	Aggregated by zone	One hour	Aggregated by zone	One hour
NEMMCO	None	n/a	Unmasked unit-specific	One day

It is difficult to assess the costs and benefits of publicly releasing bid and offer data to increase transparency. There may be few, if any short-term dispatch efficiency benefits from releasing bid/offer data with a three month lag. However there may be long-term investment benefits as well as efficiency gains from increased market scrutiny. Specifically, the bid and offer data can provide investors with an idea of how much revenue they may earn if they invest in a generating facility in Ontario by evaluating when their offers would have (or would not have) been accepted. The costs include implementation costs and potential efficiency losses due to collusion or tacit collusion as a result of information sharing among large players, although an appropriate release lag can help minimize this. The policies of the other markets reviewed imply a belief that the release of masked bid and offer data is beneficial on balance.

In a recent review, Frank Wolak (Chairman of the Market Surveillance Committee of the California Independent System Operator and an expert on electricity markets) discussed these issues and looked for positive or negative impacts on markets.[121] He noted there is some evidence of a positive correlation between the extent of publicly available data and how well the wholesale market works. Wolak found no evidence that withholding data (e.g. not publishing unit-level bid and production data) enhances market efficiency. Finally, he discussed the issue of masking the identity of market participants, and

[121] Wolak, Frank A., "Managing Unilateral Market Power in Electricity" (September 2005). World Bank Policy Research Working Paper No. 3691, page10-15.

favoured the identification of individual market participants, the primary value being that of "putting all markets participants at risk for explaining their behaviour to the public".

ISO New England was granted approval to move from a six month delay before publication of bid and offer data to a three month delay in October 2007, and did so in March 2008. In order to do so they were required to obtain Federal Energy Regulatory Commission (FERC) approval, allowing for a public review of the proposal. FERC approved the request, concluding that the issues raised by intervenors were of limited concern, given that a three month time lag was retained and that the ISO-NE retained the ability to modify its practices in the event that problems emerged.[122] FERC appears to believe that producing bid and offer data is important for market transparency, since in a recent FERC Advance Notice of Proposed Rulemaking on Competitive Wholesale Markets, it has proposed that ISO's publish masked bid and offer data with a three month lag.[123] The three month lag was proposed to protect commercially sensitive data and to guard against any misuse of the data.

The Alberta market practice prior to 2002 was to publish bid and offer data graphically, almost in real-time. Their market also allowed participants considerable freedom in restating their bids in real-time, resulting in a more dynamic supply curve.[124] Alberta's current publishing practice delays the data until the next hour and the rules on restatement

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[122] FERC, "Order Accepting Information Policy Revision", ISO New England Inc. and New England Power Pool, Docket No.ER07-1245-000, issued October 18, 2007.

FERC refers (page 2) to the testimony of Hung-Po Chao, Ph.D., the Director of the ISO's Internal Market Monitoring Unit. The testimony states that the earlier release of bid data adds transparency that helps the public understand wholesale electricity markets, improves market confidence, and allows market participants and state regulators to supplement the market monitoring functions. Dr. Chao submits that misuse of bidding information is unlikely due to a competitive market structure, effective market monitoring and mitigation procedures, and the nature of bidding information turning "stale" with time." Dr Chao had also testified that "Seasonal variations in load and in the available generation mean that collusion and manipulation would be as unlikely with 90-day-old masked bid data as they are with 180-day-old masked bid data."

These arguments were more compelling to FERC than the concerns raised by a group of generators (page 3), "The Generators argue that shortening the lag time for release of individual participant bid and offer information would expand the potential for an individual participant to attempt to react to the bidding behavior of other individual participants." The earlier data "could enable strategic behavior in the markets, which may be inappropriate or manipulative" or may lead a participant "to learn the structure and level of a competitor's bids and its incremental and decremental bid activity in order to strategically modify the participant's own bids and activities in the market." FERC found these arguments persuasive and ruled in favour of shortening the bid and offer data release lag.

[123] See page 78 in FERC's Notice of Proposed Rulemaking titled "Wholesale Competition in Regions with Organized Electric Markets" on June 22, 2007. The report is available on FERC's website at http://www.ferc.gov/whats-new/comm-meet/2007/062107/E-3.pdf

[124] http://www.albertamsa.ca/files/MSAFEOC110405.pdf , page 4; and see *Guidelines for the use of the 'Locking Restatement'*, http://ets.powerpool.ab.ca/downloads/guidelines_locking_restatement.pdf.

of bids have been progressively tightened. (The latest tightening of rules on the restatement of offers, which occurred in December 2007, prevents importers and exporters from restating bids within 2 hours for anything but acceptable operational reasons.)

Within the jurisdictions reviewed, Ontario is the only electricity market in which no form of offer or bid data, masked or unmasked, is released. The three month release lag proposed by FERC in its NOPR and approved for application by ISO-NE, relies, to some degree, on data becoming stale over time (especially with seasonal changes taking place) to prevent any anti-competitive use. Alberta's market has moved away from real-time release of data to a slight delay, coupled with some limitations on the restatement of bids and offers. Allowing a time lag (as long as a season) limits any anti-competitive applications of the data. With its abundance of hydroelectric generation, a slightly longer reporting lag may be appropriate in Ontario. A four-month lag would guarantee that bid/offer data would not be publicly known by participants during periods when water conditions are similar.

The Panel remains of the opinion that greater transparency generally enhances market efficiency. It therefore recommends that lagged and masked bid and offer data be released and that the MAU monitor the market to ensure that this has no adverse impacts.

Recommendation 3-2:
The MSP recommends that the IESO publish masked bid and offer data on a four month time lag.

Operational Data

In Table 3-6, operational data reporting practices for production and outages are compared across jurisdictions. NEMMCO, AESO, and the IESO are the more open ISO's as far as releasing operational data on generators is concerned. On the other hand, ISO-NE does not publish any operational data on generators. The IESO releases actual unit-specific output and availability information published with a two-hour lag.[125]

Table 3-6: Generator Production and Outage Data Release Practices in Seven Jurisdictions

Jurisdiction	Generator Production Data		Outage Data	
	Format	Reporting Lag	Format	Reporting Lag
IESO	Actual production	2 hours	Yes	2 hours
NYISO	No	n/a	No	n/a
ISO-NE	No	n/a	No	n/a
MISO	Aggregate resource production	1 hour	Aggregate resource outages	1 hour
PJM	Aggregate resource production	1 hour	Aggregate resource outages	1 hour
AESO	Actual production	1 hour	Yes	1 hour
NEMMCO	Actual production	End of day	No	n/a

When the market opened in 2002, some generators were concerned that releasing production information by unit could lead to inappropriate market behaviour. The Panel recommended that unit production data be released, but with a two hour time lag due to concerns by Ontario Power Generation that more timely release of this information could lead to withholding by other generators.[126] To date, the MAU has not observed any inappropriate behaviour resulting of publication of output data. Indeed, OPG itself is now releasing its masked generator output by fuel type on a 15 minute basis, well ahead of the IESO's publication. Considering OPG's generation accounts for over 75 percent of Ontario's electricity production, there is no longer any reason for imposing a two hour delay on the release of these data by the IESO.

Recommendation 3-3:

The MSP recommends that the IESO publish generating unit output using a one-hour lag rather than the current two-hour lag.

[125] IESO data is published a full hour after the end of the dispatch hour, i.e. two hours after the start of the dispatch hour or equivalently, at the beginning of the second hour after the dispatch hour.
[126] See Market Surveillance Panel report on Proposed Changes to IMO Information Confidentiality Catalogue, March 17, 2003, http://www.oeb.gov.on.ca/documents/msp/panel_mspdatapublication_170303.pdf

The IESO does not publish unit-specific outage information. When there is a loss of a generator in excess of 250 MW, however, the IESO publishes this outage information in its System Status Report process (SSR) without naming the specific unit. In general, outages to generating facilities with a capacity of 250 MW or more are viewed as being most important to market participants as they have a greater impact on market prices.

Presently, specific information on forced outages is known to the generation owner and can only be inferred by other market participants. Releasing the type of generating unit experiencing an outage will facilitate a more widespread understanding of its implications for future market prices in Ontario and allow market participants to respond more quickly and with greater certainty to the outage situation. For example, knowing that the forced outage is a nuclear unit as opposed to a fossil unit, market participants would expect the outage to last two days or more, and can respond to that information once it is released.

Recommendation 3-4

The MSP recommends that when the System Status Reports indicate that a generating unit of greater than 250 MW has been forced from service, the IESO should also disclose the fuel type of the unit in order to increase the information available to all market participants regarding future market conditions.

Supply Cushion

The supply cushion is an important measure of the amount of excess supply available for dispatch in a given hour. In the Panel’s view, it is a simple yet powerful indicator of supply and demand conditions in the province and its publication would be beneficial to market participants. If published in advance of the hour using forecast demand and expected available supply, this indicator could increase the ability of market participants and others to understand price movements and to make more efficient production/import and consumption/export decisions.

At this point, a similar statistic is not published by any of the jurisdictions reviewed including the IESO. However, the IESO does have plans to publish an hourly supply cushion statistic for all of Ontario beginning in September 2008 as an entry in the IESO's public Adequacy Report.[127] We understand the supply cushion statistic that the IESO plans to publish is the difference between total offered energy from all generators and importers and forecast demand (energy plus OR) divided by forecast demand. This measure does not take into account forced outages or deratings or the actual import capabilities of the various interties. A supply cushion so defined overstates actual supply availability and may not be of much value to market participants. The Panel is of the opinion that prior to publishing supply cushion data, the IESO should consider refining its supply cushion formula to provide a more accurate reflection of actual supply conditions in the market.

Recommendation 3-5

The IESO is planning to publish the supply cushion on a hourly basis. Its current calculation, however, does not represent actual supply capability. The MSP recommends that the IESO refine its formula to take into account forced outages, deratings, and import capabilities at the interties.

Demand Data

Table 3-7 compares actual, scheduled, and forecast load data release practices by jurisdiction. The IESO currently publishes hourly actual system load in real-time and hourly load by zone with a four-day lag. The IESO also provides participants with the longest lead-time when it produces hourly demand forecasts. Through its Security and Adequacy Assessment Report (SSA), the IESO publishes hourly forecasts of system load 14 days in advance. The IESO's pre-dispatch runs are also a source of forecasted demand up to 36 hours ahead. With the exception of the IESO, PJM, and Alberta all other jurisdictions publish load by zone in real-time. Furthermore, NYISO, PJM, ISO-NE, MISO, and NEMMCO all provide seven day hourly load forecasts by zone.

[127] See the IESO' Market Facing Target Release Plan R20.0 under the IT Release Caladar dated June 25, 2008 available at http://www.ieso.ca/imoweb/pubs/it/it_TargetReleasePlan200.pdf

Table 3-7: Actual and Forecast Load Data Release Practices in Seven Jurisdictions

Jurisdiction	System Load		Load by Zone		Forecasted Load	
	Type	Lag	Type	Lag	Type	Lead-time
IESO	Hourly actual load	Real-time	Yes, Actual load	4 days	Hourly through pre-dispatch runs/Hourly through System Adequacy Report	36 hours ahead/ 14 days ahead
NYISO	Hourly actual load	Real-time	Yes, Actual load	Real-time	Hourly by zone and aggregate	7 days
ISO-NE	Hourly actual load	Real-time	Yes, Scheduled load	Real-time	Hourly by zone and aggregate	7 days
MISO	Scheduled load	Real-time	No	n/a	Hourly by zone and aggregate	7 days
PJM	Hourly actual load	Real-time	Estimated by control area	3 days	Houly by control area and aggregate	7 days
AESO	Hourly actual load	Real-time	Yes, Actual Load by market participant	2 days	Hourly aggregate	Day-ahead
NEMMCO	Hourly actual load	Real-time	Yes, Actual load	Real-time	Houly by zone	7 days

In the past, the Panel has not observed any adverse impacts from providing either actual system load in real-time or forecast system load 14 days in advance. The Panel believes the IESO's present practice of publishing hourly actual system load in real-time, hourly load by zone with a four-day lag, and forecast load is appropriate.

Price Forecasts

Price forecasts inform the production and consumption decisions of market participants. Table 3-8 describes price forecast publication practices by jurisdiction. The IESO currently provides projected prices for the following day though the pre-dispatch price mechanism and updates the projection every hour. In addition, the IESO recently released a day-ahead price forecast model and now provides market participants with a price signal of next day's hourly prices.[128] The model uses publicly available information day-ahead and reports hourly forecasts of HOEP along with upper and lower thresholds based on a 95 percent confidence band.

[128] The Day-Ahead Price Forecast model provides day-ahead price forecasts at 17:00 EST for Monday through Friday and is available at: http://www.ieso.ca/imoweb/marketdata/DAPF.asp

In jurisdictions with a functioning day-ahead market (NYISO, ISO-NE, PJM, and MISO), the day ahead market settles the majority of real-time transactions and the day ahead price can be considered as a forecast of the real-time price. Alberta with only a real-time market provides a forecast pool price two hours ahead of the hour. Australia, also with only a real-time market, does not provide price forecasts.

Table 3-8: Price Forecast Data Release Practices in Seven Jurisdictions

Jurisdiction	Basis of Forecast	Lead Time
IESO	Price Forecast Model and Pre-dispatch projections	One day for forecast, One hour for projections
NYISO	Day-ahead market	One day
ISO-NE	Day-ahead market	One day
MISO	Day-ahead market	One day
PJM	Day-ahead market	One day
AESO	Forecast Pool Price	Two hours
NEMMCO	None	n/a

It would be difficult to provide meaningful price forecasts more than one day ahead of time without a process for running the unconstrained sequence using offers and bids. As a result, the IESO's pre-dispatch process and the derived price forecasts the day ahead, which have the same lead time as the day-ahead markets in various jurisdictions, is all that can reasonably be expected based on the current design of the Ontario market.

Pre-dispatch Shadow Prices

On June 4, 2008, the IESO began publishing pre-dispatch shadow prices for the Ontario intertie nodes.[129] The data are published for market participants as a market signal to help improve their bid/offer strategies. Although the information is useful to participants, the MAU found the data was not easily accessible in its reported format on the IESO's website. The MAU recommended to the IESO that it would be beneficial to a larger group of market participants if the data were made more accessible using an improved format for displaying these pre-dispatch prices. It is the Panel's understanding this change has recently been made.

[129] IESO Participant News Release, "New Net Interchange Scheduling Limit Shadow Prices Report Posted June 4", May 29, 2008. http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4108

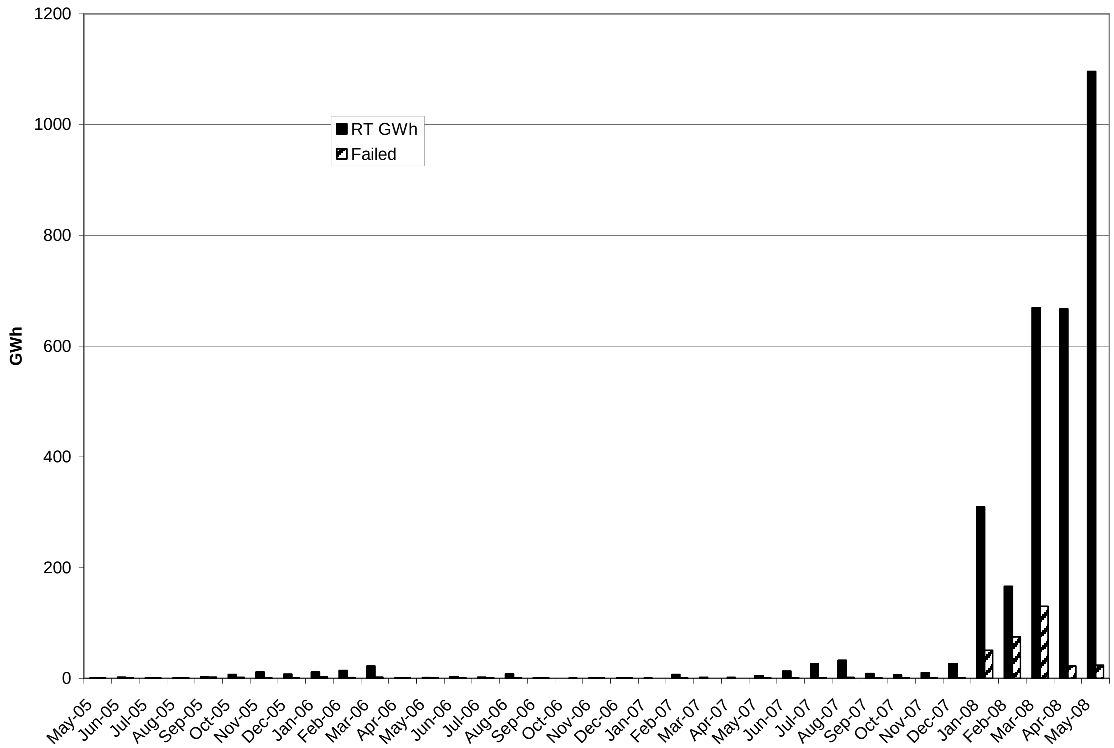
3.2 Linked Wheeling Transactions[130]

As shown in Chapter 1, linked wheeling transactions through Ontario increased significantly beginning in January 2008. The purpose of any import/export transactions is to move power from a low cost area to a high cost area. We would generally expect wheeled transactions to be globally efficient as they reduce the total production cost of meeting the same demand over a larger area.

The Panel noted in Chapter 1 that along with the very significant growth in linked wheeling transactions there has been an increase in failed linked wheels. Figure 3-6 shows the monthly magnitude of successful linked wheels as well as total failed linked wheels since May 2005. Linked wheels increased sharply in January 2008, and reached a historic high of 1,100 GWh in May 2008. Failed linked wheels increased to a historic high of 130 GWh in March 2008, but dropped to 22 GWh in April after the intertie failure charge (IFC) was extended by the IESO to linked wheels (this is discussed more fully in section 3.2.2 below).

[130] Background information on linked wheels prepared for the IESO's Technical Panel is available at http://www.ieso.ca/imoweb/pubs/tp2008/tp216-3b-Linked_Wheel-Backgrounder.pdf

Figure 3-6: Total Linked Wheels and Total Failed Linked Wheels, May 2005 to May 2008 (GWh)



In the sections below we explore both the underlying reasons for the increase in linked wheels, and the subsequent actions that were taken by the IESO to deal with the increase in failed linked wheels.

3.2.1 <u>Quantity of Linked Wheeling Transactions</u>

In an interconnected grid power flows along multiple parallel transmission lines or interfaces.[131] While the power produced for a linked wheeling transaction can be specified as flowing along a unique path ('the contract path'), this path is unlikely to be the same as the actual power flows for the wheel.[132] For example, although a linked

[131] Because transmission lines are interconnected, power from the injection point may actually flow on many parallel lines to reach the withdrawal point. Physically, these flows can be characterized by 'distribution factors' which represent the portion (from 0 percent to 100 percent) of the transaction flowing across a given transmission line or interface. For example, suppose there are three lines (A, B, and C) linking Generator G to Load L. Each line has different features (such as the distance or impedance of each line, or the existence of flow control devices) which can influence the actual flow. The actual flow from G to L may have 10 percent going on line A, 30 percent on line B and 60 percent on line C.

[132] This discrepancy applies to all power flows including transactions between adjacent markets or even for power generated for consumption within a given market. However, because of the increased distances involved for linked wheels, there is a greater tendency for a mismatch between actual and scheduled or assumed flows.

wheel through Ontario may show the transaction as being scheduled to flow from New York through Ontario and MISO to PJM, the actual power flow may involve a large portion flowing east and south, directly from New York to PJM, with a small portion flowing through Ontario.

Different jurisdictions approach the pricing of imports, exports and linked wheels differently. One difference is the assumption related to distribution factors – whether the power flows according to the contract path or is distributed along multiple paths. NYISO, PJM and MISO all use some form of distribution factors. The use of distribution factors by these system operators is intended to provide a better approximation of the cost or value of the trade and a more accurate economic assessment and dispatch. However, Ontario uses its unconstrained scheduling algorithm for purposes of pricing, and it treats transactions as flowing 100 percent across the specified intertie (contract path) rather than applying distribution factors.[133]

A second key choice in pricing intertie transactions is related to the assumed source (the generation area) and sink (the consumption area) of the transactions: whether the flow is assumed to start and stop in adjacent markets, or whether the ultimate source and sink for a wheeling transaction are considered. MISO and PJM incorporate the information about the original source and final sink markets, while the NYISO and the IESO assume power flows to or from the adjacent market, even for linked wheels which may begin or end in a more distant market. For example, in a linked wheel from NYISO through the IESO and MISO to PJM:

- NYISO treats the transaction as strictly going from New York to Ontario,
- IESO treats the transaction as starting in New York and ending in MISO, and
- MISO and PJM treat the transaction as starting in New York and ending in PJM.

For the transaction in this example, the actual flows might be seen as about 80 percent moving directly from NYISO to eastern PJM and the remaining 20 percent flowing from

[133] The treatment in the constrained sequence is more complicated as the IESO tries to somewhat emulate distribution factors through its modelling of loop flow and the impact on the interfaces.

New York through Ontario and arriving in western PJM via MISO. Each of these system operators would be aware of the actual flows and may also take them into account in their scheduling process. If the different scheduling approaches of the IESO's involved assume flows for the transactions concerned that are different from the actual flows, however, then the transaction prices in these would be inconsistent.. For example, if a transaction flows across a congested interface where additional flow relieves the congestion and saves $50/MWh, that transaction would be viewed as having a different cost impact (or value) by two markets if one models it as having 200 MW of flow and the other as 400 MW of flow on the congested interface. Inconsistencies in pricing such as this may provide intertie traders with arbitrage opportunities and create incentives for wheels which may or may not be globally efficient.

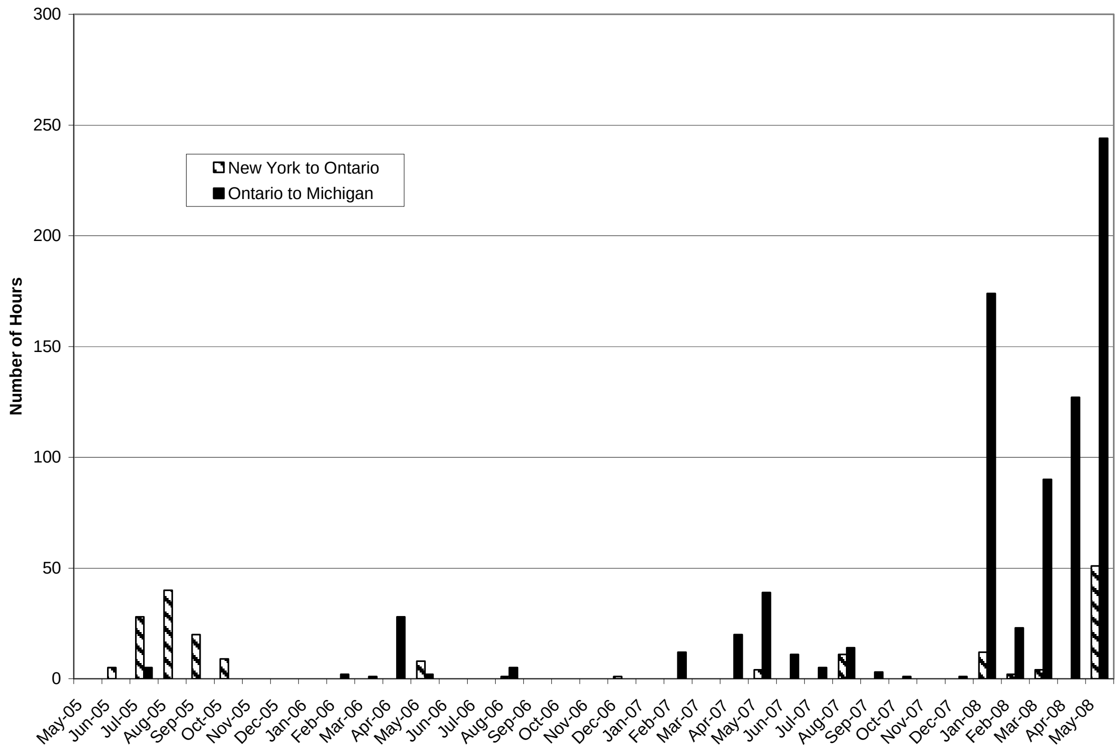
The mix of pricing algorithms among markets appears to be the main reason for the large quantity of linked wheeling transactions through Ontario since January 2008. The majority of the linked wheels being observed are for transactions originating in NYISO with a contract path moving through the IESO (and MISO), and ending in PJM. As indicated above, only a portion of the actual flows follow this contract path, and the various markets may assume different flows for their pricing algorithms, leading to different prices.[134]

One effect of the high levels of linked wheels is increased intertie congestion. For example, 1,000 MW of linked wheels flowing from NYISO through Ontario to MISO uses 1,000 MW of the available scheduling capability for imports from NYISO and exports to MISO. Other trades could add to this, congesting the interties, or trades in the opposite direction could reduce the net flows. In the 5 months with elevated linked wheels, January to May 2008, as shown in Figure 3-7, we observe that there was little corresponding congestion for imports from NYISO because of large offsetting exports to New York. There was, however, a dramatic increase in congestion for exports to MISO,

[134] For example, for 1,000 MW wheel starting in New York and ending in PJM which is scheduled to flow via Ontario and MISO may have an 80:20 distribution factor. In this example only 200 MW actually flows through Ontario. The discrepancy between actual and scheduled path is unscheduled flow, called loop flow, which has been discussed earlier in the Panel's December 2006 Monitoring Report, pages 113-117. It is interesting to note that the Lake Erie Circulation (LEC is the loop flow around Lake Erie) has changed its direction since January 2008 from traditionally counter-clock wise flow to clockwise. This was roughly coincident with the increase in linked wheeling transactions from New York to PJM via Ontario and MISO.

some of which was due to reduced intertie capability with Michigan as the result of transmission outages during that period.

Figure 3-7: Total Monthly Number of Hours with Congestion on the New York and Michigan Interface, May 2005 – May 2008



The Panel has been reviewing these trades to understand their implications for efficiency and their impact on the Ontario market. Because this involves transactions over a large area, the MAU have been in contact with its counterparts in the U.S. who are interested in the effect of linked wheels on the market.

To date linked wheels do not appear to have had a significant impact on the efficiency of the Ontario market. When a wheeling transaction flows but contributes to congestion, the trader must pay the congestion rent, as would other importers or exporters. Since the wheeling participant is directly affected by the congestion price (by paying a higher congested export price, or receiving a lower import price when there is congestion) that trade can be presumed no less privately efficient than other imports or exports; the congestion price effectively rations the use of the limited intertie.

Congestion internal to Ontario may be a different matter since, with the uniform pricing system, the cost associated with internal congestion is muted as a price signal to load and exporters since they pay only a fraction of the incremental cost through the CMSC portion of uplift. There could be an impact on Ontario efficiency if internal transmission were to become congested and the IESO has to re-dispatch internal resources in order to allow these linked wheel transactions to flow. As an example, if the Queenston Flow West (QFW) transmission line, a critical internal transmission interface to deliver power between New York and Michigan was to become congested due to the wheels, efficiency effects would occur. It would be necessary for the IESO to reduce low cost generation to the east of this interface in the Niagara area and at the same time increase high cost generation to the west of this internal interface to accommodate these wheels. In other words, the IESO would have to constrain down generation in the Niagara area and constrain up generation to the west of QFW, leading to an efficiency loss, which is not captured by the congestion prices in the unconstrained sequence. The same could be true of other import or export transactions, including implied wheels and the high levels of linked wheel flows that have recently emerged would make this more likely.

The Panel has asked the MAU to continue to monitor linked wheels through Ontario and report on any efficiency effects they may have.

3.2.2 Failure of Linked Wheeling Transactions in Ontario

As the linked wheeling transactions in Ontario have increased, failed transactions have also increased. Unlike imports and exports that face an Intertie Failure Charge (IFC), until March 2008, the Ontario market did not explicitly apply IFC to linked wheels.[135] As a result, as far as the Ontario market was concerned, linked wheel traders had little incentive to avoid failed transactions. When there was an economic advantage in doing so, they could accept (or even arrange) a failure, for example by not offering into other markets. There may have been circumstances in which these linked wheel transactions

[135] The introduction of the Intertie Failure Charge in June 2006 is described in our December 2006 Monitoring Report, pages 121-125.

pre-empted intertie transmission capacity that would have been more efficiently used by others.

In light of the significant increase in linked wheel failures in January and February 2008, the IESO extended the IFC to failed linked wheels on March 20, 2008. The failure rate of linked wheels dropped after the IESO's action, as shown in Figure 3-6 and Table 3-9. During the period January 1 to March 19, 2008, failed linked wheels amounted to 247,667 MWh and accounted for 22 percent of total linked wheels scheduled in pre-dispatch. In contrast, in April 2008, after the implementation of the failure charge, failed linked wheels accounted for only 3 percent of total wheels scheduled in pre-dispatch.

