MARKET SURVEILLANCE PANEL

MONITORING REPORT ON

THE IMO-ADMINISTERED ELECTRICITY MARKETS

FOR

THE PERIOD FROM

SEPTEMBER 2002 – JANUARY 2003

MARCH 24, 2003

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1. Introduction

This chapter reports on activity in the IMO-administered markets for the September 2002 to January 2003 period.

Demand for electricity continued to grow compared to earlier years. As we moved into the fall, supply was reduced because of depleted hydroelectric resources and as planned generator outages began. The month of September was unseasonably hot and the higher than expected demand coincided with planned outages to provoke relatively high on-peak prices compared to neighbouring markets. For the rest of the period, prices compared favourably with those in neighbouring United States markets.

In November the Government of Ontario announced plans to fix the commodity price of electricity for a large segment of consumers, as described in the next section.

2. Impact of Government Initiatives on the Wholesale Market

On November 11, 2002 the Government of Ontario presented its "Action Plan to Lower Your Hydro Bill" that set a new context for the supply of electricity in the province, although not directly changing the operation of the IMO-administered markets. Bill 210 was given first reading in the legislature on November 25, 2002 and the *Electricity Pricing, Conservation and Supply Act, 2002* became law on December 9, 2002.

The legislation fixes the commodity price for electricity at 4.3 cents per KWh (or $43/MWh) for all customers deemed to be "low volume or designated consumers". Low volume customers are defined in the legislation as consumers who annually use less than 150,000 KWh of electricity or such other amount specified in regulations. Designated consumers are specific entities such as hospitals, universities, municipalities and others, again as prescribed by regulations. The rate freeze, which is scheduled to last until

April 30, 2006, applies to these consumers unless they choose to opt out or if they enter into a contract after the coming into force of the legislation.

On March 21, 2003 the government announced its "Business Protection Plan for Large Electricity Consumers" that extended the $43 per MWh price guarantee to all consumers using 250,000 kilowatt hours per year or less. With this extension it is estimated that approximately one-half of Ontario load comes within the terms of the price guarantee.

The remaining 50 percent of load who consume above the threshold remain in the wholesale market but will receive the Market Power Mitigation rebate quarterly. The rebate is to be fixed at 50 percent of the amount by which the average wholesale market price exceeds $38 per MWh.

Another rate initiative contained in the legislation is the fixing of the wholesale market services charge at 0.62 cents per KWh for directly connected low volume and designated customers and local distribution companies. This charge represents all amounts assessed by the IMO, excluding the energy price, transmission charges and the debt retirement charge. It includes most uplift charges, notably the intertie offer guarantee and constraint payments.

To date the legislation and other initiatives have had no direct impact on the manner in which the wholesale electricity market operates. The five-minute price and Hourly Ontario Energy Price (HOEP) continue to be determined on the basis of bids and offers, as has been the case since May 1, 2002. Any difference between the HOEP and $43/MWh is reconciled in a complex set of settlement procedures involving the IMO, the Ontario Electricity Financial Corporation, local distribution companies and market participants so that the end use customers are charged the fixed price.

Two other aspects of the legislation are worthy of note. First, while the $43/MWh applies only to the commodity price for electricity, the legislation provides the means to freeze transmission and distribution charges until April 30, 2006. Any changes to transmission or distribution rate changes require the written approval of the Minister of Energy and the Minister may grant approval only under specified circumstances. In considering these circumstances the Minister is obliged to consider "…the interests of consumers with respect to prices and the reliability and quality of electricity service."

The second change to note is that the Minister of Energy now has an oversight role regarding the making of market rules. While the IMO is responsible for making the market rules, it is now required to provide to the Minister in advance, an assessment of the impact of proposed rules on the interests of consumers as described above. The Minister also has the power to revoke a proposed rule before it comes into effect if it will unduly and adversely affect these consumer interests.

While the full ramifications of the government's initiatives remain to be determined, the March 21 announcement allows for both the continued and meaningful operation of wholesale market and its ongoing evolution. It provides a continued opportunity for further improvement of both the operation of the market and the efficiency of the marketplace.

3. Ontario Electricity Demand

3.1 Peak Demand and Energy Consumption

The demand for electricity in Ontario during the May 2002 to January 2003 period set both a new annual peak demand record and new summer and winter peak demand records. The new summer and all-time peak hourly demand of 25,414 MW was set on August 1, 2002 and a new winter peak hourly demand record of 24,158 MW was set on January 22, 2003.

Table 1-1 shows how 20-minute system peak demands for 2002-2003 compare to peaks since 1984.[1] While measurements may be slightly different between the market and pre-market, the table illustrates how significant the period under review was in terms of peak demand. New historic peaks have been observed in five of the nine months since the market opened, and peak demands in the remaining four months have been the second highest on record. Although we have made no effort to normalize for weather effects, it seems reasonable to assume that at least a large part of the increase is due to weather extremes and may or may not be repeated.

Table 1-1: 20-Minute System Peak versus Historic Peak Demands

	2002 –2003 20-Minute System Peak (MW)	**Date / Hour Ending**	**Rank from 1984 – 2003**	**Historic 20-Minute System Peak (MW)**	**Year**	**Date / Hour Ending**
May	19,994	30 / hr 16	2	20,343	2000	8 / hr 16
June	23,501	26 / hr 16	2	23,608	2001	2 / hr 20
July	25,330	22 / hr 12	1	24,013	2001	24 / hr 16
August	25,608	12 / hr 15	1	25,269	2001	8 / hr 16
September	24,974	9 / hr 17	1	23,191	2000	01 / hr 13
October	21,307	1 / hr 19	1	19,788	1997	27 / hr 18
November	22,028	28 / hr 18	2	22,375	1989	29 / hr 18
December	23,437	9 / hr 18	2	23,630	1989	13 / hr 18
January	24,233	22 / hr 18	1	24,007	1994	19 / hr 18

Monthly energy consumption data since 1994 also demonstrate the unprecedented levels of demand in 2002-2003. Table 1-2 shows that in the nine months since market opening, there have been seven new monthly energy consumption records set and the other two months are the second highest energy consuming months in history.

[1] 20-minute measurement was the traditional measurement for peak demand used in Ontario. Unless noted, other data is based on the standard 60-minute measurement.

Table 1-2: Monthly Energy Consumption (TWh)*

Month	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Monthly Maximum
Jan	13.96	12.67	13.25	13.31	12.81	13.45	13.64	13.63	13.18	**14.49**	14.49
Feb	12.10	12.01	12.17	11.57	11.36	11.60	**12.46**	12.26	12.13	N/A	12.46
Mar	12.12	11.80	12.20	12.21	12.21	12.49	12.22	**12.87**	12.85	N/A	12.87
Apr	10.53	10.74	10.95	10.98	10.72	10.86	11.29	11.21	**11.82**	N/A	11.82
May	10.18	10.24	10.52	10.68	11.08	11.03	11.60	11.38	**11.87**	N/A	11.87
Jun	10.61	10.94	10.53	10.91	11.54	12.09	11.70	**12.26**	12.19	N/A	12.26
Jul	11.03	11.47	10.84	11.54	11.90	12.91	12.07	12.40	**14.03**	N/A	14.03
Aug	10.89	11.96	11.55	11.20	12.27	12.06	12.68	13.36	**13.75**	N/A	13.75
Sep	10.10	10.27	10.61	10.61	11.13	11.51	11.61	11.48	**12.59**	N/A	12.59
Oct	10.42	10.55	10.93	11.22	11.05	11.48	11.71	11.77	**12.40**	N/A	12.40
Nov	10.95	11.64	11.65	11.73	11.56	11.73	12.17	11.88	**12.66**	N/A	12.66
Dec	11.98	12.75	12.21	12.42	12.31	12.88	**13.78**	12.40	13.48	N/A	13.78

*The quantities in this table are derived from the constrained schedule after April 2002.

The autumn 2002 energy consumption data are significant because generators traditionally begin major maintenance outage programs in the two low demand periods – September to late November, and March to May. Maintenance is usually done during these periods because loads tend to be lighter. The unexpected higher loads during the fall period together with the planned maintenance outages has exacerbated ongoing supply tightness and led to higher prices in the wholesale market.

4. Impacts of Outages on Supply and Prices

Generators require outages for maintenance, whether they are low cost or high cost units. Planned outages to perform maintenance can be as short as one day or a weekend, and as long as three to four months for the major maintenance necessary to prepare for long periods of intense operations to meet summer and winter demands.

Planned outages are permitted by the IMO provided they do not impact reliability. While the IMO assesses and authorizes outages with regard to reliability, the Market Rules do not permit the IMO to take efficiency or price impacts into consideration when authorizing planned outages.

Forced outages occur when critical pieces of equipment required for the operation of the generator fail to function properly.[2] Until the equipment can be repaired, the unit must be removed from service or its MW output derated. These types of forced outages are not predictable, but they do provide a longer-term measure of the 'health' of the unit. The statistics of forced outages and deratings are constantly being measured by generating companies as a signal of the capital investment required to maintain asset life.

Generation outages – either planned or forced – can have a significant impact on price. This can be seen by comparing typical offer curves for July and October, as presented in Figure 1-1 below. The October curve, reflecting a greater level of outages, becomes steeper at lower levels of supply. Because of this impact the Market Surveillance Panel (MSP) has asked the Market Assessment Unit (MAU), in its monitoring activity, to carefully review the level of outages, both planned and forced.

[2] Another type of forced outage occurs when hydroelectric resources are energy limited such that output is limited by a lack of water.

Figure 1-1: Comparison of a July to an October Domestic Offer Curve

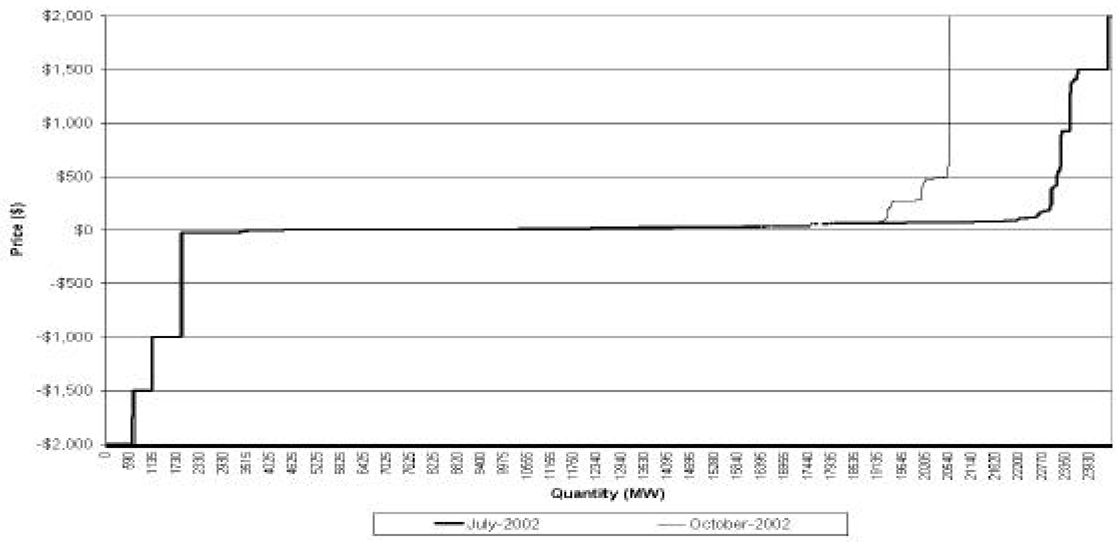
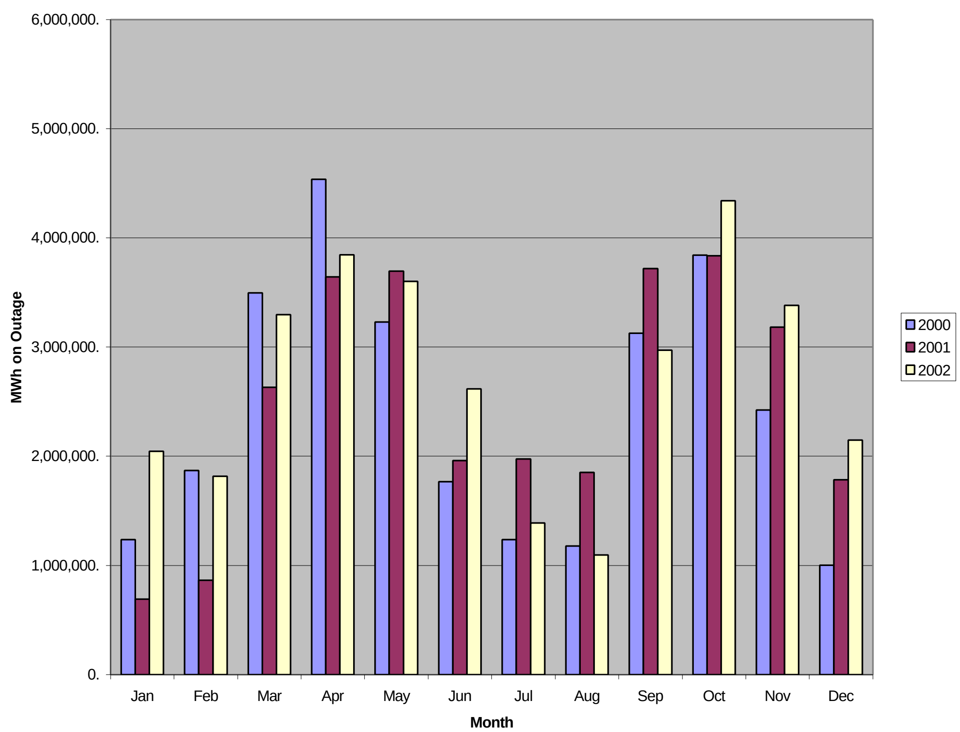


Figure 1-2 provides a comparison of outages in 2002 with those recorded in 2000 and 2001.

*Figure 1-2: Planned Outages in MWh by Month for 2000 to 2002**

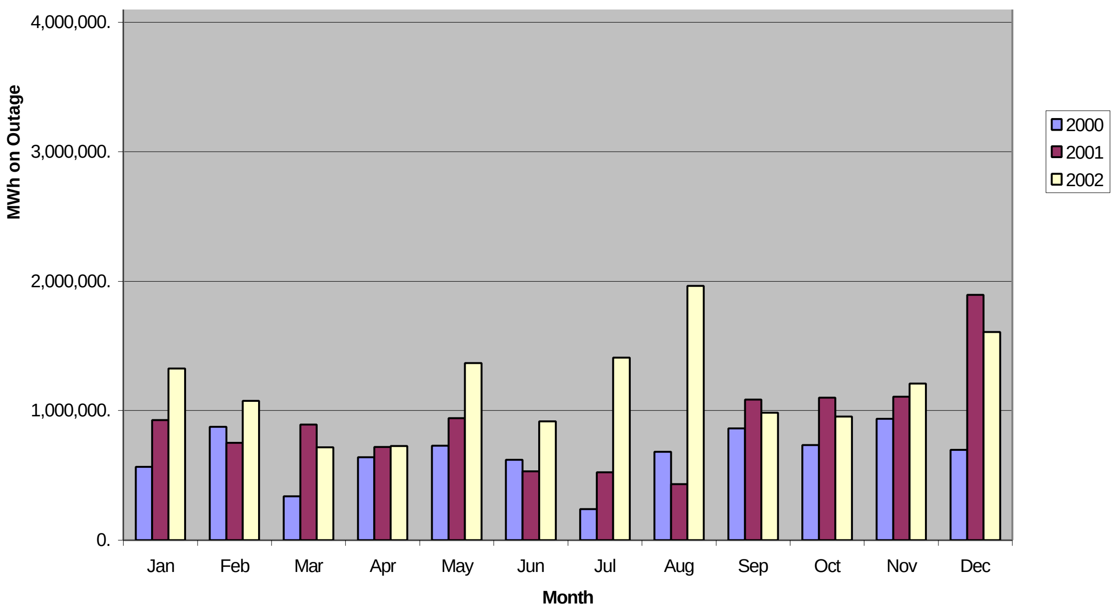


*Planned outages in MWh assume the maximum potential energy from the unit over the duration of the outage.

Planned outages appear to follow the normal planning process – with major outages continuing to occur in the spring and autumn months. Outages in the month of October 2002 accounted for over 4,000,000 MWh of potential energy off-line. The graph shows little difference between 2000, 2001 and 2002 in the volume of planned outages in the high priced months of July, August and September.

Figure 1-3 shows forced outages during the period since market opening. While the magnitude of forced outages is much less than planned outages, the figure suggests much higher levels of forced outage during the summer months of 2002. During these high demand periods of the summer, forced outages contributed to higher prices.

Figure 1-3: Forced Outages in MWh by Month for 2000 to 2002

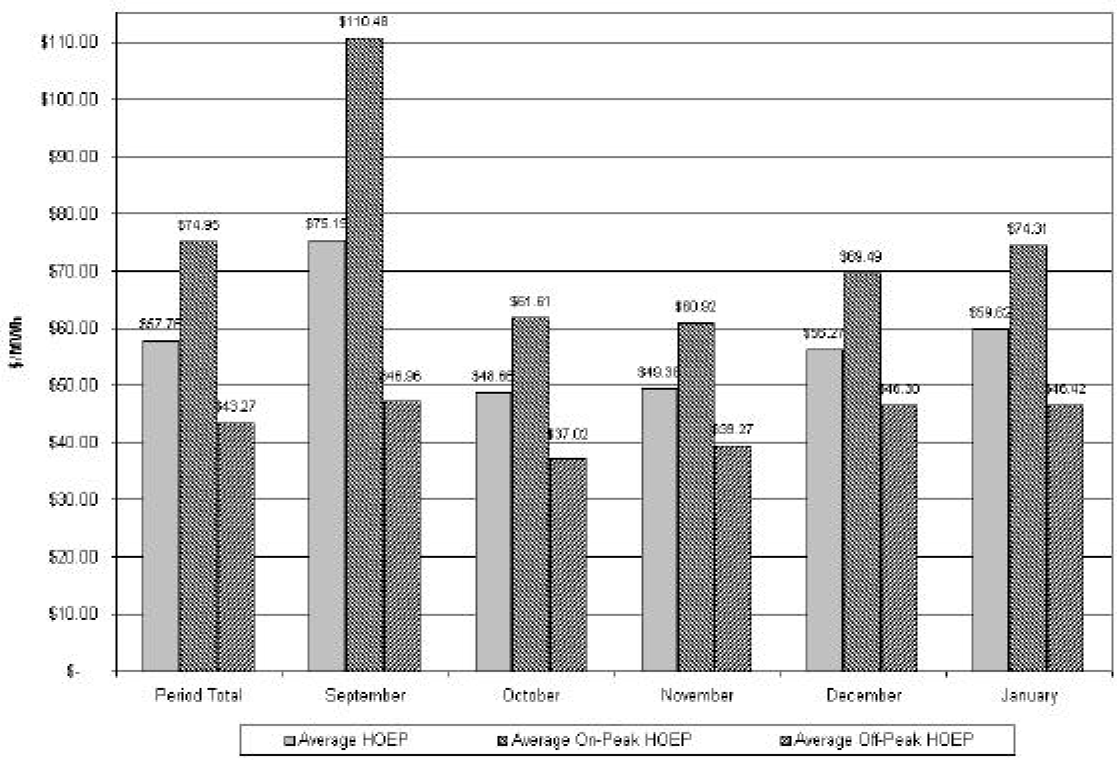


The figure shows a substantial increase in forced outages in July and August 2002 relative to the same months in 2000 and 2001. This is related to a change in reporting requirements related to market opening. The effect on reported forced outages is particularly significant for hydroelectric plants, but also applies in some circumstances to fossil plants. Prior to market opening, hydroelectric units that experienced a lack of water were managed on a 'minute-to-minute' basis to optimize water use, and resulting deratings were not reported in a manner consistent with the current market requirements. Similar conditions applied with regard to deratings of fossil plant that occurred as a result of environmental conditions limiting discharge. As a result of market opening, all deratings must be reported to the IMO. It is not clear how much of the large apparent increase in forced outages through the summer is due to changed reporting requirements with respect to deratings, and more experience with the operation of the market will be necessary before accurate comparative assessments can be made.

5. The HOEP and Uplift

The combined impact of higher demand and outages is reflected in the prices for the period, shown in Figure 1-4 below.

Figure 1-4: Average HOEP for September 2002 – January 2003



In September, on-peak prices averaged $110.48 MWh, the highest monthly average since market opening.[3] Much of the price increase in September 2002 over August 2002 can be attributed to high prices on a relatively small number of days when the Ontario primary demand reached the highest-ever September levels.

Table 1-3 provides more information on the frequency distribution of prices during the September-January period. The HOEP is in the $60 to $70 range more frequently in October and November and in the $70 to $100 + range more frequently in December and January.

Table 1-3: Frequency Distribution of HOEP for September 2002 to January 2003

HOEP Price Range ($/MWh)	May – August 2002 % of hours	Sept 2002 – Jan 2003 % of hours	September % of hours	October % of hours	November % of hours	December % of hours	January % of hours
<$10	0.31	0.00	0.00	0.00	0.00	0.00	0.00
$10.01-$20.00	5.18	0.08	0.00	0.00	0.00	0.00	0.40
$20.01-$30.00	19.28	27.53	1.67	32.53	30.14	38.17	34.41
$30.01-$40.00	37.50	14.68	34.03	14.11	10.69	6.45	8.60
$40.01-$50.00	9.18	8.01	13.89	7.53	8.19	5.38	5.24
$50.01-$60.00	5.56	7.79	8.33	8.47	11.25	6.18	4.84
$60.01-$70.00	7.11	14.08	9.72	20.30	28.47	7.39	4.84
$70.01-$100.00	11.62	22.03	20.69	15.73	10.56	30.11	32.66
$100.01-$200.00	3.56	4.66	6.94	1.34	0.56	5.51	8.87
$200.01+	0.71	1.14	4.72	0.00	0.14	0.81	0.13
Average On-Peak	$58.75	$ 74.95	$ 110.48	$61.61	$ 60.92	$ 69.49	74.31
Average Off-Peak	$36.49	$ 43.27	$ 46.96	$37.02	$ 39.27	$ 46.30	46.42
Average	$46.74	$ 57.76	$ 75.19	$48.66	$ 49.38	$ 56.27	59.62

One of the features of the Ontario marketplace described in our first report is the high reliance on imports in times of tight supply. This reliance on imports led to high uplift charges, either through Intertie Offer Guarantee (IOG) or Congestion Management Settlement Credit (CMSC) payments to importers. Those wholesale customers directly connected to the IMO-controlled grid pay the hourly uplift in addition to HOEP.[4] Table 1-4 below provides an illustration of the 'all-in' energy price (HOEP and hourly uplift) that a spot market wholesale customer faces.

[3] On-peak hours are Monday to Friday, hours 8 to 23 inclusive. Off-peak hours are all other hours Monday to Friday, all day Saturday and Sunday, and holidays.

Table 1-4: Frequency Distribution of HOEP Plus Hourly Uplift* for September 2002 to January 2003

HOEP + Uplift Price Range ($/MWh)	May – August 2002 % of hours	Sept 2002 – Jan 2003 % of hours	September % of hours	October % of hours	November % of hours	December % of hours	January % of hours
<$10	0.30	0.00	0.00	0.00	0.00	0.00	0.00
$10.01-$20.00	4.44	0.10	0.00	0.00	0.00	0.00	0.40
$20.01-$30.00	16.09	24.45	1.25	26.34	26.81	34.95	29.84
$30.01-$40.00	37.64	16.57	28.19	17.47	11.81	8.60	12.23
$40.01-$50.00	11.04	9.7`2	18.19	8.47	8.47	5.38	4.84
$50.01-$60.00	5.52	7.24	7.22	7.53	9.03	6.18	4.97
$60.01-$70.00	6.10	12.69	9.72	13.71	22.64	6.32	4.84
$70.01-$100.00	12.13	23.35	21.94	24.19	20.00	30.78	30.11
$100.01-$200.00	5.18	3.88	6.53	2.28	0.97	6.45	12.50
$200.01+	1.56	2.00	6.94	0.00	0.28	1.34	0.27
Average On-Peak	$ 66.45	$ 82.02	$ 131.45	$ 66.04	$ 64.20	$ 75.55	$ 76.92
Average Off-Peak	$ 38.18	$ 43.58	$ 49.31	$ 38.81	$ 41.41	$ 48.16	$ 48.26
Average	$ 51.20	$ 60.86	$ 85.82	$ 51.69	$ 52.04	$ 59.94	$ 61.82

* These figures are based on an average of the hourly HOEP plus hourly uplift.

6. The Supply Cushion

In our first report, the Panel introduced the notion of 'supply cushion' and demonstrated its relationship to both the HOEP and the hour ahead pre-dispatch price.[5] The supply cushion is a measure of the amount of unused energy that is available for dispatch in a particular hour. It is expressed as a percentage derived arithmetically as:

$$SC = \frac{EO - (ED + OR)}{ED + OR} x100$$

where,

EO = total amount of available energy offered

ED = total amount of energy demanded

OR = operating reserve requirements.[6]

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[4] The wholesale market charge is fixed for the segment of customers who are not directly connected.
[5] See MSP, "Monitoring Report for the First Four Months, May-August 2002", October 7, 2002, pp. 53-60.
[6] EO measures only 'available' energy offers in the sense that it does not include offered quantities from fossil units that are not running nor does it include offered quantities that are made unavailable due to an unplanned outage or derating. For the purpose of calculating the supply cushion, ED consists of the non-dispatchable load component of demand plus the quantity demanded by dispatchable load and exporters at

The supply cushion, given its focus on hourly available energy offered, is an indicator of the adequacy of supply at a point in time, specifically a particular delivery hour. The supply cushion can be calculated for both the one-hour ahead pre-dispatch market and the real-time market.[7] Furthermore, for some monitoring applications it is often instructive to modify the supply cushion so that it includes only those energy offers made available by domestic generation facilities, thereby ignoring the impact of imports and exports. One application of this 'domestic' supply cushion is that it can be used to provide an indication of the role of imports in maintaining supply adequacy in any given hour.[8] Given that supply and demand must be in balance at all times, a negative domestic supply cushion implies that imports were required to maintain this balance.

The MAU uses the supply cushion in its monitoring activities to analyze and understand events that warrant further assessment. This section summarizes how the supply cushion has evolved in the period under review in this report and uses this information to explain the abnormally high prices in September. Chapter 2 provides information on how the supply cushion has been used to help assess particular events.

The analysis of the relationship between the supply cushion and price conducted in the October 2002 MSP report revealed the following main conclusions.

- There is an inverse relationship between the clearing price (HOEP or the one-hour ahead pre-dispatch price) and the supply cushion with a smaller supply cushion implying a higher clearing price.

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a price of $2,000, the MMCP. EO, ED, and OR are each reported as hourly values calculated as the arithmetic average of the twelve five-minute values in the hour.

