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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2005 – April 2006

PUBLIC

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Preface

The 8th Market Surveillance Panel monitoring report covers the period November 1, 2005 to April 30, 2006. This was a period which saw a return to more normal conditions with a more favourable balance between demand and supply.

During this period, Fred Gorbet resigned his position as Chair of the Market Surveillance Panel to become a member of the Board of Trustees, the governing body of the North American Electric Reliability Council (NERC). We offer best wishes to Fred and many thanks for his leadership as Chair of the MSP. The Panel looks forward to the appointment of his successor by the Ontario Energy Board.

Following the established format of our previous semi-annual reports, we provide standard data on market operations and performance in Chapter 1 and the Statistical Appendix. Chapter 2 surveys 'high' and 'low' prices, identifies other anomalous matters worthy of comment and reviews the Transmission Rights market. Chapter 3 provides a status of issues raised previously, reviews other material changes that have occurred and assesses the IESO's Transitional Demand Response Program. The final chapter summarizes our perspective on the operation of the market in a general sense and comments on arrangements for future supply. Following a summary of limitations of uniform pricing noted to date the chapter concludes with a recommendation related to constrained off payments and locational pricing.

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Table of Contents

List of Tables

List of Figures

Chapter 1: Market Outcomes November 2005 – April 2006

1. *Introduction*

This chapter provides an overview of the main outcomes of the IESO-administered markets over the period November 1, 2005 to April 30, 2006. It contains the usual data series and analysis presented in past reports with comparisons to the same period a year earlier. New this time is preliminary information on the performance of wind generation. We also update the information on zonal prices and add a new section describing congestion payments in the 10 identified internal zones.

November 2005 through April 2006 was a remarkable period of transition from the record high prices of last summer and late fall to the lowest prices ever in the Ontario market occurring at the end of the period. The highs and lows effectively cancelled each other out so that over the six month period the average monthly price was $55.88/MWh, roughly the same as a year earlier although about $20/MWh lower than summer 2005.

In general, the decline in electricity prices reflected reduced Ontario demand, moderating fuel (coal and natural gas) prices and higher levels of supply, particularly from nuclear generation. The derivation of ‘implied’ heat rates for a range of natural gas-fired units suggests that offer prices were simply tracking fuel cost changes. As one would expect, Ontario’s electricity prices are related to those in neighbouring markets. However, comparisons based on an Ontario price representative of transmission congestion and losses (the Richview Shadow Price) demonstrate that Ontario is not as low cost a supplier of energy as implied by the published uniform price, the Hourly Ontario Energy Price (HOEP).

2. *Ontario Energy Price*

Table 1-1 shows that the monthly HOEP was higher in November and December 2005 compared to the same months in 2004. It was substantially higher in December, particularly on-peak. The HOEP was lower than the previous year in both on and off-peak hours in all months after December. The lowest monthly average prices for the period occurred in April, especially off-peak where the average HOEP was slightly over \$35/MWh. There were some unusually low prices in April, for example on April 15th the hourly price was \$4/MWh, in Hour 3 and there was even a negative price interval during the hour, minus \$.08/MWh.

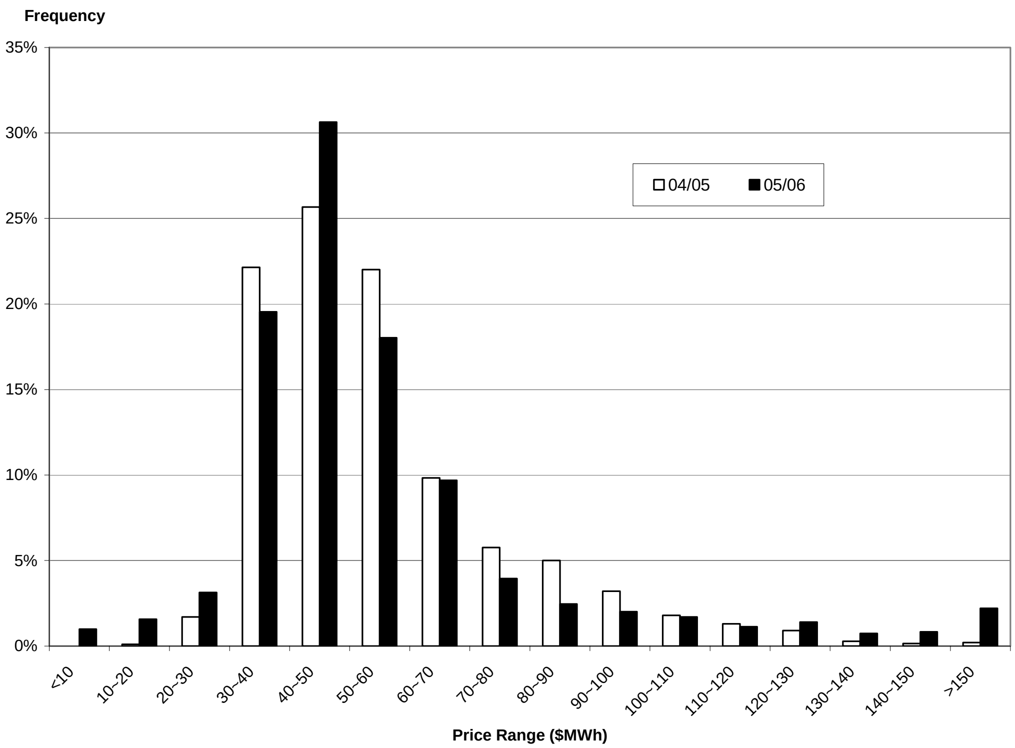
Table 1-1: Average HOEP, On-Peak and Off-Peak, November-April, (\$/MWh)

	Average HOEP		**Average On-Peak HOEP**		**Average Off-Peak HOEP**	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
Nov	52.28	58.25	61.94	74.11	43.82	44.39
Dec	50.82	79.77	59.84	101.29	43.40	63.52
Jan	57.90	55.54	68.99	64.95	49.53	47.79
Feb	49.58	48.13	56.51	53.98	43.29	42.82
Mar	59.87	49.01	67.86	57.62	53.29	40.59
Apr	61.93	43.52	69.57	55.96	55.24	35.23
Average	55.48	55.88	64.14	67.95	48.19	45.89

The highs and lows balanced each other out so that the average price for the November-April period was effectively the same as a year ago, \$55.88 vs. \$55.48 in 2004-2005.

Figure 1–1 plots the frequency of price outcomes for the HOEP. \$40-50/MWh remains the dominant price range, but the bands on either side declined compared to the same period a year earlier. At the same time, there was a greater occurrence of prices higher than \$120/MWh.

Figure 1-1: Frequency Distribution of HOEP, November-April



3. *Demand*

Ontario energy demand declined by 2.21 TWh or 2.78 percent compared with a year earlier and was in fact lower in all months than it was a year earlier.