Table 3-9: Linked Wheel Failures Before and After Imposition of the Failure Charge, January 1 to April 30, 2008

(MWh and %)

	Pre-dispatch Schedule (MWh)	Real-Time Schedule (MWh)	Failure (MWh)	Failure Rate (% of Pre-dispatch Schedule)
Before March 20, 2008	1,130,214	882,547	247,667	22
After March 20, 2008	959,813	929,535	30,278	3

Rent Deficit in the Transmission Rights Market

In the period studied, the IESO TR account experienced a large deficit, with collected congestion rent falling $6.3 million short of the TR payout.[136] That is, the transmission rights payout to TR holders was much greater than the congestion rent collected. The majority of congestion in this period was export congestion on the Michigan interface. The reason for this is that most of the linked wheels were from New York to PJM through Ontario and Michigan, so that the linked wheels increased congestion on the Michigan interface and reduced congestion on the New York interface which is typically an export interface.

A portion of the TR rent deficit during the period was due to linked wheel transaction failures. A full analysis of the impact of failed linked wheels on the TR deficit is complicated because the congestion price impact is difficult to assess and the behaviour of linked wheelers is difficult to model. A simple approach is to estimate the direct effect of the failed linked wheels assuming the congestion price unchanged. Had all failed linked wheels not failed, the TR deficit would have been $600,000 lower in the period January 7 to February 8, 2008.

The Panel has asked the MAU to report back on the issue of TR deficits due to transaction failures.

3.3 *Impact of Coding Intertie Transaction Failure*

In Chapter 2, the Panel discussed some anomalous outcomes of intertie failures that resulted from the use of different reason codes by the IESO. In particular:

- A failed import in the constrained sequence can increase imports in the unconstrained sequence and thus decrease the real-time price; or
- A failed export in the constrained sequence can increase exports in the

[136] The IESO anticipated deficits in any given hour as a consequence of IESO policy on setting the TR auction quantities. See "Transmission Rights and Transfer Capabilities" http://www.ieso.ca/imoweb/pubs/tr/Transmission_Rights_sw_r24.pdf

unconstrained sequence and thus increase the real-time price.

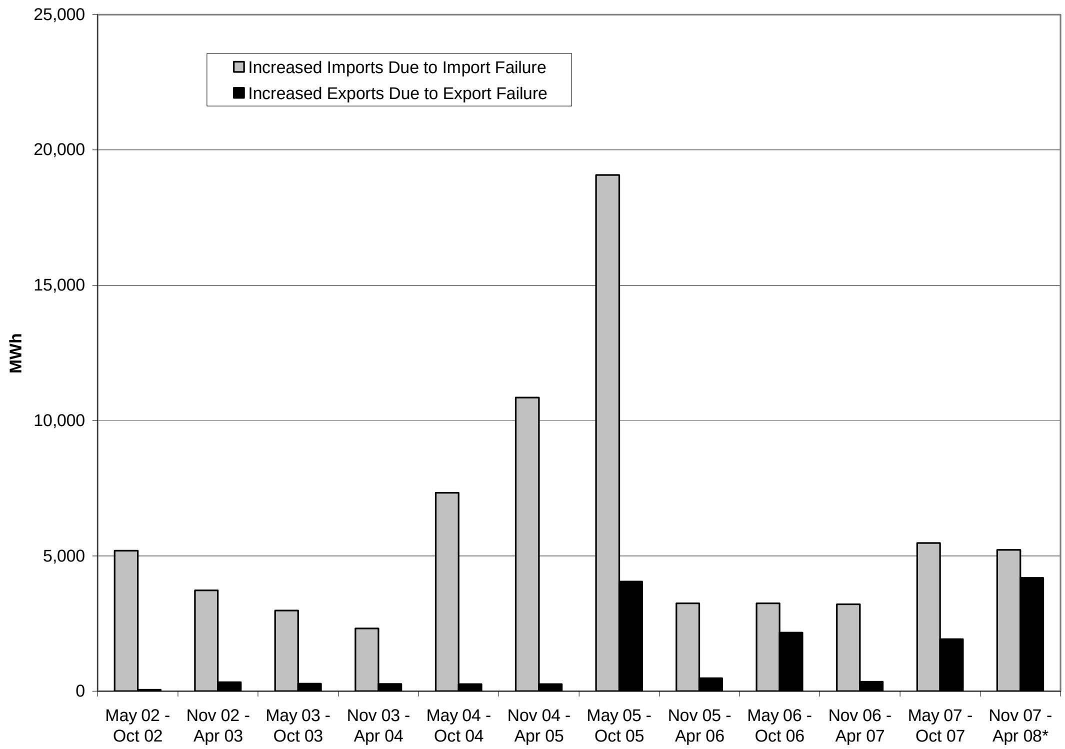
These anomalous outcomes are a result of the two-sequence dispatch algorithm and the way the IESO assigns a reason code to a failed transaction.

The MAU has attempted to quantify the occurrence of these types of anomalous outcomes due to the assigning of a reason code to the failure. Figure 3-8 depicts the impact of failed imports (exports) increasing imports (exports) in the unconstrained sequence by period since market opening due to the use of 'ADQh', 'ORA', 'OTH', 'TLRe' and 'MrNh'.[137] It appears that these IESO procedures have generally had a greater effect on imports. That is, imports are more likely increased in the unconstrained sequence due to import failures, implying the real-time price is more likely to be suppressed by the failure of imports than to be increased by the failure of exports. However, the amount of increased exports due to export failure in the constrained sequence appears to have increased during the period May 2007 to April 2008, implying increasing upward pressure on the real-time price. In total, there has been:

- an increase of about 72,000 MWh in imports in the unconstrained schedule due to import failure in the constrained schedule; and
- an increase of about 15,000 MWh in exports in the unconstrained schedule due to export failure in the unconstrained schedule.

[137] Since December 20, 2007, the IESO has used 'OTH' for an export failure on the New York interface when the transaction is not scheduled in the New York. In the past, 'TLRe' was used. The change makes the isolation of the effect of different reason code impossible.

Figure 3-8: Increased Unconstrained Transactions Resulting from Transaction Failures, by Report Period
May 2002 to April 2008



It is interesting to note that during the period November 2004 to October 2005 there was a significant increase in imports in the real-time unconstrained sequence. During that period, Ontario imported significant amounts of energy from external markets because of the tight domestic supply conditions (especially during summer 2005). With the high volume of imports came an increased probability of failure in the constrained schedule. The treatment of these import failures by the IESO actually had the effect of suppressing the real-time price so that it did not properly fulfill its role of signaling the prevailing scarcity conditions to the market.

Figure 3-9 lists total number of incidents with import increases in the unconstrained sequence due to import failure in the constrained sequence and the average MWh per incident by delivery hour since market opening. In 994 hours (or 116 hours each year) over the past six years, increased imports occurred with an average of 72 MWh per incident. It appears that the counter-intuitive pricing problem is more likely an on-peak problem as most incidents occurred in on-peak hours. Note that imports can increase as a result of an import failure only when the import concerned is constrained on (i.e. fewer MW in the unconstrained sequence than in the constrained sequence before failure). That is, the counter-intuitive incidents are more likely to occur during a period when supply is tight. This in turn implies that the on-peak price is likely suppressed when shortage conditions are most severe. For example, in HE 14 in which both demand and the market price are typically high, there have been almost 70 hours in which imports were increased in the market schedule as a result of import failure in the constrained schedule, or about 80MWh increase in each incident in the past six years.

Figure 3-9: Increased Imports due to Import Failure by Hour
May 2002 to April 2008

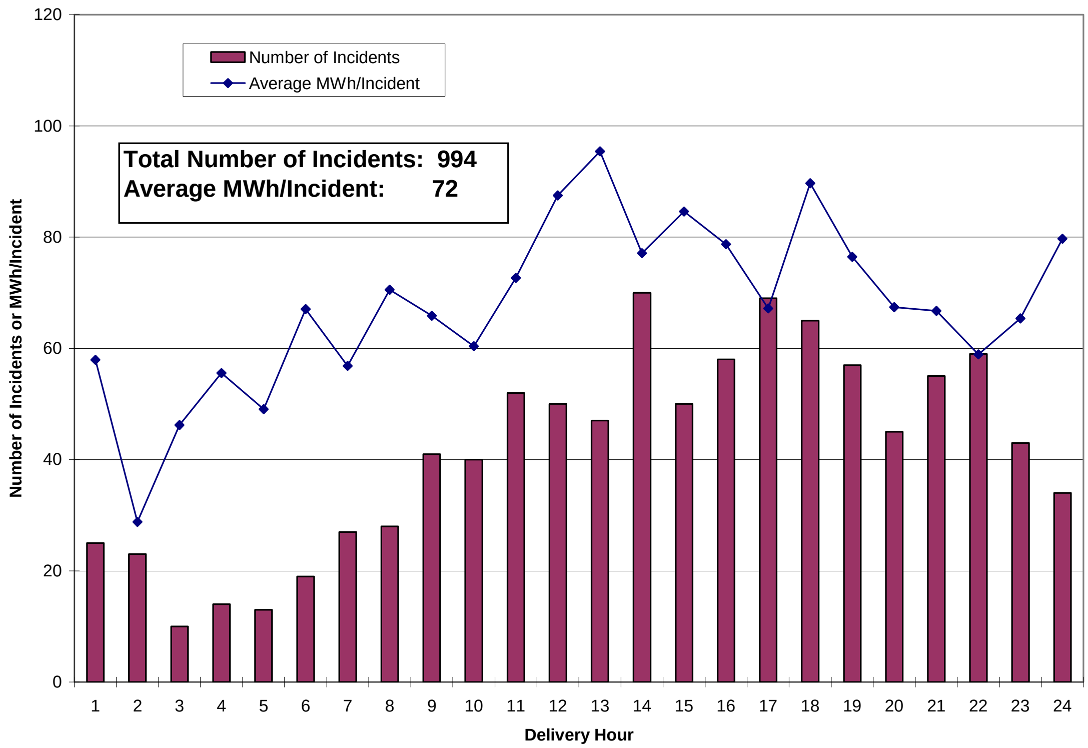


Figure 3-10 depicts total number of hours with export increases in the unconstrained sequence due to export failures in the constrained sequence and the average MWh per incident by delivery hour since market opening. In the past six years, there have been 349 hours with increased exports with an average 42 MWh per incident. Both the number of incidents and the size per incident are much smaller than the increased imports and the difference between on-peak and off-peak is not so marked.

Figure 3-10: Increased Exports due to Export Failure by Hour
May 2002 to April 2008

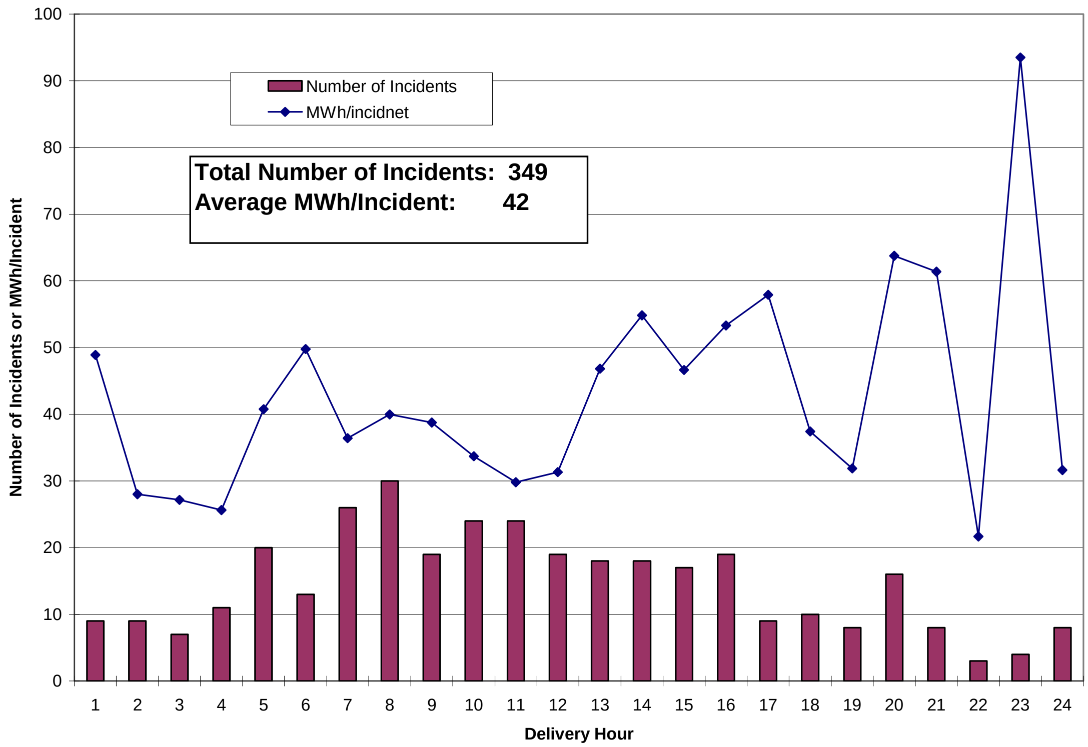


Table 3-10 lists all codes used for intertie transaction failures in the constrained sequence, the main reasons for each code, and the respective impacts on CMSC payments and the constrained and unconstrained schedules. The table also lists the respective shares of transactions failed between the final one hour ahead pre-dispatch and the real time dispatch accounted for by each failure code. It appears that most failures, about 83 percent were due to market participants' actions or external security concerns.

Table 3-10: Failure Reason Codes and Their Frequency of Use June 2007 to April 2008

Code	Main Reasons	Eligibility for CMSC	Affects Constrained Schedule (CS)	Affects Unconstrained Schedule (US)	Failure Charge	Use Frequency in June 2007–April 2008 (%)*
ADQh	internal resource adequacy	No	Yes	Yes (sets US equal to CS)	No	0.57
MrNh	inability to acquire transmission service or ramping limitation in MISO or New York	No	Yes	Yes (sets US equal to CS)	No	9.26
OTH	incorrect e-tag or the corresponding transaction not being scheduled in the external market	No	Yes	Yes (sets US equal to CS)	Yes	52.33
TLRe	external security or adequacy	No	Yes	Yes (sets US equal to CS)	No	30.87
NY90[138]	NYISO – IESO 90 minute checkout	Yes	Yes	No	No	N/A
ORA	Operating reserve activation	Yes	Yes	No	No	0
TLRi	internal transmission congestion or IESO internal scheduling errors	Yes	Yes	No	No	6.36

*excluding linked wheel transactions because the same code may be used on both legs which leads to double counting on the same transaction.
(Source: IESO Procedure 2.4-7 “Interchange Operations”, Appendix B: Summary of Instructions on the Application of Reason Codes, Table B-1 “Impact of Reason Codes on CMSC and Schedules” and Table B-2 “Summary of proper reason codes usage”)

A transaction is considered to fail or partially fail only if, the final resulting schedule with the neighbouring market operator differs from the IESO’s schedule in the pre-dispatch constrained sequence. So we see in the table that the constrained schedule is always affected. However, four codes (OTH, TLRe, MrNh, and ADQh) also have an impact on the unconstrained sequence and exclude the market participant involved from being eligible for CMSC (since the IESO sets the unconstrained schedule equal to the constrained schedule). Forcing the unconstrained schedule to match the constrained

[138] NY 90 was not discussed in Chapter 2 because this code is applied to transactions on the New York interface following the IESO’s 90 minute checkout with the New York ISO. Since NYISO limits its 75 minute ahead schedules to the amounts identified by the IESO in its two-hour ahead pre-dispatch, the IESO also applies the same limit for its one-hour ahead pre-dispatch using the NY90 code. A transaction can also fail during the 90 minute checkout if the transaction has no corresponding offer or incorrect tag in New York. Because such failures happen between the Ontario’s two and one hour ahead pre-dispatch, they do not have the same impact on real-time as failed transactions scheduled one-hour ahead and are treated differently (e.g. there is no intertie failure charge). We do not further discuss NY90 in this section.

schedule in some of these situations has led to the types of counter-intuitive prices explained above and in Chapter 2 as well.

We understand that it is important for the IESO to separate transaction failures by reason as this process can help the IESO to find the exact causes and improve system operation in the future. However, the modification of the unconstrained schedule that occurs when some of these reason codes are applied can interfere with the operation of the market (by virtue of increasing an unconstrained import or export when it fails), and can lead to both distorted price signals and reduced market efficiency.

An intertie transaction can be failed by the actions of one of the three actors: external system operators, market participants, or the IESO, each with one or more associated reason codes.

- *External system operators:* external system operators may curtail an intertie transaction for their own internal security ('TLRe') or because of ramp rate ramp limitations ('MrNh'), both of which affect the unconstrained schedule. Market participants are exempted from the IESO's Intertie Failure Charge (IFC) for ramp limitations when transactions are arranged in real-time, and for internal security when transactions are arranged day-ahead or in real-time.
- *Market participants*: market participants can fail a transaction because of their own errors (e.g. wrong NERC tag and/or incorrect offers/bids) or business strategies (e.g. in anticipation of an uneconomic transaction). 'OTH' is associated with this type of failure, and participants are subject to the IESO's IFC.
- *IESO:* the IESO can curtail a transaction mainly for internal transmission congestion ('TLRi'), operating reserve activation ('ORA'), and internal resource adequacy ('ADQh'). As shown in Table 3-10, 'TLRi' and 'ORA' have no impact on the unconstrained schedule, but 'ADQh' does. Market participants with such failures are exempted from the IESO's IFC.

When an external system operator fails a transaction to or from Ontario, the curtailment means that the transaction is not feasible independent of its economics in Ontario. In this case, the unconstrained schedules should be changed accordingly.

When a trader fails a transaction due to its own errors or its bidding in an external market this implies that notwithstanding its bids or offers in Ontario, the transaction is not economic. In other words, the bids or offers in Ontario do not reflect the full economics of the transaction as seen by the market participant concerned and this should be reflected in the unconstrained schedules.

When the IESO takes an action to limit a transaction, it does so (or should do so, to the extent possible) consistent with the economics of each transaction as reflected by market participants' bids and offers. That is, the curtailed transaction should be the scheduled import with the highest offer or the scheduled export with the lowest bid. This would minimize the efficiency loss due to the curtailment. The Panel is of the view, however, that the unconstrained schedules should not be changed when transactions are curtailed by the IESO if this increases the unconstrained scheduled amount. The reason is that the IESO, as the market operator, should not alter a market participant's stated preference (i.e. the willingness to buy or the willingness to sell). Increasing the unconstrained schedules by the IESO ignores the bids and offers of the market participants concerned.

With the current treatment of reason codes, the IESO's actions of curtailing imports/exports for reliability can provide the market a misleading signal regarding supply/demand conditions and thus lead to market efficiency losses. For example, when the IESO cuts exports for ADQh and removes them from constrained and unconstrained schedules, it implicitly ignores the bids of the exporters involved and assumes that the opportunity cost of cutting them is zero.[139] While the sudden reduction in demand due to the export curtailment represents a saving in generation cost this is more than offset by the value of exports foregone which is a loss to the market. The value of foregone exports is not recognized by the unconstrained sequence, however, because curtailed

[139] The IESO on rare occasions may cut imports for internal resource adequacy when there is too much baseload load supply during the nighttime hours.

exports are simply removed from the demand side regardless of how much the trader has bid for them. As a result, the market price collapses. The use of ADQh leads to a dilemma. When supply is tight, the market price fails to reflect this scarcity because of the export curtailment. The failure of the market price to signal the prevailing scarcity conditions, in turn, encourages more consumption/exports and discourages supply/imports, which further tightens supply/demand conditions.

Recognizing that the prices during emergency operation may not reflect shortage conditions, the FERC issued a Notice of Proposed Rulemaking (NOPR) on February 22, 2008, proposing to administer prices to reflect shortage conditions or to change market rules to allow a demand response to set the shortage price.[140] This proposal is analogous to the treatment of ADQh proposed by the Panel in its December 2007 report and in this report.

In Chapter 2, the Panel observed that when the constrained schedule is modified, setting the unconstrained schedule equal to the constrained schedule may not be logical: at times, a failed import in the constrained sequence could turn into a failed export (i.e. a larger import) in the unconstrained sequence, while a failed export in the constrained sequence could become a failed import (i.e. a larger export) in the unconstrained sequence. This was seen to lead to counter-intuitive pricing. Limiting the unconstrained schedule to be no more than the failed constrained schedule would make more sense, and be consistent with the notion that the failure is similar to a forced derating of a resource. We recommend the IESO to revise the procedure of equating the schedules in both sequences.

Recommendation 3-6

1. ***For interjurisdictional transactions that fail because of market participants' ('OTH') or external system operators' actions ('TLRe' and 'MrNh'), the MSP recommends the IESO revise its procedures to avoid distorting the unconstrained schedule. This would prevent counter-intuitive pricing results (and would allow traders in those instances to receive the Congestion Management Settlement Credit***

[140] "Wholesale Competition in Regions with Organized Electric Markets", Docket Nos. RM07-19-0000 and AD07-7-000, dated February 22, 2008)

payment consistent with other situations where such payments are currently available).

2. ***The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy ('ADQh') should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted.***[141]

4. *New Items to Report*

4.1 Counter-intuitive Pricing Due to CAOR Scheduled in Pre-dispatch

In August and October 2003 in an effort to reduce the instances of counter-intuitive market prices, 400 MW of out-of-market OR was introduced into the market as Control Action Operating Reserve (CAOR).[142] A subsequent 400 MW tranche was added in November 2005.[143] This CAOR is backed by the IESO's potential control actions, rather than resources in the marketplace. These measures appear to have succeeded in lessening counter-intuitive effects of out of market control actions on market prices by eliminating the IESO's former practice of reducing OR requirements in the face of OR shortages. We now observe, however, that CAOR has itself become associated with counter-intuitive prices following a change in procedure by the NYISO and more recently by the MISO.

Prior to the introduction of CAOR, if there was a supply shortage or a potential supply shortage, the IESO took a variety of control actions in real-time, including reducing OR purchases from the market, cutting exports or reducing voltage. This had an effect of reducing overall generation requirements, and dramatically reducing prices at a time when supply was short – which is counter-intuitive since the market should signal supply problems with higher prices. The inclusion of control actions as OR by the IESO does not reduce the overall OR requirement, rather it allows the control actions to substitute

[141] The Panel's December 2007 Monitoring Report, pages 96-103.
[142] The IESO's market rule amendment MR-00235-R00-R05, effective on August 6, 2003
[143] For details, See http://www.ieso.ca/imoweb/marketData/ControlActionOR.asp

for OR provided by market participants. By assigning prices to the control actions (CAOR), less operating reserve is purchased from market participants (the intended result of the control action) without causing a reduction in the OR or energy prices. The first 400 MW of CAOR was set at a price of $30.10/MWh in the 10N and $30.00/MWh in the 30 OR markets. The $30.00/MWh price point was chosen to ensure that CAOR would used subsequently "at roughly the same frequency in which the 'out-of-market' sources of reserve were used via manual intervention during the first year of the market".[144]

To ensure reliability, the IESO put in place an operational procedure to designate as recallable an amount of exports equivalent to the CAOR scheduled for 10 minute OR in pre-dispatch.[145] Exports are identified as recallable typically starting from the lowest bid prices.

Exports are designated as recallable for two reasons. First, according to IESO operating procedures, exports should be curtailed before Ontario load is reduced via 3 and 5 percent voltage cuts if a contingency were to occur.[146] Second, being prepared with the knowledge of which exports are most likely to be recalled if there is a problem in real-time, benefits both the IESO and surrounding ISO's receiving these imports.

In November 2005, a further tranche of 400 MW of CAOR was introduced in real-time only in an effort to eliminate the remaining incidents of the IESO reducing the OR requirement in real-time.[147] This second tranche of CAOR was priced at $75.00/MWh for the first 200 MW and $100.00/MWh for the remaining 200 MW. The 400 MW of CAOR was applied in the 10 minute OR only. The availability of increased CAOR supply at higher prices can also be construed as creating an Operating Reserve demand curve for OR supplied by market participants, since the availability of CAOR results in reduced

[144] Market Pricing Working Group, Issue 36: Pricing CAOR, dated on July 2004.
[145] Operation Manual 2, Part 2.4 Section 5 "Control Actions Scheduled as Operating Reserve Resources (CAOR)". If CAOR is scheduled for 30 minute operating reserve in excess of 4 hours and the forecast reduction in demand is not sufficient to cover the amount of 30 minute CAOR schedule, the IESO may need to make exports recallable during the transaction checkout process.
[146] Market Operation Manual 7, Part 7.4, Appendix E: Emergency Operating State Control Actions.
[147] The Panel in its June 2005 Monitoring Report observed that the reduction in the OR requirement in real-time does not increase the reliability but has an effect of reducing real-time price (page 76)

purchases of OR from market participants as the OR price increases. NYISO accomplished a similar result when it introduced a demand curve for OR in its market.

Figure 3-11 depicts the monthly total CAOR scheduled in the pre-dispatch unconstrained and constrained sequences. CAOR is scheduled more in the constrained sequence, and more in the freshet period when peaking hydro units are supplying energy.

Figure 3-11: Monthly CAOR Scheduled in the Pre-dispatch Unconstrained and Constrained Sequence, August 2003 to April 2008

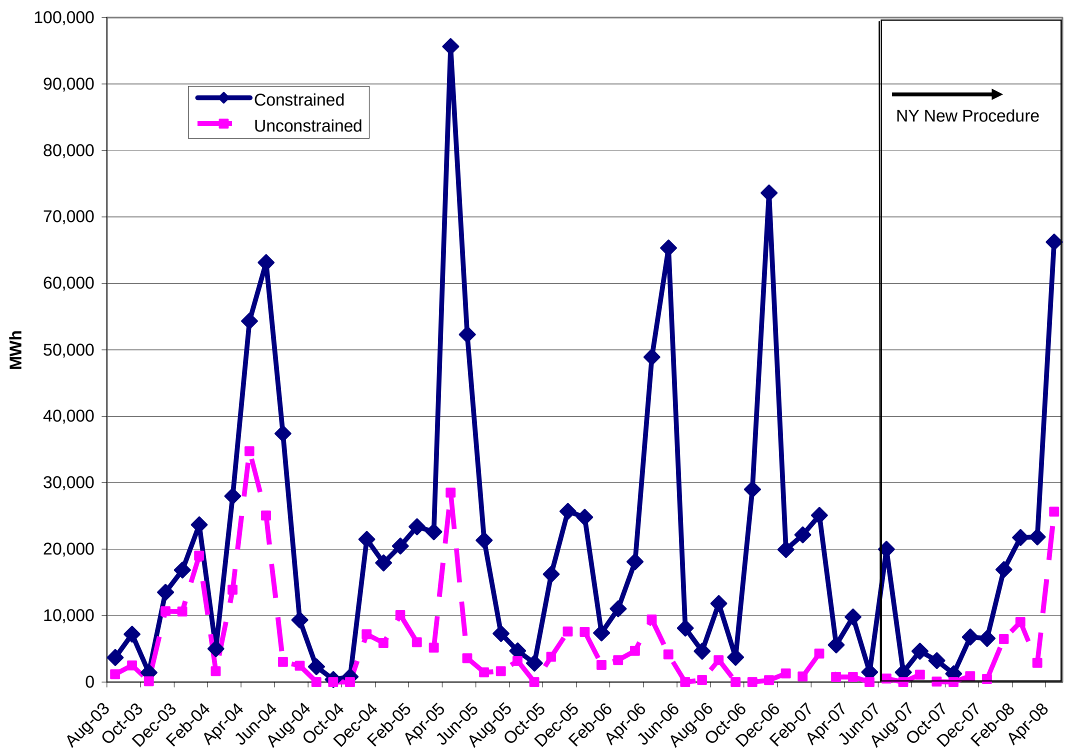
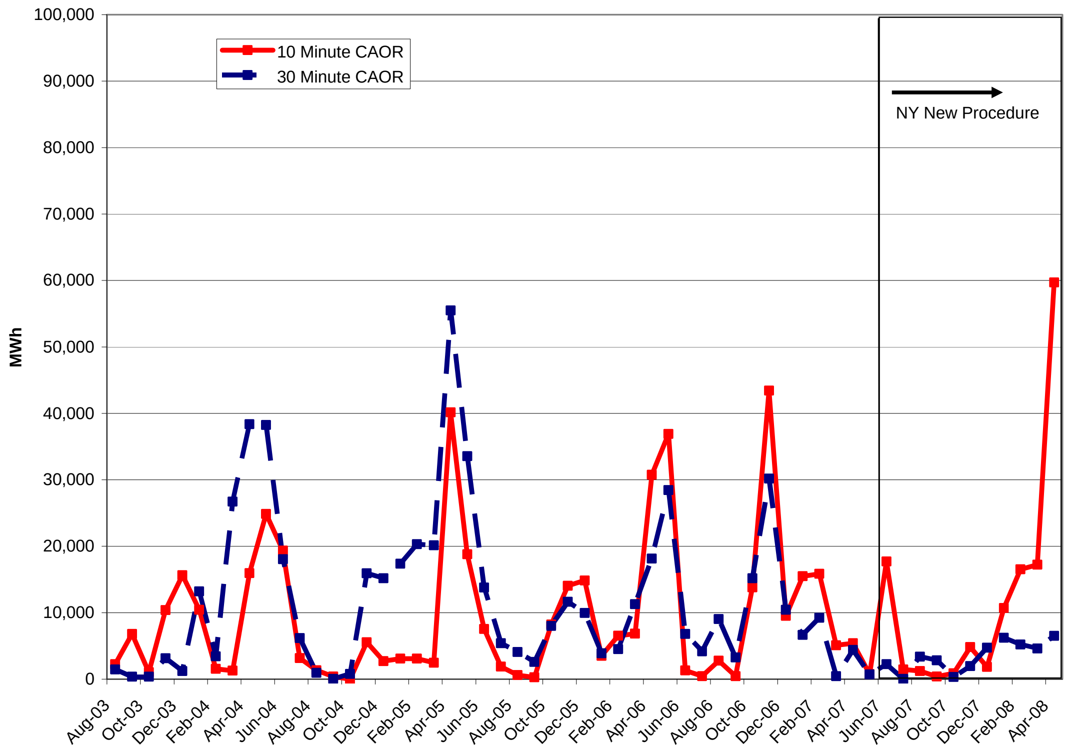


Figure 3-12 shows the monthly 10 and 30 minute CAOR scheduled in the pre-dispatch constrained sequence. It appears that in the earlier part of this period 30 minute CAOR was scheduled far more than the 10 minute CAOR, especially in winter months. However, in April 2008, the majority of CAOR was scheduled for 10 minute OR, implying an insufficient 10 minute OR supply. The lack of 10 minute reserve may be related to the early arrival of freshet period because most 10 minute reserve is typically provided by peaking hydro generators, which were providing energy instead.