[7] The pre-dispatch supply cushion differs from the real-time supply cushion in the following ways. First, the pre-dispatch cushion uses forecast values for energy demand and operating reserve requirements. Second, the pre-dispatch supply cushion uses all offers from importers and those export quantities bid at a price of $2,000. The real-time supply cushion uses only the scheduled amounts of net imports. Finally, the pre-dispatch supply cushion does not reflect outages that may happen in real-time.

- As the supply cushion declines, there is more volatility in clearing prices. Generally speaking, when the cushion was below 10 percent in real-time and 20 percent in pre-dispatch, the range of prices was more widely dispersed around the statistically fitted relationship. Furthermore, the probability of a price spike (arbitrarily defined as HOEP greater than $200) increases significantly as the supply cushion declines below the 10% level in real-time (HOEP never exceeded $200 in real-time when the supply cushion was greater than 10%). This is discussed in more detail in Chapter 2.

- In many hours during the summer the domestic supply cushion was negative, highlighting the Ontario market's heavy reliance on imports during peak hours in the summer.

The relationship between the HOEP and the supply cushion is captured in the scatter diagram presented in Figure 1-5 below.[9] The first series in the diagram (dark) plots the relationship between the real-time supply cushion and the actual HOEP for the May 2002 to January 2003 period. As was done in the first MSP report, the relationship between supply cushion and price was statistically estimated and the fitted values of this relationship plotted as the second series (light). The estimating model allowed for monthly variability in the relationship and this variability was frequently statistically significant.[10] As the supply cushion declines, the fitted values branch into several curves intimating month to month shifts in the relationship between the supply cushion and the HOEP.

[8] The use of the word 'domestic' in this context means domestic to Ontario rather than domestic to Canada. The domestic supply cushion does not include imports/exports from other provinces such as Manitoba or Quebec.
[9] The data for May through August has been updated from the first report to incorporate improvements in our outage database.
[10] The statistical model presented in Figure 1-5 was an Ordinary Least Squares (OLS) regression of the natural log of the HOEP on the natural log of the supply cushion and monthly intercept and slope coefficient dummies with a correction for second order autocorrelation.

Figure 1-5: Relationship between HOEP and the Supply Cushion

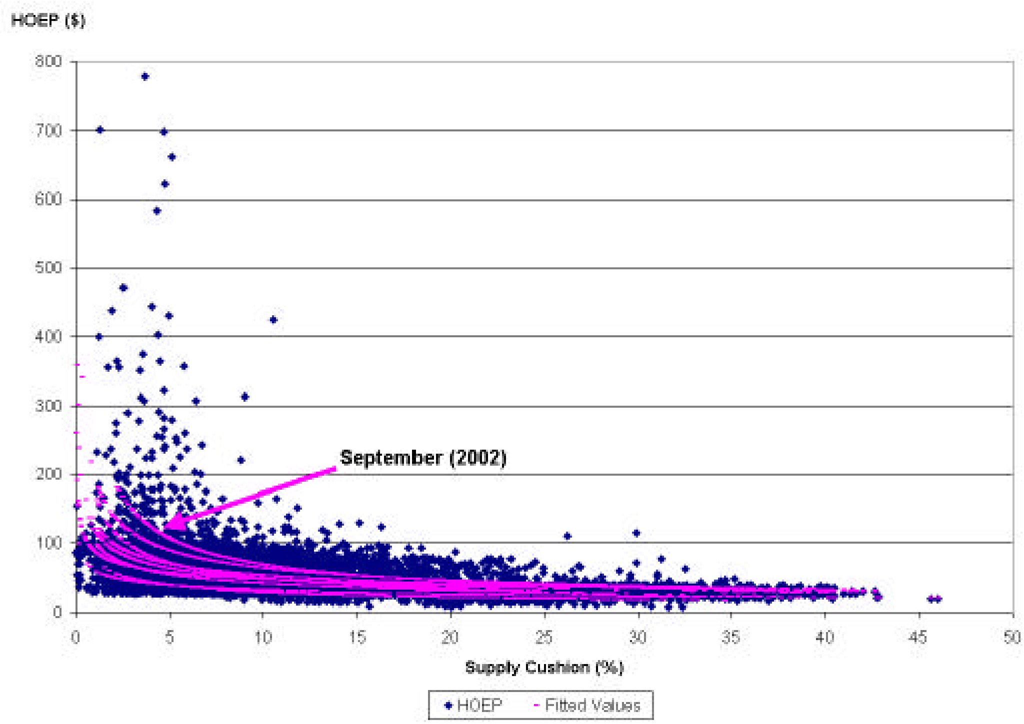


Figure 1-5 confirms the first two conclusions of our first report: (i) the inverse relationship between the HOEP and the supply cushion; and (ii) a greater degree of price volatility for supply cushions below 10% (in only one case was HOEP greater than $200 and the supply cushion greater than 10% – price was $402.70 when the supply cushion was 10.5%).

What is most striking about Figure 1-5 however is how the relationship can change from month to month. For example, the relationship shows that for a given supply cushion the HOEP was considerably higher in the month of September than in any other month. Both the intercept and slope coefficients for the month of September were significantly (statistically) larger than all other months (in Figure 1-5, September is represented by the highest branch in the fitted results). That is, when compared to any other month, in September, the statistical model predicts higher HOEP for a given supply cushion.

As suggested earlier in the report, the key factor causing the HOEP/supply cushion relationship to differ for September compared to other months was the combination of the large number of planned outages and the unusually high demands. The large number of planned outages occurred for the generation facilities that are typically lower cost, such as nuclear plants or coal-fired plants. This meant the relatively cheaper generation that was available in other months was now unavailable and hence removed from the offer curve. This generation was replaced in the offer curve by higher priced peaking hydroelectric generation, gas-fired generation or imports. Removing the relatively cheap nuclear or coal-fired generation and replacing it with higher cost generation causes the offer curve for September to be higher than it was in any other month. Furthermore, the unexpectedly higher demand meant that these higher priced offers set the price more often in September than for any other month. As a result, while the hourly supply cushions for the month of September may have been similar to other months, the upward shift in the offer curve meant that higher prices occurred.

The domestic supply cushion also provides an indication of the reliance on imports in these months. Table 1-5 provides a monthly comparison of the number of hours that the domestic supply cushion was negative for both the real-time and pre-dispatch markets. As Table 1-5 indicates, Ontario’s heavy reliance on imports continued through the fall. The domestic supply cushion was negative in more hours in September and October, the typical lower demand months of the summer/fall, than in the months of July and August. This reliance on imports in these two months is related to the unusually high demand in these months and the large number of outages.

Table 1-5: Negative Supply Cushion Events, May 2002 – January 2003

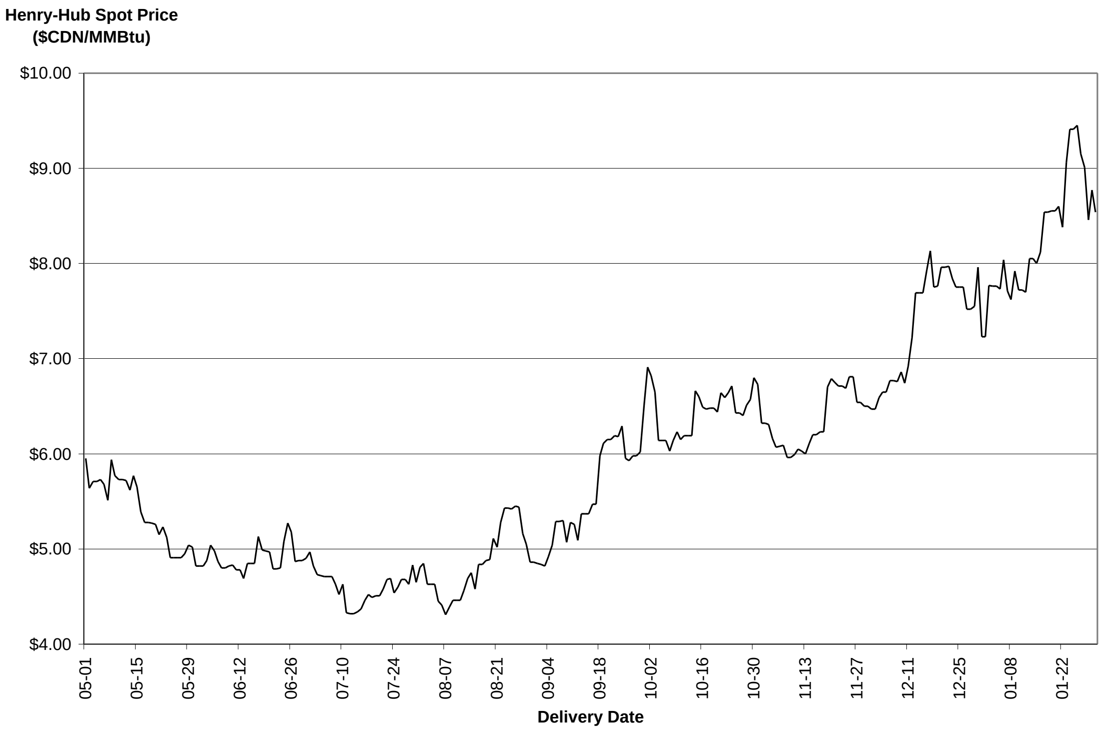
	Negative Domestic Supply Cushion (Number of Hours/% of Total Hours)			
	Real-time		Pre-dispatch	
May 2002	0	0%	7	1%
June 2002	19*	3%	114	16%
July 2002	125*	17%	168	23%
August 2002	133*	18%	174	23%
September 2002	236	33%	234	33%
October 2002	177	24%	206	28%
November 2002	106	15%	140	19%
December 2002	86	12%	138	19%
January 2003	46	6%	46	6%

*These figures differ from October report because of improvements in the outage database.

7. Effect of Natural Gas Prices on Wholesale Electricity Prices

There has been a steady increase in the spot price of natural gas since the beginning of August 2002. Figure 1-6 plots the spot price of natural gas since market opening, at one of the major reference points, Henry-Hub. Natural gas prices were roughly $6.00/MMBtu on May 1. This price declined through the spring and reached a low of $4.31 on August 7, 2002. The price steadily increased throughout the rest of the summer and through the fall and early winter. It reached its zenith for the period on January 24, 2003 at $9.41 before declining slightly to end the month at $8.54.

Figure 1-6: Daily Natural Gas Prices



Rising natural gas prices can impact the HOEP in three ways. First, the price of natural gas is the key variable cost component for natural gas-fired electricity generation facilities. Currently in Ontario, there are two natural gas-fired facilities that are five-minute dispatchable facilities (total capacity of approximately 2,200 MW or 8% of Ontario's current operating installed capacity). In a competitive market, as natural gas prices increase, the energy offer prices of gas-fired facilities should increase to reflect the increase in variable cost. This should cause higher HOEP, particularly during peak demand periods when these units are more likely to be marginal units.

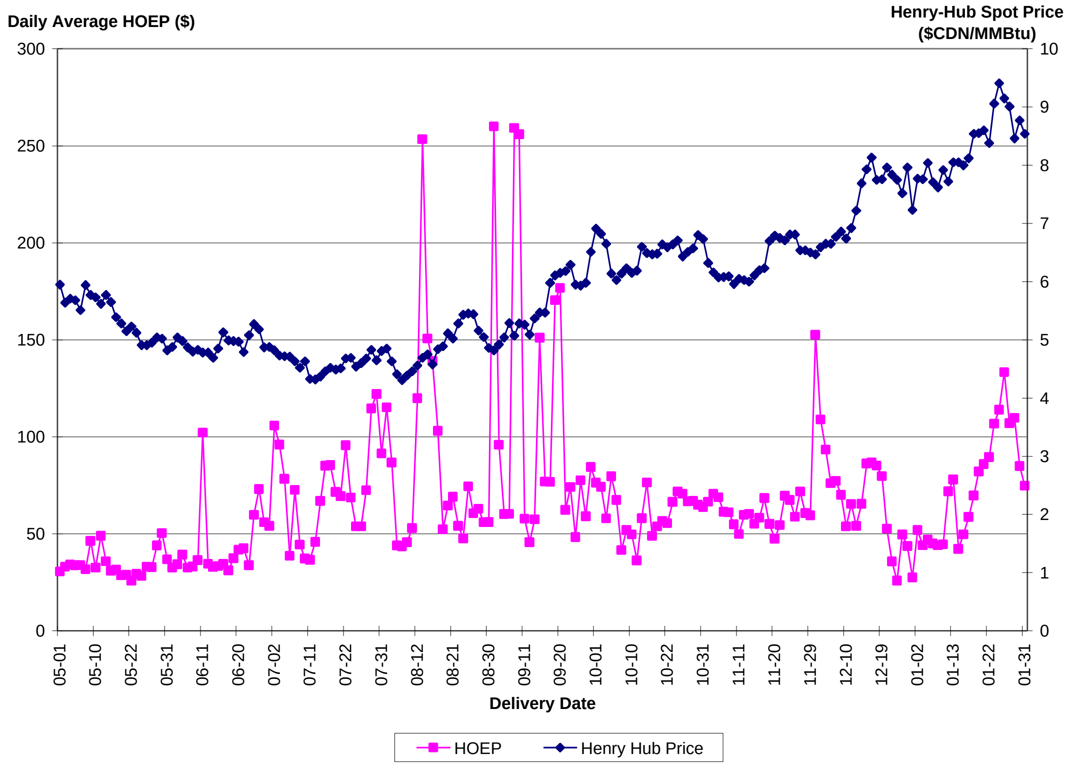
Second, increases in natural gas prices can influence the import offers into Ontario and export bids out of Ontario. Gas-fired generation accounts for approximately 40% of capacity in New York and 30% in New England. One would expect energy prices in these control areas to rise as natural gas prices rise. In periods when the Ontario price is set by relatively lower cost facilities such as coal-fired generation, the increased price in neighbouring control areas should cause fewer imports to be offered to Ontario (or offered at higher prices) and more exports to be bid to leave Ontario. Both of these responses would place upward pressure on the HOEP.

Third, many of the self-scheduling and intermittent generators (formerly known as non-utility generating facilities or NUGS) are gas-fired facilities. These facilities have long term fixed price contracts with the Ontario Electricity Financial Corporation (OEFC) to provide electricity to Ontario. Many of these generators (as an obligation of their original financing arrangements) also have secured long term fixed price gas contracts. As natural gas prices increase, at some point, it becomes more profitable for these entities to exercise options in their contracts with OEFC that allow them to sell their gas back to the spot market rather than produce electricity. When they stop producing electricity, this causes upward pressure on the HOEP. During the period May through November, gas prices did not rise to levels that caused a large number of generators to stop producing. Even in December 2002 when gas prices reached $8.00 only two NUGS reduced their electricity production.[11]

Figure 1-7 provides a comparison of the natural gas price and the daily average HOEP since market opening. While there is a distinct upward trend in the natural gas price starting in August, there does not appear to be a similar discernible trend in the HOEP over this same period.

[11] In February, gas prices increased to roughly $18 CDN/MMBtu at which time a large number of NUGs reduced their production.

Figure 1-7: Trend in Natural Gas Price and HOEP, May to January



For the May–July period, the HOEP experienced a steady increase while natural gas prices trended downwards. The HOEP then essentially levelled off over the August–December period, while natural gas prices steadily increased. By the end of December 2002 and through January 2003, both the HOEP and the natural gas price began to increase steadily.

The MAU tested several statistical models of the potential relationship between these two price series over the period May to January. However no significant relationship was found. [12] In short, the natural gas price does not appear to explain the movements in the HOEP during the period May to January.

[12] The MAU first applied Ordinary Least Squares to the first difference in HOEP and natural gas prices. This regression indicated that no statistically significant relationship existed between the HOEP and the natural gas price. Time dummy variables for both the intercept and slope coefficients were then added to the regression however no significant structural break in the relationship was detected. The MAU then ran the same regressions using the one-hour ahead pre-dispatch price instead of the HOEP. The pre-dispatch price was chosen since the influence of imports and exports are better reflected in this price than in the HOEP. No statistically significant relationship was identified. The MAU also applied the same models

There are several explanations for the absence of a statistical relationship between the HOEP and the natural gas price over the sample period. First, natural gas-fired generation facilities represent only a small portion of the Ontario supply and these units ran too infrequently to influence the HOEP. Second, even when these units were running, other factors influencing the HOEP (such as operating reserve shortages, the joint optimization of energy and operating reserve, failed transactions and other supply shocks) had more impact. The variability in the HOEP resulting from these factors masked the relatively small effects of gas prices. Gas prices increased further to $18/MMBtu in February and when the models were rerun to include data from that month, they showed a statistically significant relationship between the HOEP and the gas price for the month of February. The relationship between the natural gas price and the HOEP and the impact of natural gas prices on February prices will be explored in more detail in our next report.

8. Wholesale Electricity Prices in Neighbouring Control Areas

Three other electricity spot markets operate in the northeast United States as 'neighbours' to Ontario. Comparing hourly spot market prices in each of these areas to the HOEP in Ontario provides a useful comparison of the respective costs of energy in these control areas. Although these prices may differ because of market characteristics such as uplift, day-ahead markets, bilateral contracts, market rules and/or other specific features, the comparison is still relevant as it represents the market price of energy in a given hour.

Table 1-6 shows that the average HOEP in Ontario was very similar to that in neighbouring control areas over the first nine months since market opening. Ontario's average prices were the second highest but only $2.70 higher than those in New York at

(HOEP, HOEP plus uplift and pre-dispatch price) to peak prices and to hourly prices. In all cases no statistically significant relationship was found. The MAU then incorporated dummy variables that distinguished the hours in which a gas-fired generation facility was scheduled. No structural break in the relationship was detected. Including dummy variables to indicate the hours in which the gas-fired the zone closest to Ontario.[13] The table also shows that the Ontario average was pulled up by prices in the last five months, September to January.

Table 1-6: Average HOEP Relative to Neighbouring Control Areas

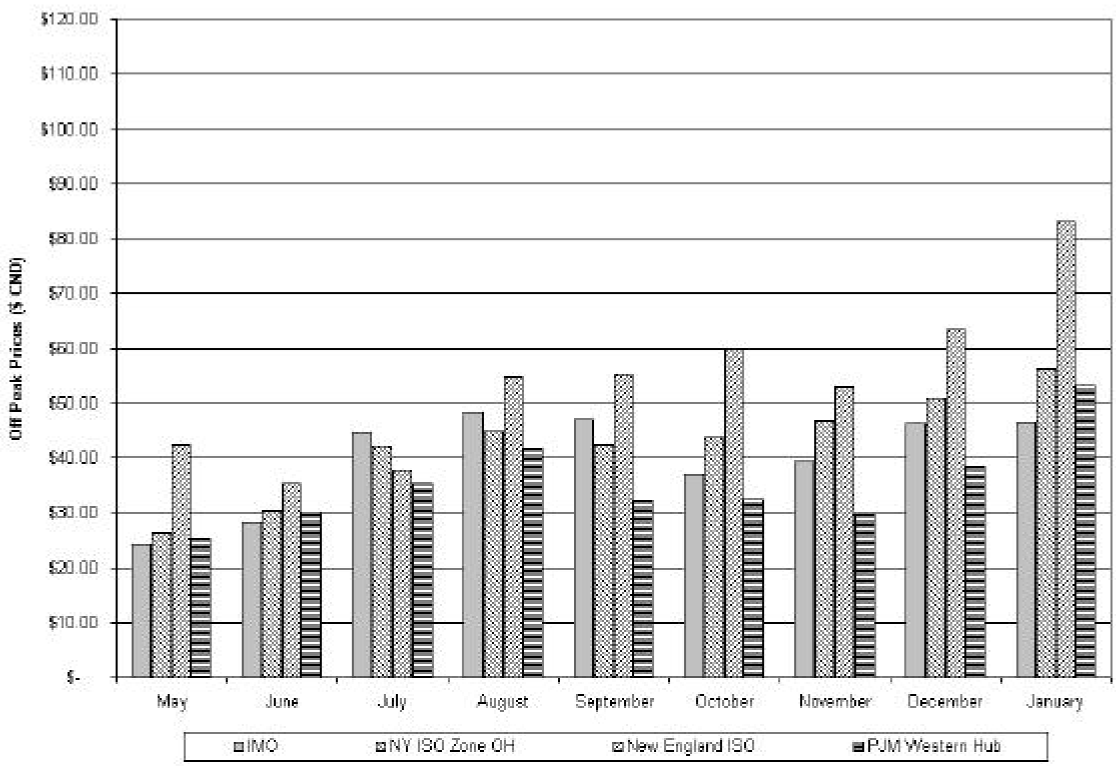
	May 2002 to January 2003 ($CDN per MWh)	May 2002 to August 2002 ($CDN per MWh)	September 2002 to January 2003 ($CDN per MWh)
IMO	52.86	46.65	57.82
NYISO Zone OH	50.16	47.86	52.00
ISO New England	59.01	53.63	63.32
PJM Western Hub	44.50	46.23	43.11

Figure 1-8 shows that Ontario off-peak prices did not differ greatly from neighbouring control areas. In only one month (July) was the average off-peak price in Ontario the highest price. In six of the nine months, Ontario posted the lowest or next to lowest average price.

generation facilities were the marginal price setting unit also failed to show a statistically significant relationship.

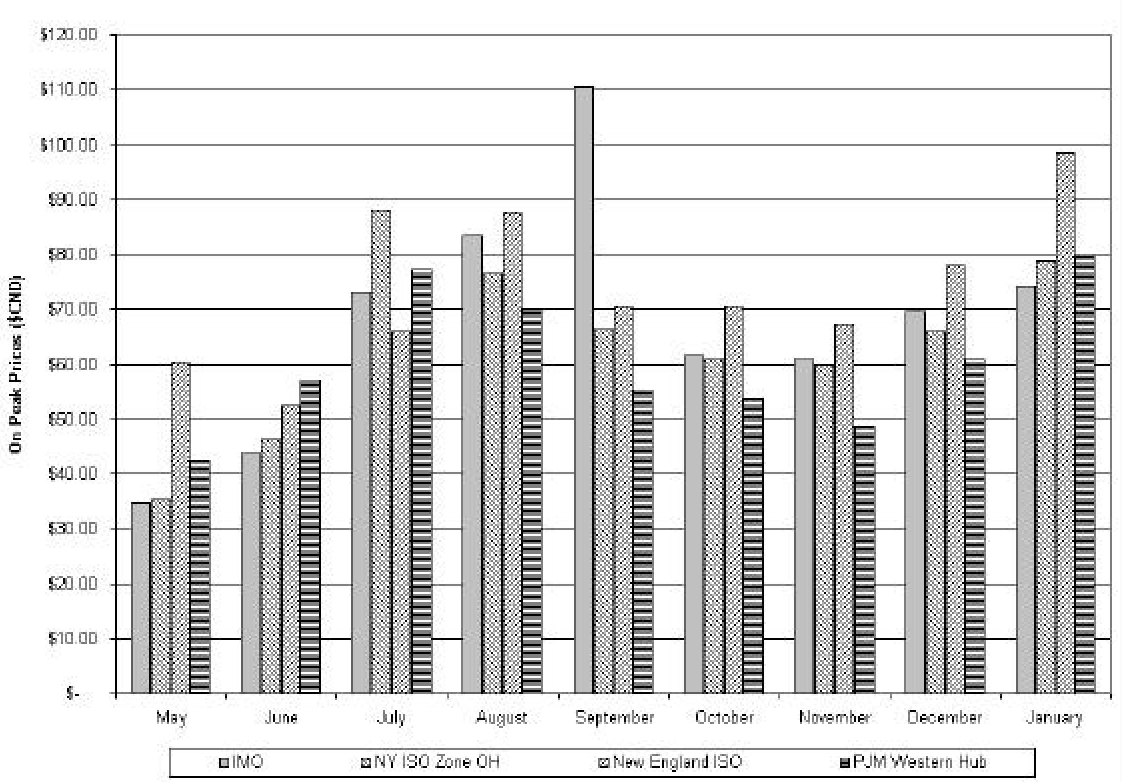
[13] Average prices in the New York City Zone were greater than the NYISO Ontario Zone.

Figure 1-8: Average HOEP Relative to Neighbouring Control Areas, Off-peak



A comparison of on-peak prices is shown in Figure 1-9. The difference between the September average price in Ontario and the prices prevailing in the other control areas was very large. For the rest of the September to January period, however, the Ontario price was more in line with prices in neighbouring markets.

Figure 1-9: Average HOEP Relative to Neighbouring Control Areas, On-peak



9. Price Setters

Another picture of market outcomes can be obtained by reviewing which facilities set price. Those who set price in pre-dispatch include injections and offtakes while in real-time only generators and dispatchable loads can set price.

Table 1-7 deals with real-time price setting facilities, i.e. domestic generation and dispatchable load. The first observation that can be made is that coal facilities continue to dominate the market in terms of price setting but there has been an increase in the frequency with which oil/gas units set price. This implies either that the offer curve is shifting to the left or that demand has been shifting outward, i.e. to the right. From section 2, we can see that demand has actually fallen from the summer highs, implying a reduction in the quantity of energy offered at a given price, i.e. a leftward shift of the offer curve.

Table 1-7: Share of Real-time MCP Set by Resource

	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan
Coal	75%	80%	70%	68%	58%	52%	47%	53%	51%
Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%
Oil/Gas	1%	5%	19%	16%	18%	29%	42%	29%	36%
Water	24%	15%	11%	16%	23%	19%	11%	18%	13%

This information was broken down to a finer level of detail of on-peak and off-peak price setters. As is expected, during off-peak periods coal-fired generation is by far the dominant price setter. During the period November 2002 through January 2003, however, there has been a marked increase in the frequency with which off-peak prices are set by oil/gas generators.

Table 1-8: Share of Real-time MCP set by Resource, Off-Peak

Fuel Type	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan
Coal	67%	81%	81%	79%	76%	75%	67%	64%	69%
Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%
Oil/Gas	0%	0%	10%	11%	10%	8%	18%	19%	21%
Water	33%	19%	9%	10%	14%	17%	15%	16%	10%

Table 1-9: Share of Real-time MCP set by Resource, On-Peak

Fuel Type	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan
Coal	86%	77%	61%	56%	35%	23%	21%	37%	30%
Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	0%
Oil/Gas	3%	12%	27%	21%	30%	57%	73%	43%	55%
Water	11%	11%	12%	23%	36%	21%	6%	20%	16%

There has always been a significant production cost difference between coal-fired and natural gas-fired plants. At differing times both of these types of plants set MCP. While the price of coal has stayed relatively flat through the period we have observed a significant price increase in natural gas.

The growth in the cost difference between these two types of price setting plants has led to the bi-modal distribution of prices observed through December and January.

With respect to on-peak hours, oil/gas units set price even more frequently. The domination of oil/gas units in setting the MCP through the fall-winter period is a result of both planned outages through the October to December period and high demands in both the on-peak and off-peak hours.

9.1 Composition of Energy Supply

The data contained in Table 1-10 provide an interesting comparison to the information in Table 1-7. One example is with regard to hydroelectric resources. Table 1-7 shows that hydroelectric resources set real-time MCP more often in September and October than in other months (except May). However, Table 1-10 shows no significant increase in the share of total generation resources in the real-time market schedule through the fall and winter months. One explanation is that the hydroelectric resources were depleted and adjusted their offers accordingly.