The lower demand in January through April appears to have been weather related as temperatures across these 4 months were on average 2.53 degrees Celsius warmer than a year earlier. The largest monthly reduction, January, corresponds to a significantly higher average monthly temperature (see Table A-2, Statistical Appendix) and the load reduction appears largely attributable to residential consumers.

While Ontario demand was lower, exports increased by 1.9 TWh or 37 percent over a year ago. The total of exports and Ontario energy demand declined by 0.32 TWh or .38 percent as compared with a year ago.

Table 1-2: Monthly Energy Demand (TWh), Market Schedule, November – April

	Ontario Demand*			Exports			Total Market Demand		
	2004/ 2005	2005/ 2006	% Change	2004/ 2005	2005/ 2006	% Change	2004/ 2005	2005/ 2006	% Change
Nov	12.61	12.48	(1.03)	0.62	1.12	80.65	13.24	13.60	2.72
Dec	14.01	13.77	(1.71)	0.91	1.04	14.29	14.92	14.81	(0.74)
Jan	14.63	13.62	(6.90)	1.13	1.20	6.19	15.75	14.82	(5.90)
Feb	12.77	12.57	(1.57)	1.00	1.09	9.00	13.77	13.66	(0.80)
Mar	13.52	13.22	(2.22)	0.94	1.23	30.85	14.47	14.45	(0.14)
Apr	11.86	11.53	(2.78)	0.50	1.32	164.00	12.36	12.85	3.96
Total	79.40	77.19	n/a	5.10	7.00	n/a	84.51	84.19	n/a
Average	13.23	12.87	(2.78)	0.85	1.17	37.25	14.09	14.03	(0.38)

* Non-dispatchable loads plus dispatchable loads

Table 1-3 below isolates the demand reduction by wholesale consumers who are directly linked to the IESO-controlled grid. One can see that in some months, reduced consumption by wholesale customers accounts for a large share of the reduction in Ontario Demand. For example, in November 2005, wholesale consumers reduced their consumption by 0.22 TWh, while Ontario Demand as a whole declined by only 0.13 TWh.

Table 1-3: Demand Reduction, November 2005 – April 2006

	Wholesale Loads (TWh)	Ontario Demand (TWh)
Nov	0.22	0.13
Dec	0.19	0.24
Jan	0.18	1.01
Feb	0.16	0.20
Mar	0.13	0.30
Apr	0.13	0.33
Average	0.17	0.37

Figure 1-2 compares wholesale consumption to consumption by Local Distribution Companies (LDC) since market opening in 2002. It shows an opposing longer term trend for these components of Ontario Demand. On average, there has been a reduction of approximately 170 MW by wholesale customers while LDC load continues to grow. Note also the smaller variation in wholesale load consumption compared to the pronounced seasonal fluctuations by the LDC sector.

Figure 1-2: Monthly Total Energy Consumption LDC vs. Wholesale Loads, May 2002 – April 2006

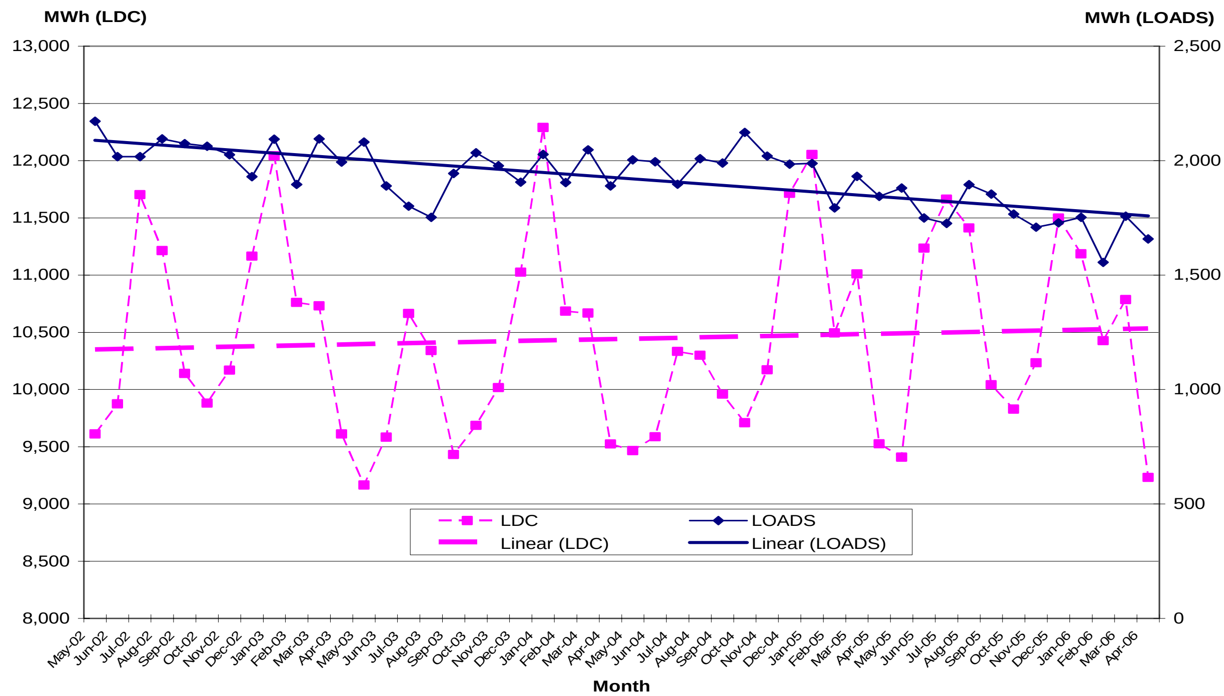
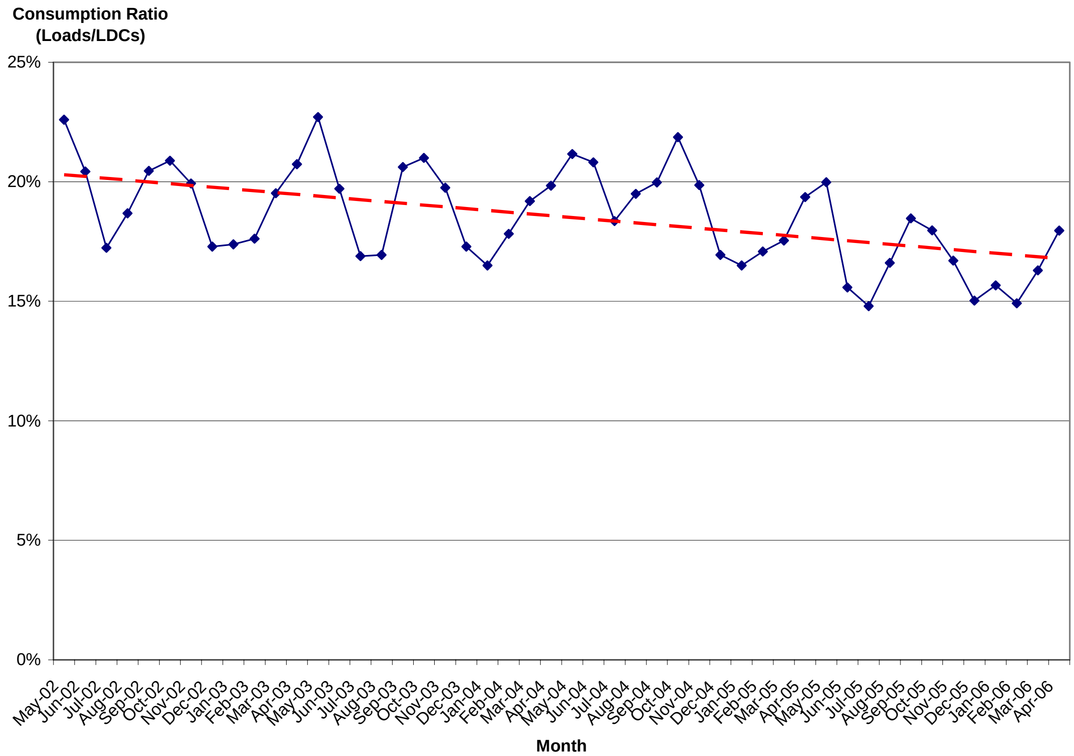