Figure 3-12: Monthly 10 and 30 Minute CAOR in the Pre-dispatch Constrained Sequence, August 2003 to April 2008



The Impact of the Change in Procedure in New York

Since June 2007, the NYISO has not accepted recallable imports from other jurisdictions or markets.[148] In other words, imports to New York must be capacity backed (i.e. firm) in the originating market.

In electricity markets, import transactions that are resource-backed by the sending control area are traditionally not differentiated from those that are not. That is, similar to domestic offers, the system operators consider all external offers as backed by resources committed to support the transaction by the source control area. This allows resources to be efficiently scheduled among markets but also means sharing some supply uncertainty from external markets. In New York, however, those transactions that are not resource-

[148] New York ISO, Technical Bulletin 151: Import Transactions, final date: June 5, 2007.

backed (traditionally called "recallable imports") are not accepted. This enables the NYISO to commit adequate resources to meet internal reliability requirements with greater certainty. It should be noted that Ontario does not accept recallable imports either and as of June 17, 2008, neither does MISO.[149]

Prior to the institution of markets, recallable exports were a common form of transactions between control areas. As an example, Ontario Hydro might sell a recallable export to New York simply because the energy associated with the transaction was cheaper than producing that energy in New York. It was recognised by both parties that in the event of a contingency in the home market the transaction would be recalled and the receiving market must be prepared for that contingency by having sufficient OR to sustain the loss of the transaction. But contingencies were rare and in terms of reducing energy costs these transactions were efficient. The present market designs both in Ontario and the surrounding markets are doing away with this form of transaction. The Panel is of the view that it might be worthwhile to reconsider the elimination of recallable exports as a form of trade.

Currently, the IESO schedules almost all of its recallable exports on the New York and Michigan interfaces because the majority of its exports are scheduled on the two interfaces. Given that neither NYISO nor MISO will accept recallable exports, any export identified as recallable for CAOR will be failed. There is little need or advantage recalling exports on the Manitoba and Minnesota interfaces, which are located in Northwest where supply is bottled so that recalling exports would not help to relieve a supply shortage in southern Ontario. The Quebec interfaces also offer little opportunity for recalling exports, since trade with Quebec typically involves imports to Ontario during on-peak hours when recalls would most likely be needed.

Since the implementation of CAOR in August 2003, the IESO's procedure has been to identify sufficient exports in pre-dispatch to cover the pre-dispatch CAOR 10 minute

[149] According to Appendix 7.6 of the Market Rules, section 1.2.11.3, regarding interchange scheduling, "Transactions shall be one hour in duration".

obligation in the constrained schedule.[150] Since June of 2007, these export transactions from Ontario that are identified as "recallable" to New York are failed as a result of the change in procedure in New York. The IESO identifies recallable exports to New York after the IESO's two-hour ahead pre-dispatch (in the 90 minute check-out). In turn, New York rejects these exports, and the IESO's one-hour ahead pre-dispatch has these exports removed from both the constrained and unconstrained schedules. The removal of these exports reduces market demand in Ontario and this usually reduces the amount of CAOR needed and scheduled in the final pre-dispatch run. If the final pre-dispatch run schedules CAOR, and also contains exports on the New York interface, these may, in turn, be designated recallable and subsequently removed during the 30 minute checkout with New York. Exports failing in the 30-minute checkout have the effect of suppressing the real-time price.

It is less likely that exports rejected in the 90-minute checkout also reduce real-time prices, if, in the final pre-dispatch, the reduction in exports is offset by a reduction in imports. Table 3-11 lists the number of hours in which imports setting the pre-dispatch price in a month and in which CAOR was scheduled in pre-dispatch. During the period June 2007 to April 2008, imports set the pre-dispatch price more than one-third of time, implying that about one-third of time a reduction in exports was likely to be offset, partially or fully, by a reduction in imports. This offsetting effect is more apparent in hours when CAOR was scheduled: during the period June 2007 - April, 2008, about half of the reductions in exports due to CAOR were likely to be offset to some extent by a reduction in imports.

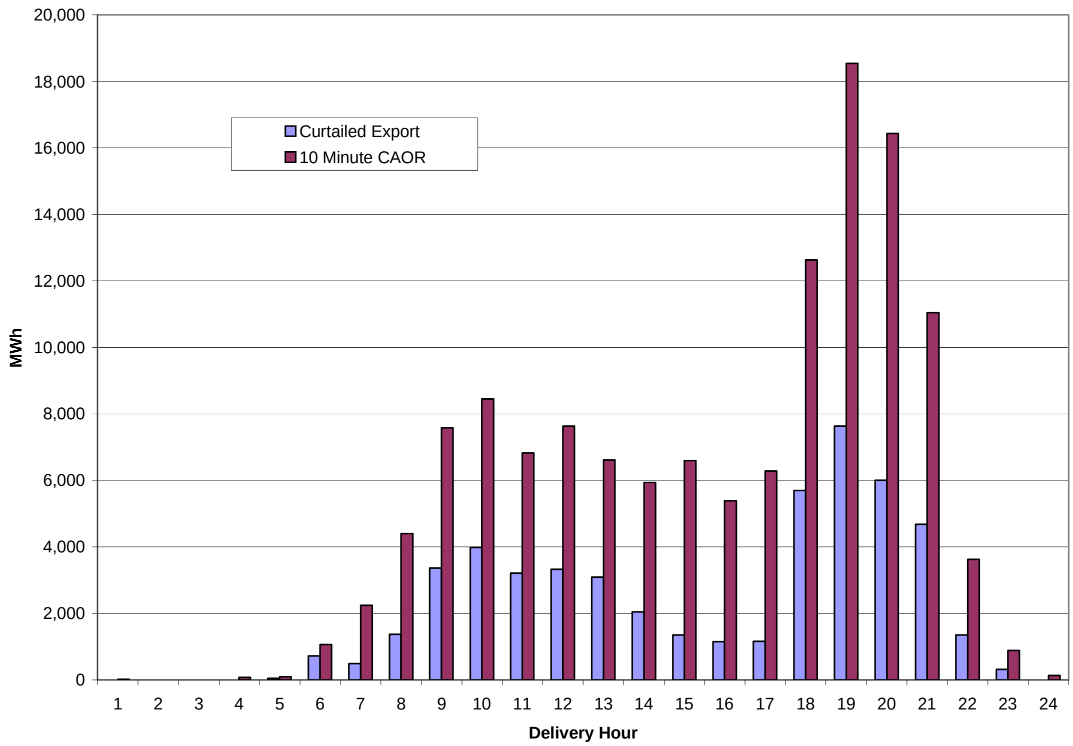
[150] The IESO's Operation Manual 2, part 2.4, section 5

Table 3-11: Frequency of Import Setting the Pre-dispatch Price, June 2007- April 2008

Month	Hours with Imports Setting the PD Price	Total Number of Hours	% of Total Hours in the Month	Hours with Import Setting the PD Price and CAOR was Scheduled	No of Hours with CAOR	% of Hours with CAOR
Jun-07	215	720	30	63	103	61
Jul-07	193	744	26	11	20	55
Aug-07	233	744	31	5	9	56
Sep-07	193	720	27	2	6	33
Oct-07	243	744	33	3	7	43
Nov-07	289	720	40	15	32	47
Dec-07	297	744	40	7	15	47
Jan-08	267	744	36	35	71	49
Feb-08	283	696	41	39	91	43
Mar-08	301	744	40	41	96	43
Apr-08	287	720	40	116	235	49
Total	2,801	8,040	35	337	685	49

The MAU examined the frequency with which exports that are designated recallable for CAOR have been rejected by NYISO since the change in procedure in New York. As shown in Figure 3-13, roughly half of those designated exports were subsequently cut by NYISO. The rejection of recallable exports typically occurs on-peak (especially HE 18 to 21). Given that the supply curve is typically steeper in these hours than in off-peak hours, the curtailment of exports has a greater price-suppressing effect on the HOEP on-peak

Figure 3-13: Scheduled 10 Minute CAOR in Pre-dispatch and Export Curtailment for CAOR by Hour, June 2007 to April 2008



Economic Surplus Implications

The refusal of recallable exports by New York, has the effect of suppressing the Ontario real-time price. Those exports designated as recallable and subsequently failed represent a lost value to exporters (and to potential purchasers in New York) for seams issues. These failures reduce the HOEP relative to the pre-dispatch price. There is not only an increased financial risk to internal generators because of the unexpected lower prices, but there is a reduction in economic gain to the market (total consumer and producer surplus) because of the loss of the exports that had been economically scheduled in pre-dispatch.

We are unable to quantify the aggregate effect of the rejection of recallable exports because we cannot simulate alternative scenarios under the constrained sequences over a long period of time. However, we can provide an example to illustrate how prices and economic surplus can be affected in response to CAOR recallable exports being cut. It would be preferable to use recallable exports in pre-dispatch, but given these exports fail we explore an alternative below.

To perform the analysis, we focus on a single hour and assume an alternative treatment of CAOR. We then calculate the increased net benefit of this alternative by comparing the bid prices for the increased exports, with the increased cost (based on offers) for energy and operating reserve in real-time. For this example, we have assumed that the CAOR is effectively removed from pre-dispatch (by setting its price to $2000/MWh), but is still available in real time.

An example: July 9, 2008 HE 16[151]

On July 9, 2008, HE 16, 265 MW of CAOR (all for 10 minute reserve) was scheduled in the final one-hour ahead pre-dispatch constrained sequence, 255 MW of which was backed by designating exports on the New York interface as recallable. There was 94 MW of CAOR scheduled in the unconstrained sequence. During the 30 minute check-out, the NYISO rejected all 255 MW of exports which were designated for CAOR on the interface, which led to a 255 MW export reduction in the unconstrained sequence.[152] The resulting HOEP of $115.18/MWh was lower than the pre-dispatch price of $145.50/MWh, and this was due in part to the export curtailment.

To avoid exports being cut due to CAOR, one option is to increase the CAOR price to a higher level (such as $2,000/MWh) in pre-dispatch but keep all CAOR in real-time at the current prices. Simulation analysis shows that in the case above if the price of CAOR was increased to $2,000/MWh, there would have been a 77 MW increase in imports and 255 MW increase in exports in the real-time constrained sequence (relative to the actual real-time schedules and flows), and 49 MW increase in imports and 209 MW more exports in the real-time unconstrained sequence (relative to the actual real-time schedules). The simulation results are summarized in Tables 3-12 to 3-14.

[151] In order to perform the analysis of the impact of CAOR in the constrained and unconstrained sequences for a selected hour, IESO tools limit selection to a recent dispatch day. This has necessitated selecting a day outside the 6 month winter period being reviewed in this report.
[152] When the export is rejected by NYSIO, both constrained and unconstrained schedules are set at the same value, typically 0 MW.

Pre-dispatch Prices

With a $2,000/MWh offer price, there would have been no CAOR scheduled in pre-dispatch. Table 3-12 lists the actual and simulated price and scheduled CAOR in both the constrained and unconstrained sequence. The pre-dispatch constrained energy price (as represented by the Richview nodal price) would have been $5.91/MWh higher and the 10S and 10N prices would have been $80.45/MWh higher. The unconstrained energy price would have been only $0.01/MWh higher, but the 10S and 10N prices would have been $33.27/MWh higher. As can be seen in Table 3-13, with the higher pre-dispatch prices in the constrained sequence, imports would have increased by a 77 MW in the constrained sequence and 49 MW in the unconstrained sequence. In contrast, exports would not have changed in the constrained sequence (in the pre-dispatch) but would have been 46 MW lower in the unconstrained sequence (in the pre-dispatch).

Table 3-12: Comparison of Actual and Simulated Pre-dispatch Prices, July 9, 2008 HE 16 ($/MWh)

	Constrained (Richview)			Unconstrained		
	Actual	Simulated	Difference	Actual	Simulated	Difference
CAOR (MW)	265	0	-265	94	0	-94
HOEP	149.79	155.70	5.91	145.50	145.51	0.01
10S	30.10	110.55	80.45	30.10	63.37	33.27
10N	30.10	110.55	80.45	30.10	63.37	33.27
30R	21.08	23.26	2.18	21.08	21.08	0

Real-time Prices

Because of recallable exports being curtailed, the real time price is suppressed. If no CAOR were scheduled or no CAOR exports were made recallable in the pre-dispatch sequence, there would not have been any exports being failed. Combined with the change in schedules, there would have been 178 MW more in net exports in the constrained sequence (255 MW not curtailed minus 77 MW more imports) and 160 MW more in net exports in the unconstrained sequence (255 MW not curtailed minus 46 MW less scheduled exports minus 49 MW more scheduled imports).

For the simulated case, changing all CAOR prices in pre-dispatch to $2000/MWh and using actual prices in real-time increases the HOEP by $6.97/MWh but does not change OR prices. The impact of increasing all CAOR prices in pre-dispatch on the Richview nodal price (the constrained reference price) is even greater, with a $47.44/MWh increase in the energy price.

Table 3-13: Actual and Simulated Real-time Prices, July 9, 2008 HE 16 ($/MWh)

	Constrained (Richview)			Unconstrained		
	Actual	Simulated	Difference	Actual	Simulated	Difference
Export Curtailed (MW)	255	0	(255)	255	0	(255)
Additional Exports (MW)	0	0	0	0	(46)	(46)
Additional Imports (MW)	0	77	77	0	49	49
HOEP	106.7	154.14	47.44	115.18	122.15	6.97
10S	30.1	30.1	0	30.1	30.1	0
10N	30.1	30.1	0	30.1	30.1	0
30R	27.1	27.1	0	30	30	0

The increase in the pre-dispatch CAOR price and subsequent reduction in export failures increases economic surplus in the market relative to the current situation. Table 3-14 shows the nature and magnitude of the net surplus gain resulting from the reduction in failed exports. There is a gain to the market of $51,001 from the additional 255 MW of exports would have been made by Exporters 1 to 3 (calculated as the sum of bid price times quantity exported). The costs incurred to supply these additional exports are: (1) $10,982 for an additional 77 MW of imports (Importers 1 and 2) that would have been scheduled and; (2) $23,215 for the 178 MW of additional domestic generation that would have been scheduled.[153] The net gain in economic surplus in the energy market (increased

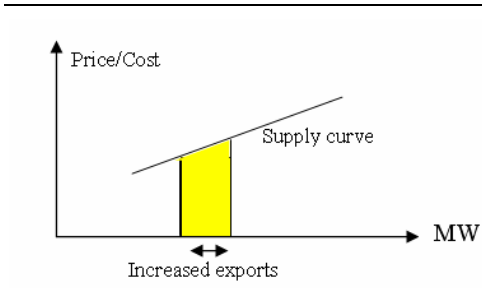
[153] The production cost is approximated as half of the 85 MW times the difference between the simulated and actual Richview price, which is the shaded area in the following graph. The underlying assumption is that the slope of supply curve is linear and thus the cost increase is the area below the sloping up supply curve. Because the simulated and actual Richview prices are close, this approximation should provide a very good estimate of production cost.

bid price times quantity from exports less the cost of additional imports and domestic generation) $16,805. In other cases, the elimination of CAOR in pre-dispatch might also increase the cost of OR in real-time and this cost increase would have to be taken into account when calculating the net gain to the market. In this case, however, the change in net exports had no impact on the price of OR, so that there was no additional cost in the OR market.[154] As a result, in this particular case, the net gain to the Ontario market from raising the price of CAOR to $2,000 in pre-dispatch would have been $16,805. Put another way, there would be an efficiency gain in the amount of $16,805 from raising the price of OR to $2,000 (i.e. eliminating CAOR) in pre-dispatch.

Table 3-14: Efficiency Gain from Increasing the CAOR Price: Example Where Recallable Exports Cannot Be Used, July 9, 2008 HE 16

	Offer/Bid Price ($/MWh)	Actual Real-time (MW)	Simulated Real-time (MW)	Bid Price Times Increased Quantity of Exports ($)	Increase in Cost ($)
Import 1	145.51	0	37	n/a	5,384
Import 2	139.95	10	50	n/a	5,598
Export 1	200	(0)	(49)	9,800	
Export 2*	200.01	(0)	(122)	24,401	
Export 3	200	(0)	(84)	16,800	
Production Cost Increase					23,215
Total				51,001	34,197
Net Efficiency Gain	16,805				

* For simplicity, only the portion of export that was curtailed is considered here. There was another 78 MW successfully scheduled common to both actual and simulated cases and therefore not included.



154 With the higher level of net exports in the simulated case, there may actually have been a reduction in OR purchased from market participants, with more OR being provided by CAOR. Because of tool limitations, we could not easily identify the specific OR schedule changes and associated prices. A lower purchase from the market, however, would imply a lower cost, and increased surplus, which we have not accounted for in the calculation.

Conclusions

CAOR was initially introduced to the Ontario market to deal with counter-intuitive price issues caused by the manual reduction in OR requirements due to reserve shortages. Since June of 2007, a change in the procedures of the NYISO has resulted in CAOR recallability itself creating both counter-intuitive prices and discrepancies between pre-dispatch and real-time price differences. It is our understanding that as of June 16, 2008 MISO no longer accepts recallable exports from Ontario further aggravating this problem.

Potential solutions may include:

1. Re-pricing Pre-dispatch (PD) CAOR to a price point where exports are no longer induced in Pre-dispatch.
2. Removing the 400 MW tranche of PD CAOR, in other words re-pricing it to $2000 in both the Pre-Dispatch and Real-time markets.
3. Stop backing CAOR with recallable exports. Put the CAOR in the pre-dispatch, do not make exports recallable, and in turn if something happens in real-time simply use the list of control actions.
4. Investigating with the various other ISO's the option of buying operating reserve in the receiving market for these recallable exports as the energy trade on its own is efficient.

Recommendation 3-7:
The MSP recommends that the IESO explore a solution to the emerging problem posed by recallable exports that are designated for Control Action Operating Reserve (CAOR), which induce counter-intuitive prices when rejected by the New York Independent System Operator and the Midwest Independent Transmission System Operator.

4.2 Increased Operating Reserve Activation

As shown in the Panel's December 2007 report and in Chapter 1 of this report, both the frequency and the magnitude of operating reserve activations (ORA) have been increasing. An operating reserve activation is "selected based on an 'unoptimized' simple stacking of the lowest to highest energy costs (offers) for the facilities with an operating reserve schedule".[155] Simultaneously with the activation of OR, the IESO lowers the OR requirement by the amount equal to the activation, following the NERC procedures.[156, 157] As the Panel has pointed out on various occasions, including its July 2007 Monitoring Report, the action of lowering the OR requirement can lead to lower OR and energy prices (due to the joint optimization of DSO).[158] These price movements are counter-intuitive in that they do not signal the scarcity conditions that forced the IESO to activate OR in the first place. This is especially true when the system experiences a large contingency and the IESO activates OR. The reduction in the OR requirement as a result of an OR activation may have a significant suppressing effect on the HOEP, thus sending a signal to the market that less rather than more supply would be desirable.

The IESO activates operating reserves for a variety of reasons, the most important of which are:

- to deal with a sudden loss of a large generator or a main transmission line;
- to restore Area Control Error (ACE) from a large negative (above 200 MW) to zero;[159, 160] and
- rarely, to activate OR for Shared Activation of Reserve or Regional Reserve Sharing at the request of external markets or jurisdictions.

Operating reserves are activated for large generation or transmission outages, which are relatively rare, and more often for ACE excursions for other reasons, such as load forecast error or generators deviating from their dispatch. The IESO calculates ACE

[155] For details, see IESO's discussion paper "Operating Reserve Activations (ORA) vs One Time Energy Dispatch (OTD), April 4, 2007, and Market Rules, Chapter 5, Section 7.4 and 7.5.
[156] The OR requirement is 1,418 MW under normal conditions. After the implementation of the NPCC Regional Reserve Sharing (RRS) Program, the IESO can lower the requirement to 1,318 MW.
[157] NERC standard BAL-001-0: Real-Power Balancing Control Performance
[158] The Panel's July 2007 Monitoring Report, pages 86-90.
[159] ACE is a function of generation output deviation from their schedule, frequency deviation, and a small term adjusted for operational metering error. ACE is mainly affected by internal generation off-dispatch, forced outage, as well as ACE deviation in adjacent markets.
[160] Market and System Operations Part 2.4: Real-time Operating Procedures, Section 2: Assess Impact on Routine Operations. When ACE is positive by a large number, the IESO will manually dispatch down generators, based on generators' preference when the IESO verbally communicates with the generators.

every four seconds. ACE fluctuates around zero and thus can be either positive or negative. Typically, a positive ACE means there is more generation than demand (over-generated) at that instant, and a negative ACE more demand than generation (under-generated).

The NERC performance standard requires that the IESO recover the deviated ACE to zero within 15 minutes.[161] In addition, it requires that "Control Performance Standard 1" (CPS 1) remains at least 100 percent and "Control Performance Standard 2" (CPS 2) at least 90 percent.[162, 163] The IESO's self-imposed performance target is to meet and exceed the industry median value (which is typically in the range of 145 percent for CPS 1 and 95 percent for CPS 2).[164] As Table 3-15 shows, the IESO has consistently exceeded the target levels since market opening.

Table 3-15: NERC Standard and IESO Performance for ACE Control, January 2002 to April 2008*

		2002	2003	2004	2005	2006	2007	January to April 2008
CPS1 (NERC Standard >=100%)	**IESO Performance**	172	170	164	161	162	163	159
	Industry median	156	148	142	143	142	N/A	N/A
	IESO rank	3	5	2	1	1	N/A	N/A
CPS2 (NERC Standard >=90%)	**IESO Performance**	97	98	98	96	96	96	96
	Industry median	96	95	94	95	95	N/A	N/A
	IESO rank	2	1	2	2	3	N/A	N/A

* NERC stopped reporting the CPS since June 2007 because of data confidentiality.

When the ACE deviates by a small amount, the generators providing Automatic Generation Control (AGC) automatically correct the deviation by increasing or decreasing production, thereby moving the ACE back towards zero. The IESO presently contracts for approximately 100 MW of AGC.[165]

[161] NERC Performance Standard BAL-002-0: Disturbance Control Performance
[162] CPS1 is a statistical measure of ACE variability and its relationship to frequency error over a 12 month period. CPS 2 is a statistical measure designed to limit unacceptably large net unscheduled power flows by measuring a 10-minute period average of ACE. For details, see NERC Performance Standard BAL-001-0
[163] On March 1, 2008, the IESO began participating in the "Eastern Interconnection Proof-of-Concept Field Trial" which uses an alternative measure to CPS2, called Balancing Authority ACE Limit (BAAL).
[164] The IESO compares its performance with 10 other control areas, which are either similar in size to Ontario or are adjacent to Ontario.
[165] The contract of AGC is confidential between the IESO and AGC capacity supplier.

However, when the ACE deviates by more than the AGC amount, the IESO may adjust generators' schedules manually to increase or reduce generation. The manual adjustment process is traditionally called One-Time Dispatch (OTD). When issuing OTD instructions, the IESO identifies one or a group of generating units that may be able to ramp up or down quickly, then verbally communicates with the generator to reschedule units based on their stated preferences. [166] OTD may be inefficient if the IESO cannot quickly identify the least costly generation to re-dispatch or the generator for expediency does not select its lowest-cost option. OTD is also not transparent to the market as no market participant other than the one who receives the OTD instruction knows that it is occurring. Those units selected for OTD are typically hydroelectric units, which can ramp up or down most rapidly.

When the ACE is large and negative and keeps decreasing, the IESO has two means to deal with it: use OTD or activate OR. In this situation, OTD and ORAs are alternatives to each other. However, they differ in terms of how the energy is selected and what is reflected in the market schedule. Table 3-16 highlights the main differences between OTD and ORA. OR is activated based on the merit order of the energy offer (or bid) price of facilities with an operating reserve schedule and reported to the market whereas OTD are not reported. Under the current market design, OTD has no impact on the market price, while ORA does.

Table 3-16: Comparison of OTD and ORA

	Dispatch Merit	Generation Units	OR Requirement	Impact on the Market Price	Transparency
OTD	IESO's initial selection and Generators' verbally stated preference	Any units with a high ramp capability	No impact	No impact	Only generators who receive OTD know
ORA	From the lowest offer to the highest	Units that are scheduled for OR	Reduced by the amount of activation	Could suppress the energy and OR price	All market participants know

[166] Market and System Operations Part 2.4: real-time Operating Procedures, Section 2: Assess Impact on Routine Operations, and Section 6,:Respond to ACE Excursion.

Unfortunately, there is no guarantee that, using the above selection mechanisms, the use of either OTD or ORA would lead to the least-cost supply for the additional energy. OTD may lead to dispatching a higher cost generation unit since the IESO may not be able to identify the lowest-cost generation and the operational preference of the generator at the time of the request. ORA may select the lowest cost resource but only from the limited group of those scheduled for OR. In each case, there may be other lower cost generation, not scheduled for OR or energy, that could provide the additional energy needed at the time.

Figure 3-14 lists the monthly total number of OTD for a positive ACE and OTD/ORA for a positive ACE since May 2003.[167] It appears that before early 2005, a negative ACE was more like to occur than a positive ACE, but both were at a relative low level compared to 2007 and 2008. In the period from early 2005 to mid-2006, both OTD and ORA first decreased but then increased. In October 2006, both OTD and ORA suddenly and significantly increased, with OTD for a positive ACE subsequently decreasing while OTD/ORA for a negative ACE continuing to increase.

[167] One OR activation can have many units being activated. Similarly, one OTD can have many units being rescheduled.