Table 1-10: Resources Selected in the Real-Time Market Schedule (TWh)

	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan
Injections	2%	2%	5%	8%	8%	7%	9%	9%	6%
Offtakes	1%	2%	1%	0%	1%	3%	3%	4%	5%
Fossil-Coal	16%	20%	26%	26%	25%	27%	27%	28%	30%
Fossil-Oil/Gas	5%	5%	8%	7%	6%	8%	8%	8%	7%
Hydroelectric	33%	30%	22%	19%	19%	22%	21%	20%	19%
Nuclear	45%	44%	40%	41%	43%	39%	39%	40%	43%
Injections	0.19	0.29	0.65	1.04	1.06	0.87	1.12	1.16	0.87
Offtakes	0.12	0.23	0.09	0.04	0.13	0.35	0.40	0.55	0.69
Fossil-Coal	1.88	2.45	3.62	3.53	3.10	3.33	3.42	3.75	4.28
Fossil-Oil/Gas	0.63	0.63	1.09	0.98	0.78	0.94	1.00	1.11	1.07
Hydroelectric	3.93	3.64	3.08	2.65	2.38	2.74	2.61	2.64	2.75
Nuclear	5.36	5.38	5.63	5.57	5.40	4.87	4.91	5.38	6.22
Total	11.88	12.16	13.99	13.72	12.59	12.41	12.66	13.49	14.49

*This figure differs from October report as preliminary data has been replaced by final data.

Table 1-10 shows that Ontario has been a significant net importer of energy since market opening. Tables 1-11 and 1-12 provide information on the monthly level of trade flows, by area, since market opening. Most exports flow to New York and the table clearly shows the increase in off-peak exports over the September–January period. There has also been a notable increase in imports from Michigan over this period. It appears that these flows are responsive to higher prices in New York and New England due to the heavier reliance on natural gas-fired units. Indeed, a substantial portion of the Michigan imports appears to be wheeled through Ontario en route to New York. Imports from Quebec were an important factor in the Ontario market in the July–September period, but have decreased as Quebec has increasingly utilized supply to meet winter peak demand in that province.

Table 1-11: Offtakes by Intertie Zone both On-peak and Off-peak (MWh)*

	On/Off-Peak	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan
MB	**Off-peak**	0	0	0	0	0	0	130	0	13
	On-peak	0	0	0	0	0	0	114	0	0
MI	**Off-peak**	12,227	11,334	9,216	0	0	200	250	0	1,415
	On-peak	20,264	47,370	53	0	450	3,000	0	176	8,306
MN	**Off-peak**	0	1,800	1,400	0	3,965	1,140	0	0	1,260
	On-peak	400	1,215	540	1,000	4,745	2,385	0	695	0
NY	**Off-peak**	57,106	79,837	46,353	26,694	89,543	258,720	267,209	374,664	363,451
	On-peak	20,503	87,937	30,418	15,447	13,625	50,683	68,306	119,697	253,297
PQ	**Off-peak**	9,005	4,495	624	350	13,617	26,536	41,236	41,915	37,257
	On-peak	550		0		722	5,155	22,512	16,522	22,707

*MB - Manitoba, MI - Michigan, MN - Minnesota, NY - New York, PQ - Quebec

Table 1-12: Injections by Intertie Zone both On-peak and Off-peak (MWh)*

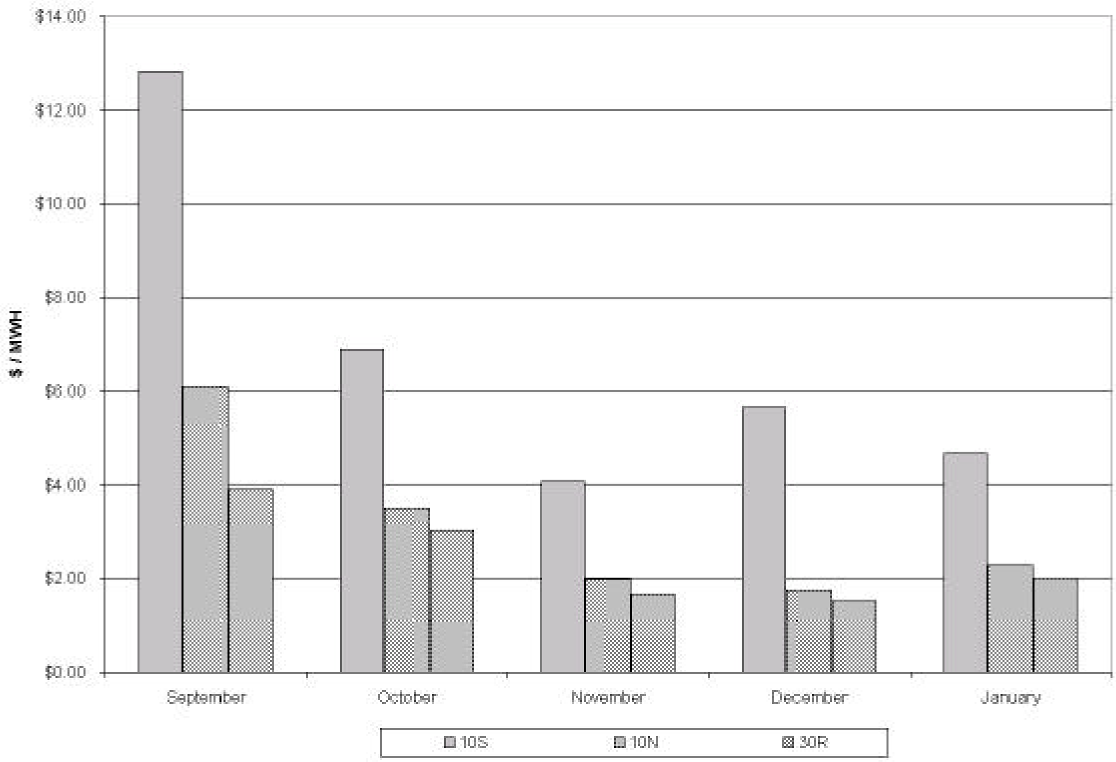
	On/Off-Peak	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan
MB	**Off-peak**	60,456	73,090	82,875	106,514	100,261	73,250	86,173	101,180	99,284
	On-peak	72,027	63,040	79,410	87,863	78,701	62,454	74,594	76,467	90,591
MI	**Off-peak**	187	4,671	35,522	208,749	257,363	260,874	406,874	450,013	298,261
	On-peak	176	5,726	96,261	244,916	243,642	274,506	372,829	358,898	273,923
MN	**Off-peak**	9,182	16,279	5,255	11,930	19,789	32,009	31,818	32,742	33,262
	On-peak	2,985	9,495	2,501	15,200	13,597	26,843	28,208	23,959	30,663
NY	**Off-peak**	348	4,044	32,733	20,312	68,481	18,954	17,638	41,925	14,896
	On-peak	1,416	8,923	88,086	95,944	205,410	101,980	98,114	74,569	25,709
PQ	**Off-peak**	6,422	28,739	59,426	94,465	12,407	1,209	105	304	640
	On-peak	37,627	72,703	171,284	154,851	56,357	22,430	2,813	2,408	3,660

* MB - Manitoba, MI - Michigan, MN - Minnesota, NY - New York, PQ - Quebec

10. The Market for Operating Reserve

Real-time operating reserve prices for the period September 2002 to January 2003 are summarized in Figure 1-10. Prices increased dramatically in the month of September to over $12 for 10 minute spinning from $6.25 in the previous month. After this rise, prices declined in October, November and December, except for 10-minute spinning reserve where prices increased again in December.

Figure 1-10: Average Hourly Operating Reserve Prices (Real-Time), September 2002 to January 2003



High average OR prices for the month of September result in part from extraordinary events on a limited number of days, as shown in Table 1-13 below, which breaks out the prices for 10-minute spinning reserve in September.

Table 1-13: Real-Time Prices for 10-Minute Spinning Reserve, September 2002

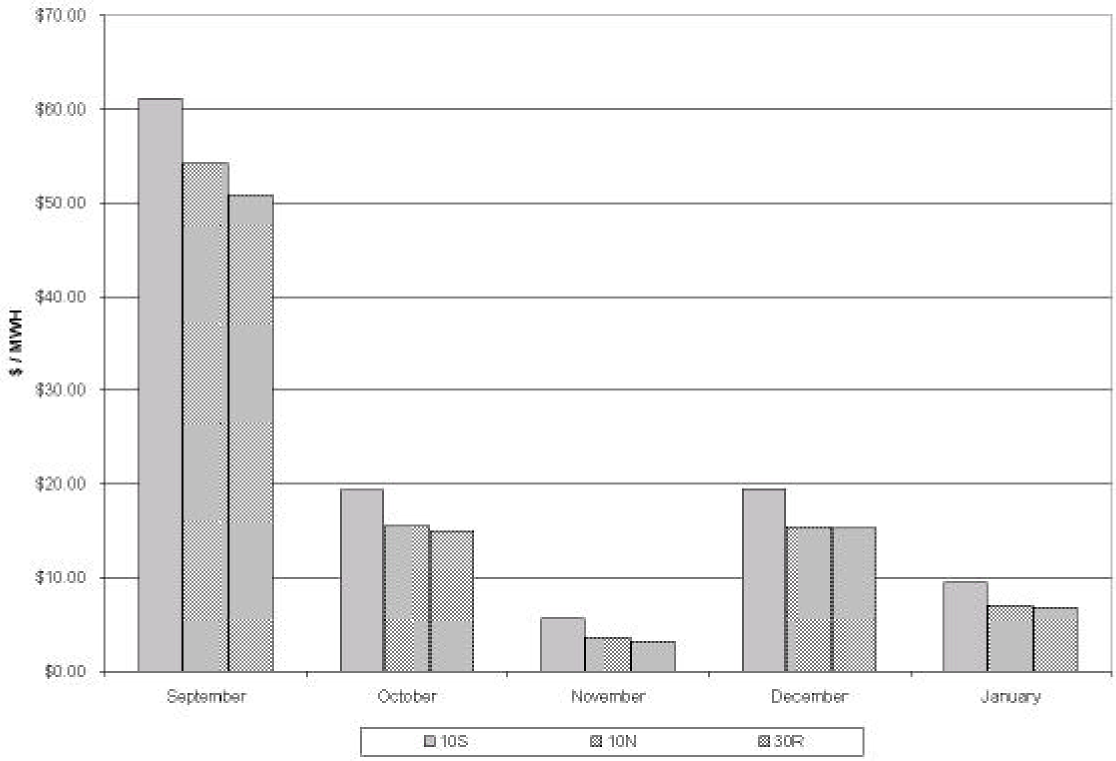
Date	Average Real-Time Price $
September 3	65.17
September 9	16.00
September 16	35.78
September 19	27.80
Balance of month (excluding 4 days noted above)	9.25
Average for month of September (including 4 days noted above)	12.80

On the four dates noted above, operating reserve shortfalls led to the operating reserve price effectively being set equal to the market clearing price for energy. Each of these events was characterized by actions taken to augment operating reserves, including combinations of voltage reductions, the purchase of emergency energy supplies and 'out-of-market' operating reserve reductions.

Pre-dispatch operating reserve prices, as shown in Figure 1-11, were much higher than real-time prices for the September to January period. In September the pre-dispatch OR price was close to $60 for 10-minute spinning operating reserve and only $13 for real-time. This was also the case in the May to August period. The discrepancy between pre-dispatch prices and real-time prices is primarily attributable to the continuing use of 'out-of-market' operating reserve actions that reduce the real-time price in times of operating reserve shortfalls.[14]

[14] The use of such actions was described in some detail in the October report of the MSP. See pp 97-101.

Figure 1-11: One-Hour Ahead Pre-dispatch OR Prices, September 2002 to January 2003



The highest pre-dispatch OR prices occurred in the month of September, where high pre-dispatch prices were not spread evenly across the month, but concentrated in three days, September 9, 10, and 20. On these high-demand days, temperatures were higher than average and OR prices were driven by energy prices. Pre-dispatch OR prices were as high as $1,556, $1,887, and $1,922 respectively for the peak hours. Under-generation advisories were issued and emergency power was purchased on all three days from New York and Michigan. In all cases, out-of-market control actions were used to supplement resources with the resultant depressing effect on real-time prices.

In December there were also three consecutive days (December 2-4) with extremely high pre-dispatch OR prices, with the highest being $1,800 for December 3. On these dates, exports to New York were recalled, emergency energy was purchased from New York, and out-of-market control actions were used to supplement resources with the resultant depressing effect on real-time prices.

11. Hourly Uplift and its Components

Hourly uplift consists of four components:

- Intertie Offer Guarantee (IOG) payments to imports,
- Congestion Management Settlement Credit (CMSC) payments to facilities constrained,
- Line losses on the transmission system, and
- Operating reserve (OR) payments.

Table 1-14 shows the monthly amounts of total hourly uplift and each of its four components since market opening.

Table 1-14: Total Hourly Uplift Charge, May 2002 – January 2003

	Total Hourly Uplift **$ Millions**	**IOG*** **$ Millions**	**CMSC** **$ Millions**	**Operating Reserve** **$ Millions**	**Losses** **$ Millions**	**Count of hours Negative RT Domestic Supply Cushion**
May 2002	18	0	4	5	9	0
June 2002	25	1	6	7	10	19
July 2002	123	67	30	5	21	125
August 2002	110	47	39	2	22	133
September 2002	163	84	48	7	25	236
October 2002	40	6	15	4	15	177
November 2002	36	2	15	3	16	104
December 2002	56	23	13	3	18	86
January 2003**	34	4	9	3	18	46
Sept-January	328	118	101	19	91	649
May-January	604	233	179	38	153	926

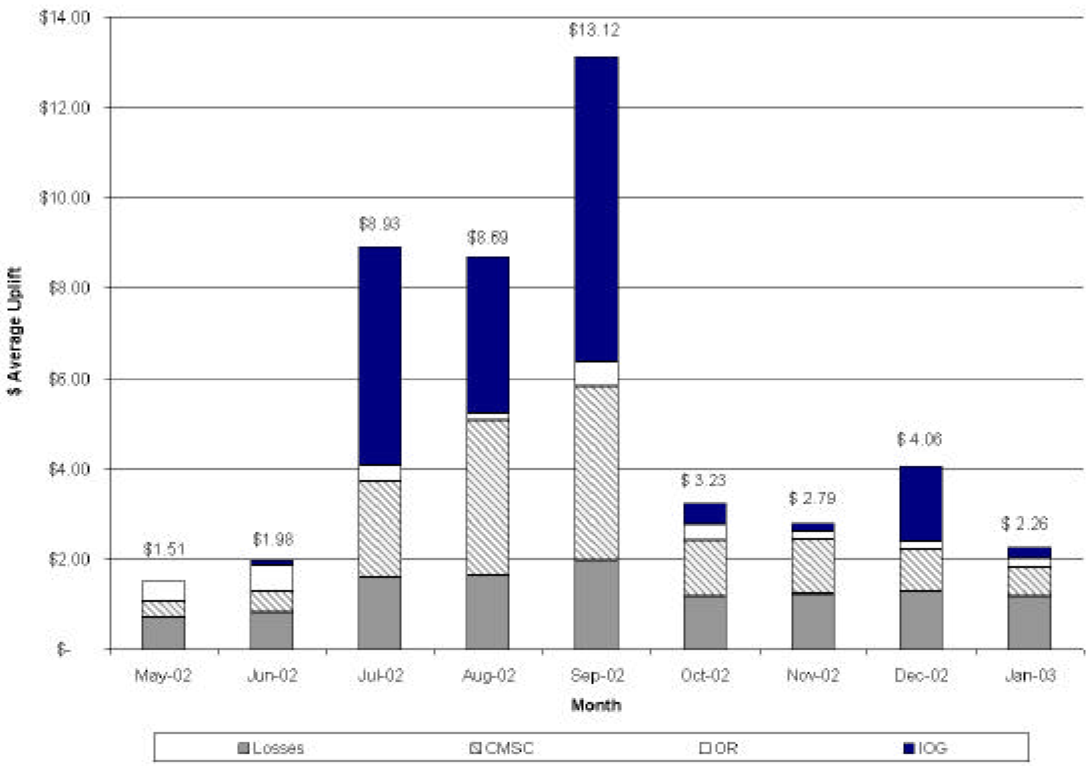
* Numbers are not net of IOG offset, which was implemented in July and totalled $3.2 Million in recoveries by the end of January 2003. See Table 1-19 and accompanying description.
**Note that due to the timing of this report, the January 2003 numbers are preliminary.

As shown in Table 1-14, the total uplift in September was far greater than that for other months since market opening. The main contributor was the IOG payment, at close to $84 million.

Figure 1-12 shows the monthly hourly uplift and its components in the form of average cost per MWh. The figure shows that in September, the total uplift per MWh was $13.12/MWh (or about 17% of average HOEP).

The amount of uplift attributable to losses is determined by the amount of energy flows through the system and the amount attributable to operating reserve is relatively minor. The following discussion focuses on CMSC and IOG payments, which together account for about 70% of total hourly uplift.

*Figure 1-12: Average Hourly Uplift by Month, by Component**



*The results in this figure do not compare exactly with Table 1-4 because the former uses a simple average and the latter a weighted average. Note, August is based on final data and consequently differs slightly from the preliminary results for August in the October 2002 Monitoring Report.

11.1 Congestion Management Settlement Credits

When a market participant's dispatch instructions require performance that differs from the participant's market schedule, the market participant receives a congestion management payment (CMSC). The bulk of the CMSC payments are related to transmission congestion but some relate to other aspects of reliability.

During the period under analysis, CMSC accounted for $101 million or over 30% of total hourly uplift payments. Table 1-15 shows the CMSC payments for energy and operating reserve, broken down by month.

Table 1-15: CMSC Payments, Energy and Operating Reserve, September 2002 to January 2003*

	Energy CMSC Payments $ Millions		Total CMSC for Energy $ Millions	Operating Reserves $ Millions	Total CMSC Payments $ Millions
Month	**Constrained Off**	**Constrained On**			
September	5	38	48	.2	48
October	7	7	15	.5	15
November	6	7	15	.1	15
December	3	10	13	.0	13
January	6	3	9	.1	9
Sept-January	28	65	100	1.0	101

*The sum of constrained on and constrained off CMSC payments does not equal the total energy figure in some months. This is due to the process for assigning the constrained on and constrained off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC figures.

The high level of constrained on payments during the last four months of 2002 is attributable to the need to constrain on high priced imports. Constrained on payments were highest during September and December. Constrained on payments for imports accounted for over 69% of the total constrained on payments in September, and 64% of the total constrained on payments in December. Table 1-16 shows the percentage breakdown of monthly constrained on payments, as between imports and domestic generation.

Table 1-16: Share of Constrained On Payments by Import and Domestic Suppliers

Month	Import (%)	Domestic (%)
May	7	93
June	49	51
July	68	32
August	83	17
September*	78	22
October	67	33
November	66	34
December	71	29
January	24	76

*Beginning in September, payments for dispatchable load and exports were included as part of constrained off payments. This will affect comparison with May to August figures where these elements were considered part of constrained on payments.

Constrained off payments over the September–January period are similar in magnitude to those reported in the May–August period. The units being constrained off tend to be facilities in bottleneck areas and there is considerable overlap between those facilities constrained off in the first four months of the market and those constrained off in the September–January period.

The distribution of CMSC payments continues to be highly concentrated as shown below in Table 1-17. Although CMSC payments have been made to over 400 internal and external facilities, the top ten facilities receiving the most constrained on payments for energy and operating reserve received 62% of the total constrained on payments.

Table 1-17: Concentration of CMSC Energy Payments, September 2002 to January 2003*

	Share of total payments received by top 10 facilities		Share of total payments received by top 5 facilities	
Month	**Constrained off (%)**	**Constrained on (%)**	**Constrained off (%)**	**Constrained on (%)**
September	47.09	71.31	34.89	61.61
October	47.87	73.12	33.98	63.13
November	43.07	77.53	25.31	63.00
December	48.42	61.27	30.17	50.06
January	67.07	43.12	58.65	26.89
Sept-January	42.65	61.67	30.89	53.45

*The CMSC figures included here are the positive CMSC payments only. See also the footnote in Table 1-16.

The main constrained off facilities tend to be those in the Northwest, due to the East West Transfer limit. The main constrained on facilities are importers.

11.2 Intertie Offer Guarantees

The IOG continues to be the largest component of the hourly uplift in this period, with IOG payments totalling more than $127 million for the September–January period. IOG payments are clustered in periods where the Ontario market is in short supply. Indeed, almost 92% of these payments were made in ten days when substantial amounts of imports were required. Table 1-18 shows these ten days in which the largest IOG payments were recorded.

Table 1-18: IOG Payments, Top 10 days, September 2002 to January 2003

Time Period	Guaranteed Imports for day (MWh)	IOG payment ($ millions)*	Average IOG payment ($/MW)	Peak Demand in 5-min interval (MW)	Number of hours (out of 24) in which real-time domestic supply cushion was negative
09/10/2002	31,856.0	32.69	1,026.11	24,941.1	12
09/20/2002	24,511.8	29.98	1,223.13	22,649.6	15
12/03/2002	18,368.4	17.53	954.50	23,430.2	16
09/09/2002	28,482.5	15.45	542.34	24,922.2	12
09/19/2002	7,475.8	4.60	615.45	22,290.8	14
10/30/2002	7,151.3	3.21	449.18	20,467.2	3
12/02/2002	7,310.1	2.59	353.93	23,158.0	15
12/04/2002	17,914.1	1.30	72.74	23,250.2	12
10/01/2002	14,301.5	0.56	39.19	21,402.1	14
10/29/2002	5,626.5	0.40	70.42	20,535.7	8
	Total top 10 days	108.31			
	Total for period	117.88			
	%	92.0			

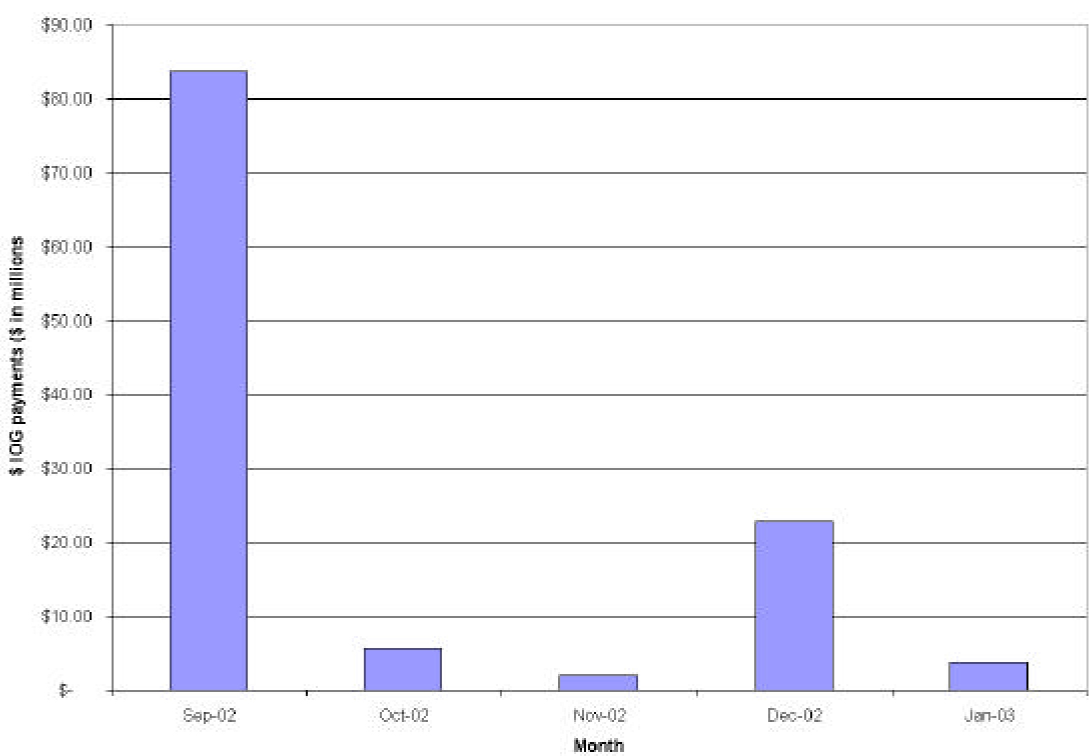
* Numbers are not netted against IOG offset. See Table 1-19 and accompanying description.

The highlighted portion in Table 1-18 above shows that three days in September and one day in December accounted for almost 81% of the total IOG paid during the period.

IOG payments are equal to the difference between the offer price of imports accepted in pre-dispatch and the corresponding market clearing price. All payments listed in Table 1-18 were in those hours where the real-time domestic supply cushion was negative. There are two implications of this. The first is that during these periods domestic supply is not sufficient to meet demand and imports are required to maintain reliability. The second is that in such situations, operating reserve shortfalls also tend to appear and to the extent that these are managed by ‘out-of-market’ control actions, the real-time market clearing price tends to be reduced relative to the pre-dispatch price. Both of these factors combine to result in large IOG payments.

Figure 1-13 illustrates how IOG payments are distributed by month. Over the September–January period, the bulk of the IOG has flowed to imports coming through New York and Michigan. This reflects the fact that those control areas had enough spare supply and capacity on the intertie, to offer into the Ontario electricity market during those times where we most needed the imports.

Figure 1-13: IOG Payments by Month



As mentioned in the first MSP report, the IMO initiated a rule change in July to eliminate any financial incentives to wheel power through Ontario. The rule allowed the IMO to recover IOG for imports where the same market participant had exports scheduled for the same hour. Table 1-19 shows the IOG recovered since the initiation of the rule change. The majority of the IOG recovered was for transactions moving from Michigan to New York via Ontario.