Figure 1-3 shows the ratio of consumption by wholesale loads to the consumption by LDC. Consistent with Figure 1-2, the proportion of consumption by wholesale loads relative to LDC has been dropping since late 2004 and in approximate terms has declined 10%. This trend could be due to any or all of: population growth (more residential customers); more efficient use of electricity by wholesale customers; a change in the mix of wholesale customers; declining levels of production by wholesale customers; a reduction in the number of wholesale customers.[1]

[1] There has, in fact, been little if any change in the number of entities registered as wholesale consumers in the IESO-administered markets.

Figure 1-3: Ratio of Wholesale Load to LDC Consumption, May 2002 – April 2006

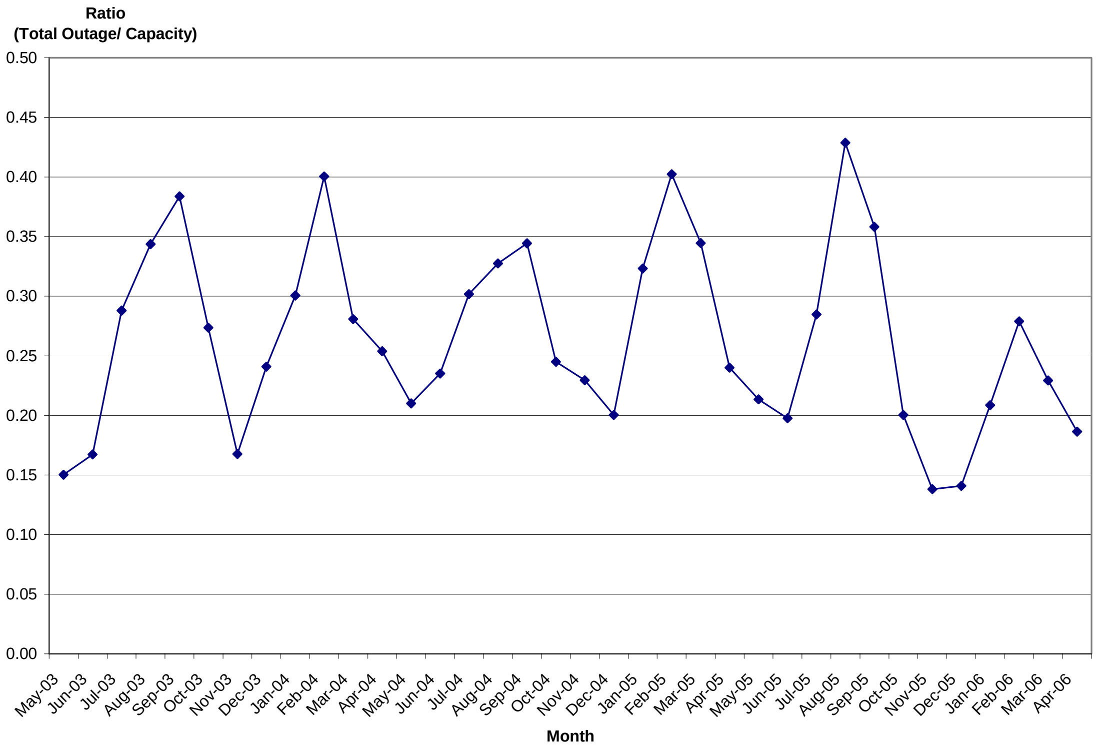


4. *Outages*

Generators take outages either for scheduled maintenance of their equipment (planned outage) or because of sudden equipment failure that forces them from service. Typically, planned outages are taken in shoulder months – spring and fall - when market demand and prices tend to be lowest. Outages, especially forced outages, usually have an impact upon market clearing prices.

Figure 1-4 shows combined (planned and forced) outages relative to total domestic capacity since 2003. This ratio has an advantage over the simple outage metric because it normalizes the impact of new additions or exits in capacity. Figure 1-4 shows two prominent results: first, as expected, outages are seasonal and, second, there has been a downward trend since the end of the third quarter 2005.

Figure 1-4: Total Outages (Planned & Forced) Relative to Total Capacity May 2003 – April 2006



A trend towards lower total outages is only apparent beginning in 2005, but forced outages have declined continuously since May 2003 as shown in Figure 1-5. This chart displays the monthly ratio of total forced outages to the total domestic generating capacity net of capacity that is on a planned outage. One can see that this measure of forced outages has been trending lower over time with the lowest mark reached in winter 2006.