Figure 3-14: Monthly OTD Events for a Positive ACE and OTD/ORA for a Negative ACE, May 2003 to April 2008

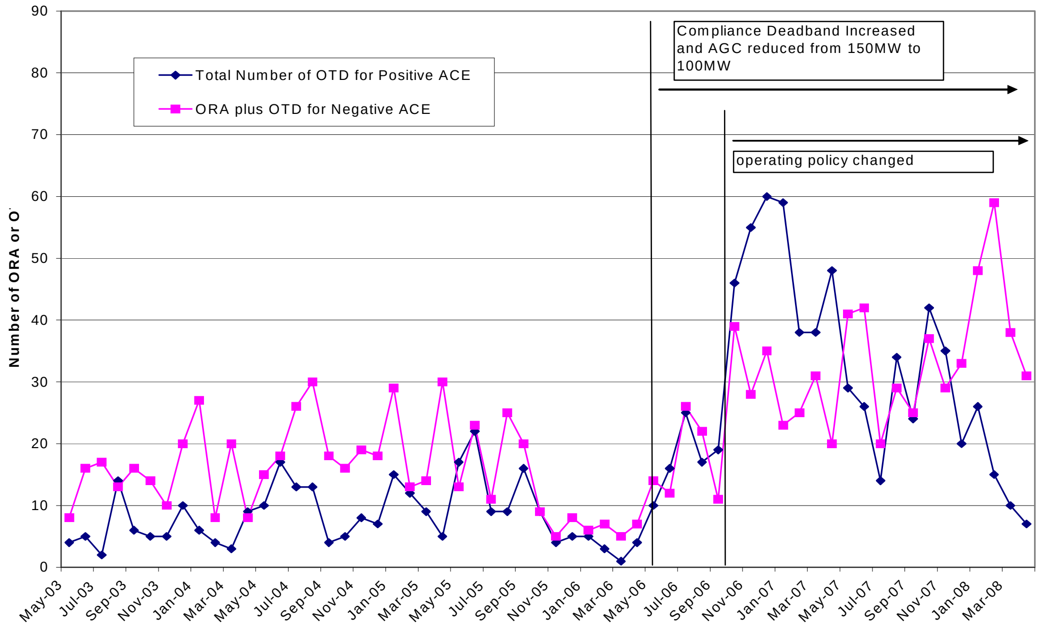
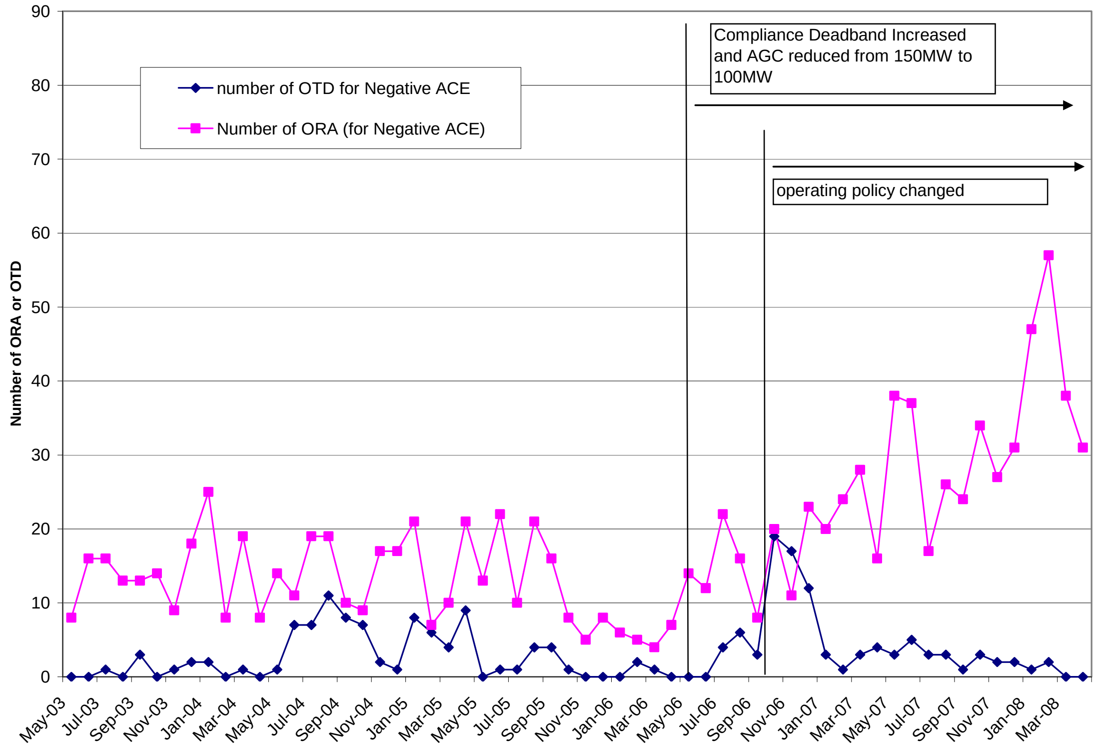


Figure 3-15 shows the monthly total number of OR activations and total OTD for a negative ACE by month since May 2003. The total number of OTD for a negative ACE was low for the whole period except for the months of October to December 2006. Since January 2007, the monthly OTD for a negative ACE has remained under five times per month. The number of ORA was stable during the period May 2003 to September 2005, then stayed at a very low level from October to April 2006, and then increased continually since May 2006.

Figure 3-15: Monthly OR Activation and OTD for a Negative ACE, May 2003 to April 2008



There were two major changes in May 2006 that could have led to increased use of OTD or ORA.

- On May 4, 2006, the IESO lowered the minimum AGC requirement from 150 MW to 100 MW, in an effort to reduce the AGC cost. The 50 MW reduction in AGC capacity had some effect of increasing the use of OTD and ORA.[168]
- On May 8, 2006, the IESO increased the compliance deadband from 10 MW to 15 MW. That is, since that time, the actual output of a unit has been allowed deviate by an additional 5 MW from its received dispatch instruction without any compliance consequences. As generators are operating independently, some units may be producing more while others produce less, thus offsetting each other. However, at times an OTD or ORA may be needed when many units deviate in the same direction. This is especially true in periods of increasing or decreasing load where typically fossil generators, which have a limited ramp capability, are

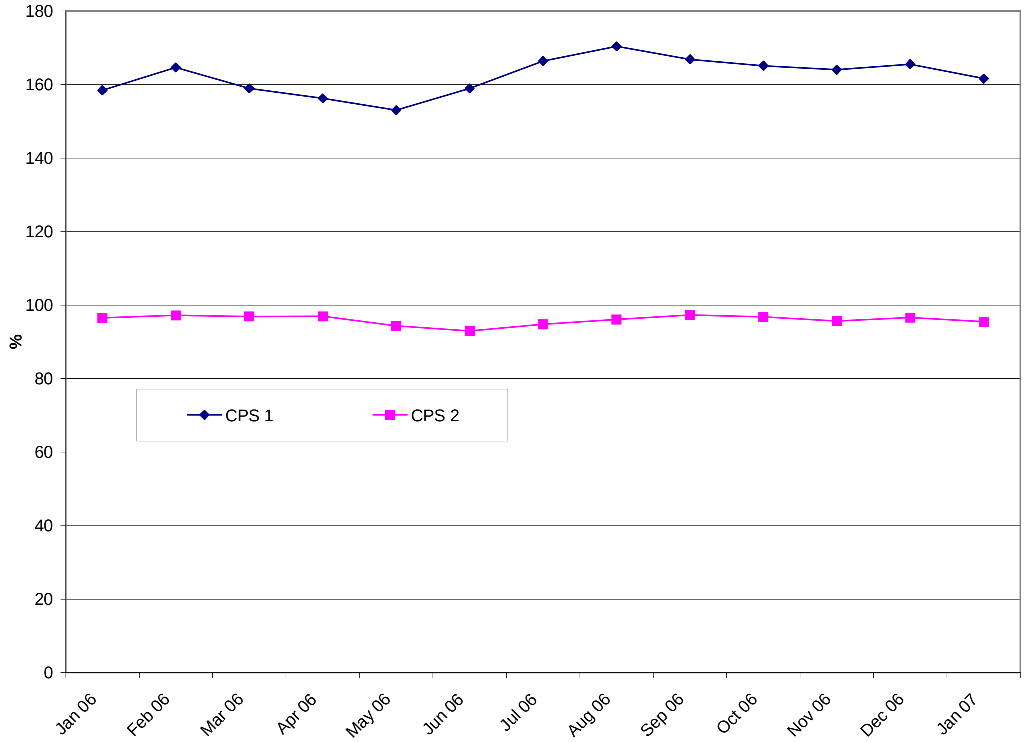
[168] See the IESO's study "DIWG – AGC Requirement", December 12, 2006 and "Proposal for Minimum Scheduling of AGC', February 16, 2007

moving in the same direction. There has been no published study by the IESO or other parties on the impact of the increased deadband.

Another important factor leading to a significant increase in OTD and ORA is that in late September 2006, the IESO changed its operating policy regarding the monitoring of CPS obligations. The change was to improve the CPS in light of what the IESO viewed as a low CPS level in the spring of 2006, seen in Figure 3-16.[169] This change immediately led to a significant increase in OTD.[170] Although the increased use of OTD did keep the IESO's control performance at a high level in late 2006 compared to summer 2006, it appeared to have had little impact on the general performance in 2007. As Table 3-15 shows, the achieved CPS levels in 2007 were essentially the same as in 2005 and 2006, implying the increased OTD and ORA may be related to the reduction of AGC and the increase in deadband.

[169] Even though the CPS levels were lower than historical levels in the first half of 2006, they were still considerably higher than the Industry median values of 142 or 143 between 2004 and 2006, as noted in Table 3-15.
[170] See the IESO's study "Proposal for Minimum Scheduling of AGC', February 16, 2007.

Figure 3-16: Monthly CPS's, January 2006 to January 2007



Because OTD is not market-based and not transparent, market participants complained about the high level of OTD after the IESO changed its policy.[171] In response, the IESO has gradually reduced the use of OTD for negative ACE control and beginning in early 2007, increased the use of ORA. However, the IESO also continues to use OTD for controlling a negative ACE occasionally (typically less than five times per month).[172]

Assessment

When the ACE is positive (over-generated) and beyond the capability of AGC generators, the only way the IESO can manually restore it is to use OTD to back down generators. In contrast, when the ACE is negative (under-generated) and beyond the capability of AGC generators, the IESO can either issue OTD to manually increase generation or activate OR to increase energy supply.

[171] See for example "OPG's Comments on IESO's Feb 16/07 Proposal for Minimum Scheduling of AGC", March 2, 2007.
[172] Between January to April 2008, the number of ORA plus OTD for negative ACE was much greater than the number of OTD for a positive ACE, implying the ACE was more likely to be negative than positive. We have asked the MAU to further study the causes for this and report back to us.

It is possible to reduce the frequency and the amount of OTD and ORA by increasing AGC capacity. However, there may be a significant cost associated with maintaining a larger AGC capacity. AGC capacity is usually provided by an energy limited resource: if it is used now, it cannot be used later. This has three implications:

- First, when energy-limited hydroelectric units are providing AGC energy to increase ACE, the energy is used at that moment and the opportunity of supplying energy later when the value may be higher is forgone. When fossil units are providing AGC, the cost could be even greater as there may be other, lower cost resources available for dispatch.
- Second, when the AGC units' production is backed down in order to reduce ACE, these units are foregoing the opportunity to supply energy even though it may be more economic for them to supply energy.
- Third, most of the time, when little AGC response is needed, the AGC capacity must be still be held in reserve. In other words, most of the time, this capacity cannot be dispatched for energy even though it is economic. This appears to be the most significant operating cost increase resulting from maintaining a larger AGC capacity.

While a full study of the relative costs of relying on OTD and ORA as opposed to AGC would be complex, the Panel is of the view that given the increase in ORA, a study of this nature is warranted.

The Panel does not question the IESO's objective of recovering ACE deviations as required by the NERC. The Panel also respects the IESO's goal of having a higher performance standard than required by the NERC if the benefit of a higher standard is greater than the cost of achieving it. The Panel believes, however, that the IESO can achieve its objectives in a way that is more compatible with market efficiency than it is now doing.

The New York ISO deals with ACE deviations by re-running its energy dispatch to determine the efficient unit to be re-dispatched for energy. This would appear to be the preferred alternative to determine the efficient unit to dispatch to meet an energy deficiency, but that alternative is not presently available to the IESO. The second best alternative is to use ORA rather than OTD whenever possible. ORA is partially market based as energy is activated based on the energy offer (or bid) price. Furthermore, joint optimization of DSO minimizes the total cost when an OR is activated. OTD is not transparent and may be inefficient if if the IESO is not able to identify the lowest-cost solution or the generator for expediency does not select its lowest-cost option. [173]

In periods in which an OR is activated due to ACE deviations rather than the loss of a generator, the present practice of reducing the OR requirement is not consistent with the function of OR because there has been no change to the probability or potential magnitude of contingencies that may affect reliability. The reduction in the OR requirement also distorts market price signals and leads to market inefficiency. The Panel has previously recommended that OR be replenished as soon as possible after a contingency occurs in order to ensure efficient short term price signals. Where OR is activated in response to ACE, maintaining the OR requirement would avoid distorting market prices.

Recommendation 3-8

1. ***To avoid distorting market prices, the MSP recommends that the IESO maintain the Operating Reserve requirement when Operating Reserve is activated in response to Area Control Error (ACE).***
2. ***If the IESO believes that it must maintain a higher standard than the NERC Control Performance Standard, the MSP recommends that the IESO conduct a cost-benefit analysis comparing alternatives for responding to Area Control Error (ACE) deviations, that is: providing more Automatic Generation Control (AGC); using One-Time Dispatch (OTD); using Operating Reserve Activation***

[173] Given that the generator would receive CMSC to compensate for additional costs or lost profits, it is not necessarily worse off if it does not choose the lowest-cost alternative.

(ORA); and establishing a capability to re-run the dispatch algorithm on demand.

3. ***In the interim, until a cost-benefit study of the alternatives for handling ACE deviations is completed, in accordance with Recommendation 3-8(2), and assuming the IESO adopts Recommendation 3-8(1) regarding the maintenance of the Operating Reserve requirement level when Operating Reserve is activated for ACE, the MSP recommends that the IESO should use ORA instead of One-Time Dispatch to deal with negative ACE whenever possible.***

5. *CMSC Payments and Dispatch Deviations*

The Panel has long questioned what benefits the market receives from constrained off payments.[174] One of the major explanations for this market design feature was that, in a uniform price market, providing constrained off payments encouraged market participants to follow their dispatch instructions. It has been argued that without these payments generators might continue to supply above their dispatch in order to avoid losing profit associated with production at higher prices.[175]

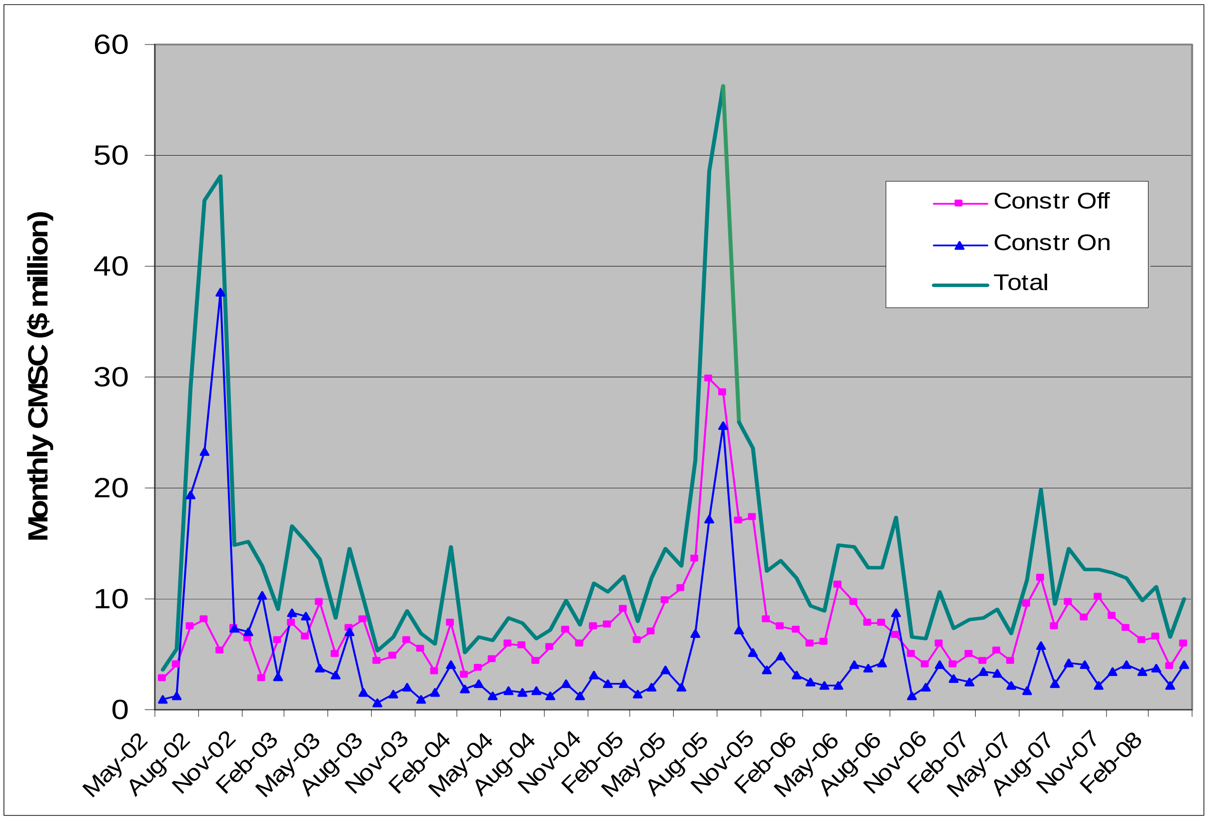
We are now observing that there are fairly regular large dispatch deviations by generators which result in the need for the IESO to activate operating reserve or use one-time dispatches to correct for shortfalls in generation (see section 4.2). We had already noted in our 2003 consultation on CMSC that it is quite possible that when a slow-ramping resource falls short of its dispatch, that deviation itself may induce constrained off CMSC. This earlier observation had led to a market rule change which allowed reduction of some CMSC payments to dispatchable loads, but not generators.[176]

[174] See our special report titled: "Congestion Management Settlement Credits (CMSC) in the IMO-Administered Electricity Market: Issues related to constrained off payments to generators and imports", February 2003, and more recently, our June 2006 Monitoring Report at pp.121-128.
[175] A second argument has been that constrained off payments are a substitute for physical rights to access transmission. However, the link between constrained off payments, physical flows and rights is somewhat tenuous, in that flows and rights are related to transmission capability and what flows on it, whereas constrained off payments are associated with the power that does not flow.
[176] MR-00195-R00, "Recommendations from July 2003 Market Surveillance Panel Report – Self Induced Constrained-Off CMSC Payments and Negative Priced Import Offers", effective January 6, 2004.

In Chapter 1 of each monitoring report we have shown monthly CMSC payments as part of the total hourly uplifts (see Table 1-20 in this report). In the Statistical Appendices to our reports we have provided somewhat more detail, identifying CMSC payments for constrained on and constrained off situations, as well as CMSC for operating reserve (see Appendix Table A-17). Figure 3-17 shows the monthly total CMSC (for energy) as reported in the various Statistical Appendices to our monitoring reports, since the market opened in May 2002.

The most obvious feature of these payments is the high values that emerged for a few months in the summer of 2002 and again in 2005. These were associated with tight supply conditions in Ontario. Otherwise, payments have been roughly constant, at approximately $10 million per month. The second observation is that constrained off payments have averaged about 60 percent more than constrained on payments. There have been more than $550 million in constrained off CMSC payments since the market opened, on average about $7.6 million per month, compared with $4.8 million per month for constrained on payments.

Figure 3-17: CMSC Payments by Month, May 2002 - April 2008 ($ million)



The Panel continues to hold the view that constrained off CMSC payments cannot be justified by the assumption that these encourage resources to comply with dispatch instructions. In spite of these payments, we have seen an increase in deviations from dispatch, and have seen deviations induce CMSC payments. Also, about one-quarter of the constrained off CMSC payments are to imports and exports for which there is no possibility of deviations, because of scheduling protocols between markets.

Recommendation 3-9:

The MSP recommends that the IESO review the benefits of constrained off payments with a view to their discontinuation.

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Chapter 4: The State of the IESO-Administered Markets

1. *General Assessment*

This is our 12th semi-annual monitoring report on the IESO-administered markets covering the winter period November 2007 to April 2008. As in our previous reports we conclude that the market has operated reasonably well according to the parameters set for it.

For just over two years now, energy prices have been relatively stable, as downward pressure from the modest amount of new supply has been accompanied by an upward pressure on prices induced by higher fuel costs. The average monthly HOEP this winter period was slightly higher (by 0.5 percent) at $49.16/MWh, than the HOEP corresponding to the period a year ago, with on peak HOEP being 1.8 percent higher and off peak HOEP 1.0 percent lower. However, market-related uplift payments for congestion, supply guarantees and other matters were about 18 percent higher than the corresponding period a year ago, primarily as the result of more congestion (bottled supply) particularly in the northwest of the province.

Fuel price movements had little apparent overall impact on the average HOEP during this winter period. The period began with natural gas prices lower than the same period last year, but increased more than 50 percent over the six months. The end-of-period gas prices were thus higher than last year, but the average price was the same as the previous winter, consistent with little change in HOEP. Appalachian coal prices also rose substantially over the 6 winter months, almost doubling by April relative to the year earlier. As we have seen previously, changes in coal prices have a lesser influence on average HOEP than gas prices, although we did note an upward shift in the frequency that coal was the fuel of the marginal generating units, setting prices 59 percent of the time this winter compared with 53 percent the previous winter. Therefore gas-fired generation set prices less often.

There were 2 hours with HOEP over $200/MWh, compared with only one hour last year. There were 261 hours this winter with prices below $20/MWh compared to 189 hours last year, continuing a trend toward more low-priced hours. These included five hours with a negative HOEP. Our review of these and other anomalous hours led us to conclude that the price movements in these hours were, for the most part, consistent with the supply/demand conditions prevailing at the time.

As is customary, the MAU communicated with market participants from time to time to review and understand market behaviour. We found no evidence of gaming or abuse of market power during the review period.[177] There were however occasions where actions by market participants or the IESO led to less desirable market outcomes. In one instance reported, there was the unexpected use of deratings by a market participant rather than modified offers to limit supply from some of its fossil units that prevented HOEP from falling and reflecting the level of surplus energy in the market. There were other situations where IESO actions have caused the HOEP not to accurately reflect market conditions, and these have led to recommendations by the Panel below.

Ontario energy demand was almost unchanged this winter compared with last, due to colder temperatures and higher demand early in the period being offset by lower demands later in the period. The major component, local distribution company demand, has been fairly constant year-over-year, but we observe a continued decline in wholesale load consumption. Total market demand (Ontario demand plus exports) has increased, driven by a substantial rise in exports to 8.5 TWh. This represents an increase of 3.1 TWh, or more than 60 percent. An important cause was linked wheel transactions in which an import offsets the export and there is no net effect on HOEP. Such transactions had been uncommon, but during this winter period grew by a factor of approximately 150 times relative to last year, as discussed in Chapter 3.

[177] In spite of this general conclusion, the Panel observes that as usual there have been many instances of CMSC adjustment through the administrative activity performed by the MAU under the Local Market Power mitigation rules.

The remainder of this Chapter is organized as follows. Section 2 provides a status report of actions in response to previous Panel recommendations. Finally, Section 3 excerpts and lists the recommendations made in the body of this report.

2. *Implementation of Previous Panel Recommendations*

Many of the recommendations in Panel's reports are directed to the IESO. In November 2006, the IESO began to formally report on the status of actions it has taken in response to these recommendations. The IESO posts this information on its web site and discusses the recommendations and its actions with the Stakeholder Advisory Committee (SAC).[178]

In this section we review the status of the recommendations from our last monitoring report, released in December 2007. The IESO responses to these are summarized in Table 4-1 below.[179]

With respect to Recommendation 3-6, Hydro One has advised the MAU that it continues to view the transmission expansion as important and is prepared to complete the project in a matter of weeks, once the factors beyond its control are resolved.

Regarding Recommendation 4-1, we understand that the Ontario Power Authority plans to make public in the near future additional information related to the impact on the price of electricity of the cost of conservation and demand response, as well as generation supply it has under contract.

[178] See "IESO Response to MSP Recommendations" at http://www.ieso.ca/imoweb/marketSurveil/surveil.asp

[179] Based on a presentation to the Stakeholder Advisory Committee (SAC), "Briefing note on IESO Response to the Market Surveillance Panel (MSP) Report ", February 6, 2008.

Table 4-1: Summary of IESO Responses to Recommendations in December 2007 Market Surveillance Panel Report

Recommendation Number & Status	Subject	Summary of Action
1-1[180] **In Progress**	Wind Forecast Error	"This recommendation is currently being addressed in the Stakeholder Engagement Plan SE-29. With increasing penetration of wind on the system, accurate short-term wind energy forecasts are necessary for effectively managing potentially large fluctuations on the system."
2-1 **In Progress**	Export Curtailment	"There are several issues regarding the appropriate market price during curtailment of exports due to adequacy. Currently the IESO has undertaken a related review of the scheduling and activation of Operating Reserve. We will combine the study needed to investigate this recommendation in this effort. Any possible outcomes resulting from that review will be discussed at the Market Pricing Working Group (MPWG)."
3-1 **In Progress**	Load Predictor Tool	"The IESO agrees with this recommendation and has undertaken an initiative to improve load predictor performance. This is consistent with the recommendation #4 from the November, 2006 to April, 2007 MSP report: (http://www.oeb.gov.on.ca/documents/msp/msp_report_20070810.pdf)"
3-2 **In Progress**	Phase Angle Regulators	"(a) The IESO agrees with this recommendation and is currently working towards making the Phase Angle Regulators operational. (b) The IESO will ensure that Hydro One is aware of this recommendation."
3-3 **In Progress**	15-minute Dispatch Algorithm	"The IESO will be initiating a review of the current real time dispatch and pricing to address the drivers for load following and ramping services in the context of the generation fleet of today and tomorrow."
3-4 **In Progress**	Congestion Management Settlement Credits	"The IESO intends to bring this issue to the Technical Panel by the end of Q3 2008, as a market rule amendment submission, for determination whether consideration is warranted."
3-5 **In Progress**	Intertie Offer Guarantees	"The IESO intends to bring this issue to the Technical Panel by the end of Q2 2008, as a market rule amendment submission, for determination whether consideration is warranted."
3-6 **In Progress**	QFW Transmission Expansion	"The IESO concurs with the MSP with regards to the importance of the improvements to the QFW transmission expansion."
3-7 **In Progress**	Forecasting of Embedded Generation Production	"This issue is currently being addressed in Stakeholder Engagement Plan SE-57. The IESO has prepared a discussion paper to facilitate the discussion with stakeholders on the integration of these and other embedded generators into the reliable operation of the IESO-controlled grid and the efficient administration of the markets."
3-8 **In Progress**	OPA Contract Efficiency	"The IESO concurs that future contracts should be structured to maintain the energy market price as the driver for production decisions. The IESO is consulting with the OPA towards that goal."
4-1 **In Progress**	Transparency of Payments for OPA Contracts	"(a) Where appropriate, the IESO is in support of greater transparency in the market. (b) Currently the IESO publishes information that allows participants to calculate these payments. The IESO will explore with OPA whether there are more effective ways of presenting this information to the market."

[180] Recommendations are labelled according to the numbering in our December 2007 Monitoring Report, e.g. "1-1".

3. *Summary of Recommendations*

At its February 2008 meeting, the IESO's Stakeholder Advisory Committee encouraged the Panel to provide additional information about the relative priorities of the recommendations in its reports.[181] The Panel endeavours to do so below for the recommendations made in this report. In doing so, the Panel notes that it has in the past and will continue to provide efficiency, frequency or other measures of quantitative impact where this is feasible, but that some issues are not readily quantifiable (e.g. the transparency recommendations in this report). In addition, the Panel has always recognized that recommendations may have implications which extend beyond its focus on market power, gaming and efficiency and that the mandate and resources of the Panel do not extend to stakeholdering of potential changes or detailed assessments of implementation issues. Accordingly, many of the Panel's recommendations are framed as encouraging responsible institutions such as the IESO to conduct detailed cost-benefit analysis, stakeholder consultation and/or other forms of evaluation in order to determine whether, when and how a particular recommendation should be implemented.

In providing comments regarding the relative priorities of the recommendations in this report, the Panel considered that it would be useful to group the recommendations thematically under the following categories: price fidelity, dispatch, transparency and hourly uplift payments. In each area, the Panel has identified the recommendations that it believes would have the most significant effects. However, this should not be regarded as implying that other recommendations are unimportant. The Panel will not put forward a recommendation unless it believes that it would make a meaningful contribution to improving the operation of the market. Note also that changes that may individually not be regarded as large can have a substantial cumulative effect, as well as a spillover benefit, in improving the confidence that market participants have in the operation of the Ontario market.

[181] See Agenda Item 4 in the minutes of the February 6, 2008 meeting of the Stakeholder Advisory Committee at http://www.ieso.ca/imoweb/pubs/consult/sac/sac-20080206-Minutes.pdf

3.1 Price Fidelity

The Panel regards price fidelity as being of fundamental importance to the efficient operation of the market. Based on the frequency and magnitude of occurrences, the Panel would rank the five recommended procedural changes in this area in the following relative order:

Recommendation 3-7 (Chapter 3, section 4.1)

The MSP recommends that the IESO explore a solution to the emerging problem posed by recallable exports that are designated for Control Action Operating Reserve (CAOR), which induce counter-intuitive prices when rejected by the New York Independent System Operator and the Midwest Independent Transmission System Operator.

Recommendation 3-6(2) (Chapter 3, section 3.3)

The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy ('ADQh') should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted.

Recommendation 3-8(1) (Chapter 3, section 4.2)

To avoid distorting market prices, the MSP recommends that the IESO maintain the Operating Reserve requirement when Operating Reserve is activated in response to Area Control Error (ACE).

Recommendation 3-6(1) (Chapter 3, section 3.3)

For inter-jurisdictional transactions that fail because of market participants' ('OTH') or external system operators' actions ('TLRe' and 'MrNh'), the MSP recommends the IESO revise its procedures to avoid distorting the unconstrained schedule. This would prevent counter-intuitive pricing results (and would allow traders in those instances to receive the Congestion Management Settlement Credit payment consistent with other situations where such payments are currently available).