Table 1-19: IOG Offsets due to Implied Wheeling

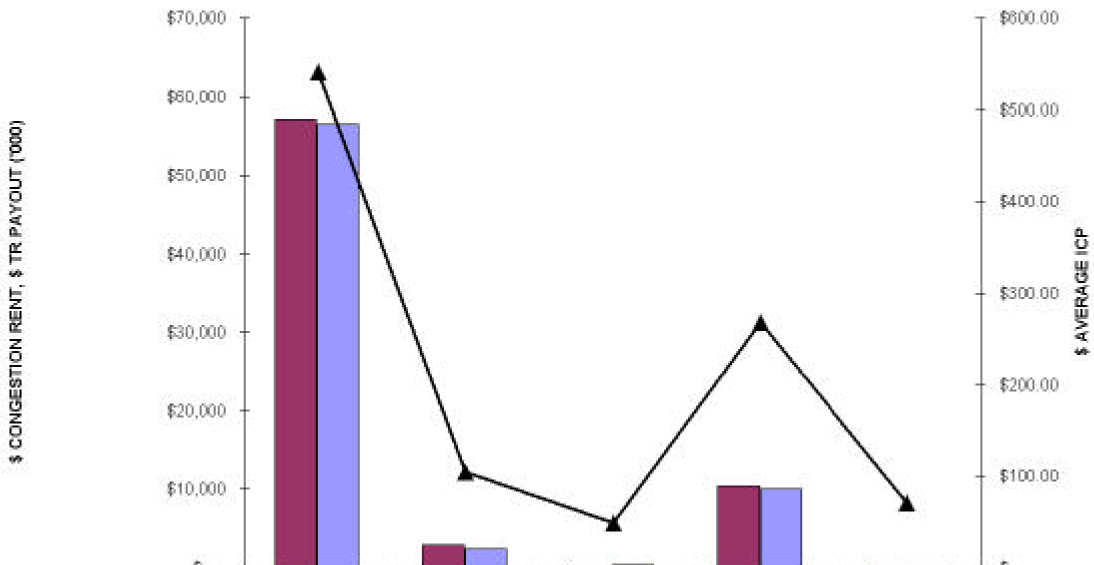
Month	IOG offset in ($'000)
July 2002	465
August 2002	745
September 2002	1,223
October 2002	27
November 2002	49
December 2002	582
January 2003	170

12. Transmission Rights[15]

When an intertie path becomes congested, the energy price of the intertie zone will differs from the Ontario zone price. A physical market trade over this intertie path will be charged this price difference or 'congestion' cost. Transmission Rights (TRs) provide a contractual right to a settlement amount that is based on this price difference. TR market participants are not required to participate in the physical market, but a physical market trader could buy a TR to hedge again the risk of congestion costs for its physical trades.

[15] In the first report, Transmission Rights were referred to as Financial Transmission Rights.

Figure 1-14: Congestion Rents, TR Payouts, and Average ICP September 2002 to January 2003 ($'000)



	02-Sep	02-Oct	02-Nov	02-Dec	03-Jan
CONGESTION RENTS (000)	$57,151	$2,886	$248	$10,483	$194
TR PAYOUTS (000)	$56,449	$2,372	$324	$10,046	$149
AVERAGE ICP	$541.21	$104.71	$48.72	$268.90	71.36
FREQUENCY	96	30	32	27	8

Figure 1-14 provides an overview of the operation of the TR market during the September–January period. It shows the magnitude of congestion rents, TR payments and the average zonal price differences (intertie congestion price or ICP). September by far had the highest payouts of the first nine months of the market and December had the second highest payout.

Chapter 2: Assessment of Market Behaviour

1. Introduction

A key responsibility of the Market Assessment Unit, under the direction of the Panel, is to continuously monitor the market for 'anomalies'. Anomalous events are outcomes that are inconsistent with expectations and that fall outside of typical patterns or norms. As indicated in our first report, the MAU's definition of anomalous events and the metrics applied to identify their occurrence are still evolving. As a matter of routine however, the MAU analyses all hours where the HOEP is greater than $200 (See subsection 2.1) and all hours where the uplift is greater than the HOEP (See subsection 2.2).

The MAU also monitors other events that appear to be anomalous, even though they may not meet these 'bright-line' price tests, and reports its findings to the Panel. Section 3 provides a discussion of three such identified events.

The MAU monitors for potential abuses of market power. As well the Panel may be requested by any person to investigate the behaviour of market participants under Chapter 3, subsection 3.4.3 of the Market Rules. During the September–January period, the MAU did not identify any potential abuse of market power. There was one request for investigation into the behaviour of a market participant. The Panel considered the request for investigation and our findings are reported in section 4 of this chapter.

2. Analysis of High Priced Hours

As noted above, the MAU regularly reviews all hours where the HOEP exceeds $200/MWh and where the hourly uplift exceeds the HOEP.

Both types of events were considered in our October report and that report identified a number of factors that explained both high HOEP and high uplift events.[16] During the September–January period, the MAU assessed similar events to determine whether they could be explained satisfactorily by the same factors that were identified in the earlier period, or whether other factors were at play.

The MAU found that the factors identified in the October report continued to be present through this reporting period and essentially explained the high HOEP events.[17] The high uplift events exhibited many of the same characteristics as those identified in the previous period, but the MAU recognized an additional factor that contributed to high uplift and this is described in subsection 2.2 below.

2.1 Hours with HOEP above $200

In the September–January period there were 42 hours where HOEP exceeded $200/MWh. These events occurred for 34 hours in September, one hour in November, six hours in December, and one hour in January. The key underlying data for these 42 events are summarized in Table A-1 in Appendix A to this chapter.

As observed in the first four months of the market, high prices are associated with a tight real-time supply cushion. In the events reviewed at that time, the squeezing of the supply cushion was caused by at least one of the following factors:

- Real-time demand was much higher than the pre-dispatch forecasts of demand.
- One or more imports failed real-time delivery.
- Real-time provision of energy by self-scheduling and intermittent generators was less than scheduled in pre-dispatch.
- One or more generating units was made unavailable in real-time as a result of a forced outage or derating. These changes in supply were not recognised in pre-dispatch.

[16] See “MSP Monitoring Report, October 2002”, pp. 70-77.
[17] Chapter 3 provides a status report on these factors.

For all of the 42 events reviewed in this report, there was a tight real-time supply cushion with at least one of the above factors present. Failed imports were a factor in 40 of the 42 events observed in the current period. Under-generation by self-scheduling and intermittent generators was comparatively frequent (25 events). There were 11 events in this period where the actual peak load for the hour exceeded the pre-dispatch demand. Forced outages occurring after the pre-dispatch sequence had solved were a contributing factor in nine of the cases. Even though under-generation of self-scheduling and intermittent generators was relatively frequent, the amount rarely exceeded 150 MW, so compared with the much larger magnitudes of failed imports, this was not as significant a factor in affecting HOEP.

2.2 Hours where the hourly uplift charge is higher than HOEP

This part of the analysis covers 17 hours in the period where the hourly uplift value exceeded the hourly energy price. The summary data for this analysis are displayed in Table A-2 in Appendix A.

In our report on the first four months of the market, the main factor associated with high uplift was high IOG. This was further assessed as being the result of three conditions:

- a large difference between the pre-dispatch price and the HOEP
- energy demand greater than domestic supply (i.e., hours when the domestic supply cushion is negative), and
- a large percentage of the imports scheduled in pre-dispatch being scheduled at a price greater than HOEP.

These conditions still hold for the 17 events analysed between September and January. An additional factor that has emerged is intertie congestion, which can contribute to increasing the amount of IOG paid.

As can be seen in Table A-2, in the 17 hours reviewed where hourly uplift exceeded HOEP, domestic supply cushions were negative and relatively large. Imports were required as well as higher-priced resources from Ontario, resulting in pre-dispatch prices of $1,100 to $2,000/MWh. In real-time, as we have often seen, the HOEP turned out to be much lower than the pre-dispatch price, ranging from $51 to $179. (Note that none of these events exhibits an HOEP price above $200, even though the uplift values themselves reach almost $300 per MWh.)

In all 17 hours there was congestion on the New York or Michigan interties, the former being congested in 16 hours and the latter congested in 5 hours. In these hours the congested zonal price pre-dispatch was much below the Ontario pre-dispatch price, by at least $825. Because the HOEP is much below the pre-dispatch price, and since the pre-dispatch zonal price was also so much lower than the Ontario pre-dispatch price, real-time zonal prices became large negative values (up to -$2,000).

Without the pre-dispatch to real-time price drop there would be no IOG, but this coupled with congestion ensures there will be IOG payments. An import which sets the zonal price or the pre-dispatch price will get the maximum IOG payment possible under the circumstances. Since during these congestion events there is a tendency for the import bid prices to be similar, the other offers will also get near maximum IOG payments. Thus, with congestion IOG payments will tend to be large.

Appendix B provides an explanation of the derivation of zonal prices and their use in the IOG calculation.

3. Analysis of Other Anomalous Events

The following events are described in some detail to provide the reader with a sense of the type of specific anomalous events that the MAU looks for and assesses. This exercise does not always result in the discovery of problems or issues that need attention. Indeed, in the three events described here explanations of anomalies were discovered that satisfactorily explained them. The process of review and explanation is essential, as it inevitably assists in increasing the understanding of the MAU and of the Panel about how the market is operating, and also serves as a filter to isolate events that do warrant further attention. The description of the events in this section is presented in order to increase the transparency of the operations of the MAU and the Panel, so that market participants can better understand our operating procedures.

3.1 Event 1: Anomalous changes in the one-hour ahead pre-dispatch prices

Anomalous event: On October 28, 2002 and continuing through October 30, the MAU began to notice substantial increases from the two-hour ahead pre-dispatch price to the one-hour ahead pre-dispatch price for several on-peak delivery hours. For example, on October 28, the two-hour ahead pre-dispatch price for delivery hour 18 (issued at approximately 3:00 p.m.) was $243.64/MWh. One hour later (approximately 4:00 p.m.) the one-hour ahead price for delivery hour 18 increased to $400, a change of $156.36. The actual HOEP for the delivery hour 18 (which runs from 5:00 p.m. to 6:00 p.m.) was only $69.18. This two-hour to one-hour price change was considerably larger than the typical price changes for this period. The average price change between the two-hour ahead and one-hour ahead pre-dispatches for delivery hour 18 typically was $2.00 for September and October with the largest change being an increase of $24.45.

To understand the unusual price change between the two pre-dispatches, the MAU examined whether there were any unusual supply or demand shocks that occurred between the running of the two-hour ahead and one-hour ahead pre-dispatches. The demand forecast between the two hours was virtually unchanged. At the same time there were no substantial outages that occurred between the two pre-dispatch runs. Finally, since the mandatory offer and bid window closed prior to the running of the two-hour ahead dispatch, the price jump could not occur as a result of changes in market participant offers or bids.

On the following day, the substantial price increase between the two-hour ahead and one-hour ahead pre-dispatches continued for delivery hours 18 through to 21. For example, for delivery hour 18, the two-hour ahead price was $350/MWh. However the one-hour ahead price more than doubled, to $728.74. The largest price change occurred for delivery hour 20 where the two-hour ahead price was $150 while the one-hour ahead price jumped to $1,500.

Once again, the MAU considered whether there were any unusual changes in supply or demand factors between the two pre-dispatches. In hour 19, there was an increase in the demand forecast from the two-hour ahead to the one-hour ahead pre-dispatch of approximately 200 MW. However, in the other hours there were no substantial changes in demand or supply between the two pre-dispatches.

On October 30, the two-hour ahead to one-hour ahead pre-dispatch price increases for hours 18, 19 and 20 were even larger. The largest price change for the period occurred for delivery hour 19 on this day where the two-hour ahead price was $350 and the one-hour ahead price was $1,999.99. The MAU examined whether there were any unusual shocks to supply or demand between the two pre-dispatches and nothing unusual was found.

Identified cause of the anomaly

The large price changes between the two-hour ahead and one-hour ahead pre-dispatches were caused by a change that had recently been made to the IMO-NYISO scheduling protocol. A few days prior to the anomalous price changes, the IMO in co-operation with the NYISO made several changes to the process for scheduling imports and exports between the Ontario-New York interconnections. The purpose of these changes was to reduce or eliminate the number of failed transactions that had been occurring over the interface. In short, new procedures were implemented that identified those transactions that were destined to fail in advance of the final one-hour ahead pre-dispatch and then remove them from the one-hour ahead pre-dispatch scheduling process.

This change was made to improve system reliability. Prior to the October protocol, when a large number of imports was scheduled in the final pre-dispatch but failed to flow in real-time, the IMO would often face a shortage of available supply to meet both energy demand and operating reserve requirements.[18] As a result, the IMO would either utilize 'out-of-market' mechanisms to offset the shortage of operating reserve offers[19] or in more extreme shortage circumstances, purchase emergency energy from a surrounding control area. In either case, the failure of the imports increased the risk that the IMO would have to implement load-shedding programs, specifically in times when the Ontario supply/ demand balance was tight and the Ontario energy demand exceeded the available capacity of domestic generation.

Under the October protocol, by removing the imports that are destined to fail from the final one-hour ahead pre-dispatch scheduling process, the IMO can instead schedule imports from other interties. This process increases the amount of available supply in real-time, and reduces the instances where the IMO runs short of operating reserve in real-time or purchases emergency energy. It also reduces the risk of possible load-shedding.

The protocol was implemented consistently in the peak hours over the three days in October to address reliability issues caused by unseasonably high demand levels and significant shortages of available Ontario generation. As the demand and supply balance improved over the next few months the protocol was used less frequently and never consistently over a span of a few days. As a result, the anomalous market outcomes of October 28 to 30 have not resurfaced.

[18] In responding to real-time supply shortages, the IMO can schedule only Ontario generation, as imports are no longer available.
[19] Under the Market Rules, when there is a shortage or expected shortage of available offers to meet both the energy demand and the operating reserve requirement in the constrained schedule, the IMO has the authority to reduce the operating reserve requirements applied in the market to the level of the reserve shortfall. They then can rely on 'out-of-market' mechanisms such as 3 percent and 5 percent voltage cuts to satisfy the industry operating reserve standards.

The following is a brief summary of the enhancements made to the scheduling protocol and a description of how these changes contributed to the anomalous price increases between the two-hour ahead and one-hour ahead pre-dispatches on October 29 to 30.

October Scheduling Protocol

There are five stages to the Ontario-New York scheduling protocol. Stages 1-4 have been essentially in place since May 2002. Stage 5 was added in October.

- Stage 1: At approximately 120 minutes before a given delivery hour, the IMO runs its two-hour ahead pre-dispatch. At this time the tentative schedules for all resources, including transactions between Ontario and the NYISO are determined. As an illustrative example, assume that 10 offers to import power from New York to Ontario were submitted to the IMO for delivery hour 19. [20] Following the running of the two-hour ahead pre-dispatch, 6 of the 10 imports were tentatively scheduled for dispatch in delivery hour 19. Of the 6 scheduled imports, 5 were scheduled for the entire amount of their offered quantities. One of the imports, (Import A), had offered 200 MW of imports for the hour but was scheduled for only 100 MW. The other 4 imports, which were offered at higher prices, were not selected for dispatch.

- Stage 2: At approximately 90 minutes before the delivery hour the IMO informs the NYISO which transactions are tentatively scheduled for dispatch on the Ontario-New York interface in the IMO market for the given delivery hour. The NYISO then filters from their Balancing Market Evaluation (BME) offers/bids to include only those corresponding bids/offers of the transactions that were tentatively scheduled by the IMO for the delivery hour. If a transaction was scheduled for only part of its offer in Ontario, the NYISO removes the unaccepted portion of the transaction's offer/bid from its BME. The filtering of these transactions from the New York BME ensures that the imports that were not accepted in Ontario in the two-hour ahead pre-dispatch will not be scheduled to flow out of New York to Ontario.

- Stage 3: At the same time, in preparation for the next pre-dispatch scheduling process, the IMO fixes the constrained schedule of the imports that were not scheduled in the two-hour ahead pre-dispatch to 0 MW. The IMO also fixes the schedules of the imports that were scheduled for part of their offered quantities to the level of the amount scheduled in the constrained schedule in the two-hour ahead pre-dispatch run. By doing this, the IMO assures that it will not schedule quantities in the constrained schedule from imports that it knows the NYISO will not schedule.[21] In our example, the IMO would fix the one-hour ahead constrained schedule for the 4 imports not accepted in the two-hour ahead pre-dispatch to 0 MW, and the constrained schedule for Import A to a maximum of 100 MW.

- Stage 4: At approximately 75 minutes before the delivery hour, the NYISO runs its final pre-dispatch (their hour ahead market or HAM). This market is run to include only those transactions that survived the BME filter. The HAM, based on least cost dispatch, determines which transactions on the Ontario–New York interface will be scheduled for dispatch out of the New York market. For our example, the NYISO would run the HAM but include only 6 of the export bids from New York to Ontario – it would not include the export bids from the 4 transactions that were not accepted in the IMO's two-hour ahead pre-dispatch. Assume that following the running of the HAM, only 4 of the 6 exports included in the BME were scheduled for dispatch out of the New York market. Three of the imports were accepted for their full offered quantities. Import A was accepted, but for only 50 MW.

[20] Note that a market participant that submits an offer in the IMO market to import electricity from New York to Ontario must submit a corresponding bid with the NYISO to export electricity from New York to Ontario.

[21] The IMO fixes the constrained schedules since these schedules affect the actual flow of energy in Ontario and hence impact more directly on system reliability. The IMO does not fix the unconstrained schedule ('market schedule') for these imports – these are considered fictitious flows for reliability purposes. As a result, depending on changes that can occur between the two-hour ahead and one-hour ahead pre-dispatch runs (i.e., an increase in demand forecast) these imports can still be scheduled in the unconstrained sequence above the levels that were fixed for their constrained sequence. In this situation, the imports will receive a constrained off payment.

- Stage 5: At approximately 60 minutes before the delivery hour, and just prior to the running of the IMO's final pre-dispatch, the NYISO contacts the IMO to inform them which transactions with Ontario are scheduled for dispatch in the upcoming delivery hour. The IMO then reviews all import offers and export bids with New York for the upcoming delivery hour to identify those offers/bids from market participants that were not identified by the NYISO as being scheduled for dispatch. These transactions, if scheduled, will fail dispatch in real-time. The IMO also reviews or considers the impacts that the failure of each of these transactions would have on system reliability. If in its discretion the IMO believes that scheduling these imports (which it knows will fail to be dispatched in real-time) will threaten system reliability, it will remove their offers/bids from the one-hour ahead pre-dispatch scheduling. This will allow the DSO to search for imports on other interties that will be more likely to be dispatched in real-time. The IMO then runs its final pre-dispatch to determine the final pre-dispatch schedules for transactions and the one-hour ahead pre-dispatch price. If the IMO discerns that the failure of these transactions will not threaten system reliability, they will leave the offers/bids in the final pre-dispatch for scheduling. Then in real-time, they will fail the transaction and replace the lost supply with supply from Ontario generation.[22] In our example, the NYISO would inform the IMO that only 4 exports out of New York are scheduled for delivery hour 19 with Import A being scheduled for only 50 MW. The IMO would then remove the offers of the two imports that were not accepted to leave New York. It would also limit Import A to an offer quantity of only 50 MW. The IMO then runs the final pre-dispatch. At this stage of the protocol, when the IMO removes the offers it does so for both the constrained and unconstrained sequences. As a result, imports removed at this stage are not eligible for a constrained on or constrained off payment.

[22] In some cases they may still have to reduce the operating reserve requirement and utilise out-of-market mechanisms to satisfy the industry reserve standards.

Impacts of the October protocol on the one-hour ahead pre-dispatch prices and schedules

The overall effect of the enhanced protocol as implemented over the three-day period, was to reduce the amount of available offers (import offers from New York) from the two-hour ahead pre-dispatch to the one-hour ahead pre-dispatch. The unsuccessful transactions were replaced by other, higher priced offers and this caused the one-hour ahead pre-dispatch price to increase substantially over the two-hour ahead price. However, those additional higher priced transactions mitigated real-time shortfalls and limited the extent to which 'out-of-market' control actions would have been used.

Response of the IMO to the anomalous event

By delivery hour 21 on October 30, the reliability impacts of potential failed transactions were reduced and the IMO therefore stopped removing failed transactions according to Stage 5 of the protocol. As the weather cooled and Ontario generation facilities began returning from planned outages, fewer reliability issues arose. Since October 30, the IMO has rarely removed transactions from the pre-dispatch in accordance with Stage 5 of the protocol and we have not experienced the large price differences between the two-hour and one-hour ahead pre-dispatch prices.

The re-emergence of reliability concerns would lead to reapplying the protocol, and this would likely lead to the re-emergence of large price changes between the two pre-dispatches. The MAU will continue to monitor pre-dispatch price movements during such periods.

3.2 Event 2: An external zonal price of -$2,000/MWh

Anomalous event: On December 3, the one-hour ahead pre-dispatch price was established at $1,800/MWh. In this hour, 5,301 MW of imports were offered at the New York zone and 5,101 MW were offered at a price below $1,800. However, the import capacity of the intertie connecting New York and Ontario was only 2,010 MW. As a result, the NY zone was import congested to Ontario and only 2,236 MW of imports (226 MW of exports for a net import amount of 2,010 MW) were scheduled for the hour. The offer price of the last MW accepted was $350/MWh (the offer price of all other import offers was less than $350/MWh). Given that the zonal price is the value of the next MW of imports from the zone, this would suggest that the New York zonal price would be $350/MWh. However, the New York zonal price was set at -$2,000/MWh.

<u>Identified cause of the anomaly</u>

Upon investigation, the IMO determined that the cause of the anomalous zonal price was a product of two factors: the one-hour ahead pre-dispatch was deficient operating reserve and the New York zone was import congested. It was also a result of the manner in which the IMO systems calculated the external zonal price. The following is a summary description of what occurred.

- The DSO ran the one-hour ahead pre-dispatch and determined that there were insufficient energy and operating reserve offers to meet the forecast total energy and operating reserve requirements of Ontario. When the DSO identifies a deficiency of offers in a sense it determines that there is no mathematical solution to the problem it is seeking to solve (i.e., to maximize the gains from trade). To deal with these scenarios, the DSO uses 'penalty' functions to set mathematical priorities within the algorithm in order to determine a viable solution. These penalties can influence the price and in this case the Ontario price was established at $6,063.71/MWh. Once the DSO has solved the price it then calculates an intertie congestion price (ICP) for any intertie that is congested. On this day it calculated the ICP for the New York Zone by subtracting the offer price of the last MW accepted from New York from the Ontario price. That is ICP = $350 - $6063.71= -$5,713.17.
- Just before market opening, there was a change to the Market Rules regarding the prices to be set in times of energy and operating reserve offer deficiencies. Initially, when the DSO determined that there was a deficiency of energy and operating reserve offers to meet the total Ontario requirements, the market clearing prices (energy and

operating reserve) would be established at MMCP ($2,000/MWh). However, the Market Rules were changed so that when the DSO identifies a deficiency, rather than set the MCP to $2,000/MWh, the DSO will make a second run. In the second run, the DSO will reduce the market requirement of operating reserve to exactly the amount of the shortage less 2 MW. For example, suppose the market demand was 20,000 MW and the total operating reserve requirement was 1,380 MW. Suppose also that when the DSO ran it determined that it only had enough energy and operating reserve offers to satisfy the market demand and 1,300 MW of operating reserve.[23] Under the new Market Rule, the DSO would run a second time but this time it would use as its requirements the 20,000 MW for energy demand but only 1,298 MW of total operating reserve (the 1,300 of offers available less 2 MW). The energy clearing prices would then be determined as usual. The operating reserve prices would be set as the higher of the energy clearing price or the highest operating reserve offer available.

- On December 3, hour 18, pursuant to the Market Rules, the DSO made a second run but with a lower operating reserve requirement. With the lower reserve requirement the new Ontario price was set at $1,800.
- Following the second DSO run the external zonal prices were recalculated. The external zonal price was now calculated by adding to the new Ontario price, the ICP that was calculated following the first DSO run. The zonal price was calculated as $1,800 +(-$5,713.17) = -$3,913.71. Given the zonal price was lower than the minimum market clearing price of -$2,000, the DSO established the zonal price at the minimum level.
- The shortcoming of the DSO in calculating the zonal price was that it did not recalculate an ICP following the second run before establishing the New York zonal price. Instead it used the initial ICP. If the DSO had calculated a new ICP based on the new Ontario price, the new ICP would have been $350 -$1,800 = -$1,450. Then when the zonal price was recalculated it would be $1,800+(-$1,450)=$350 instead of the -$3,913.71 that was actually calculated.

[23] The penalty functions are such that the DSO will run deficient of operating reserve first before running deficient of energy to meet demand.

Response of the IMO to the anomalous event

The IMO recognized that this was an anomalous outcome. In response it changed the DSO so that if a second run is required due to energy and operating reserve deficiency, a new ICP is calculated.

3.3 Event 3: Forced Outages May-August 2002

Anomalous Event: As reported in Chapter 1, the MWh on forced outage in the summer months of May to August 2002 were considerably higher than the same months in 2000 and 2001. The data on forced outages is summarized in Table 2.20 below. The MAU was asked to review this information.

Table 2-20: Forced Outages by Month for 2000 to 2002 (MWh)

	2000 (MWh)	2001 (MWh)	2002 (MWh)
January	565,715	926,706	1,324,580
February	873,919	751,243	1,075,130
March	337,759	890,951	716,838
April	638,379	717,061	725,834
May	728,722	941,415	1,366,580
June	619,675	530,547	917,177
July	239,461	523,328	1,408,662
August	682,483	431,868	1,963,218
September	863,515	1,084,871	983,684
October	734,181	1,100,612	953,372
November	936,329	1,108,561	1,208,249
December	697,528	1,893,464	1,606,536
Total	7,917,666	10,900,627	13,791,145

Identified cause of the anomaly

Two major factors were identified in explaining the high incidence of forced outages through this period.

First, an incident at the Bruce Power G6 unit in June during a planned maintenance outage caused a forced extension to the outage. This amounted to about 600 GWh during August. As a result of a request to investigate this incident, the MAU reviewed the circumstances of this outage in detail and found no evidence to warrant an investigation by the Panel.

Second, as indicated in Chapter 1, the opening of the market resulted in a change in the way in which deratings are recorded. Prior to market opening, operational deratings of hydroelectric and fossil plants due to such factors as limited water, or environmental considerations, were recorded but not in a way that allowed them to be consistently added to the forced outage information. With the opening of the market, procedures require that these events be reported to the IMO in a manner that provides a consistent and comparable data series on forced outages. The MAU reviewed in detail the filings related to all outages during this period, and also compared the detailed records for certain fossil plants over this summer period compared with previous periods to determine how significant this change in reporting practices was. It concluded that the change in reporting requirements satisfactorily explained the remaining differences.

Response to the anomalous event

Because of the importance of this issue we have asked the MAU to develop a more rigorous approach to analysing outages and testing for physical withholding in the future.

4. Investigations into the Behaviour of Market Participants

During the period under review the Panel has not initiated any investigations into the behaviour of market participants under Chapter 3, subsection 3.4.1 of the Market Rules.

In late September 2002, the Panel received a request that it conduct an investigation into the extended forced outage at Bruce Power which occurred during the summer of 2002.

The request questioned whether "those few who knew there would be a prolonged, significant operational impact would have been in a position to profit in the market, and possibly influence prices." Following the procedures set out in Chapter 3, Section 3 of the Market Rules, the Panel requested the MAU to examine all available information related to the behaviour in question to determine whether there is a reasonable prospect that inappropriate market conduct had occurred. Based on the MAU's review of the circumstances in this case, the Panel concluded that an investigation was not warranted. The reasons for the Panel's decision not to investigate in this case are available on the IMO web site (http://www.theimo.com/imoweb/marketSurveil/investigation.asp).