***Figure 1-5: Forced Outage Relative to Total Capacity,
May 2003 – April 2006***

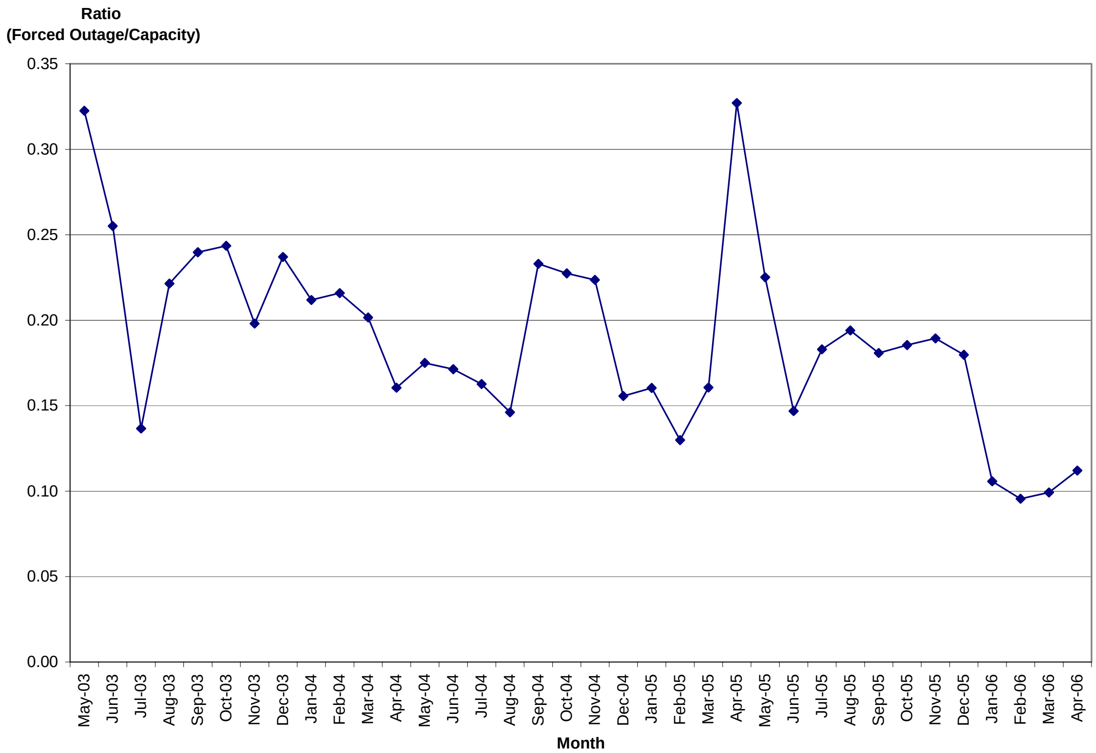
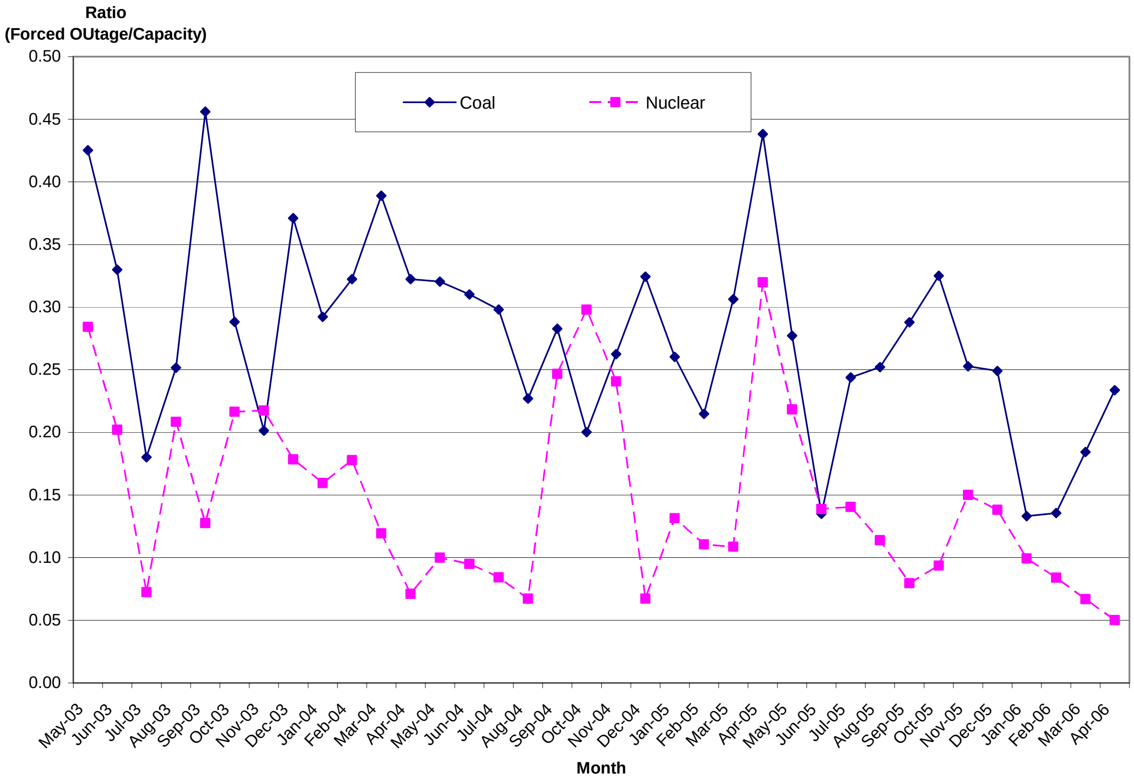


Figure 1-6 isolates the amount of generation on forced outage relative to total capacity net of the capacity on a planned outage for coal and nuclear units. We focused on these two generation resources because nuclear outages are relatively large and coal-fired energy is often the price setting resource in the province. The coal units had been improving their real time operation over time. Nuclear units' performance is also variable but less improved since the summer of 2005.

Figure 1-6: Forced Outage Relative to Total Capacity by Domestic Generation Fuel Type May 2003 – April 2006



5. *Supply Conditions and the Supply Cushion*

The supply cushion is a measure of unused energy that is available for dispatch in a particular hour.[2] We have previously reported that when the supply cushion falls below 10 percent one can expect upward pressure on prices and probably price spikes. Since this measure includes domestic generation only, it can occasionally be negative during periods of high market demand. During these tight supply periods, imports from neighbouring jurisdictions become critical to meet Ontario demand.

[2] The supply cushion is derived arithmetically as:

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

EO = total amount of available energy offered
ED = total amount of energy demanded
OR = operating reserve requirements.

Table 1-4 illustrates the real-time supply cushion for the period November 2005 – April 2006 compared to the corresponding period a year earlier. In all months the average supply cushion increased. Correspondingly, the number of hours when the supply cushion was negative dramatically decreased to 19 hours from 175 hours a year earlier. This occurred despite self-scheduling generators shutting down and selling their gas supplies back into the market in November and December and the retirement of Lakeview GS in the spring of 2005. In fact, on average self-scheduling generators lowered their production by 154 MW in November and 231 MW in December compared to one year ago.