<u>Recommendation 2-2 (Chapter 2, section 2.2.4)</u>

The MSP reiterates the recommendations in its December 2006 and June 2007 reports, respectively, regarding Shared Activation of Reserve (SAR), and prompt replenishment of the Operating Reserve requirement levels. In addition, the MSP recommends the IESO review the application of Regional Reserve Sharing (RRS) because the current treatment of RRS in the unconstrained sequence also induces counter-intuitive prices.

With the exception of the SAR/RRS change, these recommendations appear to the Panel to involve relatively straight-forward procedural changes. However, the Panel notes that although the SAR/RRS events arise infrequently, when they do occur, the system is in a critical supply condition and a price signal that reflects scarcity is important to encouraging all feasible supply and demand responses in these situations.

3.2 Dispatch

Efficient dispatch is one of the primary objectives to be achieved from the operation of a wholesale market. The Panel would rank order the relative importance of the three dispatch-related recommendations in this report as follows:

<u>Recommendation 2-1 (Chapter 2, section 2.2.1)</u>

The MSP reiterates the recommendation in its June 2007 report that the IESO should review the 700 MW Net Interchange Scheduling Limit (NISL). This review should take into account the effects on potential efficient exports from Ontario in addition to the import issues raised in the MSP's prior report.

<u>Recommendation 3-8(2) (Chapter 3, section 4.2)</u>

If the IESO believes that it must maintain a higher standard than the NERC Control Performance Standard, the MSP recommends that the IESO conduct a cost-benefit analysis comparing alternatives for responding to Area Control Error (ACE) deviations, that is: providing more Automatic Generation Control (AGC); using One-Time Dispatch (OTD); using Operating Reserve Activation (ORA); and establishing a capability to re-run the dispatch algorithm on demand.

<u>Recommendation 3-8(3) (Chapter 3, section 4.2)</u>

In the interim, until a cost-benefit study of the alternatives for handling ACE deviations is completed, in accordance with Recommendation 3-8(2), and assuming the IESO adopts Recommendation 3-8(1) regarding the maintenance of the Operating Reserve requirement level when Operating Reserve is activated for ACE, the MSP recommends that the IESO should use ORA instead of One-Time Dispatch to deal with negative ACE whenever possible.

A change to the NISL would appear to be relatively easy to implement if and when a revised amount is selected. The interim recommendation relating to use of ORA in preference to OTD would appear to be a procedural change that could be implemented quickly and easily, pending the more complex analysis and implementation that may be involved in an overall cost-benefit assessment of the four alternatives available to deal with ACE deviations.

3.3 Transparency

The Panel believes that transparency can facilitate improvements to short-term and longer-term decision-making by market participants provided appropriate care is taken to avoid facilitating coordinated anti-competitive behaviour. Given the size of the largest Ontario generator relative to other market participants, transparency can also reduce information asymmetries which in turn may enhance competition. More generally, a high degree of transparency should contribute to the confidence of market participants and the public in the operation of the market.

The Panel would rank the potential benefits from the four transparency recommendations in this report in the following order:

Recommendation 3-5 (Chapter 3, section 3.1)
The IESO is planning to publish the supply cushion on a hourly basis. Its current calculation, however, does not represent actual supply capability. The MSP recommends that the IESO refine its formula to take into account forced outages, deratings, and import capabilities at the interties.

Recommendation 3-3 (Chapter 3, section 3.1)
The MSP recommends that the IESO publish generating unit output using a one-hour lag rather than the current two-hour lag.

Recommendation 3-4 (Chapter 3, section 3.1)
The MSP recommends that when the System Status Reports indicate that a generating unit of greater than 250 MW has been forced from service, the IESO should also disclose the fuel type of the unit in order to increase the information available to all market participants regarding future market conditions.

Recommendation 3-2 (Chapter 3, section 3.1)
The MSP recommends that the IESO publish masked bid and offer data on a four month time lag.

The Panel notes that the changes relating to generator output (Recommendation 3-3) and forced outages (Recommendation 3-4) would appear to be straight-forward procedural changes and that the disclosure of masked bid and offer data (Recommendation 3-2) is essentially an administrative step. The operationalization of a correct supply cushion statistic may involve more complicated tool changes, but the Panel believes this would be particularly valuable information to allow participants to make more informed bids and offers.

3.4 Hourly Uplift Payments

The Panel examines hourly uplift payments both in respect of their contribution to the effective HOEP and also their impact on the efficient operation of the market.[182] The two recommendations related to uplift payments in this report would be ranked in the following order based on the magnitude of the potentially unnecessary payments that are involved:

Recommendation 3-9 (Chapter 3, section 5)
The MSP recommends that the IESO review the benefits of constrained off payments with a view to their discontinuation.

Recommendation 3-1 (Chapter 3, section 2.2.4)
As market supply conditions have improved, an increasing fraction of Intertie Offer Guarantee (IOG) payments is being paid in hours when there appear to be negligible reliability concerns. The MSP recommends the IESO review the real-time IOG program and determine if it is providing commensurate improvements in reliability.

[182] Hourly uplift is the term used to describe wholesale market related uplifts as opposed to other forms of uplift payments.

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 2007 – April 2008

PUBLIC

2008

In some instances, the data reported in this Report has been updated or recalculated and therefore may differ from values previously quoted in our earlier reports.

List of Tables

Table A-1: Monthly Energy Demand, May 2006 – April 2008
(TWh)

	Ontario Demand*		Exports		Total Market Demand	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	11.99	11.83	1.20	1.08	13.18	12.91
Jun	12.59	12.69	0.91	1.04	13.51	13.74
Jul	13.89	12.85	1.03	1.30	14.92	14.15
Aug	13.32	13.47	1.21	1.12	14.53	14.60
Sep	11.58	11.95	0.83	0.92	12.41	12.88
Oct	11.99	11.92	0.98	0.93	12.97	12.85
Nov	12.22	12.39	0.53	0.97	12.75	13.35
Dec	12.92	13.45	0.67	1.31	13.58	14.76
Jan	13.79	13.63	0.78	2.06	14.57	15.70
Feb	13.04	12.90	1.19	1.65	14.24	14.54
Mar	13.21	13.01	0.91	1.89	14.12	14.89
Apr	11.86	11.52	1.16	2.42	13.02	13.94
May – Oct	75.36	74.71	6.16	6.39	81.52	81.13
Nov - Apr	77.04	76.90	5.24	10.30	82.28	87.18
May - Apr	152.40	151.61	11.40	16.69	163.80	168.31

* Data includes dispatchable loads

Table A-2: Average Monthly Temperature, March 2002 – April 2008
*(°Celsius)**

	2002	2003	2004	2005	2006	2007
May	11.21	12.23	13.31	12.14	14.59	14.77
Jun	19.18	18.53	17.78	22.54	19.76	20.84
Jul	24.14	21.71	20.65	24.09	23.50	21.42
Aug	22.63	21.85	19.57	22.53	21.22	22.27
Sep	20.09	17.12	18.4	18.33	15.79	18.34
Oct	9.16	9.04	10.85	11.01	9.07	14.11
Nov	3.18	4.91	5.29	5.06	5.25	2.91
Dec	(1.82)	(0.03)	(2.54)	(3.13)	1.94	(2.12)
Jan	(7.68)	(9.13)	(6.78)	0.30	(2.65)	(2.07)
Feb	(7.02)	(3.29)	(3.60)	(3.56)	(7.99)	(4.99)
Mar	(0.57)	2.26	(1.29)	1.21	0.59	(1.46)
Apr	5.53	6.88	8.18	8.36	6.29	9.48
May - Oct	17.74	16.75	16.76	18.44	17.32	18.63
Nov - Apr	(1.40)	0.27	(0.12)	1.37	0.57	0.29
May - Apr	8.17	8.51	8.32	9.91	8.95	9.46

* Temperature is calculated at Toronto Pearson International Airport

Table A-3: Number of Days Temperature Exceeded 30°C, March 2002 – April 2008
*(Number of days)**

	2002	2003	2004	2005	2006	2007
May	0	0	0	0	2	1
Jun	5	4	2	9	3	6
Jul	16	4	1	11	9	4
Aug	8	4	0	7	3	8
Sep	4	0	0	2	0	4
Oct	0	0	0	0	0	1
Nov	0	0	0	0	0	0
Dec	0	0	0	0	0	0
Jan	0	0	0	0	0	0
Feb	0	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May - Oct	33	12	3	29	17	24
Nov - Apr	0	0	0	0	0	0
May - Apr	33	12	3	29	17	24

* Temperature is calculated at Toronto Pearson International Airport

Table A-4: Outages, May 2006 - April 2008
*(TWh)**

	Total Outage		Planned Outage		Forced Outage	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	5.08	5.38	2.62	3.63	2.46	1.75
Jun	3.91	3.58	1.52	1.36	2.39	2.22
Jul	2.93	3.34	0.41	0.95	2.52	2.39
Aug	3.24	3.59	0.96	0.45	2.28	3.14
Sep	4.81	5.43	2.46	2.41	2.35	3.02
Oct	5.36	6.47	2.93	3.77	2.43	2.70
Nov	5.72	5.47	3.33	2.96	2.39	2.51
Dec	4.31	3.69	2.47	1.58	1.84	2.11
Jan	3.71	2.88	1.83	0.96	1.88	1.92
Feb	2.92	3.10	1.13	0.79	1.79	2.31
Mar	5.15	4.97	2.85	2.39	2.30	2.58
Apr	4.88	5.30	3.10	2.44	1.78	2.86
May – Oct	25.33	27.79	10.90	12.57	14.43	15.22
Nov - Apr	26.69	25.41	14.71	11.12	11.98	14.29
May - Apr	52.02	53.20	25.61	23.69	26.41	29.51

* There are two sets of data that reflect outages information. Past reports have relied on information from the IESO's outage database. This table reflects the outage information that is actually input to the DSO to determine price. 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.

Table A-5: Average HOEP, On and Off-Peak, May 2006 – April 2008
($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	46.32	38.50	59.18	53.78	34.77	24.77
Jun	46.08	44.38	56.04	57.32	37.36	33.06
Jul	50.52	43.90	63.25	57.70	41.72	32.54
Aug	52.72	53.62	65.05	69.80	41.64	39.10
Sep	35.42	44.63	43.85	58.27	28.67	34.66
Oct	40.20	48.91	49.64	60.19	32.44	38.77
Nov	49.71	46.95	60.13	56.35	39.75	37.96
Dec	39.25	49.08	53.06	62.96	29.71	39.48
Jan	44.48	40.74	53.44	50.89	36.43	31.62
Feb	59.12	52.38	70.93	67.48	48.39	39.52
Mar	54.85	56.84	68.31	68.60	42.76	48.72
Apr	46.05	48.98	57.58	63.61	37.63	34.99
May – Oct	45.21	45.66	56.17	59.51	36.10	33.82
Nov - Apr	48.91	49.16	60.58	61.65	39.1	38.72
May - Apr	47.06	47.41	58.37	60.58	37.6	36.27

Table A-6: Average Richview Slack Bus Price, On and Off-Peak, May 2006 – April 2008 ($/MWh)

	Average Richview Slack Bus Price		Average On-Peak Richview Slack Bus Price		Average Off-Peak Richview Slack Bus Price	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	64.45	41.69	96.58	57.84	35.60	27.18
Jun	52.09	71.03	61.00	103.80	44.29	42.38
Jul	55.71	49.16	68.17	66.92	47.11	34.54
Aug	59.78	61.53	73.72	82.04	47.26	43.10
Sep	35.32	51.71	44.01	71.36	28.38	37.35
Oct	41.83	55.73	50.96	68.24	34.32	44.49
Nov	55.24	54.33	68.11	64.14	42.93	44.94
Dec	40.97	55.46	56.03	71.37	30.57	44.47
Jan	51.24	49.67	61.90	64.99	41.67	35.92
Feb	69.49	60.84	83.83	78.58	56.45	45.73
Mar	66.40	65.23	86.19	79.77	48.64	55.19
Apr	50.63	62.24	60.15	80.80	43.67	44.49
May – Oct	51.53	55.14	65.74	75.03	39.49	38.17
Nov - Apr	55.66	57.96	69.37	73.28	43.99	45.12
May - Apr	53.6	56.55	67.55	74.15	41.74	41.65

Table A-7: Ontario Consumption by Type of Usage,
May 2006 – April 2008
(TWh)

	LDC's*		Wholesale Loads		Generators		Metered Energy Consumption**		Transmission Losses		Total Energy Consumption**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	9.63	9.55	1.66	1.58	0.18	0.20	11.46	11.33	0.47	0.49	11.93	11.82
Jun	10.13	10.49	1.66	1.50	0.19	0.19	11.99	12.18	0.56	0.51	12.54	12.69
Jul	11.48	10.61	1.61	1.44	0.19	0.19	13.27	12.24	0.58	0.60	13.85	12.84
Aug	10.99	11.13	1.67	1.46	0.16	0.20	12.82	12.79	0.49	0.66	13.31	13.45
Sep	9.43	9.79	1.53	1.38	0.16	0.18	11.12	11.36	0.40	0.56	11.52	11.92
Oct	9.77	9.75	1.50	1.44	0.15	0.15	11.42	11.33	0.54	0.58	11.96	11.91
Nov	9.97	10.19	1.49	1.39	0.16	0.17	11.63	11.74	0.55	0.61	12.18	12.35
Dec	10.73	11.19	1.47	1.40	0.16	0.17	12.36	12.75	0.52	0.66	12.88	13.41
Jan	11.38	11.33	1.58	1.43	0.16	0.17	13.12	12.93	0.64	0.68	13.76	13.61
Feb	10.97	10.74	1.40	1.35	0.14	0.15	12.51	12.23	0.53	0.67	13.04	12.90
Mar	10.83	10.76	1.57	1.42	0.18	0.17	12.58	12.36	0.62	0.64	13.19	13.00
Apr	9.60	9.31	1.53	1.40	0.17	0.15	11.30	10.86	0.53	0.66	11.83	11.52
May – Oct	61.43	61.32	9.63	8.80	1.03	1.11	72.08	71.23	3.04	3.40	75.11	74.63
Nov - Apr	63.48	63.52	9.04	8.39	0.97	0.98	73.50	72.87	3.39	3.92	76.88	76.79
May - Apr	124.91	124.84	18.67	17.19	2.00	2.09	145.58	144.10	6.43	7.32	151.99	151.42

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

Table A-8: Frequency Distribution of HOEP, May 2006 – April 2008
(Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	< 10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.67	6.59	1.61	9.01	12.77	26.61	**40.73**	**27.55**	16.26	6.72	10.48	5.65	7.26	5.11	7.39	10.75	2.42	2.02	0.40	0.00
Jun	0.42	3.19	1.53	6.11	9.44	26.11	**39.03**	**27.36**	13.61	7.08	14.44	6.39	10.69	9.17	10.28	10.00	0.56	4.31	0.00	0.28
Jul	0.54	2.82	3.49	4.84	10.89	24.19	**33.87**	**27.96**	12.37	9.01	8.74	8.74	7.93	6.59	18.95	13.98	3.09	1.75	0.13	0.13
Aug	0.13	0.81	0.40	0.67	19.22	14.52	**30.38**	27.55	8.47	10.35	9.01	7.93	12.37	6.99	12.10	**28.09**	7.66	3.09	0.27	0.00
Sep	3.33	3.06	5.42	3.19	28.61	20.42	**31.67**	**26.94**	16.81	13.61	9.58	11.25	2.64	6.53	1.67	13.33	0.28	1.67	0.00	0.00
Oct	0.94	2.69	1.88	2.15	22.72	17.61	**37.77**	**22.98**	14.78	12.37	9.14	10.62	7.12	11.69	5.51	18.82	0.13	0.94	0.00	0.13
Nov	0.97	0.97	2.50	0.42	11.25	10.14	**33.33**	**35.14**	11.81	17.78	8.89	15.28	9.17	7.64	19.72	11.81	19.72	0.83	0.00	0.00
Dec	6.32	5.38	7.53	5.11	18.01	15.32	**36.69**	**21.24**	9.81	11.29	5.65	9.27	5.11	9.14	8.33	19.49	8.33	3.76	0.00	0.00
Jan	1.08	4.84	1.34	3.09	9.68	19.09	**43.15**	**37.77**	15.32	13.31	10.08	6.72	7.26	4.30	11.29	8.60	11.29	2.28	0.00	0.00
Feb	0.00	3.16	0.00	1.15	0.15	5.60	**31.99**	**30.03**	13.54	16.95	11.01	13.07	12.50	10.78	26.04	13.22	26.04	5.89	0.00	0.14
Mar	0.00	0.00	0.00	0.00	5.78	0.13	**37.10**	24.46	9.68	**26.34**	10.62	15.73	8.06	10.35	22.18	17.74	6.59	5.24	0.00	0.00
Apr	2.36	8.61	3.61	3.06	15.14	3.47	**32.22**	**32.78**	11.94	13.75	7.36	12.64	13.89	5.83	10.28	14.86	3.06	4.86	0.14	0.14
May –Oct	1.01	3.19	2.39	4.33	17.28	21.58	**35.58**	**26.72**	13.72	9.86	10.23	8.43	8.00	7.68	9.32	15.83	2.36	2.30	0.13	0.09
Nov - Apr	1.79	3.83	2.50	2.14	10.00	8.96	**35.75**	**30.24**	12.02	16.57	8.94	12.12	9.33	8.01	16.31	14.29	12.51	3.81	0.02	0.05
May -Apr	1.40	3.51	2.44	3.23	13.64	15.27	**35.66**	**28.48**	12.87	13.21	9.58	10.27	8.67	7.84	12.81	15.06	7.43	3.05	0.08	0.07

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2006 – April 2008
(Percentage of Hours within Defined Range)

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.67	6.59	1.34	8.06	9.27	22.04	**36.96**	**30.65**	20.03	7.93	11.16	4.30	8.06	6.18	9.01	11.42	2.82	2.82	0.67	0.00
Jun	0.56	3.06	1.11	4.86	6.53	20.14	**38.06**	**31.11**	14.72	8.75	13.75	6.39	11.67	6.81	12.08	12.64	1.53	5.83	0.00	0.42
Jul	0.40	2.96	2.42	4.03	10.35	18.82	**31.85**	**30.38**	13.17	11.83	9.68	6.59	8.06	7.93	18.55	15.32	5.24	2.02	0.27	0.13
Aug	0.27	0.94	0.40	0.67	9.54	9.68	**35.89**	29.03	10.89	11.69	8.74	6.99	11.96	7.80	13.44	**29.57**	8.33	3.63	0.54	0.00
Sep	3.19	2.92	5.00	3.33	21.25	16.11	**36.25**	**28.19**	18.06	13.89	9.86	11.25	4.17	7.22	1.94	14.03	0.28	3.06	0.00	0.00
Oct	0.94	2.55	1.88	2.28	15.99	12.90	**41.26**	**23.92**	16.13	13.44	8.47	9.54	8.06	11.96	6.85	20.83	0.40	2.42	0.00	0.13
Nov	0.97	0.97	2.22	0.42	7.36	6.39	**31.67**	**32.64**	14.72	18.89	10.42	15.42	6.53	10.97	20.69	12.64	5.42	1.67	0.00	0.00
Dec	5.65	4.84	7.53	4.84	13.71	13.58	**38.31**	**21.37**	11.29	10.89	5.78	9.95	5.11	9.41	8.87	18.82	3.76	6.32	0.00	0.00
Jan	1.21	4.70	1.21	2.69	8.06	15.99	**40.46**	**36.56**	17.07	15.32	11.02	7.53	7.12	5.11	12.63	9.01	1.21	3.09	0.00	0.00
Feb	0.15	3.16	0.00	1.01	0.00	5.03	**28.42**	**25.86**	15.18	17.24	9.23	13.36	13.84	12.79	25.60	14.66	7.59	6.75	0.00	0.14
Mar	0.13	0.00	0.00	0.00	3.90	0.00	**32.80**	17.61	13.58	**29.97**	9.81	15.86	9.27	10.89	22.18	19.22	8.33	6.45	0.00	0.00
Apr	2.08	8.06	3.47	3.33	12.36	3.61	**32.78**	**25.83**	11.94	16.53	8.06	13.75	14.72	6.67	10.69	16.81	3.75	5.28	0.14	0.14
May- Oct	1.01	3.17	2.03	3.87	12.16	16.62	**36.71**	**28.88**	15.50	11.26	10.28	7.51	8.66	7.98	10.31	17.30	3.10	3.30	0.25	0.11
Nov - Apr	1.70	2.73	2.41	2.05	7.57	7.43	**34.07**	**26.65**	13.96	18.14	9.05	12.65	9.43	9.31	16.78	15.19	5.01	4.93	0.02	0.05
May -Apr	1.35	2.97	2.22	2.96	9.86	12.02	**35.39**	**27.76**	14.73	14.70	9.67	10.08	9.05	8.65	13.54	16.25	4.06	4.11	0.14	0.08

* Bolded values show highest percentage within month.

Table A-10: Total Hourly Uplift Charge as a Percentage of HOEP, On and Off-Peak, May 2006 – April 2008
(%)

	On-Peak and Off-Peak		On-Peak		Off-Peak	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	5.37	4.68	6.10	6.13	4.70	3.38
Jun	4.34	5.69	4.75	6.77	3.98	4.74
Jul	4.06	4.47	4.35	4.87	3.86	4.13
Aug	4.12	4.26	4.32	4.97	3.95	3.62
Sep	3.36	4.65	3.57	5.60	3.20	3.94
Oct	3.69	4.27	4.03	5.17	3.40	3.45
Nov	5.05	5.08	5.93	5.58	4.20	4.61
Dec	4.52	4.57	4.92	4.46	4.24	4.65
Jan	4.14	4.40	4.63	5.09	3.69	3.79
Feb	3.86	3.80	4.20	5.20	3.55	2.61
Mar	4.04	4.24	4.62	4.53	3.52	4.04
Apr	3.81	7.72	4.38	5.93	3.40	9.43
May- Oct	4.16	4.67	4.52	5.59	3.85	3.88
Nov - Apr	4.24	4.97	4.78	5.13	3.77	4.86
May -Apr	4.20	4.82	4.65	5.36	3.81	4.37

Table A-11: Total Hourly Uplift Charge by Component, May 2006 – April 2008 ($ Millions)

	Total Hourly Uplift*		RT IOG**		DA IOG*		CMSC***		Operating Reserve		Losses	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	35.52	24.03	3.85	2.48	N/A	0.33	14.93	9.70	3.03	1.00	13.71	10.54
Jun	28.23	39.12	2.03	2.26	0.35	1.08	12.53	20.58	0.51	1.24	12.82	13.97
Jul	31.69	26.25	1.85	1.51	0.55	0.65	11.65	8.75	0.84	1.10	16.81	14.24
Aug	36.83	35.96	2.91	2.31	0.72	0.64	16.20	14.58	1.05	0.60	15.95	17.83
Sep	15.22	29.76	0.59	1.72	0.16	2.79	5.27	12.30	0.81	0.77	8.40	12.18
Oct	18.88	27.81	1.65	2.47	0.16	1.35	5.72	10.21	0.96	0.84	10.39	12.94
Nov	33.84	30.72	3.38	2.98	4.18	1.20	10.72	11.70	1.34	1.49	14.23	13.35
Dec	24.95	32.94	2.56	3.98	1.08	0.25	7.18	11.38	1.49	1.10	12.64	16.22
Jan	26.73	30.04	2.53	4.05	0.50	0.10	7.28	9.42	2.13	2.25	14.29	14.22
Feb	31.04	34.10	4.21	5.68	0.16	0.27	8.54	11.31	2.24	2.27	15.90	14.57
Mar	31.00	35.62	4.55	3.99	1.31	0.22	8.62	12.82	1.03	1.40	15.49	17.19
Apr	22.80	37.39	2.41	4.22	0.08	0.11	7.15	14.31	1.49	4.77	11.67	13.99
May- Oct	166.37	182.93	12.88	12.75	1.94	6.84	66.30	76.12	7.20	5.55	78.08	81.70
Nov - Apr	170.36	200.81	19.64	24.90	7.31	2.15	49.49	70.94	9.72	13.28	84.22	89.54
May -Apr	336.73	383.74	32.52	37.65	9.25	8.99	115.79	147.06	16.92	18.83	162.30	171.24

* 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-16. All IOG Reversals have been applied to RT IOG.
*** Numbers are adjusted for Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments.

Table A-12: Operating Reserve Prices,
May 2006 – April 2008
($/MWh)

	10N		10S		30R	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	3.28	0.78	4.55	2.17	3.28	0.78
Jun	0.33	1.21	1.42	2.98	0.33	1.21
Jul	0.50	1.00	2.89	1.97	0.50	1.00
Aug	0.73	0.41	3.19	1.78	0.73	0.41
Sep	0.21	0.63	3.73	1.95	0.21	0.63
Oct	0.56	0.62	2.88	1.90	0.56	0.62
Nov	1.06	1.20	3.73	1.99	1.06	1.09
Dec	1.39	0.96	2.89	1.71	1.39	0.96
Jan	2.09	2.53	3.38	2.77	2.08	2.45
Feb	2.63	2.67	3.64	3.20	2.56	2.55
Mar	0.97	1.56	1.94	2.13	0.95	1.49
Apr	1.40	6.22	2.69	6.38	1.39	5.55
May- Oct	0.94	0.78	3.11	2.13	0.94	0.78
Nov - Apr	1.59	2.52	3.05	3.03	1.57	2.35
May -Apr	1.26	1.65	3.08	2.58	1.25	1.56

*Table A-13: Baseload Supply relative to Demand and HOEP, Off-Peak, May 2006 – April 2008 (Average Hourly MW)**

	Nuclear		Baseload Hydroelectric		Self-Scheduling Supply		Total Baseload Generation		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	8,857	9,381	1,725	1,992	688	727	11,270	12,100	13,565	13,429	33.04	24.02
Jun	9,403	9,362	1,642	1,716	803	698	11,848	11,776	14,522	14,582	33.52	27.22
Jul	10,169	9,700	1,768	1,659	751	641	12,688	12,000	15,298	14,309	35.09	27.65
Aug	10,823	9,487	1,699	1,573	750	687	13,272	11,747	14,979	15,056	36.28	35.25
Sep	9,582	8,725	1,812	1,665	799	683	12,193	11,073	13,570	13,879	25.79	29.53
Oct	8,852	8,195	1,821	1,814	887	802	11,560	10,811	13,571	13,506	30.35	32.25
Nov	8,226	8,480	1,858	1,822	890	815	10,974	11,117	14,520	14,797	35.49	35.97
Dec	9,455	10,322	2,114	1,750	871	837	12,440	12,909	15,093	15,786	28.61	37.16
Jan	9,216	10,964	1,844	1,760	958	845	12,018	13,569	16,165	15,922	35.45	31.64
Feb	9,721	9,956	1,925	1,896	929	847	12,575	12,699	17,235	16,296	48.25	41.92
Mar	8,986	8,735	1,977	2,153	920	786	11,883	11,674	15,589	15,430	43.92	47.66
Apr	8,860	8,617	1,944	2,041	761	689	11,565	11,347	14,220	13,745	32.83	31.43
May- Oct	9,614	9,142	1,745	1,737	780	706	12,139	11,585	14,251	14,127	32.35	29.32
Nov - Apr	9,077	9,512	1,944	1,904	888	803	11,909	12,219	15,470	15,329	37.43	37.63
May -Apr	9,346	9,327	1,844	1,820	834	755	12,024	11,902	14,861	14,728	34.89	33.48

* In this table, off-peak hours are defined as HE22 to HE7, inclusive, for all days of the week.

*Table A-14: Baseload Supply relative to Demand and HOEP, On-Peak, May 2006 – April 2008 (Average Hourly MW)**

	Nuclear		Baseload Hydroelectric		Self-Scheduling Supply		Total Baseload Generation		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2006 2007	2007 2008	2006 2007	2007 2008	2006 2007	2007 2008	2006 2007	2007 2008	2006 2007	2007 2008	2006 2007	2007 2008
May	8,843	9,376	2,212	2,381	822	884	11,877	12,641	16,963	16,767	55.80	48.84
Jun	9,412	9,364	2,103	2,238	936	828	12,451	12,430	18,264	18,980	55.05	56.64
Jul	10,169	9,711	2,314	2,080	875	756	13,358	12,547	20,038	18,504	61.54	55.51
Aug	10,826	9,482	2,236	2,002	900	785	13,962	12,269	19,125	19,443	64.45	66.75
Sep	9,538	8,740	2,205	1,882	932	752	12,675	11,374	16,964	17,678	42.29	55.42
Oct	8,830	8,195	2,270	2,057	993	884	12,093	11,136	16,996	16,957	47.24	60.80
Nov	8,247	8,492	2,315	2,242	1,032	898	11,594	11,632	17,820	18,044	59.87	54.80
Dec	9,446	10,332	2,462	2,057	1,008	910	12,916	13,299	18,189	18,812	46.85	57.58
Jan	9,188	10,973	2,378	2,031	1,088	936	12,654	13,940	19,345	19,110	50.92	47.25
Feb	9,745	9,958	2,338	2,220	1,090	927	13,173	13,105	20,029	19,179	66.88	59.85
Mar	8,984	8,752	2,390	2,429	1,070	873	12,444	12,054	18,340	18,032	62.66	63.40
Apr	8,865	8,595	2,349	2,418	921	804	12,135	11,817	17,109	16,657	55.50	61.52
May- Oct	9,603	9,145	2,223	2,107	910	815	12,736	12,067	18,058	18,055	54.4	57.33
Nov - Apr	9,079	9,517	2,372	2,233	1,035	891	12,486	12,641	18,472	18,306	57.11	57.40
May -Apr	9,341	9,331	2,298	2,170	972	853	12,611	12,354	18,265	18,180	55.75	57.36

* In this table, on-peak hours are defined as HE8 to HE21, inclusive, for all days of the week.