Appendix A: Summary Data on Anomalous Events

Table A-1: Summary Data on Hours with HOEP Greater than $200/MWh

Delivery Date	03-Sep-02	03-Sep-02	03-Sep-02	03-Sep-02	03-Sep-02	04-Sep-02	09-Sep-02	09-Sep-02	09-Sep-02	09-Sep-02	09-Sep-02	09-Sep-02	09-Sep-02	10-Sep-02	10-Sep-02	10-Sep-02	10-Sep-02	10-Sep-02	10-Sep-02	10-Sep-02	10-Sep-02
Delivery Hour	13	14	15	16	17	8	12	13	14	15	19	20	21	10	11	12	13	14	15	16	17
HOEP ($/MWh)	200.6	1028.4	889.1	584.1	365.2	424.3	256.2	252.9	260.8	290.5	621.9	661.2	801.4	220.2	243.4	443.8	777.3	307.2	351.1	402.6	312.8
Hourly Uplift ($/MWh)	13.9	67.3	61.0	57.5	71.1	13.1	41.1	65.4	58.7	143.1	119.5	114.6	79.7	18.4	38.0	75.6	113.6	244.3	224.0	234.0	234.8
Ont Pre-dispatch Price ($/MWh)	100	450	249	691.2	249	59	271	691.2	1844.9	1200	1000	1844.8	1000.8	517.6	525	693.8	1199	1700	1700	2000	1975
Pre-dispatch Demand (MW)	22,446	22,186	22,538	22,765	22,956	18,673	24,419	24,763	24,974	25,035	24,665	24,349	24,148	23,657	24,310	24,219	24,713	25,046	25,312	25,728	25,502
Average Actual Demand (MW)	22,249	22,409	22,448	22,664	22,606	18,606	23,525	23,930	24,222	24,505	23,715	23,892	22,652	22,271	22,985	23,578	23,876	24,097	24,431	24,634	24,283
Actual Peak Demand (MW)	22,466	22,625	22,664	22,849	22,852	19,218	24,015	24,464	24,544	24,854	24,224	24,265	23,943	22,769	23,412	23,887	24,113	24,378	24,941	24,831	24,596
Failed Imports (MW)	463	200	600	425	800	0	472	708	529	561	805	1108	1460	192	350	217	500	147	475	1175	847
Failed Exports (MW)	0	0	0	0	0	0	150	0	150	150	150	150	150	0	0	0	200	200	0	400	400
Self Schedule Under-generating (MW)	122	-78	114	147	198	69	145	152	152	120	123	125	122	93	109	107	126	113	87	120	106
Pre-dispatch Supply Cushion (%)	4.9%	8.2%	8.2%	8.3%	7.6%	19.9%	7.1%	5.6%	5.5%	5.1%	7.6%	9.3%	10.6%	8.0%	7.3%	8.5%	8.1%	6.6%	6.2%	5.4%	5.9%
Real-Time Supply Cushion (%)	6.7%	3.8%	4.3%	4.3%	4.5%	10.5%	4.3%	5.4%	5.8%	4.4%	4.7%	5.1%	3.3%	8.8%	6.7%	4.1%	3.7%	6.4%	3.4%	4.4%	9.0%
Forced Outages (MW)	0	78	21	64	0	0	126	1	68	87	0	0	0	0	90	175	173	32	190	15	0
Known Outages In Pre-Dispatch (MW)	4911	4758	4829	4850	4914	5578	4011	4137	4138	4213	4422	4422	4422	4045	3757	3839	4014	4187	4219	4398	4398
Summary of Factors Present*	D,F,S	D,F,O	D,F,S	D,F,S,O	F,S	D,S	F,S,O	F,S	F,S	F,S,O	F,S	F,S	F,S	F,S	F,S	F,S,O	F,S,O	F,S	F,S,O	F,S	F,S

* D = Demand in real-time much higher; F = Failed import; S = Self-scheduling and intermittent generator provision lower; O = Forced outage or derating.

Table A-1: Summary Data on Hours with HOEP Greater than $200/MWh (continued)

Delivery Date	10-Sep-02	16-Sep-02	16-Sep-02	16-Sep-02	16-Sep-02	19-Sep-02	19-Sep-02	19-Sep-02	19-Sep-02	19-Sep-02	20-Sep-02	20-Sep-02	24-Sep-02	18-Nov-02	02-Dec-02	02-Dec-02	02-Dec-02	02-Dec-02	03-Dec-02	04-Dec-02	27-Jan-03
Delivery Hour	20	13	15	16	17	11	14	15	16	19	11	13	9	19	18	20	21	22	10	18	19
HOEP ($/MWh)	431.4	265.5	322.4	278.9	203.7	277.7	355.2	365.0	282.8	240.8	374.7	698.8	201.4	231.9	209.0	356.0	306.7	260.7	227.4	236.5	227.9
Hourly Uplift ($/MWh)	48.5	20.4	27.8	21.3	9.2	11.9	17.9	26.0	16.3	45.4	34.7	103.5	18.1	20.5	72.2	45.3	39.4	21.9	6.6	56.5	16.3
Ont Pre-dispatch Price ($/MWh)	350.6	108	100	114.9	95	88.6	86	89.8	87.6	500	141.7	1933.8	65	92	874	350	249	180	105.8	400	500
Pre-dispatch Demand (MW)	23,722	19,339	19,620	19,922	19,733	20,166	21,083	21,771	22,105	21,558	21,813	22,806	18,192	21,570	23,511	23,037	22,730	22,033	21,472	23,378	24,626
Average Actual Demand (MW)	22,708	18,992	19,142	19,550	19,401	20,439	21,373	21,671	22,009	21,712	21,060	21,615	18,175	20,965	22,800	22,125	21,999	21,145	20,999	22,749	24,366
Actual Peak Demand (MW)	23,831	19,249	19,524	19,865	19,731	20,781	21,649	21,924	22,291	22,097	21,624	22,265	18,361	21,432	23,158	22,487	22,543	21,746	21,300	23,250	24,570
Failed Imports (MW)	685	200	200	242	269	250	288	119	450	50	803	650	0	302	377	269	136	517	709	847	774
Failed Exports (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Self Schedule Under-generating (MW)	67	8	8	8	7	1	1	3	3	2	2	3	1	11	16	-3	18	23	58	59	100
Pre-dispatch Supply Cushion (%)	11.8%	13.2%	11.8%	10.4%	12.1%	12.2%	9.6%	6.3%	5.1%	8.1%	7.3%	8.1%	9.5%	11.8%	4.5%	4.3%	4.5%	6.7%	8.7%	8.5%	14.8%
Real-Time Supply Cushion (%)	5.0%	4.7%	4.7%	5.1%	6.4%	3.4%	2.3%	2.2%	4.7%	4.8%	3.5%	4.7%	2.3%	1.1%	5.2%	1.7%	3.6%	2.1%	-0.4%	1.9%	2.6%
Forced Outages (MW)	0	5	25	21	0	2	0	162	83	11	39	0	0	0	0	10	53	193	43	0	63
Known Outages in Pre-dispatch (MW)	4266	7316	7272	7190	7144	6370	6346	6346	6508	6707	6719	6757	7046	5644	6397	6465	6475	6528	6484	5833	2862
Summary of Factors Present*	F,S	F	F	F	F	D,F	D,F	D,F,O	D,F	D,F	F	F	D	F	F	F	F	F,S,O	F,S	F,S	F,S

* D = Demand in real-time much higher; F = Failed import; S = Self-scheduling and intermittent generator provision lower; O = Forced outage or derating

Table A-2: Summary Data on High Priced Hours with Hourly Uplift Greater than HOEP

Delivery Date	09-Sep-02	09-Sep-02	10-Sep-02	10-Sep-02	19-Sep-02	20-Sep-02	20-Sep-02	20-Sep-02	20-Sep-02	20-Sep-02	20-Sep-02	20-Sep-02	30-Oct-02	03-Dec-02	03-Dec-02	03-Dec-02	03-Dec-02
Delivery Hour	17	18	18	19	20	14	15	16	17	18	19	20	19	17	18	19	20
Ontario Pre-Dispatch Price ($/MWh)	1400	1100	1975	1975	1200	1500	2000	2000	2000	2000	2000	2000	1999.99	1500	1800	1800	1500
HOEP ($/MWh)	144.91	118.68	164.77	83.73	107.86	179.17	133.14	99.28	95.7	92.33	135.43	134.42	50.67	62.47	76.86	79.24	74.13
Price Discrepancy ($/MWh)	1255.09	981.32	1810.23	1891.27	1092.14	1320.83	1866.86	1900.72	1904.3	1907.67	1864.57	1865.58	1949.32	1437.53	1723.14	1720.76	1425.87
Domestic Supply Cushion Real-Time (%)	-9.7%	-7.2%	-5.6%	-10.9%	-12.2%	-11.1%	-10.4%	-10.6%	-10.1%	-9.5%	-12.1%	-10.1%	-1.7%	-7.3%	-9.1%	-10.8%	-10.1%
Pre-Dispatch Supply Cushion (%)	5.1%	6.2%	6.3%	7.3%	6.3%	6.9%	4.1%	5.4%	3.8%	5.9%	8.3%	9.1%	13.7%	7.6%	5.0%	5.0%	6.7%
Imports Scheduled in Pre-dispatch (unconstrained) (MW)	3870	3757	4275	3971	3702	3853	4365	3823	4377	4202	3734	3512	2355	3094	3987	3949	3692
Limited Zone (NY or Mich) Imports Scheduled in Real-time (unconstrained) (MW)	2930	2930	3000	3000	1740	1740	1740	1140	1740	1740	1740	1740	1090	2010.1	2010.1	2010	2010
Hourly Uplift ($/MWh)	218.83	165.07	225.08	289	148.53	206.6	254.86	213.24	198.4	218.64	220.67	236.5	142.32	154.47	204.15	217.15	187.1
Hourly IOG ($/MWh)	158.00	113.83	215.91	267.66	83.44	128.30	232.68	198.66	192.97	216.89	158.87	166.90	116.32	147.81	221.60	221.22	159.44
Hourly CMSC ($/MWh)	49.41	41.73	-1.19	-5.85	31.4	71.68	17.69	13.03	3.99	-6.61	50.53	56.65	20.04	2.7	-18.49	-6.17	11.77
Pre-dispatch Demand (MW)	24719	24520	24607	24145	21933	22718	22755	22406	22766	22489	22067	21858	20855	22843	23449	23192	22944
Average Demand (MW)	24565	23909	23239	23220	21700	22246	22345	21879	21589	21390	21849	21692	20060	21391	22332	22858	22512

Appendix B: Zonal Price Derivation and Use in IOG Calculations

Zonal Price Derivation and TRs

An intertie becomes congested when there are more lower-priced offers available for import than the capability of the intertie.[24] If the imports offered and selected in the pre-dispatch unconstrained run exceed the capacity of the intertie, imports are selected up to the price of the marginal unit that can flow without congesting the line. This price will be lower than the pre-dispatch price and it is established as the zonal pre-dispatch price for that intertie. The rationale for proceeding in this way is to ensure that where insufficient capacity exists to accommodate all offers, the lowest-priced offers are accepted first and all accepted offers receive the price of the marginal unit. The difference between the zonal pre-dispatch price and the pre-dispatch price is defined to be the Intertie Congestion Price (ICP). Since the zonal pre-dispatch price will typically be lower than the pre-dispatch price, the ICP will typically be a negative number. Consider an example where the zonal price is set at $150/MWh and the pre-dispatch price is $400/MWh. The ICP would be set at -$250/MWh.

In real-time, the ICP is added to the HOEP[25] to produce a real-time zonal price that is paid to all imports flowing through the congested intertie. Thus, if the HOEP equals the pre-dispatch price of $400/MWh, the real-time zonal price would be $150/MWh [$400+(-$250)] and all imports flowing over that tie would receive $150/MW. If the HOEP is lower than the pre-dispatch price, the real-time zonal price will also be lower than the pre-dispatch zonal price by an equivalent amount.

The market for transmission rights (TRs) exists to provide a financial hedge to imports against very low (and possibly even negative) zonal prices arising from congestion. Or put another way, TRs provide importers access to the Ontario price. TRs are auctioned by

[24] Exports can also congest the interties although this has not occurred in the operation of the market to date.
[25] Strictly speaking, it is added to 5-minute MCP, but for ease of exposition we use HOEP in what follows.

the IMO and the holder of TRs has the right to receive the negative value of the ICP when the transmission line is congested.

To understand how these elements of the market design work together, consider a scenario where congestion results in a zonal pre-dispatch price of $100/MWh and an Ontario pre-dispatch price of $600/MWh. The ICP would be -$500/MWh. The real-time HOEP is $200/MWh, resulting in a real-time zonal price of -$300/MWh [$200+(-$500)]. What this means is that selected imports must actually pay the IMO $300/MWh for every MWh delivered. If the importer has purchased TRs, these serve as a hedge against the negative payment since each TR pays $500 per MWh. Load in Ontario pays $200 (the HOEP is the Ontario zonal price) for each MWh supplied, including the imports under consideration. The $500/MWh used to fund the TR payments ($300/MWh paid by the importer and $200/MWh paid by load) is collected by the IMO as a congestion rent. If the importer holds TRs, it would receive $500 for each TR and pay $300 for each MWh delivered, thus receiving the Ontario HOEP of $200 (less the cost of his TRs) for each MWh delivered, notwithstanding its offer of $100. The bottom line is that where congestion occurs the imports offered at the lowest price are selected, the marginal import sets the price on the congested line, and if the HOEP is lower than the pre-dispatch price the import is paid correspondingly less. The import can hedge against differences between the HOEP and the zonal price by purchasing TRs. This will ensure that it receives the HOEP (less the cost of the TRs) and the payout on these TRs is financed through congestion rents paid by all load.

Intertie Offer Guarantee

IOG payments were introduced shortly before the market opened as a means to enhance reliability by guaranteeing imports their selected offer in the Ontario marketplace. The theory behind the IOG was that it would ensure that an import received its offer price, even if prices in real-time were lower than pre-dispatch prices and the HOEP fell below the offer price. The calculation, however, is based not upon the difference between the offer price and the HOEP, but between the offer price and zonal real-time price. Where transmission lines are not congested, the HOEP and the zonal real-time price are identical and this has no impact. Where transmission lines are congested, the zonal real-time price equals the HOEP plus the ICP. Consider the following example:

- Importer A offers at $200/MWh on a congested tie and this sets the pre-dispatch zonal price.
- The pre-dispatch price is $1,700/MWh, making the ICP -$1,500/MWh.
- The HOEP is $300/MWh, resulting in a real-time zonal price of -$1,200/MWh [$300/MWh+(-$1,500/MWh)].
- The IOG is equal to the offer price ($200/MWh) less the zonal real-time price (-$1,200/MWh), or $1,400/MWh. This equals the drop in prices between pre-dispatch and real time. (Note that $1,400/MWh represents the pre-dispatch price of $1,700/MWh less the HOEP of $300/MWh, as well as the pre-dispatch zonal price of $200/MWh less the real-time zonal price of -$1,200/MWh.)
- The flow of payments in this case is as follows:
    - The imports pay the IMO $1,200/MWh for every MWh delivered.
    - The imports receive IOG of $1,400/MWh for every MWh delivered, thus effectively receiving the offer price of $200/MWh on the congested tie.
    - If the imports have hedged by purchasing TRs, they would also receive $1,500/MWh for each TR held. If others purchase TRs, they would receive the $1,500/MWh.
    - Combining the IOG payment and the TR leaves the importer with $200/MWh (his offer price) plus $1,500/MWh (for the TR) or $1,700/MWh, which is the original pre-dispatch price.
    - The import payments of $1,200/MWh are not netted from the IOG (because they are used by the IMO to fund payments on TRs). The IOG is therefore quite large. In this example, if imports amount to 1,000 MWh, with an IOG payment of $1,400/MWh we would see total IOG payments for the hour of $1,400,000. If total demand in the hour were 20,000 MWh, the average hourly uplift attributable to IOG would be $70/MWh.

In this example had there been no congestion, the pre-dispatch zonal price would be $1,700/MWh and the real-time zonal price would equal HOEP, $300/MWh. Since the $300/MWh is larger than the import offer price of $200/MWh, there is no IOG payment. Thus in this instance it can be seen that coupled with a large pre-dispatch to real-time price drop, congestion can be a factor which increases IOG.

Chapter 3: Status Report on the Market Performance Concerns Raised in the October MSP Report

1. Introduction

Our October report identified a number of factors impeding efficient performance of the market. A key issue identified was the persistent and often large discrepancy between pre-dispatch prices and the HOEP. The report also noted the potential for a segment of the market equipped with interval meters to respond to price signals. This chapter reports progress made in reducing the discrepancy between the pre-dispatch prices and the HOEP and provides some evidence on price responsiveness of certain large customers over the May-December period.

2. Pre-dispatch Price Signals versus Real-time Price Outcomes

In our October report, we noted the persistent and often large disparity between the pre-dispatch prices and real-time prices, and identified this as a concern for at least two reasons.

First, inaccurate or unreliable pre-dispatch prices can lead to inefficient production decisions. Pre-dispatch prices are intended to provide market participants with 'advance notice' of the likely value of electricity in Ontario in an upcoming hour. Many market participants require advance notice in order to prepare their facilities for the future period.[26] Suppliers with fossil generation facilities can require anywhere from two to twelve hours lead-time to start their units and ramp toward their desired real-time production levels. Large industrial customers may require several hours' notice before cancelling shifts and shutting-down production lines. When the pre-dispatch price is an accurate and reliable forecast of the real-time price, market participants can plan their

[26] For dispatchable loads and generators, the key price signals are the 36-hour to 3-hour ahead pre-dispatch prices; within this time frame they can modify their entire bids/offers in response to the price signal. For

actions with more certainty. This certainty ensures that only those customers who value the electricity at the real-time price will be consuming it (others will have had time to make other arrangements), and the lowest cost and correct amount of supply is on-line and available. Over time, the ability of pre-dispatch prices to predict actual outcomes relatively closely is important to potential investors in signalling the integrity and credibility of the marketplace.

Second, an inaccurate pre-dispatch price can cause real-time scheduling inefficiencies. The selection of imports and exports for real-time delivery is made in the one-hour ahead pre-dispatch. The schedules of these imports and exports are fixed during the delivery hour regardless of the real-time price. If the pre-dispatch price exceeds the HOEP, too many imports (or too few exports) are chosen. Cheaper domestic facilities are dispatched off instead of the relatively higher-cost imports, and export customers who were willing to pay more for the electricity than the real-time price cannot access it for their productive uses.[27] When the one-hour ahead pre-dispatch price is an accurate reflection of the real-time price, a more efficient choice of imports and exports is made.

The MAU has updated its examination of the discrepancies between the pre-dispatch price and the HOEP for the period September 2002 through to January 2003. In short, the absolute difference between pre-dispatch prices and the HOEP has declined slightly since the issuance of the first report. However, both the absolute and percentage differences between the prices are still quantitatively and statistically significant, and the pre-dispatch prices are still persistently higher than the HOEP. Subsection 2.1 describes these findings in more detail.

Following the release of our last report, the IMO provided comments on our findings that we believe are important and should be noted in this report.

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those non-dispatchable loads that can modify their energy consumption at any time to avoid paying higher hourly prices, all pre-dispatch prices can be used as signals for revising consumption plans.

[27] Conversely, if the pre-dispatch is less than the HOEP, more expensive domestic resources will be dispatched on (when available) rather than imports and more exports will be scheduled than should be. More imports or domestic generation in pre-dispatch can provide insurance to deal with real-time contingencies that can cause potential supply shortfalls and price spikes.

First, the IMO stated that the pre-dispatch prices are not intended to be a true forecast of the real-time price. Indeed, the pre-dispatch prices are described in the Market Rules as a ‘projection’ which means they are an estimate of future possibilities based on a current trend. In contrast, a forecast is a prediction of some future event that is a result of rational study and analysis of available pertinent data.

The pre-dispatch prices provide a *projection* of the real-time price using as inputs a single forecast value for demand (the peak demand in the hour) and the offers and bids as submitted at the time of the pre-dispatch calculation. They are an estimate of the real-time price assuming the current trend for demand (as forecasted) and the availability of offers and bids. The pre-dispatch calculation does not allow for the possibility of demand forecast error. Nor does it allow for the fact that even with no error in the demand forecast for the hour, the actual demand in some or most of the five-minute intervals differs from any single valued forecast for the hour. The pre-dispatch price calculations also ignore the possibility that some offers/bids may be made unavailable as a result of outages or derates, that some imports or exports may fail to be dispatched due to seams issues on the interconnects, or that dispatchable generators and self-scheduling generators may not respond perfectly to dispatch. However, as we described in our last report and update in subsections 2.2 to 2.5 below, demand forecast error, the occurrences of outages and derates, failed transactions and imperfect dispatch are frequent. Their respective impacts on the pre-dispatch prices are also well understood. This implies that there is pertinent information about what may happen in real-time which could be incorporated in the determination of pre-dispatch prices but which is not presently being used. A true forecast of the real-time price would recognize the possibilities of these events and incorporate the likelihood of each occurring in the prediction.

The IMO also noted that the disparate treatment of imports and exports between pre-dispatch and real-time is another reason why the pre-dispatch prices do not provide a true forecast of the real-time prices. As discussed in our first report,[28] import offers and

[28] See “MSP Monitoring Report, October 2002”, Chapter 2, Appendix 2, pp 127 – 130.

export bids are allowed to establish the pre-dispatch prices. However, in real-time these offers/bids are removed from the price determination process. The manner in which the imports and exports are included in the real-time market can exaggerate the difference between the pre-dispatch price and HOEP. The impact of the different treatment of imports and exports between pre-dispatch and real-time is also well understood. If the pre-dispatch prices were to incorporate the impact of this difference in treatment, they would be a better forecast of the real-time prices.

We agree with the IMO that the pre-dispatch prices were not designed to be a true forecast of the real-time HOEP. However, we still believe that for the market to operate efficiently, it is important that participants have a reliable signal of the probable real-time price outcomes. The pre-dispatch prices as they are currently designed are generally unreliable signals of the HOEP.[29,30] In subsection 2.6 of this chapter, we discuss some of the projects initiated by the IMO that are aimed at improving the advance price signals available to market participants. We also provide suggestions for how the current pre-dispatch prices could be improved so as to provide a more reliable signal of the HOEP.

We also believe that it is our role to continue to provide market participants and the broader public with an explanation of what is causing the differences between pre-dispatch prices and the HOEP so that they can incorporate this information into their decision-making where possible. That is the purpose of this section of our report.

[29] Reasonable criteria for assessing the reliability of any short-term forecast, are that:

- on average (or in expected terms), it is equal to the actual price;
- there be acceptably small variability about the mean; and
- differences between the forecast prices and the actual prices are independent of the actual price, independent of each other and in expected terms, equal to zero.

In evaluating the reliability of the pre-dispatch prices as signals of real-time prices, the Panel does not expect that the pre-dispatch prices should meet the above criteria at all times or even the majority of times. Indeed, they should, on average, exceed the HOEP because of the use of peak demand. However, our view is that the differences, and the volatility, should both be significantly lower than they are.

[30] The pre-dispatch prices (the 36-hour ahead to the 2-hour ahead pre-dispatch prices) are good predictors of the one-hour ahead pre-dispatch price. The one-hour ahead price is the key price for importers. Importers who are selected in the one-hour ahead pre-dispatch are guaranteed through the IOG a payment based on the higher of the HOEP or their offer prices. In this regard, reliable advance signals of the HOEP are of little importance to importers.

As a second comment on our October report, the IMO suggested that because the pre-dispatch prices are determined using a forecast for the hourly peak demand, perhaps the pre-dispatch prices are a more accurate prediction of the hourly peak MCP rather than the HOEP. Since the HOEP is the price that loads pay and the HOEP is a strong reflection of the price paid to generators, we believe that it is important that advance price signals be reliable predictors of the HOEP. That being said, if the pre-dispatch price is a good predictor of the peak hourly MCP this too may be useful information to market participants. As a result, in our analysis below we compare the one-hour ahead pre-dispatch price to both the HOEP and the peak hourly MCP.[31]

2.1 Discrepancies between pre-dispatch prices and the HOEP and peak hourly MCP

Table 3-21 below presents summary statistics of the discrepancies between the pre-dispatch prices and the HOEP and between the one-hour ahead pre-dispatch price and the peak hourly MCP for the September-January period. Column 1 reproduces summary information for the first four months of the market from a similar table in the October report. The table compares both the five-hour ahead and one-hour ahead pre-dispatch prices to the HOEP. The five-hour ahead price was chosen in our first report as it represented the last price signal dispatchable market participants received before the closing of the offer/bid window.[32] The one-hour ahead price was chosen as it is essentially the price that determines the import and export schedules. This price can also influence consumption decisions of potentially price-responsive load.

[31] Peak hourly MCP is the highest 5-minute price in the hour.
[32] Since the time of our first report, the IMO has eliminated the restricted portion of the offer/bid window allowing market participants to modify their offers/bids without restriction up to two hours prior to the delivery hour. As a result, the three-hour ahead pre-dispatch price is now the last signal participants have before their final offers/bids are made. We continued to compare the five-hour ahead price for continuity with our first report. Analysis of the three-hour ahead price provides a similar picture as that for the five-hour ahead price.

Table 3-21: Measures of Difference between Pre-dispatch Prices and HOEP and Peak Hourly MCP

	May-Aug	Sept to Jan	Sept	Oct	Nov	Dec	Jan
5-hour ahead pre-dispatch price minus HOEP ($/MWh)							
Average Difference	39.61	18.53	34.44	9.27	10.22	20.42	18.33
Maximum Difference	1,932.36	1,923.14	1,907.67	1,802.42	417.57	1,923.14	1,896.42
Minimum Difference	(661.69)	(962.94)	(962.94)	(114.78)	(111.85)	(142.43)	(83.15)
Standard Deviation	195.55	144.92	241.73	70.01	23.27	142.55	81.46
Average Difference as % of HOEP	42.2	32.7	32.7	23.1	28.6	37.6	41.4
1-hour ahead pre-dispatch price minus HOEP ($/MWh)							
Average Difference	29.17	23.89	47.93	17.63	10.51	19.83	17.59
Maximum Difference	1,929.71	1,949.32	1,907.67	1,949.32	195.05	1,723.14	525.95
Minimum Difference	(661.69)	(640.13)	(640.13)	(104.99)	(139.85)	(121.62)	(80.56)
Standard Deviation	159.95	158.18	270.92	103.13	19.51	125.44	37.84
Average Difference as % of HOEP	55.05	37.58	38.28	38.72	28.63	38.88	42.17
1-hour ahead pre-dispatch price minus peak hourly MCP ($/MWh)							
Average Difference	23.78	8.29	17.69	9.43	2.14	6.55	5.75
Average Difference as % of peak hourly MCP	31.76	19.01	22.50	22.42	11.35	18.16	20.47

The data show a reduction in the average difference between both the one-hour ahead and five-hour ahead prices and the HOEP from the period covered in the first MSP report and the September 2002 to January 2003 period. The average difference for the five-hour ahead price has declined from $39.61/MWh to $18.53/MWh – a reduction of $21.08, while the average difference for the one-hour ahead price has declined by $5.28/MWh to $23.89/MWh. The average difference as a percentage of the HOEP has also declined across the two time periods. For the period September to January, the percentage difference for the one-hour ahead price (five-hour ahead price) declined from 55.1 percent to 37.5 percent (42.2 percent to 32.7 percent).