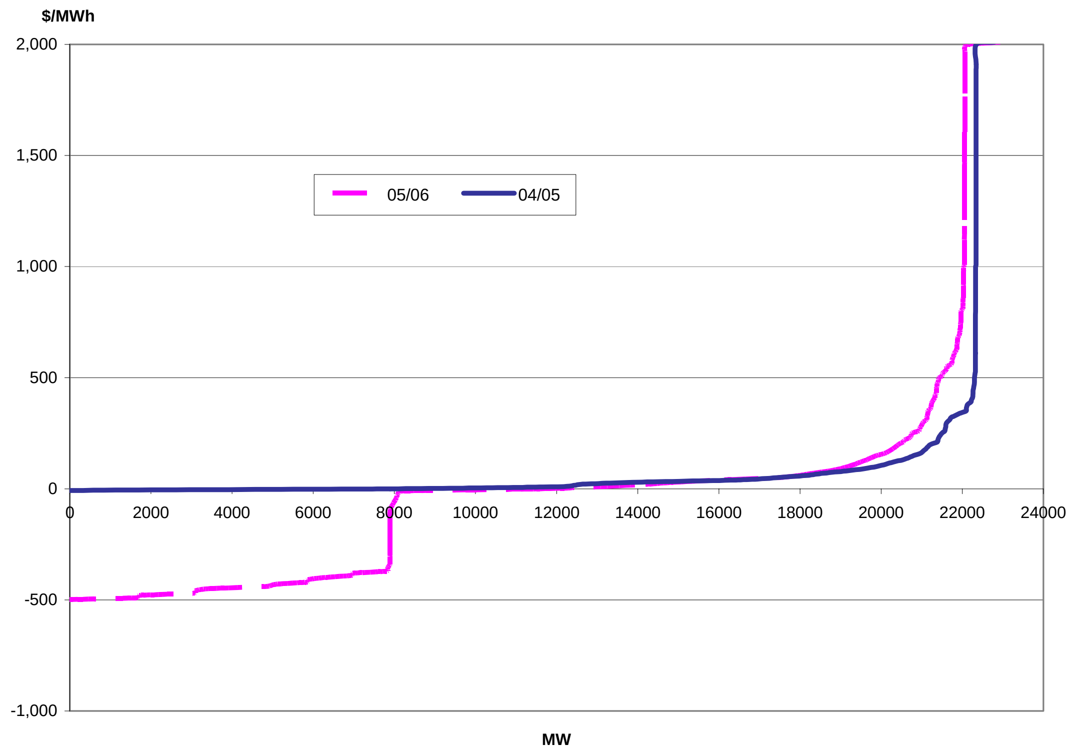
The reduction in the number of hours when the supply cushion was negative can be attributed to several factors. Supply conditions improved significantly due to the addition of a Bruce nuclear unit (830 MW) in May 2005 and a Pickering G1 unit (525 MW) in October 2005. Supply conditions were further improved when a natural gas generator owned by the Greater Toronto Airport Authority (about 130 MW) entered the market in September 2005. A reduction in forced outages by inframarginal generators also contributed as did the reduction in demand as a result of a relatively warm winter.

Table 1-4: Real-time Domestic Supply Cushion, November-April

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion Less Than 10% (# of Hours)	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
Nov	9.56	16.27	61	4	432	232
Dec	13.55	16.31	29	15	315	207
Jan	12.93	20.56	1	0	312	103
Feb	14.96	19.77	2	0	192	79
Mar	14.91	19.28	0	0	220	117
Apr	7.70	22.38	82	0	472	62

Figure 1-7 shows the average supply curve for the November-April period. The offer stack appears to have shifted slightly to the left in 2005/2006 due to an increase in net exports. There was a sharp change in the offer strategies of some generating units. In 2006, base-load hydro and nuclear typically offered at large negative prices. There was also an upward shift in the offers of price-setting units including gas, coal and peaking hydro (these units typically offer anywhere between $20 and $1000).

Figure 1-7: Average Supply Curves, November–April



While the supply cushion provides no information about the shape of the offer curve it can provide some information as to whether the market is likely to clear on the steep or flat portion of the offer curve. In turn, while the offer curve indicates that overall levels of supply including imports were similar to previous years, the increase in the offer prices of price setting generating units implies that the market clearing price would be higher given the same level of demand.

Table 1-5 shows average hourly Ontario Demand and the average hourly market schedule by resource type. One can see that: (1) nuclear supply has increased in all months (except December 2005) due to the addition of two units and improved performance at some other units; (2) hydroelectric supply was marginally up; (3) self-scheduling supply was down in all months partly due to high natural gas prices and; (4) the shut-down of

Lakeview GS reduced monthly energy supply in the order of 200 to 300 MW for most months.

Table 1-5: Average Hourly Market Schedules and Ontario Demand (MW), November-April

	Nuclear		Hydroelectric Supply		Self-Scheduling Supply		Lakeview		Ontario Demand (NDL)	
	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006
Nov	7,583	9,173	4,189	4,144	993	839	366	0	16,988	16,783
Dec	9,852	9,446	4,124	4,316	1,004	773	0	0	18,352	17,973
Jan	9,607	9,950	4,155	4,062	1,025	775	338	0	19,129	17,737
Feb	9,520	10,632	4,223	4,311	1,048	840	209	0	18,414	18,114
Mar	9,081	10,046	4,115	4,318	1,019	929	245	0	17,576	17,176
Apr	6,587	9,415	5,025	5,058	922	743	122	0	15,844	15,399

6. *Reasons for Year over Year Changes in the HOEP: Shift-Share Analysis*

Shift-share analysis isolates the impact of changes in various exogenous supply and demand factors on the year-to-year difference in the monthly HOEP. The shift-share analysis shows what the average HOEP for a given month in 2004/2005 would have been if specified supply and demand factors were to take on their 2005-2006 values rather than their 2004/2005 values. The supply and demand factors included in the shift-share analysis are exogenous, that is, they are price determining rather than price-determined. Because the factors may not be entirely exogenous, the analysis should be viewed as a rough approximation. The exogenous factors included in the shift-share analysis are:

- changes in Ontario Demand (non-dispatchable load);
- changes in the supply of base-load nuclear generation;
- changes in the supply provided by the Lakeview generation station;
- changes in production of self-scheduling and intermittent generators; and
- changes in the supply provided by base-load hydroelectric generators.[3]

[3] We looked at the price impact of base-load hydroelectric supply only in this report since it is largely independent of the market price. Base-load hydroelectric supply includes the output of Beck, Saunders, and DeCew Falls. Peaking hydroelectric sources have both exogenous and endogenous components: the total available water is exogenous, depending on the amount of rainfall, but the decision of when to use this

Tables A-12 and A-13 in the Statistical Appendix provide data on the changes in hourly average values for each of the exogenous factors identified above for off-peak and on-peak periods, respectively. Tables 1-6 and 1-7 report the monthly results of the shift-share analysis for off-peak and on-peak periods.