Table A-15: RT IOG Payments, Top 10 Days,
November 2007 – April 2008

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)*	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
2008/02/21	22,052	0.49	22.16	24,698
2008/04/02	18,516	0.45	24.10	22,957
2008/03/01	24,614	0.42	17.14	20,996
2008/02/18	15,318	0.42	27.50	22,387
2008/02/29	21,730	0.41	18.91	23,291
2007/12/05	21,987	0.38	17.33	24,693
2008/04/14	13,043	0.35	26.80	21,664
2007/12/07	18,846	0.35	18.62	23,672
2008/01/28	15,575	0.34	21.53	23,936
2008/02/11	16,026	0.32	19.78	25,657
	Total Top 10 days	**3.93**	**20.94**	
	Total for Period	**25.68**	**14.39**	
	% of Total Payments	**15.30**		

* Numbers are not netted against IOG offset for the ‘implied wheel’.

Table A-16: IOG Offsets due to Implied Wheeling,
May 2006 – April 2008
($ '000 and %)

	Real-time IOG Payments ($'000)		IOG Offset ($'000)		IOG Offset (%)	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	3,848	2,493	39	225	1.01	9.03
Jun	2,070	2,345	158	72	7.66	3.06
Jul	1,868	1,579	63	160	3.39	10.13
Aug	2,922	2,424	106	132	3.64	5.44
Sep	594	1,845	24	138	4.06	7.47
Oct	1,681	2,708	79	156	4.70	5.77
Nov	3,687	3,221	190	234	5.15	7.27
Dec	2,636	4,069	283	379	10.72	9.33
Jan	2,565	4,145	199	216	7.74	5.21
Feb	4,299	5,822	319	400	7.43	6.86
Mar	4,704	4,091	401	301	8.52	7.36
Apr	2,437	4,330	144	347	5.91	8.02
May- Oct	12,983	13,394	469	883	3.61	6.59
Nov - Apr	20,328	25,678	1,536	1,877	7.56	7.31
May -Apr	33,311	39,072	2,005	2,760	6.02	7.06

Table A-17: CMSC Payments, Energy and Operating Reserve, May 2006 – April 2008 ($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	9.68	9.57	3.99	1.77	14.61	11.76	1.83	0.59	16.44	12.35
Jun	7.78	11.93	3.76	5.75	12.76	19.91	0.58	1.46	13.34	21.37
Jul	7.78	7.50	4.26	2.27	12.74	9.52	0.41	0.92	13.15	10.45
Aug	6.70	9.76	8.77	4.26	17.34	14.59	0.40	0.49	17.74	15.08
Sep	5.04	8.33	1.32	4.04	6.51	12.72	0.14	0.49	6.65	13.21
Oct	4.11	10.13	1.98	2.13	6.36	12.72	0.64	0.53	6.99	13.26
Nov	5.97	8.37	4.12	3.45	10.67	12.29	1.62	0.52	12.28	12.81
Dec	4.05	7.40	2.81	4.02	7.37	11.93	0.83	0.45	8.20	12.38
Jan	5.00	6.21	2.52	3.37	8.18	9.92	0.90	0.77	9.08	10.69
Feb	4.36	6.51	3.47	3.77	8.35	11.04	1.08	0.98	9.43	12.02
Mar	5.25	7.00	3.35	4.03	9.02	11.89	0.79	1.40	9.81	13.29
Apr	4.36	8.02	2.22	4.39	6.87	13.44	0.82	1.77	7.68	15.21
May- Oct	41.09	57.22	24.08	20.22	70.32	81.22	4.00	4.48	74.31	85.72
Nov - Apr	28.99	43.51	18.49	23.03	50.46	70.51	6.04	5.89	56.48	76.40
May -Apr	70.08	100.73	42.57	43.25	120.78	151.73	10.04	10.37	130.79	162.12

* 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-18: Share of Constrained On Payments for Energy by Type of Supplier, May 2006 – April 2008
(%)

	Domestic Generators		Imports	
	2006/2007	2007/2008	2006/2007	2007/2008
May	62	60	38	40
Jun	77	67	23	33
Jul	61	74	39	26
Aug	29	68	71	32
Sep	74	67	26	33
Oct	77	71	23	29
Nov	71	69	29	31
Dec	77	61	23	39
Jan	76	61	24	39
Feb	79	64	21	36
Mar	80	56	20	44
Apr	65	46	35	54
May- Oct	63	68	37	32
Nov - Apr	75	60	25	41
May -Apr	69	64	31	36

Table A-19: Share of CMSC Payments Received by Top Facilities, May 2006 – April 2008 (%)

	Share of Total Payments Received by Top 10 Facilities				Share of Total Payments Received by Top 5 Facilities			
	Constrained Off		Constrained On		Constrained Off		Constrained On	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	50.87	58.89	48.39	41.69	34.08	45.46	33.50	27.10
Jun	56.30	57.61	52.09	46.56	45.72	34.93	39.47	30.40
Jul	54.69	59.77	53.18	53.11	39.90	47.84	37.61	38.24
Aug	45.46	67.12	67.07	51.85	31.34	54.33	53.52	34.86
Sep	61.36	67.24	53.48	53.98	43.57	53.91	36.53	38.09
Oct	52.05	75.42	50.27	50.83	38.33	68.27	34.97	34.78
Nov	54.76	64.73	59.80	59.43	40.09	53.27	43.48	38.67
Dec	57.64	55.99	51.97	53.48	41.64	45.72	38.30	38.16
Jan	58.93	55.64	55.80	55.45	40.44	47.39	39.19	38.54
Feb	55.44	44.57	65.89	59.55	44.30	33.94	50.43	42.48
Mar	65.46	57.87	51.99	53.29	51.66	45.63	37.26	37.34
Apr	51.33	46.04	58.03	44.50	39.75	34.32	38.21	27.51
May – Oct	53.46	64.34	54.08	49.67	38.82	50.79	39.27	33.91
Nov - Apr	57.26	54.14	57.25	54.28	42.98	43.38	41.15	37.12
May - Apr	55.36	59.24	55.66	51.98	40.9	47.08	40.21	35.51

Table A-20: Supply Cushion Statistics, All Hours,
May 2006 – April 2008
(% 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)*	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	12.8	19.0	4	0	397	145	18.4	19.9	30	4	196	159
Jun	19.5	17.8	0	0	165	205	18.5	20.0	6	15	218	192
Jul	18.8	19.1	0	0	149	198	20.9	22.3	11	0	179	134
Aug	17.7	23.7	0	0	193	52	21.5	21.8	20	8	108	126
Sep	19.4	24.3	0	0	154	17	20.5	17.6	0	28	135	256
Oct	14.8	18.1	0	0	334	154	18.4	16.6	1	3	170	270
Nov	15.2	17.6	0	0	215	164	10.5	13.2	52	20	416	362
Dec	13.1	19.6	0	0	308	93	14.9	17.6	22	7	270	193
Jan	12.0	16.0	2	0	399	271	13.6	18.0	7	23	336	223
Feb	11.8	15.7	1	0	316	208	15.2	13.1	0	33	184	312
Mar	12.3	17.2	0	0	347	143	12.7	15.6	45	2	341	240
Apr	14.3	12.7	0	6	303	383	17.6	19.3	3	0	160	110
May- Oct	17.2	20.3	4	0	1,392	771	19.7	19.7	68	58	1,006	1,137
Nov - Apr	13.1	16.4	3	6	1,888	1,262	14.1	16.1	129	85	1,707	1,440
May -Apr	15.1	18.4	7	6	3,280	2,033	16.9	17.9	197	143	2,713	2,577

* This category includes hours with a negative supply cushion

Table A-21: Supply Cushion Statistics, On-peak, May 2006 – April 2008 (% 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)*	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	6.1	11.3	4	0	305	133	10.0	11.1	30	4	166	156
Jun	11.5	10.5	0	0	149	162	10.6	10.3	6	15	179	168
Jul	11.9	10.8	0	0	104	168	11.7	12.5	5	0	131	129
Aug	10.4	15.5	0	0	178	52	13.1	12.4	20	8	99	115
Sep	11.2	16.1	0	0	145	16	12.0	8.3	0	28	133	213
Oct	8.3	12.2	0	0	248	144	11.4	8.7	1	3	137	234
Nov	10.6	11.9	0	0	171	131	5.3	6.8	34	16	303	292
Dec	8.8	14.0	0	0	197	68	7.3	10.9	20	5	208	140
Jan	6.8	9.6	1	0	296	221	7.9	10.1	5	23	252	186
Feb	8.4	10.2	1	0	220	172	10.5	6.7	0	30	148	239
Mar	7.9	12.2	0	0	263	108	6.3	9.3	44	0	271	184
Apr	7.9	6.9	0	4	235	289	11.3	13.2	3	0	123	100
May- Oct	9.9	12.7	4	0	1,129	675	11.5	10.6	62	58	845	1,015
Nov - Apr	8.4	10.8	2	4	1,382	989	8.1	9.5	106	74	1,305	1,141
May -Apr	9.2	11.8	6	4	2,511	1,664	9.8	10.0	168	132	2,150	2,156

* This category includes hours with a negative supply cushion

Table A-22: Supply Cushion Statistics, Off-peak,
May 2006 – April 2008
(% 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)*	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	18.8	25.9	0	0	92	12	25.9	27.7	0	0	30	3
Jun	26.5	24.2	0	0	16	43	25.4	28.4	0	0	39	24
Jul	23.6	25.9	0	0	45	30	27.3	30.4	6	0	48	5
Aug	24.3	31.1	0	0	15	0	28.9	30.3	0	0	9	11
Sep	25.9	30.3	0	0	9	1	27.3	24.4	0	0	2	43
Oct	20.2	23.4	0	0	86	10	24.3	23.7	0	0	33	36
Nov	19.7	23.0	0	0	44	33	15.5	19.3	18	4	113	70
Dec	16.1	23.4	0	0	111	25	20.1	22.2	2	2	62	53
Jan	16.5	21.6	1	0	103	50	18.6	25.1	2	0	84	37
Feb	14.9	20.4	0	0	96	36	19.5	18.5	0	3	36	73
Mar	16.4	20.6	0	0	84	35	18.4	20.0	1	2	70	56
Apr	18.9	18.3	0	2	68	94	22.1	25.3	0	0	37	10
May- Oct	23.2	26.8	0	0	263	96	26.5	27.5	6	0	161	122
Nov - Apr	17.1	21.2	1	2	506	273	19.0	21.7	23	11	402	299
May -Apr	20.1	24.0	1	2	769	369	22.8	24.6	29	11	563	421

* This category includes hours with a negative supply cushion

Table A-23: Share of Real-time MCP Set by Resource Type,
May 2006 – April 2008
(%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	63	61	0	0	14	13	23	26
Jun	61	61	0	0	22	18	17	21
Jul	52	58	0	0	29	20	20	22
Aug	57	44	0	0	22	38	22	17
Sep	56	52	0	0	18	25	26	23
Oct	62	46	0	0	17	30	21	24
Nov	52	55	0	0	25	23	23	22
Dec	62	47	0	0	16	27	22	26
Jan	60	70	0	0	24	12	16	18
Feb	41	60	0	0	39	19	20	21
Mar	49	59	0	0	27	15	24	26
Apr	56	62	0	0	16	13	28	25
May – Oct	59	54	0	0	20	24	22	22
Nov - Apr	53	59	0	0	25	18	22	23
May - Apr	56	56	0	0	22	21	22	23

Table A-24: Share of Real-time MCP Set by Resource Type, Off-Peak, May 2006 – April 2008 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	79	72	0	0	4	1	17	27
Jun	81	73	0	0	7	6	12	20
Jul	66	74	0	0	16	5	18	21
Aug	74	70	0	0	10	18	16	12
Sep	68	67	0	0	7	11	24	22
Oct	80	64	0	0	5	13	15	23
Nov	66	76	0	0	10	7	24	17
Dec	66	57	0	0	5	15	29	28
Jan	74	78	0	0	8	2	18	20
Feb	55	75	0	0	21	4	24	21
Mar	68	73	0	0	12	5	20	22
Apr	64	65	0	0	9	4	26	31
May – Oct	75	70	0	0	8	9	17	21
Nov - Apr	66	71	0	0	11	6	24	23
May - Apr	70	70	0	0	10	8	20	22

Table A-25: Share of Real-time MCP Set by Resource Type, On-Peak, May 2006 – April 2008 (%)

	Coal		Nuclear		Oil/Gas		Hydroelectric	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	45	49	0	0	26	26	29	25
Jun	37	47	0	0	39	31	24	22
Jul	30	38	0	0	48	39	22	23
Aug	37	15	0	0	34	62	29	23
Sep	41	32	0	0	32	45	27	24
Oct	40	26	0	0	32	49	28	26
Nov	37	33	0	0	41	40	22	27
Dec	57	32	0	0	30	45	13	23
Jan	44	60	0	0	41	23	15	17
Feb	25	42	0	0	59	36	16	22
Mar	26	39	0	0	44	29	29	32
Apr	45	59	0	0	25	22	30	19
May – Oct	38	35	0	0	35	42	27	24
Nov - Apr	39	44	0	0	40	33	21	23
May - Apr	39	39	0	0	38	37	24	24

Table A-26: Resources Selected in the Real-time Market Schedule, May 2006 – April 2008

(TWh)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear		Domestic Generation*	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.51	0.39	1.20	1.08	1.90	1.59	0.73	0.81	3.34	2.99	6.58	6.98	12.55	12.36
Jun	0.60	0.47	0.91	1.04	2.47	2.45	0.89	0.85	2.63	3.07	6.77	6.74	12.77	13.11
Jul	0.57	0.49	1.03	1.30	3.03	2.58	1.00	0.86	2.59	2.85	7.57	7.22	14.19	13.51
Aug	0.41	0.67	1.21	1.12	2.63	3.17	0.92	1.15	2.40	2.35	8.05	7.06	14.00	13.73
Sep	0.36	0.87	0.83	0.92	2.00	2.38	0.79	0.90	2.22	2.23	6.88	6.29	11.90	11.80
Oct	0.36	0.80	0.98	0.93	2.16	2.07	0.88	1.02	2.80	2.61	6.58	6.10	12.41	11.79
Nov	0.77	1.00	0.53	0.97	1.95	2.30	0.91	0.97	3.01	2.74	5.93	6.11	11.80	12.12
Dec	0.43	1.00	0.67	1.31	1.71	2.02	0.86	1.07	3.31	2.72	7.03	7.68	12.92	13.49
Jan	0.44	0.97	0.78	2.06	2.74	2.17	1.00	0.92	3.31	3.19	6.84	8.16	13.89	14.44
Feb	0.41	0.79	1.19	1.65	3.13	2.48	1.02	0.91	2.88	3.20	6.54	6.93	13.57	13.52
Mar	0.65	1.20	0.91	1.89	2.50	2.65	1.03	0.92	2.99	3.36	6.68	6.51	13.20	13.44
Apr	0.28	1.26	1.16	2.42	2.38	1.87	0.76	0.76	3.02	3.64	6.38	6.19	12.55	12.46
May – Oct	2.81	3.69	6.16	6.39	14.19	14.24	5.21	5.59	15.98	16.10	42.43	40.39	77.82	76.30
Nov - Apr	2.98	6.22	5.24	10.30	14.41	13.49	5.58	5.55	18.52	18.85	39.40	41.58	77.93	79.47
May - Apr	5.79	9.91	11.40	16.69	28.60	27.73	10.79	11.14	34.50	34.95	81.83	81.97	155.75	155.77

* Domestic generation is the sum of *Coal, Oil/Gas, Hydroelectric, and Nuclear*.

Table A-27: Share of Resources Selected in Real-time Market Schedule, May 2006 – April 2008 (% of MW Scheduled)

	Imports		Exports		Coal		Oil/Gas		Hydroelectric		Nuclear	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	4	3	10	9	15	13	6	7	27	24	52	56
Jun	5	4	7	8	19	19	7	6	21	23	53	51
Jul	4	4	7	10	21	19	7	6	18	21	53	53
Aug	3	5	9	8	19	23	7	8	17	17	58	51
Sep	3	7	7	8	17	20	7	8	19	19	58	53
Oct	3	7	8	8	17	18	7	9	23	22	53	52
Nov	7	8	4	8	17	19	8	8	26	23	50	50
Dec	3	7	5	10	13	15	7	8	26	20	54	57
Jan	3	7	6	14	20	15	7	6	24	22	49	57
Feb	3	6	9	12	23	18	8	7	21	24	48	51
Mar	5	9	7	14	19	20	8	7	23	25	51	48
Apr	2	10	9	19	19	15	6	6	24	29	51	50
May – Oct	4	5	8	9	18	19	7	7	21	21	55	53
Nov - Apr	4	8	7	13	19	17	7	7	24	24	51	52
May - Apr	4	6	7	11	18	18	7	7	22	22	53	52

*Table A-28: Offtakes by Intertie Zone, On-peak and Off-peak, May 2006 – April 2008 (GWh)**

		MB		MI		MN		NY		PQ	
		2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	Off-peak	0.0	3.1	32.0	170.2	1.2	11.8	625.5	334.2	52.4	57.6
	On-Peak	0.0	3.5	54.0	257.4	0.7	10.9	404.8	197.2	26.4	36.0
Jun	Off-peak	0.0	0.5	9.4	65.9	1.6	4.0	513.3	566.6	46.9	39.5
	On-Peak	0.1	0.7	45.7	109.9	0.1	6.9	274.6	228.6	22.4	20.3
Jul	Off-peak	0.6	0.0	47.2	76.4	7.9	6.3	606.5	638.4	47.8	42.2
	On-Peak	0.5	0.2	75.3	130.5	8.4	8.9	218.7	376.9	15.6	19.7
Aug	Off-peak	0.1	0.0	36.5	61.9	2.6	3.5	668.7	556.0	34.3	52.4
	On-Peak	0.1	0.1	95.4	201.6	1.5	6.0	355.1	215.6	15.5	27.2
Sep	Off-peak	2.0	0.0	14.8	21.3	1.9	0.3	441.7	491.4	48.4	65.7
	On-Peak	0.1	0.0	16.5	52.7	2.7	0.7	282.7	258.0	22.3	31.9
Oct	Off-peak	18.3	0.0	25.4	72.6	4.8	0.4	480.6	453.1	54.4	30.1
	On-Peak	7.6	0.0	38.0	68.6	4.8	0.5	320.9	284.9	25.0	22.9
Nov	Off-peak	30.8	0.0	9.5	30.8	0.8	1.6	275.4	496.9	28.4	43.8
	On-Peak	16.4	1.3	12.0	51.3	1.5	7.7	147.8	307.9	8.4	25.5
Dec	Off-peak	28.4	4.0	27.4	140.1	3.1	7.3	362.0	523.4	37.1	64.0
	On-Peak	13.2	1.2	42.9	90.3	0.9	6.0	138.0	446.5	12.5	31.6
Jan	Off-peak	25.6	4.7	21.2	383.8	2.2	23.8	346.6	553.4	54.6	56.7
	On-Peak	22.9	6.9	44.6	328.2	3.4	19.6	215.5	645.6	46.1	41.0
Feb	Off-peak	25.6	0.3	82.8	365.7	4.4	10.7	480.2	448.4	45.0	43.4
	On-Peak	8.4	0.2	102.0	353.4	2.3	10.7	403.5	388.2	40.3	26.0
Mar	Off-peak	16.8	0.0	38.8	473.9	0.7	11.2	457.9	614.3	55.0	54.7
	On-Peak	7.6	0.2	65.3	364.5	1.9	15.4	221.9	324.7	41.1	30.0
Apr	Off-peak	33.1	4.9	139.5	561.9	7.5	7.1	436.4	601.7	48.9	45.9
	On-Peak	11.6	2.5	240.7	599.8	8.7	8.4	206.9	560.9	29.6	31.1
May - Oct	Off-peak	21.0	3.6	165.3	468.3	20.0	26.3	3,336.3	3,039.7	284.2	287.5
	On-Peak	8.4	4.5	324.9	820.7	18.2	33.9	1,856.8	1,561.2	127.2	158.0
	Total	29.4	8.1	490.2	1,289.0	38.2	60.2	5,193.1	4,600.9	411.4	445.5
Nov– Apr	Off-peak	160.3	13.9	319.2	1,956.2	18.8	61.7	2,358.5	3,238.1	269.1	308.5
	On-Peak	80.2	12.3	507.5	1,787.5	18.7	67.8	1,333.6	2,673.8	178.0	185.2
	Total	240.5	26.2	826.7	3,743.7	37.5	129.5	3,692.1	5,911.9	447.1	493.7
May - Apr	Off-peak	181.3	17.5	484.4	2,424.5	38.8	88.0	5,694.9	6,277.8	553.3	596.0
	On-Peak	88.7	16.8	832.4	2,608.2	36.9	101.7	3,190.3	4,235.0	305.2	343.2
	Total	270.0	34.3	1,316.8	5,032.7	75.7	189.7	8,885.2	10,512.8	858.5	939.2

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

*Table A-29: Injections by Intertie Zone, On-peak and Off-peak, May 2006 – April 2008 (GWh)**

		MB		MI		MN		NY		PQ	
		2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	Off-peak	58.6	36.9	177.3	33.5	1.2	7.0	5.7	71.1	1.4	4.1
	On-Peak	50.0	17.4	125.6	43.6	13.3	9.4	23.7	55.8	41.7	109.2
Jun	Off-peak	69.7	68.0	243.0	84.5	13.8	16.1	11.7	10.0	5.0	23.3
	On-Peak	62.2	49.3	117.6	86.0	16.0	13.1	25.1	50.6	32.3	73.5
Jul	Off-peak	98.9	88.5	139.8	121.4	23.4	16.6	22.0	7.1	41.5	5.7
	On-Peak	41.9	40.9	60.8	100.7	12.8	12.2	31.6	53.6	100.7	43.5
Aug	Off-peak	78.3	79.1	105.3	173.9	17.1	23.3	7.6	24.4	12.2	5.8
	On-Peak	34.9	65.3	41.5	100.3	11.8	21.4	27.2	115.1	69.9	60.3
Sep	Off-peak	63.7	79.0	115.2	340.3	10.6	29.1	14.4	10.4	0.3	6.9
	On-Peak	47.0	57.5	88.4	252.1	9.5	25.7	6.5	46.6	8.1	19.1
Oct	Off-peak	27.2	60.2	158.4	275.4	15.1	15.7	8.5	10.3	3.5	14.3
	On-Peak	5.9	45.6	92.8	309.5	7.4	14.8	10.1	37.6	28.4	16.9
Nov	Off-peak	7.5	65.6	328.7	390.6	17.6	14.3	17.2	13.6	9.0	9.3
	On-Peak	2.7	53.1	271.0	315.5	12.4	10.8	34.4	58.2	66.2	70.4
Dec	Off-peak	14.9	52.3	111.4	351.1	15.0	16.5	13.1	76.3	39.7	1.1
	On-Peak	3.9	60.3	77.7	321.4	6.5	14.3	45.0	102.9	106.6	7.1
Jan	Off-peak	24.6	44.4	146.0	32.3	18.7	8.9	17.8	243.8	18.5	20.8
	On-Peak	11.0	46.4	87.2	76.3	10.6	11.3	25.0	405.2	81.2	77.5
Feb	Off-peak	8.5	34.0	82.3	80.0	10.3	8.1	16.7	162.3	44.7	43.0
	On-Peak	5.8	27.5	99.6	120.1	11.9	8.5	33.7	171.9	96.6	131.4
Mar	Off-peak	26.8	53.1	220.8	219.3	21.9	13.7	14.8	367.6	33.9	22.1
	On-Peak	25.3	36.8	147.2	130.4	13.3	10.4	45.8	278.7	103.9	68.8
Apr	Off-peak	21.8	53.1	41.7	188.6	15.2	11.1	11.2	343.6	43.3	10.3
	On-Peak	9.8	41.3	21.4	215.3	6.5	12.0	15.5	323.9	89.0	63.4
May - Oct	Off-peak	396.4	411.7	939.0	1,029.0	81.2	107.8	69.9	133.3	63.9	60.1
	On-Peak	241.9	276.0	526.7	892.2	70.8	96.6	124.2	359.3	281.1	322.5
	Total	638.3	687.7	1,465.7	1,921.2	152.0	204.4	194.1	492.6	345.0	382.6
Nov– Apr	Off-peak	104.1	302.5	930.9	1,261.9	98.7	72.6	90.8	1,207.2	189.1	106.6
	On-Peak	58.5	265.4	704.1	1,179.0	61.2	67.3	199.4	1,340.8	543.5	418.6
	Total	162.6	567.9	1,635.0	2,440.9	159.9	139.9	290.2	2,548.0	732.6	525.2
May - Apr	Off-peak	500.5	714.2	1,869.9	2,290.9	179.9	180.4	160.7	1,340.5	253.0	166.7
	On-Peak	300.4	541.4	1,230.8	2,071.2	132.0	163.9	323.6	1,700.1	824.6	741.1
	Total	800.9	1,255.6	3,100.7	4,362.1	311.9	344.3	484.3	3,040.6	1,077.6	907.8

* MB – Manitoba, MI – Michigan, MN – Minnesota, NY – New York, PQ – Quebec

Table A-30: Net Exports, May 2006 – April 2008
(MWh)

	On-peak		Off-peak		Total	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	231,286	269,688	454,918	424,277	686,204	693,966
Jun	89,601	93,969	227,996	474,515	317,597	568,484
Jul	70,645	285,182	384,413	523,963	455,058	809,145
Aug	282,463	88,026	521,687	367,333	804,150	455,359
Sep	164,847	(57,635)	304,446	112,928	469,293	55,293
Oct	251,726	(47,499)	370,919	180,297	622,645	132,798
Nov	(200,386)	(114,506)	(35,002)	79,738	(235,388)	(34,769)
Dec	(32,210)	69,711	263,848	241,428	231,638	311,139
Jan	117,584	424,622	224,741	672,407	342,325	1,097,030
Feb	309,106	319,136	475,559	541,020	784,665	860,156
Mar	2,242	209,884	250,960	478,247	253,201	688,131
Apr	355,182	546,762	532,213	614,612	887,395	1,161,374
May- Oct	1,090,568	631,731	2,264,379	2,083,313	3,354,947	2,715,045
Nov - Apr	551,518	1,455,609	1,712,319	2,627,452	2,263,836	4,083,061
May -Apr	1,642,086	2,087,340	3,976,698	4,710,765	5,618,783	6,798,106

Table A-31: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP, May 2006 - April 2008

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	6.60	7.63	419.55	72.88	(320.42)	(93.58)	30.00	16.11	20.83	30.63
Jun	4.85	6.83	48.06	99.04	(75.35)	(305.24)	12.76	22.95	14.02	25.54
Jul	7.51	3.58	114.61	62.49	(126.79)	(215.90)	15.25	16.64	17.92	15.97
Aug	9.18	7.68	168.10	79.74	(70.41)	(61.26)	27.51	14.90	16.67	19.45
Sep	2.43	3.91	41.59	60.95	(68.61)	(69.49)	8.99	12.18	17.98	17.71
Oct	3.86	6.73	62.51	82.25	(42.27)	(234.52)	10.85	15.40	13.59	25.54
Nov	8.85	6.68	62.20	50.18	(57.01)	(54.74)	14.87	13.48	25.36	18.56
Dec	8.16	6.62	83.82	48.05	(73.61)	(50.61)	14.21	14.24	15.19	28.43
Jan	6.48	8.78	46.19	63.38	(89.72)	(84.51)	13.18	14.28	20.38	30.31
Feb	12.93	10.79	73.34	68.85	(74.95)	(505.62)	17.30	25.50	29.42	23.44
Mar	11.31	8.55	88.29	77.36	(67.96)	(125.90)	16.83	20.29	28.05	19.54
Apr	6.76	7.42	81.19	82.12	(145.64)	(145.17)	18.26	22.34	24.35	19.39
May – Oct	5.74	6.06	142.40	76.23	(117.31)	(163.33)	17.56	16.36	16.84	22.47
Nov - Apr	9.08	8.14	72.51	64.99	(84.82)	(161.09)	15.78	18.36	23.79	23.28
May - Apr	7.41	7.10	107.45	70.61	(101.06)	(162.21)	16.67	17.36	20.31	22.88