Within the current review period, September 2002 produced the largest average difference of $34.44 between the five-hour ahead price and the HOEP and an average difference of $47.93/MWh between the one-hour ahead price and the HOEP. Since market opening, September 2002 is second only to July 2002 in terms of the month with the largest average difference – the average difference in July 2002 was $108.65/MWh and $77.94/MWh respectively for the five-hour ahead and one-hour ahead prices. The month of January 2003 produced the largest percentage difference at 42.2 percent for the one-hour ahead price and 41.4 percent for the five-hour ahead price. Only the months of July and August produced larger percentage differences since market opening.

The bottom part of Table 3-21 provides summary statistics of the comparison of the one-hour ahead pre-dispatch price and the peak hourly MCP for September to January. As expected, both the average difference and percentage difference are lower when the peak hourly MCP is used instead of the HOEP as a measure of the real-time price. However, even when the peak hourly MCP is used, there is still a tendency for the one-hour ahead pre-dispatch price to 'over-forecast' the real-time price and the margin of this difference is still quantitatively significant.

In the current period of review, there is still evidence of a persistent 'over-forecast' of price in both the five-hour ahead and one-hour ahead pre-dispatch. As Table 3-21 indicates, the average difference is positive in each month. Table 3-22 provides a closer examination of this tendency for the one-hour ahead pre-dispatch price to exceed the HOEP and the peak hourly MCP, by showing the percentage of time that the differences between the one-hour ahead pre-dispatch price and the HOEP falls within one of eight defined dollar ranges.

Table 3-22: Percentage of Time Difference between One-Hour Pre-Dispatch and HOEP Peak Hourly MCP falls within Defined Range

	Sept 2002	Oct 2002	Nov 2002	Dec 2002	Jan 2003	Sept 2002-Jan 2003	May 2002-August 2003
1-hour ahead pre-dispatch price minus HOEP							
Hourly Difference	**% of Time within Range**						
Less than -$49.99	4.6	0.8	0.7	1.6	0.4	1.4	0.5
-$50 to -$19.99	3.6	0.5	0.7	7.4	2.2	2.9	1.5
-$20 to -$9.99	1.8	1.7	1.0	3.1	1.8	1.9	1.8
-$10 to -$0.01	18.2	14.3	15.7	16.3	11.3	15.2	13.0
$0 to $9.99	48.3	49.1	46.3	37.1	41.0	44.4	58
$10 to $19.99	9.5	13.0	11.2	6.9	9.0	9.9	9.8
$20 to $49.99	8.6	17.8	22.7	24.0	24.9	19.6	8.6
$50 or greater	5.4	2.8	1.7	3.6	9.4	4.7	6.8
Greater than $0	71.0	82.7	81.9	71.6	84.3	78.4	82.3
Equal to $0	0.8	0.0	0.0	0.0	0.0	0.2	0.9
Less than $0	28.2	17.3	18.1	28.4	15.7	21.4	16.8
1-hour ahead pre-dispatch price minus peak hourly MCP							
Hourly Difference	**% of Time within Range**						
Greater than $0	47.43	57.80	54.87	49.87	57.93	53.61	61.84
Equal to $0	2.64	1.34	2.37	2.02	2.82	2.24	4.54
Less than $0	49.93	40.86	42.76	48.11	39.25	44.15	33.62

As Table 3-22 indicates, in most hours since market opening the difference between the one-hour ahead and HOEP falls within the $0 to $10 dollar range. In all months since market opening, at least one third of the observed hourly price discrepancies fell in this range. What is most striking about Table 3-22 however, is the percentage of time that the one-hour ahead price exceeds the HOEP. During the period September 2002 to January 2003, the one-hour ahead price exceeded the HOEP in 78.4 percent of the hours. In the period May 2002 to August 2002 this occurred in 82.3 percent of the hours. This indicates a persistent tendency to 'over-forecast' the HOEP in the one-hour ahead pre-dispatch, consistent with expectations given the use of peak demand as the pre-dispatch demand forecast for the hour.

When the peak hourly MCP is used instead of the HOEP, the picture is improved. As the bottom part of Table 3-22 indicates, the one-hour ahead pre-dispatch price still tends to 'over-forecast' the peak hourly MCP – in both the May–August and September–January periods, the forecast difference was greater than zero in over 50 percent of the hours. However, the data indicate that the one-hour ahead pre-dispatch price is less likely to over-forecast the peak hourly MCP than it is the HOEP. There is a more even distribution of the differences, and in September the pre-dispatch price under-forecast the peak hourly MCP in more hours than it over-forecast this price.

Figure 3-15: Percentage Difference between the One-Hour Ahead Price and the HOEP and Peak Hourly MCP by Delivery Hour, September 2002 to January 2003

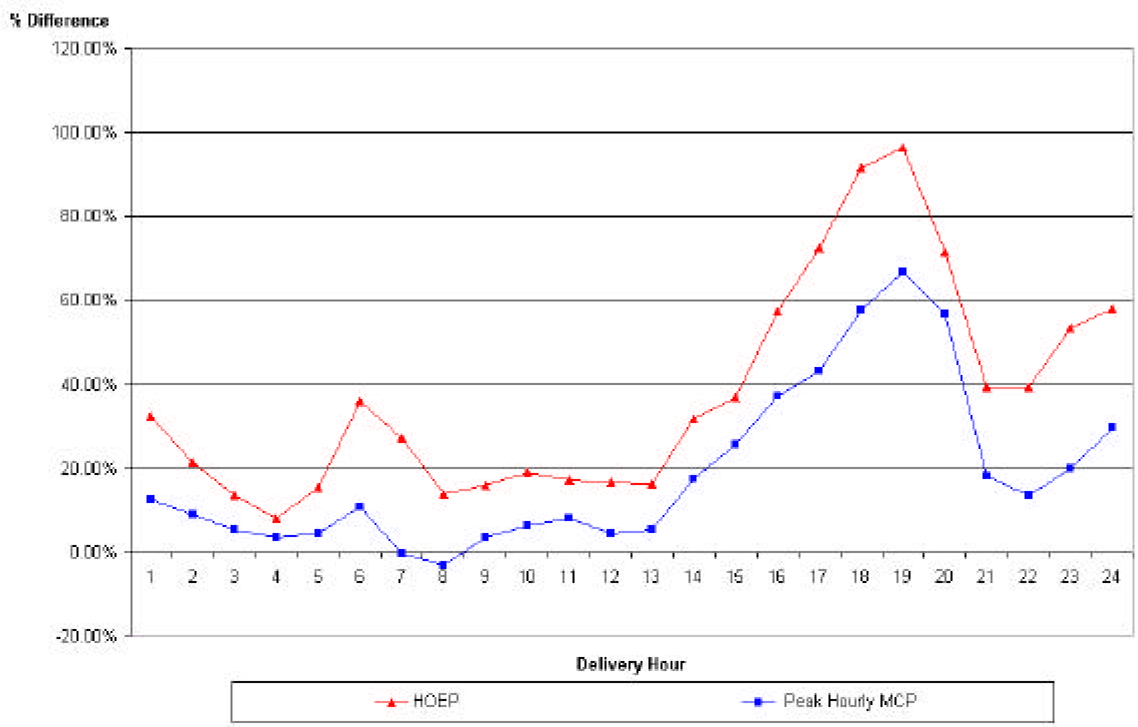


Figure 3-15 provides a further illustration of the tendency of the one-hour ahead price to exceed HOEP. Figure 3-15 plots two series: the percentage difference between the one-hour ahead price and the HOEP for each hour in the day (in triangles) and the percentage difference between the one-hour ahead price and the peak hourly MCP for each hour in the day (in squares). The time period covered for this comparison was September 2002 to January 2003. In all hours and in each time period, the percentage difference using the HOEP is greater than zero – there is an 'over-forecast'. However, the magnitude of the difference is considerably larger in certain periods of the day – generally the peak demand hours in the day. In the period September 2002 to January 2003, the peak demand hours were hours 18 and 19 when the average percentage differences between the one-hour ahead pre-dispatch price and the HOEP were the highest of all hours at 91.69 percent and 96.32 percent.

Using the peak hourly MCP, the average percentage difference is lower than the HOEP as expected. In hours 7 and 8 (the morning ramping period) the average percentage difference is minimal and in fact negative (there is an 'under-forecast'). The average percentage difference is -0.38 percent in hour 7 and -2.92 percent in hour 8.

In short, the differences between the pre-dispatch prices and the HOEP continue to be quantitatively and statistically significant, both in terms of the absolute differences and the percentage differences. Furthermore, the pre-dispatch prices continue to be a persistent overstatement of the eventual HOEP. The one-hour ahead pre-dispatch price is a better indicator of the peak hourly MCP. However both the absolute and percentage differences between these two prices are still significant.

The key factors contributing to differences between the IMO's pre-dispatch prices and the HOEP were discussed in the October report. These include:

- demand forecast error;
- the under performance of self-scheduling and intermittent generators;
- the role of imports and exports in pre-dispatch and real-time;
- out-of-market control actions in response to operating reserve shortfalls; and
- other miscellaneous factors.

An update on the impact of each of these factors since the first report is provided in the subsections below.

2.2 Demand forecast error[33]

The pre-dispatch prices are directly influenced by the IMO's demand forecast for a given dispatch hour. As discussed in the first MSP report, the IMO forecasts average Ontario demand (non-dispatchable load plus dispatchable load plus losses) for a given hour. The IMO then adjusts this hourly average demand to approximate what the peak demand will be within the delivery hour. The IMO uses this peak demand value in the DSO to determine the pre-dispatch schedules and the pre-dispatch price.[34] The accuracy of the IMO's pre-dispatch price therefore depends directly on the accuracy of its demand forecast.

The October report noted that the IMO's pre-dispatch demand forecast had contributed to the general tendency of the pre-dispatch price to overstate the HOEP. This happened in two ways. First, the practice of using the peak demand value expected within the hour in the pre-dispatch sequence as opposed to using the average demand value expected within the hour introduces a natural bias in the projection of the HOEP.[35] Second, the pre-dispatch forecast has also tended to over-forecast the peak demand value in each hour, implying that there is an upward bias in the forecast of demand. As discussed below, both of these factors continued to play a role in the tendency of the pre-dispatch price to overstate the HOEP for the period September through January.

Table 3-23 provides an update of some summary measures for the mean difference of demand since market opening. It separates the difference due to the use of peak rather than average from the general forecast error by calculating the general forecast error as the difference between the forecast for the hour and actual peak demand in the hour.

[33] The real-time demand values used in this chapter represent only the non-dispatchable load (plus losses) component of primary demand. They are calculated as the sum of the unconstrained schedules of all generation plus net imports minus dispatchable load.
[34] More specifically, the IMO inputs this forecasted value of peak primary demand into the DSO. The DSO then removes from this value an estimate of the dispatchable load component of the peak primary demand and solves for the pre-dispatch schedules (including those for dispatchable loads) and the pre-dispatch prices using only the estimate of the non-dispatchable load plus losses component of primary demand.
[35] The rationale for using peak demand was discussed in the October report, see pp. 92-94. It is also discussed below.

Table 3-23: Forecast Bias in Demand, September 2002 to January 2003

	Mean forecast difference: pre-dispatch minus average demand in the hour (MW)		Mean forecast difference: pre-dispatch minus peak demand in the hour (MW)	
	5-hour ahead	**1-hour ahead**	**5-hour ahead**	**1-hour ahead**
September 2002	384	391	112	118
October 2002	279	329	30	80
November 2002	369	372	107	112
December 2002	377	390	110	123
January 2003	383	376	122	115
Sept - January	358	371	96	109
May - August	437	417	167	148
	Mean forecast difference: pre-dispatch minus average demand divided by average demand (%)		**Mean forecast difference: pre-dispatch minus peak demand divided by peak demand (%)**	
	5-hour ahead	**1-hour ahead**	**5-hour ahead**	**1-hour ahead**
September 2002	2.36	2.33	0.73	0.70
October 2002	1.75	2.04	0.20	0.48
November 2002	2.20	2.19	0.66	0.66
December 2002	2.13	2.19	0.62	0.68
January 2003	2.01	1.97	0.64	0.59
Sept - January	2.09	2.14	0.57	0.62
May - August	2.63	2.47	1.01	0.86

The table shows that the mean forecast difference has declined since the first MSP report period, both on a MW basis and on a percentage of real-time demand basis. For example, comparing the May-August period to the September-January period, the mean difference between the five-hour ahead demand and the real-time peak demand fell by nearly half from a forecast error of 1.01% to a forecast error of only 0.57%. The mean forecast error between the one-hour ahead demand and real-time peak demand also improved to 0.62% from 0.86%. The mean difference between the pre-dispatch (five and one-hour ahead) demand and the real-time average demand also declined across the periods.

Figure 3-16: Comparison of the Mean Forecast Error to Average Hourly Load Profile

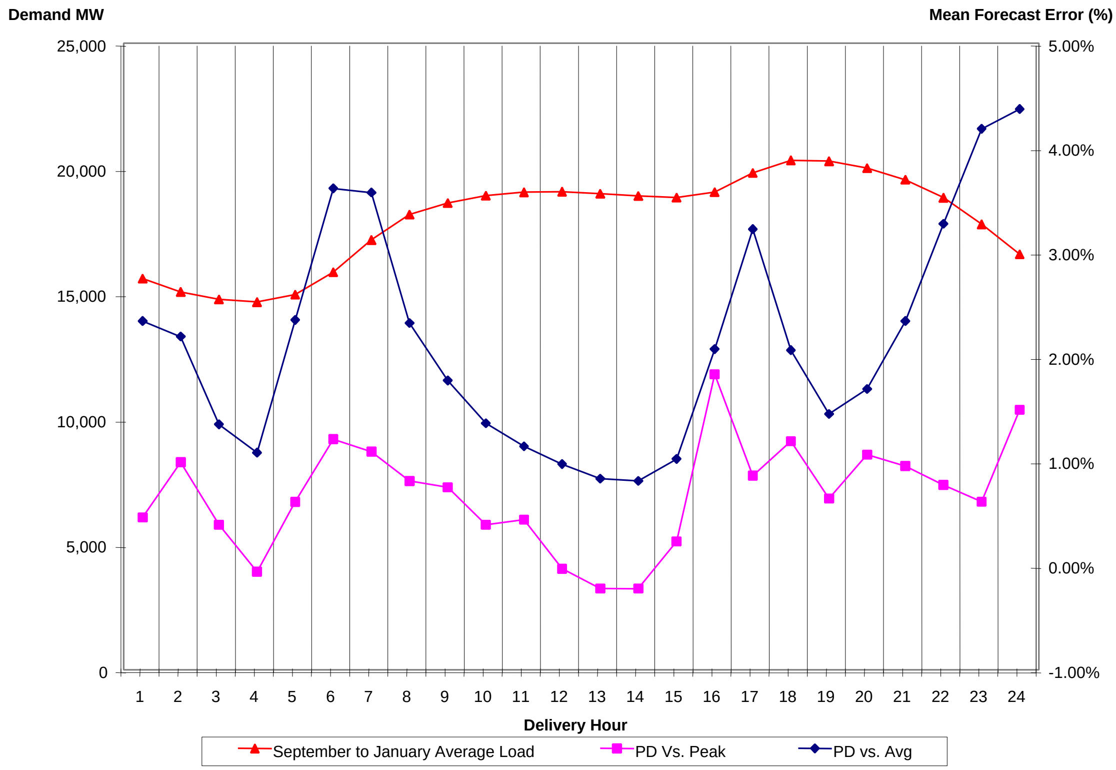


Figure 3-16 provides a slightly different picture of the mean forecast error and the role of the use of the hourly peak demand versus the hourly average demand. It depicts three series. The first series plots the average load (primary Y axis) against each of the 24 daily delivery hours. The average hourly load is calculated for the period September 2002 to January 2003. The second series plots the mean forecast difference (on the secondary Y axis) between the one-hour ahead forecast demand to real-time peak demand as a percentage of the real-time peak. The third series plots the mean forecast difference using the average real-time demand instead of the peak demand.

Figure 3-16 provides a stylized illustration of two facets of demand forecast error. First, as discussed above, the use of the hourly peak demand instead of the hourly average demand in pre-dispatch causes a natural bias towards over-forecasting the real-time demand. In all hours the mean forecast error is *necessarily* larger for the average real-time demand than for the peak real-time demand (i.e., the average real-time demand series is everywhere above the peak-real-time demand series). As a result, even if the

IMO's pre-dispatch forecast of the real-time peak demand is correct, (and with all else held constant) the real-time HOEP (the arithmetic average of the twelve 5-minute interval prices) will be lower than the pre-dispatch price as it is a function of the average real-time demand. This upward biasing of the pre-dispatch price to the HOEP is well known and accepted by the IMO. The use of the peak hourly demand is viewed by the IMO as being necessary for reliability. It provides insurance that sufficient resources have been called on-line in pre-dispatch so as to be available in real-time to meet the ramping requirements in hours of significant load growth (particularly the morning ramping hours). It also provides some insurance that sufficient resources are on-line to minimize the occurrence of operating reserve shortfalls, which are frequently caused by contingencies such as failed transactions, forced outages or the under-performance of generators. As indicated in Chapter 1, the Ontario market is frequently in a position where the domestic supply cushion is negative, indicating the need for imports.[36] In such hours, the use of peak hourly demand is necessary to schedule sufficient imports through the hour to prevent operating reserve shortages occurring in those intervals within the hour where real-time demand is greater than pre-dispatch. In other words, if average demand were used in pre-dispatch, operating reserve shortfalls would occur in every interval within the hour where actual demand was above average. This would be contrary to good utility planning practice and would result in the more frequent use of emergency control actions.

Second, the mean forecast error (using average real-time demand) is largest in those hours with rapid demand growth or rapid demand decline. These hours included hours 6, 7, 17, 23 and 24 for the period September 2002 to January 2003. These include the morning ramp up period (delivery hour 6 and 7), the early lighting period (delivery hour 17) and late evening periods when Ontario residents shutdown for the evening (delivery hour 23 and 24). The relatively large rate of change in demand in these hours results in a relatively large difference between the average demand in the hour and hourly peak demand.

[36] See Table 1-5 in Chapter 1. Imports were necessary to satisfy demand at least 12% of the time, and as much as 33% of the time, in every month from July to December.

A comparison of Figure 3-15 (hourly average price forecast error) and Figure 3-16 also provides a stylized illustration of how sensitive the price forecast is to demand forecast error in peak demand hours. Those hours in which the demand forecast error is largest (hours 6, 7, 17, 23 and 24) generally do not coincide with the hours in which the pre-dispatch to real-time percentage price difference is largest (hour 17 is the exception). Instead, the hours with the largest percentage price differences occur in the peak demand hours of the day. The percentage price difference is largest in the peak demand hours of the day because demand typically intersects the more inelastic part of the offer curve (the steep blade portion) in these hours. On this portion of the offer curve, even a small demand forecast error results in a large price forecast error. In contrast, in the off-peak periods, demand intersects the relatively elastic portion of the offer curve (the flat shaft portion). In these periods relatively large demand forecast errors result in only minor price forecast errors.

The standard for the IMO forecast error is to be within 3 percent of the actual demand value on a daily basis. As Table 3-23 indicates, the IMO was within this standard across the current review period when either the average or peak real-time demand value is used as the benchmark. Using the peak value, the highest monthly difference for the period occurred in September when the one-hour ahead price was on average only 0.70 percent higher than the real-time peak value. However, for a typical load of 20,000 MW, an error of 0.70 percent means an under-forecast of 140 MW. When the market is operating on the steep portion of the offer curve, the difference between the offer prices for a change of 140 MW of energy demanded can be anywhere from $50 to $500, and in some severe cases (such as the summer peak demand days) the difference can be $1,000 or more.[37] As a result, the accuracy of the price forecast is very sensitive to even small demand forecast errors.

[37] As we discussed in our October report (Appendix 2) the different treatment of imports and exports between pre-dispatch and real-time causes the real-time offer curve to become steeper or more inelastic. This treatment can greatly aggravate the sensitivity of the price forecast error to changes in demand forecast error.

This highlights another weakness in the design of the pre-dispatch price projection if it is interpreted as a ‘forecast’ of the HOEP. The pre-dispatch price calculation is based on a single value of demand forecast; the pre-dispatch price is essentially determined according to the intersection of the demand forecast and the offer curve. However, as one would expect, the demand forecast is never exact. Therefore, in real-time, the market will operate somewhere either to the left or right (typically to the left given the use of the peak demand as a forecast) of the initial intersection point of the forecast demand and the offer curve. When the pre-dispatch forecast is operating on the inelastic or steep portion of the offer curve, the eventual real-time price can be substantially different from the pre-dispatch price. If the pre-dispatch price were a true forecast of the HOEP, it would incorporate the likelihood of demand forecast error and the shape of the offer curve in the prediction.

Finally, in our first report we indicated that the IMO’s pre-dispatch demand forecast persistently over-forecast the hourly peak demand value. Figure 3-16 illustrates that in all hours except delivery hours 4, 13 and 14, the mean forecast error (using hourly peak) is greater than zero. The hours that had the largest mean forecast error were delivery hour 16 and 24 with a percentage forecast error of 1.83% and 1.49% respectively. Table 3-24 provides a more detailed indication of the IMO tendency to over-forecast demand. It shows the percentage of time that the mean forecast error (pre-dispatch minus the peak demand in the hour) falls within one of eight ranges. The table also indicates the percentage of time that the forecast error is greater than zero and the percentage of time it is less than zero. First, note that in 66.9% of the hours in the September-January period, the IMO over-forecast the hourly real-time peak demand. This is virtually unchanged from the May-August period when the IMO over-forecast in 66.1% of the hours. Note also that in 35% of the hours over the period September to January the over-forecast was greater than 200 MW.

Table 3-24: Percentage of Time the Mean Forecast Error (forecast to hourly peak demand) is within Defined Ranges (MW)

Month	% Time Above 500	% Time 500 to 200	% Time 200 to 100	% Time 100 to 0	% Time 0 to -100	-% Time 100 to –200	% Time - 200 to –500	% Time < -500	% Time >0	% Time <0
Sept	10.1	27.9	13.8	13.8	11.7	9.2	10.0	3.6	65.3	34.4
Oct	4.0	22.4	16.3	21.5	15.2	12.6	7.1	0.8	64.2	35.8
Nov	4.4	29.4	19.2	16.7	12.4	9.2	8.6	0.1	69.4	30.3
Dec	9.7	29.3	14.8	12.0	12.0	8.9	11.3	2.2	65.5	34.3
Jan	5.0	32.5	17.6	14.9	11.6	7.9	9.5	0.9	70.0	30.0
Sept – January	6.6	28.3	16.3	15.8	12.6	9.6	9.3	1.5	66.9	33.0
May – August	14.6	26.4	12.7	12.6	11.8	8.1	10.8	3.0	66.1	33.8

In summary, the performance of the IMO’s demand forecast is very good by industry standards. The natural bias created by using the peak hourly demand value instead of the average hourly demand value is (as expected) only a factor in the hours of rapid demand change. However, forecast error in these hours appears to be having only a minor impact on the pre-dispatch to real-time price discrepancy since in these hours, the market is on the more elastic or flatter portion of the offer curve where large differences in demand have only small price effects. On the other hand, while the IMO’s forecast error (using peak real-time demand) is small by industry standards, it is persistently an over-forecast. Given the general supply shortages of the Ontario market in peak demand hours, the market is regularly operating on or close to the steep or elastic portion of the offer curve where even small over-forecasts of demand can cause large price discrepancies between the pre-dispatch and real-time prices. As a result, demand forecast error continues to play a role in the pre-dispatch to real-time price discrepancy.

2.3 The under-performance of self-scheduling and intermittent suppliers

Another factor that contributes to the discrepancy between the pre-dispatch prices and the HOEP is the difference between the offered quantities and the delivered quantities (measured by the real-time operational meters) of self-scheduling and intermittent generators (SS generators). SS generators submit hourly offers to the IMO that specify a quantity and a ‘zero’ price (the price above which they are willing to sell all of their offered quantity). They agree that they will use best efforts to supply the specified quantity so long as the price is above their ‘zero’ price. This quantity is used to determine the pre-dispatch price. In real-time, actual delivered quantities by SS generators are estimated by telemetry readings of the facilities’ operational meters and input (with a 10-minute lag) as the unconstrained schedule for each generator. Should the offered quantities differ from the delivered quantities, there is potential for the pre-dispatch price to differ from the HOEP.

The discrepancies between offered quantities and the delivered quantities of SS generators for the September-January period are summarized in Table 3-25. The final row of the table provides a summary for the May-August period.

As Table 3-25 indicates, the average hourly discrepancy has increased since the first four months after market opening. The average difference was 76.9 MW in the September-January period, up from the 59.9 MW average difference for the May-August period. The discrepancy was particularly large in September when SS generators registered their lowest supply to the market (and highest divergence between offer and supply) since market opening. It is unclear why the discrepancy between the quantities offered and quantities actually supplied by SS generators was so large in this month.

For one hour in December, SS generators delivered 667.8 MW less than what they had offered to deliver in pre-dispatch (see Maximum Difference column). This means that the IMO had to find an additional 667.8 MW in real-time to replace the supply lost from these generators. An unexpected loss of supply of this magnitude could have serious repercussions for the reliability of the grid.

Table 3-25: Discrepancy Between SS Generators' Offered Quantities and Delivered Quantities

	Offer quantities of SS generators minus delivered quantities (MW)				
	Total MWh Offered	**Maximum Difference**	**Minimum Difference**	**Average Difference***	**% Difference**
September	695,346	305.8	-32.1	103.6	11.01
October	900,153	196.2	-86.9	59.0	4.87
November	850,818	242.4	-131.3	55.8	4.95
December	1,123,099	667.8	-317.2	96.7	6.39
January	1,188,390	575.7	-317.9	69.1	4.29
Sept - January	4,757,806	667.8	-317.9	76.9	6.3
May - August	3,343,288	350.0	-334.0	59.9	5.2

*The average monthly difference is calculated as follows. First, for each delivery hour in the month, the difference between the total MW offered by all SS generators and the total MW actually delivered by all SS generators (as measured by the operational meters) is calculated. Then, the monthly average is calculated by summing up the hourly differences and dividing by the number of hours in the month.

In all months, the average difference was positive (the delivered quantities were lower than the offered quantities). This has the effect of increasing the real-time price relative to the pre-dispatch price. The overall impact would be to make the HOEP higher relative to pre-dispatch and to offset the tendency of other factors that lead to a consistent over-estimate of the pre-dispatch price to the HOEP. However, lower delivered quantities by SS generators in real-time, along with other factors such as failed imports, cause the real-time supply to be less than what was expected in pre-dispatch. When these factors lead to a shortage of both energy supply and operating reserve in the constrained schedule, the IMO may respond by lowering the market based operating reserve requirement,[38] which has the effect of lowering the real-time price level. When the reduction in the operating reserve requirements more than compensates for the SS generator discrepancy and other real-time supply reducing factors, the real-time price can fall below the pre-dispatch price. As a result, SS generator discrepancy can indirectly contribute towards the general tendency for the pre-dispatch prices to be higher than the HOEP.