Table 1-6: Estimated Impact on '04/05 Avg. Monthly Off-Peak HOEP of Setting the Exogenous Variables at 2005/2006 Levels

Factors	Nov ($/MWh)	Dec ($/MWh)	Jan ($/MWh)	Feb ($/MWh)	Mar ($/MWh)	Apr ($/MWh)
Ontario Demand	(0.90)	(1.53)	(8.81)	(1.30)	(2.23)	(1.94)
Nuclear Supply	(6.45)	2.98	(1.71)	(2.53)	(3.77)	(8.56)
Base-load Hydroelectric Supply	0.09	0.81	(0.59)	0.20	0.20	(0.14)
Lakeview	0.47	0.00	0.95	0.20	0.48	0.03
Self-scheduling Supply	0.45	2.05	1.17	0.07	(0.35)	(0.29)
Total Effect from Above Factors	(6.34)	4.31	(8.99)	(3.37)	(5.67)	(10.90)
Observed Change in HOEP	1.97	25.44	(1.73)	(1.30)	(10.31)	(19.82)
Residual	8.31	21.13	7.27	2.07	(4.64)	(8.92)

Table 1-7: Estimated Impact on '04/05 Avg. Monthly On-Peak HOEP of Setting the Exogenous Variables at 2005/2006 Levels

Factors	Nov ($/MWh)	Dec ($/MWh)	Jan ($/MWh)	Feb ($/MWh)	Mar ($/MWh)	Apr ($/MWh)
Ontario Demand	(0.73)	(1.91)	(12.07)	(1.56)	(2.20)	(4.11)
Nuclear Supply	(10.74)	4.71	(3.07)	(5.57)	(6.70)	(21.38)
Base-load Hydroelectric Supply	0.24	(0.21)	0.50	(0.51)	0.10	(0.28)
Lakeview	2.98	0.00	3.12	1.28	1.84	1.14
Self-scheduling Supply	0.15	2.47	0.81	0.31	(1.19)	0.84
Total Effect from Above Factors	(8.10)	5.06	(10.71)	(6.05)	(8.16)	(23.79)
Observed Change in HOEP	8.84	31.45	(2.82)	(1.58)	(11.25)	(17.39)
Residual	16.94	26.39	7.89	4.48	(3.09)	6.39

The shift-share analysis provides the following insights:

- Ontario Demand was lower than in the previous year in all months in 2005/2006 and this put downward pressure on the market price. The largest price impact was in January, where the 2004/2005 price would have been $8.81 lower off-peak and $12.07 lower on-peak had the 2004/2005 demand been at the 2005/2006 levels.

resource depends on the market price. To better reflect the exogeneity of the independent variable, we use base-load hydro instead of all hydro in this report.

- The return of one nuclear generating unit and increased output from existing nuclear units put downward pressure on price in all months except December. For example, the off-peak price in November 2004 would have been $6.45 lower and the on-peak price would have been $10.74 lower had the 2004 nuclear supply been at the 2005 levels. Nuclear supply was lower in December 2005 than in December 2004 due to a planned outage of one unit and a forced outage of another and this put upward pressure on the market price.
- Base-load hydroelectric supply was marginally lower in 2005/2006 but this had a negligible impact on the market price. The largest price impact of the change in base-load hydroelectric resources was off-peak in December: the December 2004 off-peak price would have been $0.81 greater had the 2004 base-load hydroelectric supply been at the 2005 levels.
- The closure of Lakeview had an upward impact on the monthly average price in all months except December and the impact was larger on-peak. For example, in January 2005 the average price would have been $0.95 higher off-peak and $3.12 higher on-peak had Lakeview been unavailable that month.
- Supply from self-schedulers and intermittent generation was lower in all months in 2005/2006 and this had the effect of increasing the market price. The largest price impact was in December when the self-schedulers and intermittent generation reduced their production likely in response to a dramatic increase in the price of natural gas.

While the shift-share analysis cannot explain all of the difference in prices between 2004/2005 and 2005/2006, the unexplained residual is relatively small except for peak and off-peak in December and peak hours in November. Of course, the existence of residuals implies that factors other than those included in the shift-share analysis are also in play. These factors include:

- changes in fuel cost
- changes in exports and imports in response to prices in neighbouring markets and intertie transaction failures
- changes in bidding strategies

- changes in operating procedures of the IESO, related to the treatment of out-of-market control actions and emergency imports
- changes in the operating reserve requirement such as the implementation of the 50 MW Regional Reserve Sharing Program[4]
- changes in available operating reserve offers such as more offers from dispatchable loads

The impact of changes in fuel cost is discussed in section 7 which follows. The influence of changes in foreign demand and supply conditions on imports and exports and ultimately on the HOEP is examined in sections 8 and 10.

7. *Changes in Fuel Prices*

A prominent observation in the early months of the study period is soaring natural gas prices. As Table 1-8 shows, the natural gas price was 15 to 86 percent higher in November 2005 to February 2006, with the largest jump in December. In March (and April) the natural gas price was slightly lower than a year before.

The price of coal, based on the NYMEX over-the-counter price for the Central Appalachian region, decreased in all months. Note that this coal price does not fully reflect the cost of coal to Ontario generators because: (1) it does not include the transportation cost; (2) only a small amount of coal is traded on NYMEX; and; (3) other types of coal are also used by generators. In fact, Ontario generators also burn the coal from the Powder River Basin, the price of which has more than doubled compared to last year.[5] For these reasons, the cost of coal used by Ontario generators may have decreased by less than the NYMEX price.

[4] For details of the RRS program, see Section 3.1, Chapter 3 of this report.
[5] For coal prices and related analyses, see the official site of the Energy Information Administration at http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot

Table 1-8: Average Monthly Fuel Prices, November-April

	Coal Price (NYMEX OTC $CDN/MMBtu)			Natural Gas Price (Henry Hub Spot Price $CDN/MMBtu)		
	2004/2005	**2005/2006**	**% increase**	**2004/2005**	**2005/2006**	**% increase**
Nov	2.93	2.86	(2)	7.13	12.34	73
Dec	3.05	2.79	(9)	8.03	14.97	86
Jan	3.06	2.70	(12)	7.53	10.11	34
Feb	2.94	2.68	(9)	7.58	8.70	15
Mar	2.97	2.60	(12)	8.45	7.98	(6)
Apr	3.04	2.51	(17)	8.83	8.09	(8)

Table 1-9 illustrates the impact of a change in fuel cost on a hypothetical coal-fired generator (9,000 Btu/KWh), on a hypothetical efficient gas-fired unit (7,000 Btu/KWh) and on a less efficient gas-fired unit (11,000 Btu/KWh). In this analysis, transportation costs and other costs associated with the delivery of fuel are not included. One can see that the decrease in the price of coal can be translated into a $0.63 to $4.77 reduction in production costs for coal-fired units while the increase in the price of gas between December 2004 and December 2005, for example, would have increased the production cost of gas-fired generators by between $48 and $76.