Table A-32: Measures of Difference between 1-Hour Ahead Pre-dispatch Prices and HOEP, May 2006 - April 2008

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	11.94	8.23	1,739.37	71.78	(297.46)	(77.17)	67.55	14.49	29.88	35.18
Jun	5.12	6.99	44.18	94.35	(66.34)	(331.10)	11.20	21.84	15.04	25.21
Jul	6.89	5.26	60.33	62.02	(174.98)	(211.39)	13.61	15.91	18.99	22.34
Aug	9.73	8.16	262.96	74.6	(67.76)	(60.38)	25.64	13.56	19.93	20.05
Sep	3.82	5.96	34.86	83.01	(67.49)	(68.97)	8.56	12.46	24.74	22.37
Oct	6.27	8.17	52.09	66.75	(42.27)	(236.65)	10.44	14.99	21.67	30.09
Nov	8.34	7.50	59.00	56.65	(54.45)	(58.16)	14.52	12.91	24.82	20.87
Dec	8.77	7.37	91.68	52.08	(67.32)	(52.54)	13.50	13.32	22.68	28.86
Jan	7.69	9.41	40.71	64.78	(82.87)	(66.65)	12.08	13.52	23.88	34.39
Feb	14.00	11.28	80.63	107.12	(74.28)	(485.46)	16.26	25.08	32.21	32.04
Mar	11.06	10.87	87.12	77.36	(67.96)	(124.21)	16.30	18.68	28.46	23.08
Apr	9.57	8.46	95.48	77.91	(119.44)	(143.82)	17.18	21.38	31.65	68.30
May – Oct	7.30	7.13	365.63	75.42	(119.38)	(164.28)	22.83	15.54	21.71	25.87
Nov - Apr	9.91	9.15	75.77	72.65	(77.72)	(155.14)	14.97	17.48	27.28	34.59
May - Apr	8.60	8.14	220.70	74.03	(98.55)	(159.71)	18.90	16.51	24.50	30.23

Table A-33: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP, May 2006 – April 2008

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	4.34	1.13	15.2	13.6
Jun	(0.82)	(1.59)	2.2	8.4
Jul	(0.36)	(1.87)	4.4	6.3
Aug	1.08	0.99	5.1	6.1
Sep	(0.60)	(2.35)	6.4	11.5
Oct	0.51	(3.59)	8.3	6.8
Nov	(1.26)	(6.48)	5.0	(1.6)
Dec	0.73	(5.45)	18.7	3.3
Jan	0.27	(2.76)	7.8	8.9
Feb	4.13	(0.84)	13.2	12.8
Mar	1.11	(1.74)	9.5	3.3
Apr	0.68	(9.05)	12.8	15.1
May – Oct	0.69	(1.21)	6.90	8.78
Nov - Apr	0.94	(4.39)	11.20	6.97
May - Apr	0.82	(2.80)	9.10	7.88

* This is an average of hourly differences relative to hourly peak MCP

Table A-34: Average Monthly HOEP Compared to Average Monthly Peak Hourly MCP, May 2006 – April 2008 ($/MWh)

	Hourly Peak MCP		HOEP		Peak minus HOEP	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	53.92	45.60	46.32	38.50	7.61	7.11
Jun	52.02	52.95	46.08	44.38	5.95	8.57
Jul	57.79	51.04	50.52	43.90	7.26	7.13
Aug	61.37	60.80	52.72	53.62	8.65	7.18
Sep	39.84	52.94	35.42	44.63	4.42	8.31
Oct	45.91	60.66	40.17	48.91	5.74	11.76
Nov	59.25	60.93	49.71	46.95	9.54	13.98
Dec	47.37	61.92	39.25	49.08	8.12	12.85
Jan	51.90	52.94	44.48	40.74	7.42	12.20
Feb	68.99	64.50	59.12	52.38	9.87	12.12
Mar	64.80	69.45	54.85	56.84	9.95	12.61
Apr	54.94	66.50	46.05	48.98	8.89	17.52
May – Oct	51.81	54.00	45.21	45.66	6.61	8.34
Nov – Apr	57.88	62.71	48.91	49.16	8.97	13.55
May - Apr	54.84	58.35	47.06	47.41	7.79	10.95

*Table A-35: Frequency Distribution of Difference between 1-Hour Pre-dispatch and HOEP, May 2006 – April 2008 (%)**

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)															
	< -$50.01		-$50.00 to -$20.01		-$20.00 to -$10.01		-$10.00 to -$0.01		$0.00 to $9.99		$10.00 to $19.99		$20.00 to $49.99		> $50.00	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	0.8	0.7	1.2	2.4	1.2	1.5	6.2	11.0	49.3	48.5	**23.0**	17.7	17.5	17.5	0.8	0.7
Jun	0.1	**1.3**	1.9	1.7	3.1	2.5	15.7	13.6	53.6	50.4	16.1	13.6	9.4	14.6	0.0	2.4
Jul	0.3	0.8	1.2	2.2	2.7	2.6	13.6	13.0	51.6	53.1	17.9	16.5	12.4	11.3	0.4	0.5
Aug	0.5	0.1	**3.2**	1.1	3.9	1.7	13.2	13.0	44.5	51.9	16.3	16.7	15.3	14.0	3.1	1.5
Sep	0.3	0.4	1.1	1.3	1.8	3.7	12.6	13.9	**67.5**	51.8	12.8	19.4	3.9	8.8	0.0	0.7
Oct	0.0	0.3	0.9	0.5	2.8	2.0	12.3	14.9	54.7	45.3	19.3	20.3	9.8	16.5	0.1	0.1
Nov	0.3	0.1	3.1	1.5	**4.3**	3.7	11.1	14.4	42.8	44.9	19.0	20.1	19.0	14.7	0.4	0.4
Dec	0.4	0.1	0.9	2.3	1.3	2.7	10.4	**18.0**	49.1	42.7	21.5	18.4	15.2	15.6	1.2	0.1
Jan	0.3	0.3	1.2	0.5	2.4	2.3	12.9	11.6	47.3	47.2	20.0	17.9	15.9	19.1	0.0	1.2
Feb	0.2	0.1	1.0	2.0	2.8	2.2	8.9	8.9	34.1	40.4	19.8	21.1	**31.0**	22.1	2.2	**3.2**
Mar	0.3	0.8	2.0	2.2	2.7	1.9	12.9	16.0	35.9	34.8	20.8	18.7	24.3	22.6	1.1	3.1
Apr	0.6	1.7	2.2	3.7	2.5	3.6	10.1	12.5	45.1	34.7	15.6	18.8	22.6	23.5	1.3	1.5
May – Oct	0.3	0.6	1.6	1.5	2.6	2.3	12.3	13.2	53.5	50.2	17.6	17.4	11.4	13.8	0.7	1.0
Nov – Apr	0.3	0.5	1.7	2.0	2.7	2.7	11.1	13.6	42.4	40.8	19.5	19.2	21.3	19.6	1.0	1.6
May - Apr	0.3	0.6	1.7	1.8	2.6	2.5	11.7	13.4	48.0	45.5	18.5	18.3	16.4	16.7	0.9	1.3

* Bolded values show highest percentage within price range.

Table A-36: Difference between 1-Hour Pre-dispatch Price and HOEP within Defined Ranges, May 2006 – April 2008

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	90.1	84.3	0.5	0.1	9.4	15.6
Jun	78.6	80.7	0.6	0.3	20.8	19.0
Jul	82.1	81.2	0.1	0.3	17.7	18.6
Aug	79.0	83.9	0.1	0.1	20.8	16.0
Sep	83.5	80.7	0.7	0.0	15.8	19.3
Oct	84.0	82.3	0.0	0.0	16.0	17.7
Nov	81.0	80.1	0.3	0.0	18.8	19.9
Dec	86.7	76.9	0.3	0.0	13.0	23.1
Jan	82.8	85.1	0.4	0.3	16.8	14.7
Feb	86.6	86.6	0.5	0.1	13.0	13.2
Mar	82.0	79.0	0.1	0.1	17.9	20.8
Apr	84.0	78.2	0.6	0.3	15.4	21.5
May – Oct	82.9	82.2	0.3	0.1	16.8	17.7
Nov – Apr	83.9	81.0	0.4	0.1	15.8	18.9
May - Apr	83.4	81.6	0.4	0.1	16.3	18.3

Table A-37: Difference between 1-Hour Pre-dispatch Price and Hourly Peak MCP within Defined Ranges, May 2006 – April 2008

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008	2006 / 2007	2007 / 2008
May	73.7	62.1	2.3	2.4	24.1	35.5
Jun	51.4	57.1	4.2	2.9	44.4	40.0
Jul	57.9	55.7	2.2	3.6	39.9	40.7
Aug	51.8	58.7	3.8	2.4	44.5	38.8
Sep	56.5	46.8	7.2	3.5	36.3	49.7
Oct	59.7	48.9	3.9	2.8	36.4	48.3
Nov	55.0	41.7	4.2	3.1	40.8	55.3
Dec	60.0	46.0	4.0	2.0	36.0	52.0
Jan	56.3	54.7	5.1	2.2	38.6	43.1
Feb	63.1	61.5	5.1	1.9	31.9	36.6
Mar	56.1	50.9	2.8	3.2	41.1	45.8
Apr	60.0	51.2	3.5	1.5	36.5	47.2
May – Oct	58.5	54.9	3.9	2.9	37.6	42.2
Nov – Apr	58.4	51.0	4.1	2.3	37.5	46.7
May - Apr	58.5	52.9	4.0	2.6	37.5	44.4

Table A-38: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2006 – April 2008

	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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	325	285	302	259	196	173	158	142	2.0	1.8	1.9	1.7	1.2	1.1	1.0	0.9
Jun	379	418	335	350	244	287	185	209	2.2	2.4	2.0	2.1	1.4	1.6	1.0	1.2
Jul	485	399	413	337	344	275	251	201	2.6	2.3	2.3	2.0	1.8	1.6	1.3	1.1
Aug	420	455	353	382	301	307	210	225	2.4	2.5	2.0	2.2	1.6	1.7	1.2	1.2
Sep	297	368	265	318	182	237	144	180	1.9	2.3	1.7	2.0	1.1	1.4	0.9	1.1
Oct	309	336	282	307	190	192	152	160	1.9	2.1	1.8	2.0	1.2	1.2	0.9	1.0
Nov	319	310	309	300	178	178	153	154	1.9	1.8	1.9	1.8	1.1	1.0	0.9	0.9
Dec	343	352	313	316	209	256	169	203	2.0	1.9	1.8	1.7	1.2	1.4	1.0	1.1
Jan	344	367	316	327	208	205	161	163	1.9	2.0	1.7	1.8	1.1	1.1	0.9	0.9
Feb	342	344	309	313	210	212	165	180	1.8	1.9	1.6	1.7	1.1	1.1	0.8	1.0
Mar	298	344	271	302	199	238	164	188	1.7	2.0	1.6	1.7	1.1	1.3	0.9	1.1
Apr	281	284	255	263	177	182	140	154	1.8	1.8	1.6	1.7	1.1	1.1	0.8	1.0
May – Oct	369	377	325	326	243	245	183	186	2.2	2.2	2.0	2.0	1.4	1.4	1.1	1.1
Nov – Apr	321	334	296	304	197	212	159	174	1.9	1.9	1.7	1.7	1.1	1.2	0.9	1.0
May - Apr	345	355	310	315	220	229	171	180	2.0	2.1	1.8	1.9	1.3	1.3	1.0	1.0

Table A-39: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2006 – April 2008 (%)*

	> 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	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	2	1	16	12	16	15	23	21	19	22	13	16	11	13	0	0	57	49	43	51
Jun	4	4	19	19	15	14	18	17	18	16	14	12	11	15	1	3	56	53	44	47
Jul	9	4	23	21	15	12	15	17	11	17	10	14	14	13	3	1	62	54	38	46
Aug	5	5	18	24	13	16	17	15	15	12	14	11	15	15	2	2	53	60	47	40
Sep	0	3	14	16	15	16	23	20	19	18	15	11	12	15	1	2	53	54	47	46
Oct	1	1	16	18	17	19	19	18	21	21	13	13	12	9	0	1	54	57	46	43
Nov	1	2	15	15	19	15	20	23	21	19	12	15	11	11	1	0	54	54	46	46
Dec	1	3	17	19	16	11	19	14	17	17	14	14	13	20	1	2	54	48	46	52
Jan	1	3	17	18	15	18	21	22	20	19	12	11	12	10	1	0	54	61	46	39
Feb	3	3	17	20	17	15	21	18	17	20	12	11	12	11	0	2	58	56	42	44
Mar	2	2	15	24	14	13	20	18	19	16	15	11	14	15	1	1	50	57	50	43
Apr	0	1	14	14	15	16	24	19	21	22	16	14	10	13	0	1	53	49	47	51
May – Oct	4	3	18	18	15	15	19	18	17	18	13	13	13	13	1	2	56	55	44	46
Nov – Apr	1	2	16	18	16	15	21	19	19	19	14	13	12	13	1	1	54	54	46	46
May - Apr	2	3	17	18	16	15	20	19	18	18	13	13	12	13	1	1	55	54	45	46

* Data includes both dispatchable and non-dispatchable load.

Table A-40: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, May 2006 – April 2008 (MW and %)*

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	688,775	741,893	292.0	182.2	(68.5)	(194.2)	30.8	2.6	3.1	0.0
Jun	737,975	691,114	188.8	276.5	(99.3)	(144.7)	41.2	32.0	4.4	3.7
Jul	722,572	665,874	239.2	233.8	(100.7)	(147.9)	59.2	40.6	6.4	4.7
Aug	709,496	669,870	206.1	167.5	(55.1)	(167.3)	46.3	26.7	5.6	2.9
Sep	727,818	655,691	250.6	186.6	(136.4)	(162.4)	41.0	17.9	4.8	2.1
Oct	827,835	817,009	164.7	177.9	(136.8)	(247.5)	21.5	18.3	2.1	1.6
Nov	826,319	815,131	221.2	218.8	(148.7)	(161.6)	16.6	15.9	1.9	1.4
Dec	861,556	846,484	181.9	199.2	(168.0)	(214.2)	(2.5)	4.9	0.1	0.6
Jan	927,931	893,372	141.2	285.9	(216.3)	(163.5)	8.9	13.3	0.9	1.2
Feb	843,514	784,525	187.2	195.2	(179.8)	(171.5)	0.1	15.7	0.2	1.4
Mar	914,915	809,244	244.2	233.7	(191.2)	(190.5)	(14.0)	13.7	(1.1)	1.3
Apr	766,192	727,988	185.8	314.2	(194.9)	(243.2)	8.3	13.4	1.2	1.6
May – Oct	735,745	706,909	223.6	204.1	(99.5)	(177.3)	40.0	23	4.4	2.5
Nov – Apr	856,738	812,791	193.6	241.2	(183.2)	(190.8)	2.9	13	0.5	1.3
May - Apr	796,242	759,850	208.6	222.6	(141.3)	(184.0)	21.5	18	2.5	1.9

* 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-41: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2006 – April 2008

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	19,881	68,746	76.3	137.8	(61.7)	(199.9)	1.9	4.2	2.8	4.8
Jun	24,370	54,863	93.5	146.7	(124.7)	(153.0)	3.5	9.4	8.4	14.8
Jul	28,632	44,078	75.6	154.0	(97.8)	(187.8)	3.3	5.7	8.3	14.2
Aug	27,638	54,869	89.9	159.1	(91.5)	(148.8)	8.2	1.7	26.0	(11.1)
Sep	53,686	74,113	130.1	143.3	(115.1)	(205.8)	9.8	(3.3)	19.5	(2.2)
Oct	87,388	106,536	96.1	150.1	(141.1)	(227.9)	10.0	4.1	13.4	0.8
Nov	76,210	113,859	126.1	178.0	(128.6)	(166.1	11.7	11.1	17.3	9.3
Dec	112,547	120,139	177.3	183.8	(144.3)	(203.0)	6.6	3.2	7.2	4.2
Jan	105,340	152,155	145.4	205.7	(178.4)	(155.4)	13.6	5.0	16.2	5.6
Feb	118,311	105,099	167.8	148.2	(166.6)	(166.8)	8.3	15.6	7.7	12.0
Mar	112,051	119,586	150.5	136.1	(169.0)	(169.9)	(11.2)	8.1	(7.7)	5.3
Apr	90,023	107,994	123.7	180.9	(164.1)	(240.4)	3.6	(3.3)	9.3	-1.7
May – Oct	40,266	67,201	93.6	148.5	(105.3)	(187.2)	6.1	3.6	13.1	3.6
Nov – Apr	102,414	119,805	148.5	172.1	(158.5)	(187.1)	5.4	6.6	8.3	5.8
May - Apr	71,340	93,503	121.0	160.3	(131.9)	(187.2)	5.8	5.1	10.7	4.7

* Fail rate is calculated as the average difference divided by the pre-dispatch MW

Table A-42: Failed Imports into Ontario, May 2006 – April 2008
(Incidents and Average MW)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	121	192	818	453	135	135	3.1	6.3
Jun	187	148	848	400	153	95	4.6	2.9
Jul	207	112	1,020	700	123	123	4.3	2.8
Aug	171	207	405	546	113	118	4.5	3.5
Sep	54	155	300	525	76	146	1.1	2.5
Oct	109	173	240	607	69	116	2.1	2.4
Nov	242	214	595	677	114	137	3.5	2.8
Dec	137	182	384	597	102	125	3.1	2.2
Jan	138	354	553	1,255	110	259	3.3	8.7
Feb	230	342	502	1,500	92	315	4.9	12.0
Mar	217	488	550	1,586	112	340	3.6	12.1
Apr	105	303	250	660	89	157	3.3	3.6
May-Oct	849	987	605	539	112	122	3.3	3.4
Nov-Apr	1,069	1,883	472	1,046	103	222	3.6	6.9
May-Apr	1,918	2,870	539	792	107	172	3.5	5.2

* 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-43: Failed Imports into Ontario, On-Peak,
May 2006 – April 2008
(Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	66	107	818	453	123	146	3.1	6.2
Jun	78	83	490	289	132	98	3.9	2.9
Jul	115	69	587	700	107	114	4.8	3.0
Aug	72	121	405	546	91	104	3.4	3.4
Sep	20	80	300	421	99	139	1.2	2.7
Oct	60	97	240	607	74	123	3.0	2.7
Nov	148	110	595	446	112	120	4.1	2.5
Dec	73	82	300	500	101	115	3.0	1.8
Jan	67	202	553	1,255	99	281	3.0	8.4
Feb	119	165	502	1,500	93	305	4.3	9.9
Mar	131	246	400	1,190	108	349	4.1	14.0
Apr	48	166	235	660	78	165	2.6	4.0
May-Oct	411	557	473	503	104	121	3.2	3.5
Nov-Apr	586	971	431	925	99	223	3.5	6.8
May-Apr	997	1,528	452	714	101	172	3.4	5.1

* 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-44: Failed Imports into Ontario, Off-Peak,
May 2006 – April 2008
(Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	55	85	500	450	148	120	3.1	6.3
Jun	109	65	848	400	168	91	5.1	2.9
Jul	92	43	1,020	662	143	138	3.9	2.4
Aug	99	86	385	500	128	138	5.4	3.7
Sep	34	75	200	525	63	153	1.0	2.4
Oct	49	76	191	435	63	107	1.4	2.1
Nov	94	104	525	677	116	155	2.8	3.2
Dec	64	100	384	597	103	133	3.3	2.6
Jan	71	152	483	892	121	228	3.7	9.0
Feb	111	177	480	1,300	91	324	5.9	14.9
Mar	86	242	550	1,586	117	330	3.1	10.6
Apr	57	137	250	400	97	146	4.0	3.2
May-Oct	438	430	524	495	119	125	3.3	3.3
Nov-Apr	483	912	445	909	108	219	3.8	7.3
May-Apr	921	1,342	485	702	113	172	3.6	5.3

* 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-45: Failed Exports from Ontario, May 2006 – April 2008 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	564	522	1,136	938	318	202	13.0	8.9
Jun	324	382	817	733	176	167	5.9	5.8
Jul	354	350	850	1,079	201	175	6.5	4.5
Aug	399	373	914	900	187	163	5.8	5.2
Sep	422	397	788	1,071	192	208	8.9	8.2
Oct	412	390	874	898	185	194	7.3	7.5
Nov	317	368	765.5	876	157	171	8.6	6.1
Dec	387	438	865	932	169	185	8.9	5.8
Jan	415	563	801	1,840	153	288	7.5	7.3
Feb	375	533	1,220	1,675	130	387	3.9	11.1
Mar	404	582	671	1,574	142	334	5.9	9.3
Apr	455	564	1,028	943	160	205	5.9	4.5
May-Oct	2,475	2,414	897	937	210	185	7.9	6.7
Nov-Apr	2,353	3,048	892	1,307	152	262	6.8	7.4
May-Apr	4,828	5,462	894	1,122	181	223	7.3	7.0

* 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-46: Failed Exports from Ontario, On-Peak,
May 2006 – April 2008
(Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	239	199	1,029	938	256	224	11.2	8.1
Jun	123	150	785	733	153	179	5.2	6.8
Jul	126	164	850	1,079	193	201	7.1	5.8
Aug	161	155	914	900	215	154	6.9	5.0
Sep	148	146	644	942	163	204	6.9	8.0
Oct	144	160	874	645	162	171	5.6	6.8
Nov	138	147	527	633	125	149	8.5	5.3
Dec	127	175	865	650	133	182	7.5	5.3
Jan	183	283	665	1,840	117	336	6	8.4
Feb	154	226	1,220	1,675	124	355	3.3	9.3
Mar	175	253	500	1,300	91	387	4.5	11.8
Apr	209	272	930	820	142	219	5.6	4.7
May-Oct	941	974	849	873	190	189	7.2	6.8
Nov-Apr	986	1,356	785	1,153	122	271	5.9	7.5
May-Apr	1,927	2,330	817	1,013	156	230	6.5	7.1

* 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-47: Failed Exports from Ontario, Off-Peak, May 2006 – April 2008 (Incidents and Average Magnitude)

	Number of Hours with Failure*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	325	323	1,136	902	363	188	14.3	9.5
Jun	201	232	817	570	190	159	6.3	5.2
Jul	228	186	749	627	205	152	6.2	3.6
Aug	238	218	709	722	167	170	5.1	5.2
Sep	274	251	788	1,071	208	209	10.1	8.3
Oct	268	230	710	898	198	211	8.4	8.0
Nov	179	221	766	876	181	186	8.6	6.7
Dec	260	263	725	932	186	187	9.6	6.2
Jan	232	280	801	1,705	181	239	8.5	6.2
Feb	221	307	565	1,517	133	410	4.4	12.7
Mar	229	329	671	1,574	180	294	6.8	7.7
Apr	246	292	1,028	943	175	191	6.1	4.4
May-Oct	1,534	1,440	818	798	222	182	8.4	6.6
Nov-Apr	1,367	1,692	759	1,258	173	251	7.3	7.3
May-Apr	2,901	3,132	789	1,028	197	216	7.9	7.0

* 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-48: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2006 – April 2008

	Average Hourly Reserve (MW)		% of Total Requirements											
			Dispatchable Load		Hydroelectric		Fossil		CAOR		Import		Export	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	1,366	1,346	23.9	19.0	61.7	71.1	6.7	4.4	0.9	0.1	1.6	0.2	4.8	3.4
Jun	1,368	1,334	22.3	19.2	67.0	68.6	5.4	5.6	0.0	0.3	2.4	1.0	2.8	3.4
Jul	1,370	1,317	24.0	18.0	65.8	70.8	6.3	6.1	0.0	0.1	1.8	0.8	2.1	2.4
Aug	1,380	1,324	17.1	16.3	74.4	72.7	5.8	5.5	0.3	0.0	0.4	1.2	2.0	3.1
Sep	1,367	1,320	20.4	17.0	71.8	72.7	4.7	5.2	0.0	0.1	0.4	1.3	2.8	3.1
Oct	1,384	1,330	18.4	16.9	71.2	74.3	5.1	5.7	0.0	0.0	1.3	0.4	2.9	2.5
Nov	1,379	1,382	20.8	16.4	69.7	68.7	6.0	7.3	0.0	0.1	0.5	2.1	0.9	3.9
Dec	1,365	1,315	18.4	17.4	71.2	70.8	6.1	6.2	0.2	0.1	1.8	0.7	0.6	3.5
Jan	1,373	1,317	20.4	20.6	67.2	64.1	7.4	9.5	0.2	0.4	0.0	0.4	4.1	4.4
Feb	1,399	1,319	21.1	21.0	66.9	61.5	6.2	11.5	0.3	0.6	0.2	0.8	4.3	4.3
Mar	1,387	1,316	21.8	19.4	68.1	67.5	4.1	8.7	0.2	0.4	1.4	0.2	4.0	3.3
Apr	1,379	1,315	20.6	21.8	69.1	52.2	5.2	18.8	0.3	2.4	0.9	0.5	2.7	3.2
May-Oct	1,373	1,329	21	17.7	68.7	71.7	5.7	5.4	0.2	0.1	1.3	0.8	2.9	3.0
Nov-Apr	1,380	1,327	20.5	19.4	68.7	64.1	5.8	10.3	0.2	0.7	0.8	0.8	2.8	3.8
May-Apr	1,376	1,328	20.8	18.6	68.7	67.9	5.8	7.9	0.2	0.4	1.1	0.8	2.8	3.4

Table A-49: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2006 – April 2008

	Average Hourly Reserve (MW)		% of Total Requirements: Dispatchable Load		% of Total Requirements: Hydroelectric		% of Total Requirements: Fossil		% of Total Requirements: CAOR		% of Total Requirements: Import		Export	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	1,487	1,340	21.5	19.6	68.4	66.8	7.8	6.4	0.2	0.0	0.4	0.0	1.6	4.7
Jun	1,435	1,315	21.6	20.4	68.0	66.4	6.4	5.9	0.0	0.0	0.2	0.6	3.8	4.2
Jul	1,368	1,318	22.3	19.5	65.1	68.5	8.4	6.9	0.2	0.0	0.3	0.0	3.8	3.0
Aug	1,370	1,316	17.4	17.2	71.9	68.6	7.1	7.4	0.0	0.0	0.2	0.0	3.4	4.7
Sep	1,367	1,317	19.5	18.2	70.0	68.8	6.7	7.0	0.0	0.0	0.0	0.0	3.8	4.9
Oct	1,368	1,316	17.7	18.1	69.0	69.6	6.9	7.8	0.0	0.0	0.0	0.9	4.5	2.9
Nov	1,368	1,415	19.2	16.9	70.1	66.2	6.1	8.4	0.0	0.0	0.0	2.1	1.8	4.4
Dec	1,366	1,358	16.2	18.1	71.4	67.8	7.1	7.3	0.1	0.0	1.2	0.2	1.7	4.4
Jan	1,367	1,316	19.5	22.4	67.7	61.1	6.4	9.9	0.0	0.0	0.0	0.1	4.3	4.7
Feb	1,371	1,316	20.3	22.9	70.0	58.3	3.7	12.8	0.1	0.0	0.0	0.1	4.8	4.6
Mar	1,369	1,323	21.1	21.9	69.1	61.9	3.9	11.2	0.0	0.0	0.5	0.0	4.3	3.7
Apr	1,395	1,351	19.8	22.6	69.3	58.2	5.1	13.2	0.1	0.7	0.3	0.2	3.2	3.4
May-Oct	1,399	1,320	20.0	18.8	68.7	68.1	7.2	6.9	0.1	0.0	0.2	0.3	3.5	4.1
Nov-Apr	1,373	1,347	19.4	20.8	69.6	62.3	5.4	10.5	0.1	0.1	0.3	0.5	3.4	4.2
May-Apr	1,386	1,333	19.7	19.8	69.2	65.2	6.3	8.7	0.1	0.1	0.3	0.4	3.4	4.1

Table A-50: Day Ahead Forecast Error, May 2006 – April 2008
(as of Hour 18)

	Average Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 3%		Percentage of Hours with Absolute Error ≥ 3%	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	(98)	(26)	1.87	1.31	151	53	20	7
Jun	(100)	0	2.91	2.67	279	252	39	35
Jul	178	98	3.02	2.61	317	227	43	31
Aug	26	113	2.55	2.21	258	188	35	25
Sep	101	68	1.70	1.79	127	139	18	19
Oct	6	(70)	1.60	1.53	94	92	13	12
Nov	(76)	(93)	1.52	1.31	83	51	12	7
Dec	15	(115)	1.73	1.81	114	147	15	20
Jan	(67)	65	1.52	1.74	70	128	9	17
Feb	23	(17)	1.52	1.42	81	65	12	9
Mar	(77)	69	1.61	1.83	94	145	13	19
Apr	(38)	(101)	1.55	1.69	84	130	12	18
May-Oct	19	31	2.28	2.02	1,226	951	28	22
Nov-Apr	(37)	(32)	1.58	1.63	526	666	12	15
May-Apr	(9)	(1)	1.93	1.83	1,752	1,617	20	18

Table A-51: Average One Hour Ahead Forecast Error, May 2006 – April 2008

	Peak Forecast Error (MW)		Average Absolute Error (% of Peak Demand)		No. of Hours with Forecast Error ≥ 2%		Percentage of Hours with Absolute Error ≥ 2%	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	38	(2)	0.96	0.89	82	63	11	8
Jun	45	19	1.03	1.19	92	129	13	18
Jul	82	39	1.32	1.14	160	126	22	17
Aug	38	61	1.15	1.22	123	125	17	17
Sep	8	22	0.89	1.06	56	94	8	13
Oct	23	39	0.93	0.99	59	92	8	12
Nov	18	19	0.90	0.88	58	59	8	8
Dec	20	(2)	0.98	1.12	75	102	10	14
Jan	19	53	0.87	0.88	53	66	7	9
Feb	42	40	0.84	0.96	41	77	6	11
Mar	3	40	0.92	1.06	67	90	9	12
Apr	8	2	0.84	0.95	42	67	6	9
May-Oct	39	30	1.05	1.08	572	629	13	14
Nov-Apr	18	25	0.89	0.98	336	461	8	11
May-Apr	29	28	0.97	1.03	908	1,090	10	12

Table A-52: Monthly Payments for Reliability Programs, May 2006 – April 2008 ($ millions)

	DA IOG*		RT IOG*		OR		DA GCG		SGOL		TDRP		ELRP		Total	
	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008	2006/2007	2007/2008
May	N/A	0.33	3.81	2.33	3.07	1.01	N/A	1.15	0.43	0.11	-0.01	0.00	N/A	0.00	7.30	4.93
Jun	0.35	1.08	1.91	2.27	0.54	1.24	0.56	2.04	0.52	0.07	0.01	0.00	0.00	0.01	3.89	6.71
Jul	0.55	0.65	1.81	1.42	0.84	1.10	1.89	2.29	0.18	0.22	0.00	0.00	0.00	0.00	5.27	5.68
Aug	0.72	0.64	2.82	2.29	1.05	0.61	2.37	1.58	0.09	0.06	0.03	0.00	0.01	0.00	7.09	5.18
Sep	0.16	2.79	0.57	1.71	0.81	0.78	1.69	1.67	0.13	0.03	0.07	0.00	0.00	0.01	3.43	6.99
Oct	0.16	1.35	1.60	2.55	0.97	0.85	1.14	1.99	0.22	0.04	0.00	0.00	0.00	0.00	4.09	6.78
Nov	4.18	1.20	3.50	2.99	1.34	1.50	2.00	1.06	0.18	0.06	0.00	0.00	0.00	0.00	11.20	6.81
Dec	1.08	0.25	2.35	3.69	1.50	1.07	2.03	2.01	0.15	0.01	0.00	0.00	0.00	0.00	7.11	7.03
Jan	0.50	0.10	2.37	3.93	2.13	2.25	2.35	2.06	0.17	0.11	0.00	0.00	0.00	0.00	7.52	8.45
Feb	0.16	0.27	3.98	5.44	2.24	2.25	2.61	1.42	0.30	0.20	0.01	0.00	0.00	0.00	9.30	9.58
Mar	1.31	0.22	4.34	3.79	1.04	1.40	1.97	2.22	0.20	0.09	0.01	0.00	0.00	0.00	8.87	7.72
Apr	0.08	0.11	2.29	3.98	1.50	4.77	1.70	3.59	0.09	0.06	0.01	0.00	0.00	0.00	5.67	12.51
May – Oct	1.94	6.84	12.52	12.57	7.28	5.59	7.65	10.72	1.57	0.53	0.10	0.00	0.01	0.02	31.07	36.27
Nov – Apr	7.31	2.15	18.83	23.82	9.75	13.24	12.66	12.36	1.09	0.53	0.02	0.00	0.00	0.00	49.66	52.10
May - Apr	9.25	8.99	31.35	36.39	17.03	18.83	20.31	23.08	2.66	1.06	0.12	0.00	0.01	0.02	80.73	88.37

* 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 $2.36 million has been received through the IOG reversal. The data reported in this table does not account for the IOG reversal.