[38] As is discussed below, when the IMO lowers the reserve requirement it relies on out-of-market mechanisms such as the option to implement 3 percent and 5 percent voltage reductions in order to satisfy the industry standards for reserve holdings.

2.4 Failed Intertie Transactions

Imports and exports of electricity are important components of the Ontario market. Intertie transactions that appear in the pre-dispatch schedule but fail in real-time potentially raise reliability concerns and contribute to the disparity between real-time and pre-dispatch prices.[39] Table 3-26 shows that the average hourly failure throughout the period has been consistently high; most months have shown average hourly failures of at least 150 MW. In July, August and September the maximum hourly failure for imports reached or exceeded 1,000 MW. While the maximum hourly failure of exports has not been as high, more MWh of exports than imports failed over the period. In every month the average hourly failure of exports was larger than that for imports; on three occasions failed exports were more than double the average MWh of failed imports.

Table 3-26: Incidence and Average Magnitude of Failed Intertie Transactions

	Failed Imports into Ontario				Failed Exports from Ontario			
	Number of Incidents	Maximum Hourly Failure (MW)	Average Hourly Failure (MW)	Failure Rate (%)	Number of Incidents	Maximum Hourly Failure (MW)	Average Hourly Failure (MW)	Failure Rate (%)
May	66	220	61.3	1.9	120	400	120.2	10.7
June	154	300	60.5	3.0	275	600	144.4	14.5
July	256	1,000	167.8	6.1	339	800	247.7	49.0
August	232*	1,121	156.7*	3.4	280	900	264.9	63.1
September	317	1,460	202.6	5.7	188	500	201.6	23.0
October	284	700	176.0	5.4	332	986	192.0	15.5
November	194	711	126.8	2.2	179	800	156.3	6.6
December	253	871	150.3	3.2	219	740	222.5	8.1
January	187	774	86.9	1.8	247	650	181.2	6.1

*Figure differs from October report as preliminary data has been replaced by final data.

It is difficult to identify a particular pattern in the data on failures contained in Table 3-26, other than to note that failures of both imports and exports were particularly high in

[39] Failed imports raise the HOEP and failed exports lower the HOEP, relative to the pre-dispatch price. See pp. 127-130 of the MSP's October Report for a discussion of the distorting effect of failed transactions.

July, August and September. This is consistent with the other indicia of market outcomes for these months noted elsewhere in the report.

One interesting statistic contained in Table 3-26 is the intertie failure rate. This is a measure of the total MWh of intertie transactions that failed each month expressed as a percentage of total MWh of intertie transactions appearing in the interchange schedule for each hour of the month. The failure rate for imports is consistently lower than for exports; in July and August it was several-fold lower. This observation should be qualified by reference to the actual volume and direction of trade in those months. Table 1-10 shows imports in the order of 0.65 TWh and 1.04 TWh but exports of only 0.09 TWh and 0.04 TWh for July and August respectively. So while export failure rates were extraordinarily high the absolute volume of exports was a fraction of imported MWh. The bottom line is that significant levels of both failed exports and failed imports continue to occur in the IMO-administered market.

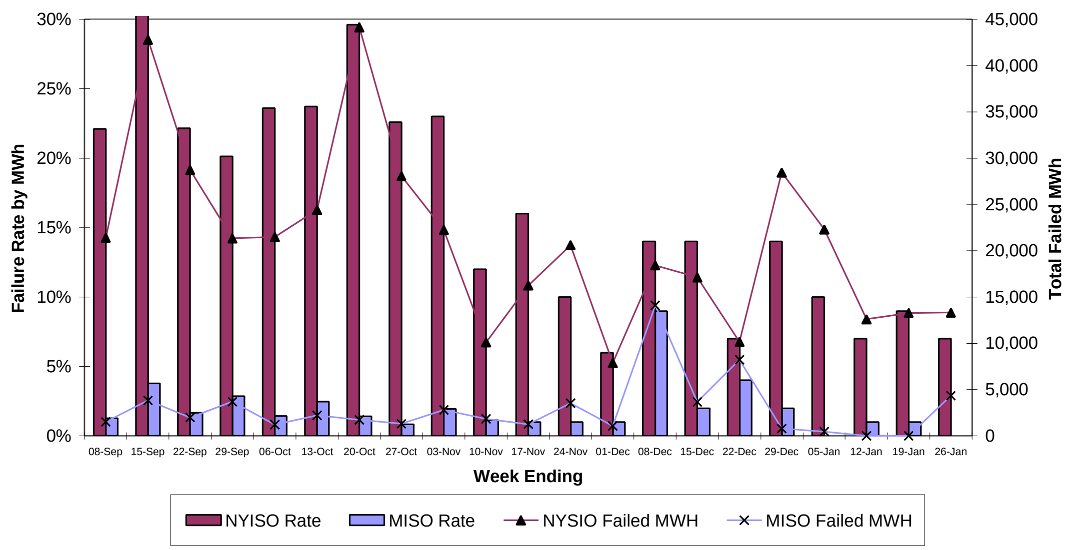
With respect to the distorting effect of intertie transaction failures on the pre-dispatch price and HOEP, recall that, other things equal, failed imports raise the HOEP and failed exports lower the HOEP, relative to the pre-dispatch price.[40] One could argue that in a general sense, import failures neutralized the price impact of export failures; however, it would be very difficult to test this proposition by measuring the countervailing impacts on an hour-by-hour basis. Also, intertie failures impose other costs and reliability concerns on the system that we identified in our October report. It is important to continue to address these failures.

All failures in intertie transactions have occurred on the interties with NYISO and the Midwest Independent System Operator (MISO). Figure 3-17 shows that failed transactions with the New York market are much more significant than MISO failures over the period since September. The New York failures are largely ‘economic’, meaning that the participant is not selected for dispatch because its bid or offer is ‘out of

[40] Recall from Chapter 2 that failed imports were a factor in 40 of 42 events when HOEP exceeded $200/MWh in the September-January period.

the money' in New York. The MISO issues do not involve the matching of the schedules of two financial markets, but relate to a number of protocol issues with surrounding control areas[41] that result in transactions failures at the IMO-MISO interface.

Figure 3-17: Weekly Failure Rates and Total Failed MWh with NYISO and MISO



Since our last report, the IMO has continued to act on two fronts to reduce failed intertie transactions. These are: 1) continued enforcement of compliance with the Market Rules and, 2) discussing measures to better align interjurisdictional trading with neighbouring systems.

Regarding the first, the IMO's Market Assessment and Compliance Division continues to pursue a number of investigations into alleged breaches of the rules related to failed intertie transactions. Where a breach is found, the rules provide for the imposition of a financial penalty that compensates for the financial impact of the lost energy (MWh failed multiplied by the greater of, the prevailing MCP, or the difference between the MCP and bid or offer price). In addition, where warranted, a multiplier can be applied to

[41] Such as PJM and American Electric Power.

this financial penalty based on an assessment of the impact of the breach on other market participants, the MCP, CMSC, financial transmission rights and hourly uplift.[42]

Over the period under review, there have been no findings that the Market Rules were breached.[43] The facts relevant to each of the alleged breaches were carefully reviewed and there has been no evidence of gaming the market. Rather, over the course of these investigations it was observed that market participants began to come to terms with their obligations under the Market Rules while coping with the complexity of navigating other markets in sequence with Ontario. The so-called 'seams' issues between Ontario and other markets can be a source, in some circumstances, of 'bona fide and legitimate' reasons why transactions fail. For example, it is important to note that the failure statistics in Figure 3-17 and Table 3-26 include failures that occur as a result of the external jurisdictions declaring a local constraint in their systems (known as Transmission Loading Relief or TLR). These failures are ordinarily accepted as outside the control of market participants attempting to arrange intertie transactions.

The second avenue being pursued by the IMO relates to these seams issues and focuses on efforts to better coordinate procedures with NYISO, MISO and other entities. With respect to New York, failures in this market involve bids or offers that are not dispatched by NYISO, either as a result of local congestion, a failure to provide an accurate NERC tag[44] for the transaction, or because the prices are too low (bids to purchase) or too high (offers to supply). The last reason, known as 'economic' failure, is the most important source of failed transactions with New York and efforts have concentrated on trying to remedy this type of failure.

In mid-November the IMO moved on a trial basis from a four-hour to a two-hour close out window that was designed in part to improve the participants' ability to manage

[42] See Market Manual 2.15: Intertie Transaction Non-Compliance Financial Penalty.
[43] One participant entered into a settlement and made a voluntary payment of $1.625 million with no admission of wrongdoing.
[44] NERC tags are a requirement by the North American Reliability Council to provide an identifier ('tag') for each interjurisdictional transaction as a means to track and ensure that there is sufficient transmission capacity.

interjurisdictional trade.[45] By shortening the time at which bids and offers had to be locked in, traders are in a better position to judge the feasibility of trading with the New York market whose window closes at 75 minutes before the hour. Figure 3-17 shows somewhat lower failure rates with the New York market after mid-November but it is not possible to determine whether the introduction of the two-hour close out window was the cause of this. Subsection 3.1 of Chapter 2 includes a description of the scheduling protocol between the IMO and the NYISO and highlights the nature of the seams issue. Discussions between the system operators are continuing with a view to developing procedures that will reduce the frequency and magnitude of intertie transaction failures.

Failures at the IMO-MISO interface can be caused by allocation of Available Transmission Capacity (ATC) by MISO. MISO follows the U. S. Federal Energy Regulatory Commission procedures and posts ATC on the OASIS[46] web site to allow transmission customers to purchase different types of transmission service such as, 'point-to-point firm' or 'point-to-point non-firm'. There is a need to improve the coordination of the release of transmission capacity on the MISO side with the transactions selected in the Ontario market for each interval. Discussions among all involved are underway to clarify issues related to NERC tags, the timelines associated with NERC tags, ramping out of control areas and other seams issues. Progress has already been made in some areas, such as the approach to losses, net scheduling and checkout procedures.

In conclusion, the level of intertie transaction failures noted in our last report is continuing but it is expected to abate over time as seams issues are addressed through enhanced protocols between Ontario and neighbouring system operators and as border entities become more responsive to the obligations placed on them through the Market Rules. Enforcement of compliance with the Market Rules is an important remedy but the ultimate solution is likely to come from further measures to address the seams problems.

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[45] The trial is to be reviewed in April 2003.

2.5 'Out-of-market' control actions

As reported in our first report, one of the key factors contributing to the discrepancy between the pre-dispatch prices and the HOEP was the IMO's use of 'out-of-market' actions in response to an operating reserve shortfall. The use of 'out-of-market' actions in the real-time market continued to contribute towards the differences between the pre-dispatch and real-time prices.[47]

The IMO integrates the 'out-of-market' measures into the market through a manual process. When the IMO observes or expects a shortage of operating reserve offers in an upcoming interval, the reserve requirement in the real-time *constrained* schedule is manually reduced to the level of market resources that have been offered into the reserve markets. The IMO focuses on the constrained schedule, as this is the schedule by which it manages reliability. The reduction permitted is up to the amount of reserve available from 'out-of-market' measures. This manual reduction in the reserve requirement has the effect of allowing the market to clear with available operating reserve offers.

This manual reduction in the reserve requirement to the level of available offers in the real-time constrained sequence is also applied equally to the real-time unconstrained sequence for the purpose of determining clearing prices for all markets. If the unconstrained sequence has the same shortage of operating reserve offers, then the manual reduction in the reserve requirement by the amount of the shortage should result in a market clearing price that reflects the shortage that exists in the constrained sequence. This 'shortage price' reflects the value of the last MW of energy available for supply in the market at the time of the shortage. The 'shortage price' would be either the highest energy offer price in the market at the time[48] or (because of joint optimization between energy and operating reserve) some combination of a lower energy offer price

[46] OASIS is the Open Access Same-time Information System that gives comparable information to all users of a transmission system to allow reservation and purchase of transmission capacity.
[47] The use of such measures and their impacts are described in some detail in the October report of the MSP. See Chapter 2, subsection 2.5.4, 'Out-of-market' control actions, pp. 97-101.
[48] The price could also be the highest dispatchable load energy bid if this is above the highest energy offer price in the market.

plus the opportunity cost of converting one MW of operating reserve to energy (where the clearing price of reserve is set by the highest reserve offer price in the market), whichever is lower. However, if the unconstrained sequence has more available offers than the constrained sequence then the DSO will not have to utilise the last MW of energy available for supply. Indeed, some of the energy supplied to the market will remain unutilised and the price will be set lower than the 'shortage price' by some lower energy offer price. In practice, due to a variety of transmission factors, this latter case is generally the normal state of operation. When the difference between the amount of operating reserve offers available between the two sequences is large (i.e., there are several MW of energy offers that are unutilised in the unconstrained sequence), the reduction in the real-time price can be considerable. When this occurs, the real-time prices will also tend to be below the pre-dispatch price.

Manual reductions in the reserve requirements are generally triggered by a number of real-time contingencies such as SS generator discrepancies, failed imports, under-performance (non-compliance) by dispatchable generators and generator or transmission line outages. Each of these factors, on its own, contributes to an increase in the real-time price relative to the pre-dispatch price. However, when these factors occur together they can collectively represent a large loss of supply in real-time and hence can trigger the use of out-of-market reserve actions to cope with reserve shortfalls. These actions overwhelm the influence of the other factors and lead to the real-time price being lower than the pre-dispatch price.

As the table below indicates, the percentage of intervals in which the IMO reduced the operating reserve requirements (and met its industry reserve requirements through 'out-of-market' mechanisms) declined moderately from the May-August period from 7.67 percent to 6.86 percent. However, the 11.7 percent figure for the month of October was the highest of all months since market opening. In short, the manual use of 'out-of-market' control actions in real-time continues to play a key role in the discrepancy between the pre-dispatch prices and HOEP.

Table 3-27: Percentage of Intervals with Operating Reserve Reductions (Unconstrained Sequence), September 2002 to January 2003

	> 0 MW	>200 MW	>400 MW	>800 MW
September	10.09	8.68	4.98	2.81
October	11.70	9.69	4.76	1.21
November	2.86	2.49	1.13	0.12
December	6.08	4.66	2.59	0.60
January	3.58	2.84	0.57	0.16
Sept - January	6.86	5.67	2.81	0.98
May - August	7.67	6.35	3.62	1.10

2.6 Concluding remarks on pre-dispatch price signals

The ineffectiveness of the IMO's pre-dispatch prices as signals for the real-time value of electricity continues to be an area of concern for the Panel. As discussed above, the pre-dispatch prices are not designed to be a true forecast of the HOEP. However, the pre-dispatch prices are currently the only advance price signal for the HOEP that is available to participants. The lack of reliable advance price signals is impeding the efficient response of market participants (particularly price responsive loads), and some have argued that it is contributing to the lack of investor confidence and thereby potentially undermining the long term efficiency of the market. The Panel urges the IMO to continue its efforts to improve the advance price signals that are publicly available to market participants.

The Panel sees three potential avenues for achieving improvements. These include:

- improving the accuracy of the existing pre-dispatch prices by correcting for some of the differences identified in this report;
- developing alternative mechanisms for providing price signals such as introducing a day-ahead market; and
- providing market participants with more information regarding the key factors affecting the real-time prices so that participants, on their own can better forecast

real-time prices.

The IMO has initiated a number of projects along all three of these avenues. These initiatives are discussed below.

(i) Improving the accuracy of the existing pre-dispatch prices by correcting for some of the differences identified in this report

In late October, the IMO created an internal team (Pricing Team) whose partial mandate was to identify ways to improve the convergence of the pre-dispatch prices and the HOEP. Under the leadership of this group, a number of changes to the design of the market were either made or are currently being considered that could improve the convergence. These include the following:

Creation of an hour ahead market for dispatchable loads

The IMO is currently considering the creation of a new class of market participants called ‘hour-ahead dispatchable loads’. This new classification would allow large industrial customers to submit bids to consume energy into the IMO market and to receive hourly consumption schedules in the one-hour ahead pre-dispatch much like imports and exports. These loads would pay the real-time price for their consumption. However, if the real-time price were to fall below their bid price, the IMO would provide participating loads with a constrained off payment to compensate them for their lost consumption opportunity.

The Pricing Team’s motivation behind the creation of this class of customers includes the following.

- The obligations on, and provisions for, dispatchable loads within the market are not compatible with the operational characteristics of the majority of customers in the IMO-administered markets. For example, most customers cannot respond to 5-minute dispatch instructions due to physical process requirements. However, these customers can generally predict far better, an hour or more in advance, how much they can reduce their consumption if they shut down part of their process.

- Pre-dispatch price signals are not sufficiently reliable for Ontario loads to make necessary business decisions as to whether or not to change consumption in response to price. This is resulting in a reduction in overall price responsiveness within the IMO-administered market.
- In tight supply-demand situations, Ontario is heavily reliant on imports of energy to meet domestic demands. The level of imports has reached levels as high as 4,000 MW. More domestic competition against imports should result in lower and less volatile prices in times of tight supply-demand and high market prices, and lead to more efficient resource use.

Initially, several large industrial customers expressed an interest in participating in this market (approximately 600 MW of potential price responsiveness). However, we understand that for a number of operational reasons, the interest of these customers has diminished. The creation of this new class, if successful, could help to reduce the discrepancy between the pre-dispatch prices and HOEP for the following reasons.

- In the past, large shares of these loads (large industrial customers) have responded to expected high real-time prices by reducing their consumption.[49] However, the IMO's demand forecast does not factor the potential for price responsiveness of this class of customers into its prediction. As a result, the IMO may project high prices in pre-dispatch because it forecasts a heavy load. But, if these loads also expect high prices and respond by reducing their consumption (say in total by 200 to 400 MW), the real-time demand will necessarily be lower than the forecast demand and the HOEP will be lower. If a large share of these customers participate in the one-hour ahead market, then their consumption patterns (price responsiveness) will be directly incorporated in the pre-dispatch price calculation. This will cause a convergence between the pre-dispatch prices and HOEP.

[49] Section 3 documents this response for a sample of customers.

- In times of tight supply, having an additional 200 to 600 MW of price responsive bids in the pre-dispatch market would act as competition to imports. The more loads that bid in the market, the more the potential that their reduced consumption replaces the need to purchase imports. This additional competition would help to reduce the pre-dispatch price in times of tight supply, which would in turn allow the pre-dispatch price to converge to the real-time price.

Elimination of the four to two hour restricted window

On November 18, 2002 the IMO began for a trial period to allow market participants to submit new or revised dispatch data for any dispatch hour without restriction until two hours prior to the beginning of that hour. It was expected that this initiative would reduce the gap between pre-dispatch and real-time prices by allowing market participants to revise dispatch data closer to the dispatch hour. By shortening the time at which bids and offers had to be locked-in in Ontario, traders are in a better position to judge the feasibility of trading with the other markets, particularly the New York market whose window closes at 75 minutes before the hour.

The shortening of the mandatory window can reduce the discrepancy between the pre-dispatch prices and the HOEP if:

- it reduces the risk of trading between control areas and thereby results in more imports being offered (more competition) and at lower offer prices. Both of these responses would lower the pre-dispatch price closer to the HOEP.
- it improves the ability of traders to manage their imports and exports causing the number of failed transaction to reduce.

The trial period is still in place and a decision on the permanency of the program will be determined in April 2003. The IMO has not been able to quantify from the available data the impact of this change on the convergence of the pre-dispatch price to HOEP, however, no negative consequences from the change have been identified.

Improving the 'seams' issues between Ontario and the neighbouring control areas

As discussed in subsection 2.4 above, the IMO is exploring the implementation of a number of measures to better align interjurisdictional trading with neighbouring systems. Improvements in the 'seams' that reduce the number of failed imports and exports would lead to a better alignment of the pre-dispatch and real-time prices.

Manage the use of the 'out-of-market' operating reserve

The IMO is considering ways to incorporate their use of 'out-of-market' sources of operating reserve into the market in a manner that would make the use of this reserve more transparent and that would reduce the impacts that it is having on the pre-dispatch to real-time price discrepancy. The IMO is looking into two possible approaches regarding 'out-of market' sources of reserve.

1. **Allowing the DSO in real-time to automatically solve for the amount of an operating reserve shortfall:** The DSO is currently designed to automatically determine the size of an operating reserve shortfall. The DSO first runs to solve schedules and prices using the real-time demand and the target operating reserve requirement. However, in times of tight supply, there may not be enough energy and operating reserve offers in the market to meet all the requirements. When this occurs, the DSO can determine the precise amount of the shortfall; due to the design of the DSO the shortfall always occurs in the operating reserve market. In these situations, the DSO is designed to essentially reduce the operating reserve requirement to the level of the available operating reserve offers (minus 2 MW) and solve for the market price. The difference between the target requirement and the one solved by the DSO as a result of the shortfall of offers is made up automatically by the 'out-of-market' sources of reserve. Allowing the DSO to automatically solve in this manner would replace the current approach in which the IMO Control Room is required to anticipate the size of any potential reserve shortfalls and manually (on a 'best efforts' basis) reduce the operating reserve requirement to the size of the shortfall.

Automating the determination of 'out-of-market' actions is likely to result in a higher incidence of price spikes in real-time and is unlikely to materially improve the signalling properties of the pre-dispatch price. Because the automatic calculation of the shortfall would occur only in real-time and not in pre-dispatch, only the real-time price would be affected in these hours. Relying on the tool would make it likely that the real-time price would be set by offers at the top of the offer stack, possibly substantially exceeding the pre-dispatch price. The limited experience with automation prior to the introduction of manual adjustments suggests that the price may approach the MMCP. Substituting substantial under-estimates of the real-time price for substantial over-estimates will not improve the signalling properties of the pre-dispatch price.

2. **Assign prices/costs to 'out-of-market' sources of reserve in both pre-dispatch and real-time:** The IMO is also considering another approach that would place an offer price on 'out-of-market' sources of operating reserve and allow these sources to compete against the reserve offers of market participants. For example, the offer price assigned to 100 MW of standby 3 percent voltage cuts may be $50 MWh.[50] Then, when the DSO determines the cheapest solution to meet the Ontario energy demand and operating reserve requirements, it may involve the scheduling of these standby 3 percent voltage cuts instead of operating reserve that was offered by a market participant but at a price higher than $50 MWh. The costing of the 'out-of-market' sources would be done in both pre-dispatch and in real-time to ensure continuity. This approach to 'out-of-market' sources of reserve would reduce the pre-dispatch to real-time price discrepancy by eliminating the ad hoc impacts that the manual implementation in real-time has. Costing these 'out-of-market' sources of reserve and including them in pre-dispatch would also provide competition to importers in the pre-dispatch markets causing downward pressure on the pre-dispatch price.

The IMO is considering incorporating 'out-of-market' sources of operating reserve into the market as part of a set of market improvements that will have an overall benefit for the operation of the market. In this context, the IMO has informed stakeholders that the implementation of initiatives with regard to 'out-of-market' reserve actions depends on the success of the other Pricing Team initiatives and the overall improvement of the Ontario supply-demand balance. We believe that the efficiency implications[51] of moving to incorporate 'out-of-market' actions are important and support assigning prices to 'out-of-market' resources in both pre-dispatch and real-time as soon as this can reasonably be done.

(ii) Developing alternative mechanisms for providing price signals such as administering a day-ahead physical market

As part of its market evolution program, the IMO is exploring the feasibility and merits of implementing a day-ahead market. As the IMO has stated, while "the design of a day ahead market determines which of the many benefits it can provide … price discovery, price certainty and operational certainty are most often listed by stakeholders as a day ahead market's main attractions." [52]

The implementation of a day-ahead market would, among other things, provide market participants with advance price signals of the next day's real-time prices. The presence of a well functioning day-ahead market would reduce the importance of the pre-dispatch prices in providing these advance signals to market participants. The IMO is studying the feasibility of introducing this market in the fall of 2004.

[50] Recall that when the IMO uses standby voltage cuts to meet its industry reserve standard, this does not mean that it implements voltage cuts. As suggested, these voltage cuts are on standby; to be activated only in the case of a contingency.
[51] The efficiency benefits of pricing 'out-of-market' reserve would include the efficiency benefits of having a more accurate price signal. This could include a more efficient use of resources by generators with large start-up cost and more effective load responsiveness. It could also include the benefits of having more investor confidence in the market.
[52] For a discussion of the different options being explored by the IMO, refer to the IMO's Phase 1 discussion paper located on the web at http://www.theimo.com/imoweb/pubs/consult/mep/mep_DAMProposal_20030131.pdf.

(iii) Providing market participants with more information regarding the key factors driving the real-time prices so that participants, on their own can better forecast real-time prices

As part of its efforts to increase the transparency of the market, the IMO is also looking to expand its publication of market data. When implemented, the Daily Market Summaries should provide market participants with additional data (key data on the price drivers of the market) so as to allow market participants to be in a better position to forecast future prices on their own rather than rely on the IMO's pre-dispatch prices. The IMO is currently consulting with stakeholders to determine the most appropriate types, formats and timing of the data to be provided. The IMO anticipates that the Daily Market Summaries will be available to market participants in the spring of 2003.

In conclusion, the Panel urges the IMO to continue its development of these and other initiatives that would improve the accuracy of advance price signals, or increase the dissemination of data or other information that would aid market participants in the price discovery process. The Panel also encourages the IMO to explore with market participants the possibility of re-designing the existing pre-dispatch price information provided to the market so that it does represent a 'true' forecast of the real-time price rather than just a projection. There are many ways in which expectations about what might transpire in real time could be integrated with the current methodology to provide a forecast of the HOEP in pre-dispatch. One way, involving Monte Carlo simulations, is described in Appendix C to this chapter as a basis for discussion.

3. Price Responsive Load

One of the main conclusions of the October report was that the full benefits of effective competition are unlikely to be realized unless a much greater portion of demand is price-responsive. The data available at that time suggested that roughly 35 percent of total load had the necessary technology (interval meters, tools to monitor prices in near real-time) to respond to hourly price movements. The potentially price responsive load is comprised of about 90 market participants - large industrial customers that are directly connected to the IMO-controlled grid (15 percent of the total load) and as much as 10,000 embedded customers with interval meters roughly 20 percent of the total load). The remaining customers either lacked the interval meters or the tools to monitor price in real-time, to effectively respond to hourly price changes.[53]

When customers cannot (or do not have the incentive to) respond to high prices by lowering their consumption, they cannot avoid paying extreme prices in periods of shortages. The lack of price responsiveness also increases the ability of suppliers to exercise market power. On the other hand, experience in other markets indicates that even a small amount of demand responsiveness can improve system reliability and mitigate occasional price spikes.

This report provides a more detailed analysis of the degree of price responsiveness observed over the period May through December of 18 of the 90 large industrial customers that are directly connected to the IMO-controlled grid.[54] Of the 90 large industrials, these 18 customers, due to the nature of their business, are the most likely to respond to changes in prices.[55] These 18 customers represent approximately 60 percent of the consumption of the 90 directly connected customers, which is roughly 10 percent (off-peak) and 7 percent (on-peak) of the total Ontario load.