Table 1-9: Estimated Production Cost , November-April

	Estimated Coal-fired Fuel Cost ($/MWh)			Estimated Gas-fired Fuel Cost ($/MWh)					
Heat Rate	**9,000 Btu/KWh**			**7,000 Btu/KWh**			**11,000 Btu/KWh**		
	2004/2005	**2005/2006**	**Change**	**2004/2005**	**2005/2006**	**Change**	**2004/2005**	**2005/2006**	**Change**
Nov	26.37	25.74	(0.63)	49.91	86.38	36.47	78.43	135.74	57.31
Dec	27.45	25.11	(2.34)	56.21	104.79	48.58	88.33	164.67	76.34
Jan	27.54	24.30	(3.24)	52.71	70.77	18.06	82.83	111.21	28.38
Feb	26.46	24.12	(2.34)	53.06	60.90	7.84	83.38	95.70	12.32
Mar	26.73	23.40	(3.33)	59.15	55.86	(3.29)	92.95	87.78	(5.17)
Apr	27.36	22.59	(4.77)	61.81	56.63	(5.18)	97.13	88.99	(8.14)

The change in production cost of fossil-fuelled generators has an impact on the market price which depends on the respective frequencies with which coal-fired units and gas-fired units set the market price. Table 1-10 presents estimates of these price effects. The column ‘Impact of Fuel Price ($/MWh) - Low’ corresponds to the efficient type of gas-fired units (7,000 Btu/KWh), and the ‘Impact of Fuel Price – High’ to the less efficient type (11,000 Btu/KWh).

A comparison between the residual effect of shift-share analysis and the estimated impact of fuel cost provides further insights into understanding the average price differences. The large shift-share residuals in November and December can be explained largely by the change in fuel cost, specifically, the increase in the natural gas price. For example, the increase in gas price can explain more than half of the on-peak residual value in November, $16.94, and about one-third of the on-peak residual value in December, $26.39.

Table 1-10: Shift-share Residual Effects and Estimated Fuel Cost Impacts-2004/2005 Marginal Resource

	On-peak			Off-peak		
	Shift-share Residual ($/MWh)	Impact of Fuel Price ($/MWh) -- Low	Impact of Fuel Price ($/MWh) -- High	Shift-share Residual ($/MWh)	Impact of Fuel Price ($/MWh) -- Low	Impact of Fuel Price ($/MWh) -- High
Nov	16.94	8.42	13.42	8.31	0.97	1.80
Dec	26.39	6.32	10.76	21.13	(0.51)	0.32
Jan	7.89	5.01	8.73	7.27	(0.86)	(0.03)
Feb	4.48	(0.64)	(0.06)	2.07	(1.78)	(1.64)
Mar	(3.09)	(2.39)	(2.86)	(4.64)	(2.63)	(2.76)
Apr	6.39	(3.50)	(4.30)	(8.92)	(3.95)	(4.21)

The remaining residual may be explained by other factors including changes in fuel delivery cost, changes in environmental regulations and changes in generators’ offer strategies. Section 9 below reports the ‘implied’ heat rates of some representative natural gas-fired generators in order to shed some light on whether their offer strategies have, in fact, changed over time.

8. *A New Approach to Analysing Year over Year Changes in the HOEP*

Shift-share analysis is helpful in identifying some of the factors that affect changes in the monthly HOEP, although it often fails to explain a substantial portion of the monthly price changes. As a consequence, the MAU, under the direction of the Panel, has developed a simple econometric model to analyse monthly HOEP changes. In this section we present a preliminary version of this model.

The basic strategy involves the estimation of a reduced form model for the monthly HOEP over the period January 2004 to April 2006.[6] In this preliminary stage we have retained all the exogenous factors used by the shift-share analysis. In addition we have also included the price of natural gas and the New York real-time price[7] as explanatory variables for the monthly HOEP. These variables allow us to infer the influence of US demand and the price of natural gas on the monthly HOEP. Moreover we have also augmented the model with monthly binary variables to capture some seasonality effects. In Table 1-11 we present the initial results of the model estimation.

[6] Data for 2003 will be added in the future.
[7] This is the NYISO Zone OH real time price and it is the interface where most trades between New York and Ontario occur.

Table 1-11: Estimation Results of 'Reduced Form Model'

Explanatory Variables	Coefficient	Std. Error	t-Statistic	P-value
Constant	-73.5090	25.142	-2.92	0.0119
Nuclear Supply	-0.0039	0.001	-4.52	0.0006
Ontario Non-dispatchable Load	0.0053	0.001	4.58	0.0005
May	14.3027	2.926	4.89	0.0003
August	13.9373	3.711	3.76	0.0024
Natural Gas Price	2.7325	0.667	4.10	0.0013
April	8.1910	2.234	3.67	0.0028
September	10.7436	3.772	2.85	0.0137
March	5.4638	0.923	5.92	0.0001
June	11.0432	3.097	3.57	0.0035
July	8.9160	1.520	5.87	0.0001
New York Price	0.6074	0.124	4.91	0.0003
Lakeview Supply	0.0122	0.007	1.70	0.1122
Base Load Hydroelectric Supply	0.0093	0.008	1.21	0.2471
Self-Scheduling Supply	-0.0032	0.008	-0.41	0.6903

Most of the explanatory variables are statistically significant at the 5 percent level. The adjusted R-square for the model is 96 percent. The last three variables turn out to be insignificant. In this preliminary stage we have chosen to retain these three variables in the model in order to facilitate a comparison of the predicted changes in price from this model with those from the shift-share analysis.[8]

Comparative Performance

The metric that we use to compare the performance of the two models is the mean absolute percentage error (MAPE). This metric expresses the prediction error as a percentage of the actual monthly HOEP observed in the relevant period.

[8] In future revisions to this preliminary model, the MAU intends to estimate the impact of model assumptions on the bias and consistency of the model parameters. In particular we will review the estimates of the statistically insignificant variables and the exclusion of correlated explanatory variables will be assessed.

Our scenario, similar to the shift-share analysis, keeps all exogenous variables constant at the level observed in the period November 2004 to April 2005 (except for the variable of interest which we replace with the 2006 level). For example if we want to estimate the effect of nuclear supply in April 2006 on the monthly HOEP in April 2005, we simulate the model with all variables constant at the April 2005 levels except for the nuclear supply which we replace with the April 2006 nuclear level. The resulting simulated monthly HOEP then yields the marginal effect of April 2006 nuclear supply on the 2005 April monthly HOEP. We then subtract this simulated April monthly HOEP from a model-calibrated April 2005 monthly HOEP to derive the model-predicted change in the April monthly HOEP. This model-predicted change is then compared with the actual change in the April monthly HOEP. Results for the two approaches for each month and for each exogenous variable are shown in the Table 1-12.