Table A-53: Low Price Hours,
November 2007 – April 2008

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
2007/11/01	2	12,850	12,698	-1.2	250	25.00	8.80	-64.8
2007/11/01	3	12,711	12,553	-1.2	325	25.00	7.85	-68.6
2007/11/01	4	12,996	12,915	-0.6	350	26.59	9.58	-64.0
2007/11/04	4	11,936	11,900	-0.3	623	21.85	4.77	-78.2
2007/11/06	3	13,275	13,220	-0.4	563	27.00	14.47	-46.4
2007/11/06	4	13,087	13,108	0.2	715	27.00	4.80	-82.2
2007/11/22	5	14,580	14,312	-1.8	0	21.00	8.07	-61.6
2007/11/22	6	15,660	15,010	-4.2	0	29.08	12.15	-58.2
2007/11/23	2	15,509	15,200	-2.0	220	28.08	4.80	-82.9
2007/11/23	4	14,995	14,928	-0.4	-76	25.75	19.79	-23.1
Nov 2007**	**10**	**13,760**	**13,584**	**-1.3**	**297**	**25.64**	**9.51**	**-62.9**
2007/12/08	3	14,580	14,433	-1.0	753	29.61	14.09	-52.4
2007/12/08	4	14,119	14,212	0.7	766	25.77	5.82	-77.4
2007/12/08	5	14,163	14,174	0.1	200	25.00	18.08	-27.7
2007/12/14	4	15,195	15,124	-0.5	798	30.55	6.28	-79.4
2007/12/14	5	15,364	15,230	-0.9	800	30.60	7.69	-74.9
2007/12/22	4	13,688	13,683	0.0	673	24.39	9.75	-60.0
2007/12/22	5	13,724	13,675	-0.4	678	24.48	7.43	-69.6
2007/12/22	24	15,357	15,152	-1.3	150	25.19	19.86	-21.2
2007/12/23	1	14,492	14,042	-3.1	21	23.42	9.68	-58.7
2007/12/23	2	13,339	13,588	1.9	334	21.87	14.11	-35.5
2007/12/23	3	12,905	13,212	2.4	782	24.10	4.61	-80.9
2007/12/23	4	12,718	13,024	2.4	802	4.90	4.39	-10.4
2007/12/23	5	12,745	12,994	2.0	273	5.15	4.85	-5.8
2007/12/23	7	13,657	13,610	-0.3	288	21.22	8.54	-59.8
2007/12/23	8	14,408	14,355	-0.4	50	22.00	16.92	-23.1
2007/12/23	9	15,337	15,288	-0.3	9	24.27	17.74	-26.9
2007/12/24	2	14,072	14,194	0.9	375	24.87	11.10	-55.4
2007/12/24	3	13,682	13,876	1.4	200	12.52	15.10	20.6
2007/12/24	4	13,600	13,812	1.6	164	12.52	14.30	14.2
2007/12/24	5	13,886	13,884	0.0	194	15.55	9.98	-35.8
2007/12/24	6	14,816	14,230	-4.0	200	25.23	4.71	-81.3
2007/12/24	7	15,807	15,029	-4.9	375	30.05	14.50	-51.7
2007/12/24	20	18,474	17,481	-5.4	77	30.90	19.77	-36.0
2007/12/24	22	17,088	16,497	-3.5	0	27.80	12.16	-56.3
2007/12/24	23	16,247	15,883	-2.2	0	25.77	17.35	-32.7
2007/12/25	1	14,546	14,182	-2.5	237	20.82	4.61	-77.9
2007/12/25	2	13,863	13,509	-2.6	27	19.74	8.16	-58.7
2007/12/25	3	13,250	13,070	-1.4	108	11.55	4.71	-59.2
2007/12/25	4	12,859	12,886	0.2	375	11.48	4.71	-59.0
2007/12/25	5	12,821	12,818	0.0	384	11.55	4.74	-59.0
2007/12/25	6	13,157	13,035	-0.9	392	11.55	4.44	-61.6
2007/12/25	7	13,720	13,516	-1.5	200	20.00	8.17	-59.2
2007/12/25	8	14,410	14,173	-1.6	100	25.00	17.09	-31.6
2007/12/25	9	15,138	14,790	-2.3	105	29.22	17.39	-40.5
2007/12/25	10	15,608	15,372	-1.5	109	25.77	15.46	-40.0
2007/12/25	11	15,999	15,748	-1.6	250	30.82	17.11	-44.5

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
2007/12/25	15	15,754	15,743	-0.1	39	20.00	17.43	-12.9
2007/12/25	16	15,885	15,761	-0.8	100	18.68	9.06	-51.5
2007/12/25	17	16,725	16,201	-3.1	26	25.00	8.53	-65.9
2007/12/25	18	17,188	16,729	-2.7	100	25.00	5.19	-79.2
2007/12/25	19	16,799	16,362	-2.6	100	24.68	5.17	-79.1
2007/12/25	20	16,492	16,072	-2.5	100	20.23	5.90	-70.8
2007/12/25	21	16,248	15,843	-2.5	109	22.75	9.03	-60.3
2007/12/25	22	15,881	15,642	-1.5	250	23.47	8.01	-65.9
2007/12/25	23	15,454	15,130	-2.1	200	25.84	19.05	-26.3
2007/12/25	24	14,657	14,362	-2.0	27	20.23	6.21	-69.3
2007/12/26	2	13,114	13,090	-0.2	189	14.81	4.06	-72.6
2007/12/26	3	12,731	12,816	0.7	250	14.81	5.40	-63.5
2007/12/26	4	12,541	12,723	1.5	100	3.02	6.93	129.5
2007/12/26	5	12,808	12,739	-0.5	92	10.00	3.17	-68.3
2007/12/26	6	13,086	12,996	-0.7	92	14.81	4.02	-72.9
2007/12/26	7	13,487	13,534	0.3	352	20.00	14.41	-28.0
2007/12/26	12	16,159	15,780	-2.3	0	26.07	4.92	-81.1
2007/12/26	13	16,010	15,685	-2.0	0	22.27	4.90	-78.0
2007/12/26	14	15,843	15,529	-2.0	-69	15.00	4.90	-67.3
2007/12/26	15	15,605	15,309	-1.9	0	15.78	4.90	-68.9
2007/12/26	16	15,845	15,386	-2.9	368	29.69	4.94	-83.4
2007/12/26	24	15,008	14,726	-1.9	100	29.00	17.43	-39.9
2007/12/27	2	13,737	13,468	-2.0	120	23.15	16.36	-29.3
2007/12/27	3	13,283	13,162	-0.9	118	19.74	10.87	-44.9
2007/12/27	5	13,309	13,132	-1.3	0	19.74	18.39	-6.8
2007/12/28	3	13,713	13,269	-3.2	347	23.93	13.60	-43.2
2007/12/28	4	13,510	13,132	-2.8	100	19.70	5.26	-73.3
2007/12/28	5	13,513	13,234	-2.1	0	18.98	11.60	-38.9
2007/12/28	6	14,287	13,637	-4.5	-100	24.53	10.39	-57.6
2007/12/28	7	15,245	14,593	-4.3	0	27.92	15.43	-44.7
2007/12/29	4	13,509	13,319	-1.4	277	22.66	15.26	-32.7
2007/12/29	8	15,109	14,523	-3.9	52	29.34	19.94	-32.0
2007/12/30	2	13,919	13,771	-1.1	-70	19.57	18.89	-3.5
2007/12/30	3	13,471	13,406	-0.5	75	19.57	19.10	-2.4
2007/12/30	4	13,250	13,196	-0.4	308	16.32	2.83	-82.7
2007/12/30	5	13,229	13,191	-0.3	70	16.76	11.58	-30.9
2007/12/30	6	13,304	13,357	0.4	160	15.00	5.46	-63.6
2007/12/30	7	13,797	13,707	-0.7	0	19.57	19.52	-0.3
2007/12/30	8	14,393	14,289	-0.7	0	18.27	16.38	-10.3
2007/12/30	15	16,235	16,319	0.5	-87	18.00	19.68	9.3
2007/12/31	22	16,664	16,255	-2.5	351	27.35	13.81	-49.5
2007/12/31	23	15,952	15,654	-1.9	107	25.57	19.79	-22.6
Dec 2007**	**78**	**14,559**	**14,366**	**-1.3**	**200**	**21.18**	**10.94**	**-48.4**
2008/01/01	6	13,483	13,365	-0.9	56	21.65	18.48	-14.6
2008/01/01	11	15,848	15,285	-3.6	15	25.94	19.85	-23.5
2008/01/02	4	14,660	14,475	-1.3	50	24.00	9.33	-61.1
2008/01/06	4	13,294	13,317	0.2	350	19.21	11.80	-38.6
2008/01/06	5	13,481	13,254	-1.7	550	18.49	5.00	-73.0
2008/01/06	6	13,458	13,384	-0.5	112	20.48	19.78	-3.4

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
2008/01/06	9	15,753	14,945	-5.1	0	26.81	12.48	-53.5
2008/01/06	10	16,095	15,606	-3.0	0	25.40	19.93	-21.5
2008/01/06	11	16,447	16,143	-1.8	0	24.97	18.65	-25.3
2008/01/06	16	17,378	16,780	-3.4	0	25.34	19.40	-23.4
2008/01/06	24	15,224	14,795	-2.8	13	19.25	13.23	-31.3
2008/01/07	1	14,358	14,049	-2.2	65	10.00	3.31	-66.9
2008/01/07	2	13,812	13,591	-1.6	207	16.52	2.63	-84.1
2008/01/07	3	13,485	13,357	-0.9	304	5.00	2.63	-47.4
2008/01/07	4	13,437	13,309	-1.0	-50	10.00	6.39	-36.1
2008/01/07	5	13,777	13,418	-2.6	-50	7.00	3.10	-55.7
2008/01/07	6	15,067	14,125	-6.3	0	20.66	6.71	-67.5
2008/01/07	23	17,150	16,352	-4.7	423	21.94	4.43	-79.8
2008/01/07	24	15,773	15,017	-4.8	250	18.14	4.03	-77.8
2008/01/08	1	14,391	14,100	-2.0	0	4.47	8.68	94.2
2008/01/08	2	13,835	13,555	-2.0	100	18.70	11.92	-36.3
2008/01/08	3	13,467	13,335	-1.0	524	19.79	3.83	-80.6
2008/01/08	4	13,210	13,115	-0.7	857	19.42	2.63	-86.5
2008/01/08	5	13,587	13,194	-2.9	356	20.10	3.10	-84.6
2008/01/08	6	14,694	13,883	-5.5	271	24.59	12.70	-48.4
2008/01/08	24	15,511	15,163	-2.2	61	22.67	15.22	-32.9
2008/01/09	1	14,318	14,139	-1.3	125	19.41	4.34	-77.6
2008/01/09	2	13,785	13,701	-0.6	-75	14.98	10.06	-32.8
2008/01/09	3	13,372	13,440	0.5	192	14.98	5.77	-61.5
2008/01/09	4	13,321	13,300	-0.2	444	14.98	2.54	-83.0
2008/01/09	5	13,618	13,369	-1.8	0	14.98	8.21	-45.2
2008/01/09	6	14,703	13,960	-5.1	0	24.76	19.01	-23.2
2008/01/10	5	14,413	14,083	-2.3	100	23.63	4.78	-79.8
2008/01/10	6	15,545	14,663	-5.7	24	27.44	7.81	-71.5
2008/01/11	3	14,540	14,417	-0.8	274	26.50	15.58	-41.2
2008/01/11	24	16,047	15,672	-2.3	125	25.00	19.55	-21.8
2008/01/12	2	14,402	14,096	-2.1	194	25.00	8.10	-67.6
2008/01/12	3	14,025	13,694	-2.4	0	18.20	6.87	-62.3
2008/01/12	4	13,871	13,503	-2.7	0	14.00	5.33	-61.9
2008/01/12	5	13,927	13,488	-3.2	0	12.00	5.90	-50.8
2008/01/12	6	14,119	13,718	-2.8	0	24.74	17.02	-31.2
2008/01/12	8	15,620	15,300	-2.0	0	25.87	12.96	-49.9
2008/01/12	16	16,968	16,753	-1.3	127	27.37	18.11	-33.8
2008/01/12	21	17,578	17,159	-2.4	200	30.05	16.42	-45.4
2008/01/12	23	16,318	15,890	-2.6	325	29.41	7.59	-74.2
2008/01/12	24	15,590	15,116	-3.0	374	29.00	5.26	-81.9
2008/01/13	1	14,319	14,393	0.5	87	4.80	8.42	75.4
2008/01/13	2	13,737	13,942	1.5	278	15.00	4.75	-68.3
2008/01/13	4	13,483	13,504	0.2	150	15.30	4.75	-69.0
2008/01/13	5	13,338	13,478	1.0	150	15.00	4.78	-68.1
2008/01/13	6	13,754	13,669	-0.6	150	15.30	4.53	-70.4
2008/01/13	7	14,340	14,071	-1.9	0	19.95	4.52	-77.3
2008/01/13	8	14,826	14,619	-1.4	-250	15.20	14.40	-5.3
2008/01/13	9	15,797	15,326	-3.0	67	15.00	4.33	-71.1
2008/01/13	10	16,378	16,072	-1.9	76	22.86	4.72	-79.4
2008/01/13	11	16,962	16,606	-2.1	76	26.62	6.36	-76.1

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
2008/01/13	12	17,144	16,926	-1.3	110	25.00	5.07	-79.7
2008/01/13	24	16,099	15,516	-3.6	178	30.00	14.39	-52.0
2008/01/19	1	15,971	15,584	-2.4	250	34.56	17.96	-48.0
Jan 2008**	**59**	**14,795**	**14,476**	**-2.2**	**139**	**20.13**	**9.48**	**-52.9**
2008/02/09	24	15,885	15,472	-2.6	1,076	33.91	8.61	-74.6
2008/02/10	1	14,719	14,633	-0.6	0	24.66	19.28	-21.8
2008/02/10	2	14,513	14,150	-2.5	89	26.36	12.96	-50.8
2008/02/10	3	14,200	13,892	-2.2	400	25.49	7.27	-71.5
2008/02/10	4	13,881	13,794	-0.6	397	23.00	7.80	-66.1
2008/02/10	5	14,081	13,767	-2.2	377	25.11	4.83	-80.8
2008/02/10	6	14,164	14,005	-1.1	161	27.48	14.76	-46.3
2008/02/10	7	14,944	14,525	-2.8	377	29.75	6.27	-78.9
2008/02/10	8	15,660	15,172	-3.1	958	33.01	4.60	-86.1
2008/02/10	9	16,343	16,004	-2.1	862	32.61	4.58	-86.0
2008/02/10	10	17,060	16,676	-2.3	300	32.00	18.23	-43.0
2008/02/17	2	15,204	14,815	-2.6	1,050	32.90	4.74	-85.6
2008/02/17	3	14,739	14,534	-1.4	566	25.46	7.30	-71.3
2008/02/17	4	14,309	14,415	0.7	438	8.17	5.11	-37.5
2008/02/17	5	14,325	14,385	0.4	448	24.69	5.48	-77.8
2008/02/17	6	14,750	14,590	-1.1	1,007	29.79	4.78	-84.0
2008/02/17	7	15,233	14,944	-1.9	655	30.16	11.82	-60.8
2008/02/17	8	16,019	15,419	-3.7	522	36.06	18.05	-49.9
2008/02/17	9	16,664	16,058	-3.6	731	36.35	18.75	-48.4
2008/02/17	10	16,969	16,652	-1.9	685	35.00	4.90	-86.0
2008/02/17	11	17,188	17,171	-0.1	600	34.29	6.90	-79.9
2008/02/18	1	14,920	14,384	-3.6	890	26.22	2.34	-91.1
2008/02/18	2	14,615	13,983	-4.3	850	7.55	-1.91	-125.3
2008/02/18	3	13,975	13,727	-1.8	683	4.80	-2.72	-156.7
2008/02/18	4	13,632	13,614	-0.1	625	4.40	-1.39	-131.6
2008/02/18	5	13,893	13,709	-1.3	603	4.50	-0.65	-114.4
2008/02/18	6	14,327	14,114	-1.5	250	4.80	3.98	-17.1
2008/02/18	7	15,229	14,745	-3.2	142	25.35	4.53	-82.1
2008/02/18	8	16,421	15,446	-5.9	425	34.92	8.63	-75.3
2008/02/18	9	16,775	16,192	-3.5	565	36.56	16.91	-53.7
Feb 2008**	**30**	**15,155**	**14,833**	**-2.1**	**558**	**25.18**	**7.56**	**-70.0**
2008/04/17	3	12,516	12,502	-0.1	250	26.02	15.19	-41.6
2008/04/17	24	13,395	13,184	-1.6	100	29.12	4.49	-84.6
2008/04/18	2	12,780	12,407	-2.9	0	28.54	8.42	-70.5
2008/04/18	3	12,545	12,282	-2.1	0	15.23	4.64	-69.5
2008/04/18	4	12,846	12,356	-3.8	0	27.20	4.43	-83.7
2008/04/18	24	12,798	12,586	-1.7	193	29.56	9.58	-67.6
2008/04/19	1	12,107	12,043	-0.5	550	24.28	4.50	-81.5
2008/04/19	2	11,627	11,676	0.4	100	4.90	4.90	0.0
2008/04/19	3	11,654	11,552	-0.9	376	15.17	4.52	-70.2
2008/04/19	4	11,663	11,507	-1.3	277	15.17	14.73	-2.9
2008/04/19	5	11,947	11,694	-2.1	215	16.20	7.40	-54.3
2008/04/19	6	12,609	12,002	-4.8	-75	30.84	4.51	-85.4
2008/04/19	7	13,645	12,853	-5.8	25	31.03	8.53	-72.5

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
2008/04/19	19	14,455	14,270	-1.3	170	25.67	7.65	-70.2
2008/04/19	21	15,057	14,549	-3.4	-100	32.93	19.39	-41.1
2008/04/19	24	12,534	12,190	-2.7	-37	25.67	12.90	-49.7
2008/04/20	2	11,302	11,301	0.0	-103	4.60	17.16	273.0
2008/04/20	3	11,193	11,182	-0.1	75	4.50	4.41	-2.0
2008/04/20	4	11,142	11,097	-0.4	75	4.30	4.22	-1.9
2008/04/20	5	11,182	11,206	0.2	125	4.10	3.61	-12.0
2008/04/20	6	11,372	11,352	-0.2	25	4.50	4.61	2.4
2008/04/20	7	12,309	11,806	-4.1	150	5.08	2.99	-41.1
2008/04/20	8	13,361	12,791	-4.3	125	35.01	7.99	-77.2
2008/04/20	22	15,127	14,172	-6.3	320	65.23	11.49	-82.4
2008/04/20	23	13,852	13,119	-5.3	217	37.15	6.61	-82.2
2008/04/20	24	12,615	12,339	-2.2	162	15.23	4.40	-71.1
2008/04/21	1	12,372	11,927	-3.6	83	10.23	4.54	-55.6
2008/04/21	2	11,925	11,773	-1.3	25	5.08	4.78	-5.9
2008/04/21	3	11,854	11,761	-0.8	25	5.08	5.50	8.3
2008/04/21	4	12,150	11,860	-2.4	25	5.55	4.77	-14.1
2008/04/21	5	12,944	12,447	-3.8	-28	28.61	9.87	-65.5
2008/04/21	6	14,602	13,726	-6.0	173	35.46	6.01	-83.1
2008/04/21	24	13,376	13,016	-2.7	16	33.48	12.87	-61.6
2008/04/22	1	12,511	12,480	-0.2	68	4.80	4.59	-4.4
2008/04/22	2	12,280	12,146	-1.1	206	4.90	4.43	-9.6
2008/04/22	4	12,360	12,085	-2.2	335	17.23	4.32	-74.9
2008/04/22	5	13,174	12,626	-4.2	249	34.49	14.06	-59.2
2008/04/22	24	13,480	13,141	-2.5	250	26.98	3.61	-86.6
2008/04/23	1	12,749	12,589	-1.3	0	4.90	4.78	-2.4
2008/04/23	2	12,436	12,297	-1.1	0	22.41	4.75	-78.8
2008/04/23	3	12,315	12,137	-1.4	100	21.00	10.30	-51.0
2008/04/23	4	12,423	12,202	-1.8	42	10.05	4.74	-52.8
2008/04/23	24	13,336	12,990	-2.6	11	31.38	4.47	-85.8
2008/04/24	1	12,640	12,499	-1.1	12	4.70	4.63	-1.5
2008/04/24	2	12,281	12,222	-0.5	145	10.29	13.18	28.1
2008/04/24	3	12,055	12,048	-0.1	364	4.90	4.59	-6.3
2008/04/24	24	13,106	13,036	-0.5	-87	25.23	8.52	-66.2
2008/04/25	1	12,682	12,512	-1.3	10	22.87	4.77	-79.1
2008/04/25	2	12,349	12,223	-1.0	0	20.26	5.94	-70.7
2008/04/25	3	12,067	12,050	-0.1	0	3.12	3.52	12.8
2008/04/25	4	12,399	12,117	-2.3	0	3.00	-0.12	-104.0
2008/04/25	5	13,288	12,685	-4.5	0	5.32	4.49	-15.6
2008/04/25	6	14,871	13,942	-6.2	0	34.62	17.39	-49.8
2008/04/26	2	11,748	11,743	0.0	200	28.29	6.65	-76.5
2008/04/26	3	11,664	11,562	-0.9	572	26.24	4.11	-84.3
2008/04/26	5	11,725	11,713	-0.1	-326	4.40	17.30	293.2
2008/04/26	6	12,613	12,078	-4.2	274	6.23	4.14	-33.5
2008/04/26	7	13,621	12,854	-5.6	294	34.49	3.84	-88.9
2008/04/26	19	14,534	14,254	-1.9	170	31.95	4.83	-84.9
2008/04/26	23	13,374	12,865	-3.8	75	32.20	14.46	-55.1
2008/04/26	24	12,331	12,098	-1.9	0	13.24	4.88	-63.1
2008/04/27	2	11,716	11,333	-3.3	168	24.85	4.58	-81.6
2008/04/27	3	11,554	11,189	-3.2	129	22.00	4.58	-79.2

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	% Change in Demand	Net Failed Export (MW)	PD Price ($/MWh)	HOEP* ($/MWh)	% Change in Price
2008/04/27	4	11,459	11,169	-2.5	152	16.00	4.66	-70.9
2008/04/27	5	11,429	11,274	-1.4	54	7.26	4.93	-32.1
2008/04/27	6	11,885	11,371	-4.3	150	20.01	4.35	-78.3
2008/04/27	7	12,697	12,034	-5.2	340	37.19	4.26	-88.5
2008/04/27	8	13,463	12,870	-4.4	103	38.00	15.38	-59.5
2008/04/27	11	14,289	14,346	0.4	219	32.95	4.90	-85.1
2008/04/27	12	14,372	14,372	0.0	50	32.95	14.54	-55.9
2008/04/27	13	14,248	14,275	0.2	185	33.51	16.65	-50.3
2008/04/27	15	14,005	14,061	0.4	355	35.18	13.45	-61.8
2008/04/27	23	13,758	13,253	-3.7	-37	34.52	12.22	-64.6
2008/04/27	24	12,740	12,419	-2.5	13	4.04	2.85	-29.5
2008/04/28	1	12,198	12,004	-1.6	-135	4.00	4.41	10.3
2008/04/28	2	11,863	11,844	-0.2	13	1.75	4.14	136.6
2008/04/28	3	11,691	11,795	0.9	-287	1.75	4.56	160.6
2008/04/28	4	12,175	12,026	-1.2	234	4.30	0.02	-99.5
2008/04/28	5	13,089	12,754	-2.6	66	10.00	11.58	15.8
2008/04/29	1	13,231	13,132	-0.7	241	29.66	17.17	-42.1
2008/04/29	2	12,975	12,919	-0.4	100	26.00	12.10	-53.5
2008/04/29	3	12,814	12,870	0.4	17	19.99	19.50	-2.5
2008/04/29	4	13,172	13,000	-1.3	36	28.44	9.13	-67.9
2008/04/30	2	13,329	13,243	-0.6	0	30.00	4.85	-83.8
Apr 2008**	**84**	**12,707**	**12,444**	**-2.1**	**103**	**19.82**	**7.54**	**-61.9**
Nov - Apr	**261**	**14,054**	**13,796**	**-1.8**	**200**	**21.13**	**9.07**	**-57.1**

* Low priced hours are defined as hours when the HOEP is less than $20/MWh.
** Monthly sub-totals reflect the total number of low-priced hours and unweighted averages of the Net Failed Exports, PD and RT Demand, and PD and HOEP prices, during those hours.