The goals of the analysis were (1) to determine the extent, if any, of the price responsiveness of these customers and (2) to quantify the potential impact of this

[53] We noted that these customers also lacked the incentive to respond to short-term prices since they did not face the short-term price. Instead (prior to the introduction of the 4.3¢/KWh price freeze), these customers were charged a rate that was influenced by the consumption patterns of all consumers within their distribution area and was averaged over a longer time frame.
[54] Due to data limitations, the MAU did not study the price responsiveness of the remaining 72 large industrials or the embedded customers with interval meters.
[55] These companies come from the steel, mining, oil and gas industry. The remaining 72 customers generally come from the manufacturing industry. Their electricity consumption is typically a smaller part of their overall production cost.

responsiveness on the market clearing price.

The MAU considered several different statistical models to estimate the extent to which this group of customers responded to real-time price changes. Of course, the accuracy of any statistical model of demand depends on a proper understanding of the factors influencing demand and the availability of data representing these factors. The model employed for this report was a multivariate regression model with hourly consumption levels as the dependent variable and the following independent variables: [56]

- *HOEP plus hourly uplift.* This is the (real-time) energy price paid by these customers. If these customers are price responsive then this variable should have a negative effect on the quantity of energy demanded.
- *The one-hour ahead pre-dispatch price.* For some production processes, customers need an advance warning of the likely real-time prices they will face in order to adjust their consumption in upcoming hours. If this is the case, the higher the pre-dispatch price signal, the lower the real-time consumption level. Of course, this depends on how accurate or reliable is the pre-dispatch price signal.
- *The forecast of the price for the next 12 hours of the day* (as available one hour before the time of consumption). Customers may choose to substitute consumption from high priced hours to lower priced hours (i.e., they may time shift consumption from peak period to off-peak periods). Including the forecast prices for the next upcoming hours in the model attempts to capture this inter-temporal substitution. The expected relationship would be positive (the higher the price of electricity in future hours the more consumption in the current hour).
- *Lagged consumption.* The model considers the extent to which consumption in the current hour is dependent on consumption in previous hours. This may be a factor for

[56] The relationship was estimated in two different ways. First, all hourly data were pooled together to estimate a single demand relationship for the sample period May to December. In this model, a single slope coefficient for each of the independent variables was estimated. Second, the relationship was estimated separately for each hour of the day (i.e., looking to determine whether the demand responsiveness varied for each hour) for the sample period May to December. In this case, a slope coefficient for each of the independent variables was estimated for each hour in the day.

some of the large industrial customers whose production process requires multi-hour planning.

- *Transition rate option.* Many customers have a contract with Ontario Power Generation which fixes the price of electricity paid by these customers for a certain portion of their typical consumption. However, for a certain number of hours in the year, OPG has the option (with 24 hours notice) to keep its contracted supply and essentially sell it in the spot market. In these hours, the customers are not protected by the fixed price and must buy at the spot market price. In the model, a dummy variable is included to indicate whether the behavior of the customers changes when they are fully exposed to the spot market price.
- *Temperature data*. The demand for electricity is typically a function of the weather parameters (temperature, humidity etc.) with the demand for electricity increasing as the temperatures rise above 15 to 20 degrees Celsius or fall below 10 degrees Celsius. The model includes temperatures (with a dummy variable indicating temperature above 15 degrees and a dummy variable indicating temperature below 10 degrees) to capture potential shifts in demand due to temperature changes.
- *Monthly intercept dummies.* The model includes monthly intercept dummies to capture seasonal shifts in demand. The monthly intercept dummies may also capture potential changes in income factors or price changes in substitute factors of production. A company's demand for electricity will depend on the demand for the product(s) that it sells – the higher the demand for the product it sells, the more it produces and hence the more electricity it purchases. The MAU did not have direct data on the output levels of the companies under study and their determinants were not available. A company's demand for electricity will also depend on the prices of substitute factors of production – the higher the price of a substitute factor, the higher the demand for electricity. Data on the prices of potential substitute factors of production were also unavailable. In place of these demand shift variables monthly dummies are intended to capture the effect of any month-to-month shift in demand resulting from changes in these factors along with other factors that may cause demand to shift.

The results of the MAU's preliminary analysis provides evidence that these customers did respond to real-time price increases by reducing their consumption in some peak periods during the summer. [57] In all models considered the real-time price (HOEP plus uplift) had a negative coefficient and was statistically significant in the key peak hours of the day.[58] This indicates that the large industrial users in our sample reduced their consumption in response to higher HOEP in these hours.[59]

The following series of graphs provide a stylized illustration of the impact of the HOEP on the consumption patterns of these customers. The figures compare the patterns for two months - June and July, as these months are most illustrative. Figure 3-18, provides a measure of the average hourly prices in June and July. As Figure 3-18 illustrates, prices in all hours were higher in July than in June. Furthermore, the price discrepancy between the two months is greater during the peak hours of the day.

Figure 3-19 plots the hourly average consumption of the 18 large industrial customers for June and July. This graph illustrates three things. First, these customers consume more in off-peak periods and less in on-peak periods. Second, their consumption was higher in all hours in June than July. Third, the reduction in consumption in July was relatively larger in the peak hours than in the off-peak hours.

[57] The summary statistics and regression results are available to the interested reader on request.
[58] Specifically, the slope coefficient for the HOEP was negative and statistically significant in delivery hours 5, 9, 13 through 15, 17 and 21.
[59] The other variables that are typically statistically significant are the lagged consumption variables (one and two period lag) and the monthly intercept dummy variables. The one-hour ahead price forecast is never significant nor is the temperature dummy variable. The forecast prices are significant for some hours in the day. However, the signs of these variables are often mixed. One of the largest difficulties with estimating the price responsiveness of these customers is in determining which information (price or other) they are using to respond. Many of the loads have noted that the IMO pre-dispatch forecasts are often unreliable. As a result, the price forecast variables used in this model may not be the most appropriate measure of the information used by the customers of the potential cost of consuming in future hours.

Figure 3-18: Average Hourly Prices; June and July

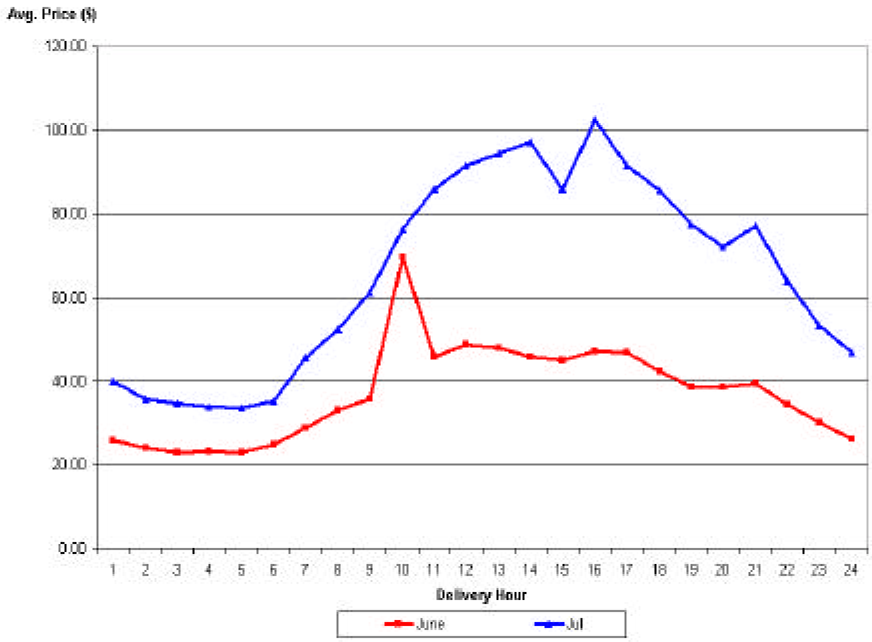
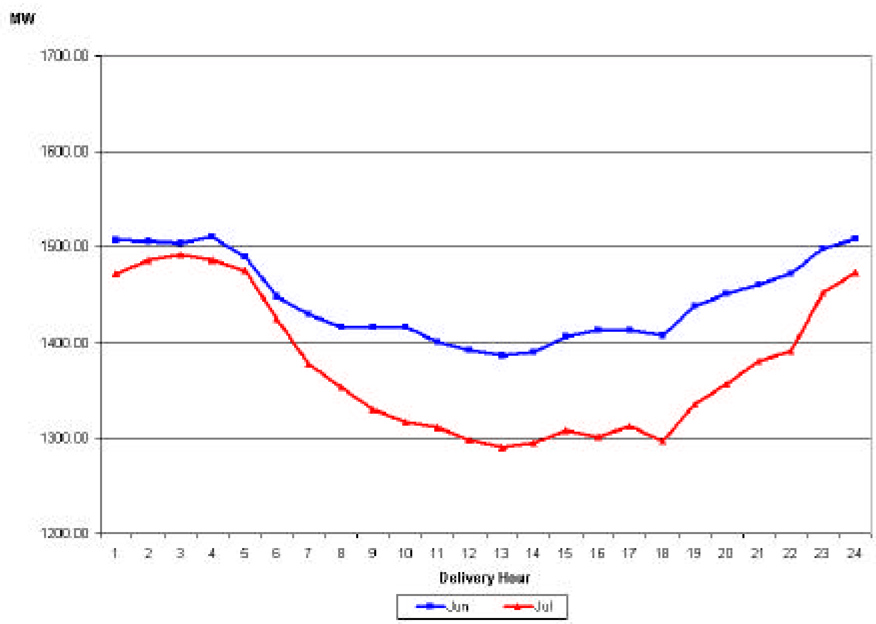


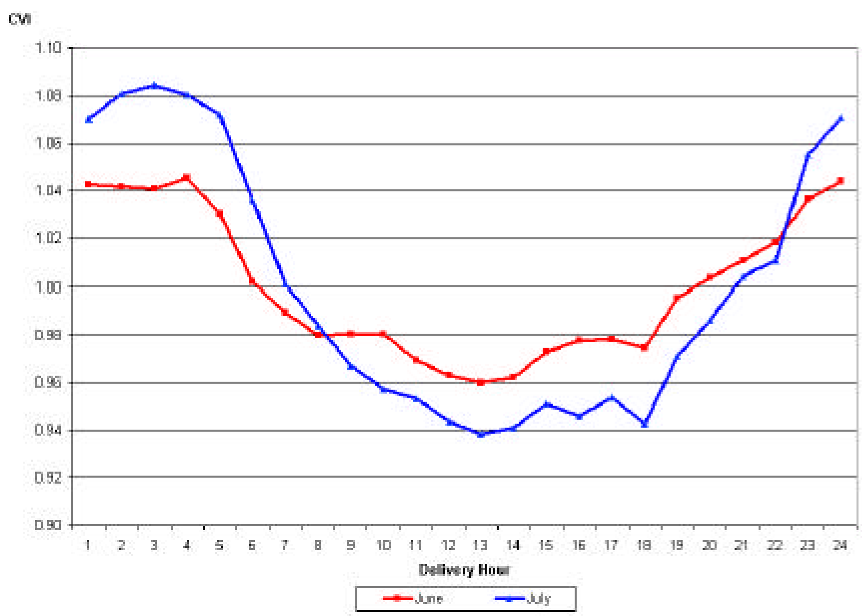
Figure 3-19: Average Hourly Consumption; June and July



Finally, Figure 3-20, plots the consumption variation index (CVI) for each hour for the months of June and July. The CVI is calculated on a hourly basis as the ratio of the average consumption for hour *i* in month *j* to the average hourly consumption for month *j*.[60] Algebraically, this is represented as:

$$CVI_i = \frac{AVGC_j^i}{AVGhourlyC_j}.$$

Figure 3-20: Consumption Variation Index; June and July



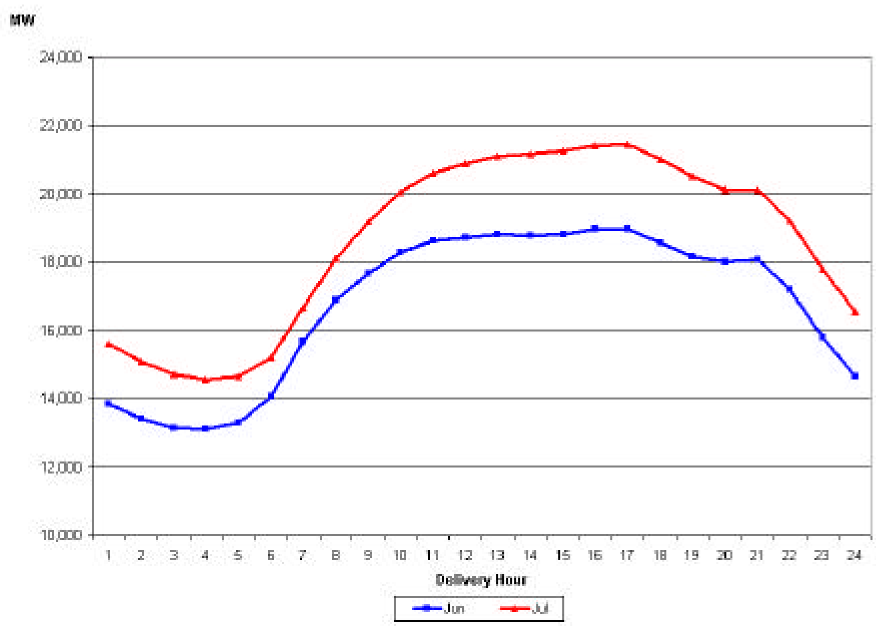
The CVI provides an indication of the proportion of a customer's total monthly consumption, consumed in a given hour. As Figure 3-20 indicates, the CVI for off-peak periods (1 through 6 and 20 through 24) is greater than 1 indicating that more of their consumption occurs in these off-peak periods.

The combination of these three figures provides a stylized demonstration of how consumers respond to price. First, as a group, these consumers consumed less in July and more in June. While there are several possible explanations for this (the usual seasonal reductions in demand due to plant shutdowns in July), the higher prices in July may explain a large part of the difference. Second, as indicated in Figure 3-19, these customers consumed proportionately more of their total monthly consumption in the off-

[60] For example, if the average consumption for hour 1 in June was 1,500 MW and the average hourly consumption (across all hours of the day) for June was 1,200 MW then the CVI for hour 1 would be 1.25.

peak periods during July when the on-peak prices were relatively higher (Figure 3-18) then in June when the on-peak prices were relatively lower. This provides an indication that these customers shifted consumption from high price hours to lower price hours in July as a response to the relatively higher July prices.

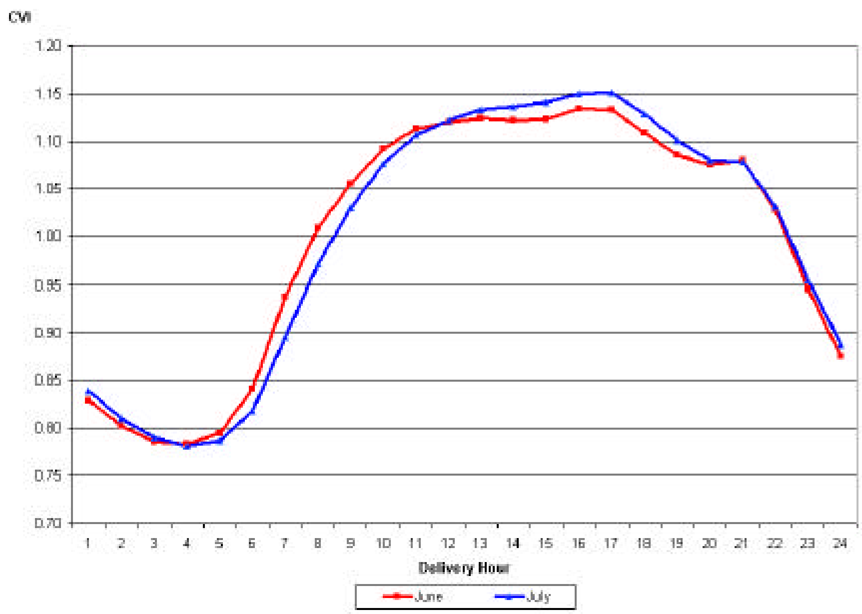
Figure 3-21: Average Hourly Consumption for Entire Non-Dispatchable Loads; June and July



In contrast, Figure 3-21 and Figure 3-22 plots the consumption patterns for the entire non-dispatchable load class. As Figure 3-21 illustrates, the non-dispatchable load class increased its hourly demand in July from June. This is the typical response to the higher temperatures in July. As Figure 3-22 indicates, there was essentially no change in the hourly CVI across the two months for this class. This indicates that unlike the 18 large industrial customers, the non-dispatchable load class did not modify its consumption patterns to consume proportionally more in the off-peak hours.

This would mean that the customers consumed proportionality more in delivery hour 1 than in the average hourly consumption in the month.

Figure 3-22: Consumption Variation Index for Entire Non-Dispatchable Loads; June and July



While the results of our preliminary estimations provide strong evidence of price responsiveness in the market for the 18 large industrial customers analyzed by the MAU, more data are required to provide a robust measure of the price elasticity of demand of this group of consumers.

Nonetheless, there is evidence that, as a consequence of their willingness and ability to shift consumption, these large customers paid a considerably lower price for their electricity than the average market price. While the weighted average price (May to December) paid by the market for energy (not including uplift) was $58/MWh, the weighted average price paid by this group of customers was only $50/MWh, and some of them paid as little as $42/MWh during this period. This indicates that if a customer is capable of shifting consumption from high priced hours to lower priced hours, it can reduce its energy charges considerably.

It is important to note that price responsive behaviour not only benefits price responsive customers directly, it benefits all load by reducing demand and shifting load from peak to off-peak periods. The result is prices that are lower than they would otherwise be, reliability is increased, and resources are used more efficiently. As an illustration, the MAU used the statistical model for these 18 large customers to estimate how much their consumption might have been shifted or reduced by price responsive behaviour, and found that total demand for the 18 was lower by as much as 200-300 MW in some hours of the summer.[61] Reduced demands of this magnitude would have made a substantial contribution to lower prices in some hours of the summer when supply was very tight. And it can also make a significant difference to reliability. As noted with respect to the California situation:

> *Demand response is critical at peak times, when a few percentage points of demand can make the difference between a reliable system and rolling black-outs. California had to institute rolling black-outs with a shortage of only 300 MW in a system of 50,000 MW, so only a tiny portion of total demand in that case needed to stop using for four hours to avoid the black-outs.*[62]

In summary, the evidence of price responsiveness by this sample of large industrial loads is significant and encouraging given the early stage of development of the market and the difficulty of predicting the market's real-time price. Demand responsiveness remains an important means for enhancing the efficiency of the wholesale market.

[61] This reduction was estimated by comparing actual consumption with what the model predicted would have been consumed at a price of $43/MWh – the regulated price before the market opened to competition.
[62] Sally Hunt, *Making Competition work in Electricity,* Wiley, New York, p. 76.

Appendix C: A Possible Approach to Redesigning Pre-dispatch Price Information

The approach set out below represents one possible approach that may be taken to provide market participants with price information, in pre-dispatch, that is a more accurate forecast of what the HOEP is likely to be. It is put forward as a basis for discussion between the IMO and market participants.

- The IMO could continue to run the pre-dispatch sequences as it does today (36 hours to one hour in advance of real-time) to project the possible schedules for generation, dispatchable load, exports and imports. Each market participant would be provided its projected schedules. However, the pre-dispatch prices that are solved from this process (in the unconstrained sequence) would not be provided to market participants. Instead, the IMO would re-run the *unconstrained sequence* several times, with each run incorporating in some probabilistic manner the type of things that are known to occur in real-time such as demand forecast error, generation outage, and failed imports/exports (discussed below). By re-running the pre-dispatch several times, the IMO would create a distribution of projected prices for each of the upcoming hours in the normal pre-dispatch run (e.g., possibly 100 prices for tomorrow's delivery hour 12) with each of these prices incorporating different possible real-time values for demand, generation availability or failed imports/exports. The IMO could then publish the mean of this distribution as well as some form of confidence band around the mean (perhaps simply one standard deviation, plus and minus, around the mean). This would provide market participants with a truer forecast of what might happen in real-time. It would also provide a measure of deviation around the prediction, which could be used as information about the relevant shape of the offer curve.
- Probabilistic measures for demand error, generation outage and derates, self-scheduling error and failed transactions could be incorporated into each running of the unconstrained pre-dispatch sequence in the following way. Using historical data the IMO would create:

  - a distribution of potential real-time demand around the average (not peak) hourly value for demand as currently forecasted by the IMO. It may be conditional on the hour of day or the season of the year;
  - a forced outage rate for each of the generating facilities;
  - a distribution of potential self-schedule error;
  - a distribution for potential failed transaction (that may be conditional on factors such as the delivery hour, Ontario demand, or even the particular market participant).
- Each time the IMO runs the unconstrained pre-dispatch sequence to calculate the distribution of projected prices, it would run a Monte Carlo simulation drawing a value from each of the distributions above. The random draws of each would be incorporated into the pre-dispatch as appropriate.
- Each time the IMO runs the unconstrained pre-dispatch sequence to calculate the distribution of projected prices, the offer and bids of imports and exports would be excluded from the offer curve and in their place, the schedules (as calculated in the initial pre-dispatch run) of these transactions would be inserted and placed at the bottom of the stack as is currently done in the real-time market.

The Panel recognises that one of the factors causing the disparity between pre-dispatch price and HOEP is the manual use of ‘out-of-market’ sources of operating reserve. If the IMO is able to follow through with its initiative to automate the use of this reserve or to cost the reserve and place it in the market (both pre-dispatch and real-time), then this would not be an issue for the pre-dispatch price forecast. Alternatively, one way to incorporate the potential manual use of this reserve is to first conduct the Monte Carlo simulation to draw values from the various distributions discussed above, then run the *constrained sequence* with these values. The constrained schedule would automatically indicate any operating reserve shortages that would arise. The IMO would then run the unconstrained sequence with the values drawn from the simulation. However, rather than use the full operating reserve requirement it would reduce the amount of the requirement to reflect the shortage identified in the constrained sequence.

Chapter 4: Conclusions

1. Price Behaviour and Outages

The September–January period continued to be marked by abnormal weather, particularly in September and December/January. In September this coincided with the regular planned maintenance of generators and the resulting shortage of supply contributed to the highest monthly average HOEP since the market opened. We asked the MAU to pay particular attention to outages – both planned and forced – through the fall period, and their report to us indicated nothing abnormal or unexpected in the planned outage program. Some of the monthly levels of forced outage appear higher than experienced in past years, but this increase in reported outages is largely due to changed reporting practices as a result of the opening of the market. We will continue to examine outages closely.

2. Anomalous Events and Inappropriate Behaviour

The MAU continued to examine all hours in which the HOEP exceeded $200/MWh (42 hours) and in which the uplift exceeded the HOEP (17 hours). The cases where HOEP exceeded $200/MWh were explained by the occurrence of the same factors that were identified and discussed in some detail in our first monitoring report. In particular, very low supply cushions reflected an imbalance between demand and availability, which was very often exacerbated in real time by failed import transactions, unexpected demand increases, and forced outages. In its examination of the 17 hours in which uplift exceeded the HOEP, the MAU found that the amount of uplift paid in each of these hours was exacerbated by congestion on either the New York or Michigan interties, or both. Such congestion was not experienced in the first four months of the market. The impact of congestion on IOG payments is reviewed in Chapter 2.

None of these high price or high uplift incidents led the MAU to conclude that there was any inappropriate behaviour on the part of any market participant.

We also report on two specific anomalous incidents examined by the MAU. The first of these was the observation, over three days in October, of large unanticipated increases in the one-hour ahead pre-dispatch price compared with the two-hour ahead pre-dispatch price. The second involved the calculation of an external zonal price of -$2,000 per MWh on December 3. In each of these cases satisfactory explanations of the observed behaviour were identified; in the second case an oversight in the way in which the dispatch algorithm operated was corrected.

During the period under review, the Panel did not initiate any investigations into the behaviour of market participants under Chapter 3, subsection 3.4.1 of the Market Rules. In September, the Panel received a request that it conduct an investigation into the extended forced outage at Bruce Power that occurred during the summer of 2002. Based on the MAU's review of the circumstances, the Panel concluded that an investigation was not warranted. The reasons for this decision are available on the IMO web site (http://www.theimo.com/imoweb/marketSurveil/investigation.asp).

3. Evolution of the Market

The actions taken by the Government of Ontario in November of 2002, have not had a direct impact on the manner in which the wholesale market for energy is operated by the IMO. The wholesale price continues to be determined by the interaction of offers and bids of market participants. The price guarantee of 4.3 cents/KWh introduced in November, reduced the incentive of the affected consumers to be price responsive. The Business Protection Plan for large energy consumers announced on March 21 extended the price guarantee to all consumers using 250,000 kilowatt hours per year or less. However, the incentive to respond to price movements remains for about 50% of consumption, and in particular for the 90 large loads that are directly connected to the wholesale grid.

The MAU analysis of the price responsiveness of eighteen large wholesale customers, reported in Chapter 3, concluded that there is significant evidence of price responsiveness within this group during the period since market opening. Indeed, MAU calculations suggest that these large customers paid about $8/MWh, on average, less than they would have over the May-December period had they not responded to price movements by shifting their energy consumption from peak to off-peak periods. This price responsive behaviour benefits all load in the market by reducing demand (both peak and overall) and contributing to lower prices than would otherwise obtain. An illustrative simulation suggests that if these 18 large industrial users faced a constant price of $43/MWh in the market their consumption would have been about 200 MW higher on-peak. This could have led to substantial price increases and even reliability concerns, given the overall demand/supply tightness in some peak periods.

As the market continues to evolve, every effort should be made to maintain and, where economic, to increase the extent of price responsiveness among consumers. This could include actions to promote price responsiveness of a greater portion of load through interval metering and associated communications equipment so that when the price cap is removed consumers have the ability and incentive to make electricity use decisions that are beneficial to their own financial position as well as to the competitive efficiency of the market.

In our first report, we pointed to a number of issues related to the operation of the market that made it difficult for market participants to understand price outcomes. These included, in particular, the large and variable differences between pre-dispatch prices and real-time prices. We identified a number of factors that contributed to these differences and suggested some actions that the IMO might take to enhance the efficiency of competition. At this stage, there are a number of initiatives underway that we believe will be helpful. These include:

- the development of an hour-ahead market for dispatchable load, with a target introduction of summer 2003,
- the development of a day-ahead market with a target introduction of autumn, 2004, and
- the inclusion of 'out-of-market' operating reserve reductions within the market, both in the pre-dispatch and real-time markets.

Failed transactions continue to be a problem. The Market Assessment and Compliance Division of the IMO has taken a more aggressive posture with regard to examining failed transactions. This should continue. However, the major benefits will come only with enhanced co-operation among neighbouring control areas to reduce seams issues in the interjurisdictional flow of energy. These discussions are continuing and some progress is being made but the issues are complex and difficult. We will continue to monitor progress in this area.

Finally, we urge the IMO to consider ways that it can modify the current design of the pre-dispatch price projections so that they represent a 'true' forecast of the real-time price. There are a number of ways of doing this and we suggest one option in Chapter 3. We encourage the IMO to explore this and other options in consultation with market participants.