Table 1-12: Comparisons of Predicted Changes in the Monthly HOEP ($/MWh)

	Econometric Model						Shift-Share					
	2005		2006				2005		2006			
	Nov	Dec	Jan	Feb	Mar	Apr	Nov	Dec	Jan	Feb	Mar	Apr
Ontario Non-Dispatchable Load	(1.08)	(1.99)	(7.32)	(1.58)	(2.10)	(2.34)	(0.80)	(1.75)	(10.71)	(1.45)	(2.21)	(3.21)
Nuclear Supply	(6.22)	1.59	(1.34)	(4.35)	(3.78)	(11.06)	(8.95)	3.99	(2.50)	(4.30)	(5.48)	(16.04)
Base Load Hydroelectric	(1.32)	(0.47)	(0.76)	(0.83)	(0.97)	(1.37)	0.18	0.22	0.05	(0.21)	0.14	(0.22)
Lakeview	(4.46)	(2.06)	(4.13)	(2.55)	(2.99)	(1.49)	1.93	0.00	2.22	0.83	1.27	0.68
Self-Scheduling Supply	0.48	0.73	0.79	0.66	0.28	0.56	0.28	2.30	0.96	0.21	(0.84)	0.37
New York price	6.78	15.76	1.16	3.72	0.80	(1.24)	n/a	n/a	n/a	n/a	n/a	n/a
Natural Gas price	11.82	17.21	6.99	3.93	(0.11)	(0.26)	n/a	n/a	n/a	n/a	n/a	n/a
Predicted Changes in HOEP	6.01	30.77	(4.60)	(0.99)	(8.87)	(17.21)	(7.37)	4.75	(9.99)	(4.93)	(7.12)	(18.42)
Actual Change	5.98	28.95	(2.37)	(1.46)	(10.86)	(18.40)	5.98	28.95	(2.37)	(1.46)	(10.86)	(18.40)
Unexplained residual	(0.03)	(1.83)	2.24	(0.47)	(1.99)	(1.20)	13.34	24.20	7.63	3.47	(3.74)	0.02

Table 1-13 compares the results of the model and shift-share analysis according to the percentage of error.

Table 1-13: Percentage of Error: Econometric Model vs. Shift-Share Analysis

	ABSOLUTE DIFFERENCE BETWEEN ACTUAL AND PREDICTED CHANGE AS PERCENT OF ACTUAL HOEP 2004/2005	
	Model	**Shift-share**
November 2004	0.06%	25.52%
December 2004	3.60%	47.61%
January 2005	3.86%	13.17%
February 2005	0.95%	7.00%
March 2005	3.32%	6.24%
April 2005	1.93%	0.03%
MAPE	2.29%	16.60%

The MAPE or mean absolute percentage error is computed over the six month period. A MAPE of less than 10 percent is a reasonable benchmark to judge the performance of a model. In this case it is clear that the econometric model is far more informative than shift-share in analysing monthly price changes. Moreover this simple model will also allow us to directly infer the marginal effects of the New York price and the price of natural gas on the monthly Ontario HOEP.

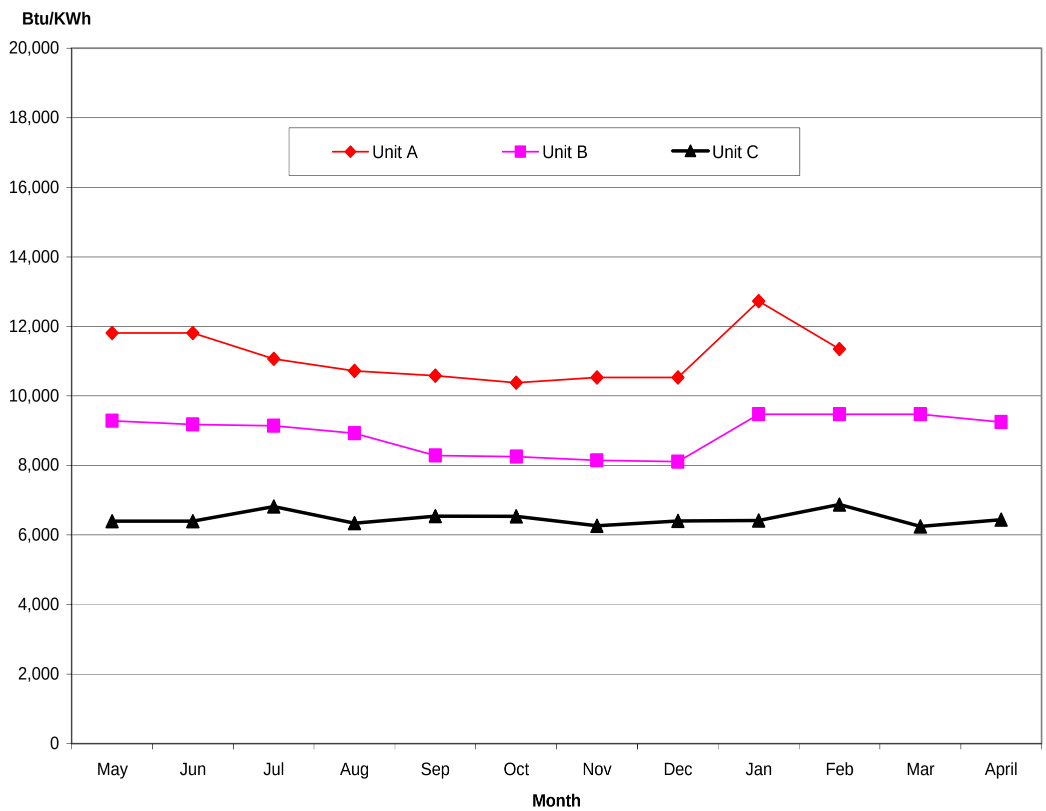
We are encouraged by the preliminary results obtained with this model and we have asked the MAU to continue to pursue ways to refine its analytical capability. In particular the development of a similar model for the on-peak and off-peak periods will be useful. We hope to use this model in the future to analyse the influence of key drivers on the electricity price in the Ontario market.

9. *Implied Heat Rate*

In our last report, we developed an index called the ‘implied heat rate’, that infers a generator’s heat rate based on its offer price and fuel price. The implied heat rate is the difference between offer price and the Operations and Maintenance cost (assumed to be $5/MWh) divided by the fuel price on the delivery day. The index allows comparison of the efficiency of generation and isolates changes in offers resulting from factors other than fuel cost. In particular, if a generator bids competitively its implied heat rate should be stable over time, regardless of the market conditions and the fluctuations in fuel cost.

Figure 1-8 illustrates the monthly average implied heat rate for three gas-fired units since May 2005. It is apparent that the implied heat rates for all three units were very stable and even decreasing from May through December 2005. However, two units show a significant increase in the implied heat rate starting from January 2006. The reason for the increase is that these two units were rarely dispatched in January through April due to low demand levels. Because they didn't expect to be dispatched by the system operator or expected to be dispatched at a low level, the two units offered a high price so that their start-up costs could be recovered.

Figure 1-8: Implied Heat Rate, May 2005 – April 2006 [9]



[9] Note that Unit A was either dispatched at its minimum load point in a few hours or not in the market in March or April.

10. *Imports and Exports*

There is significant trade between Ontario and neighbouring jurisdictions, especially on the New York and Michigan interfaces. Traditionally, Ontario is a large exporter to New York and a large importer from Michigan.

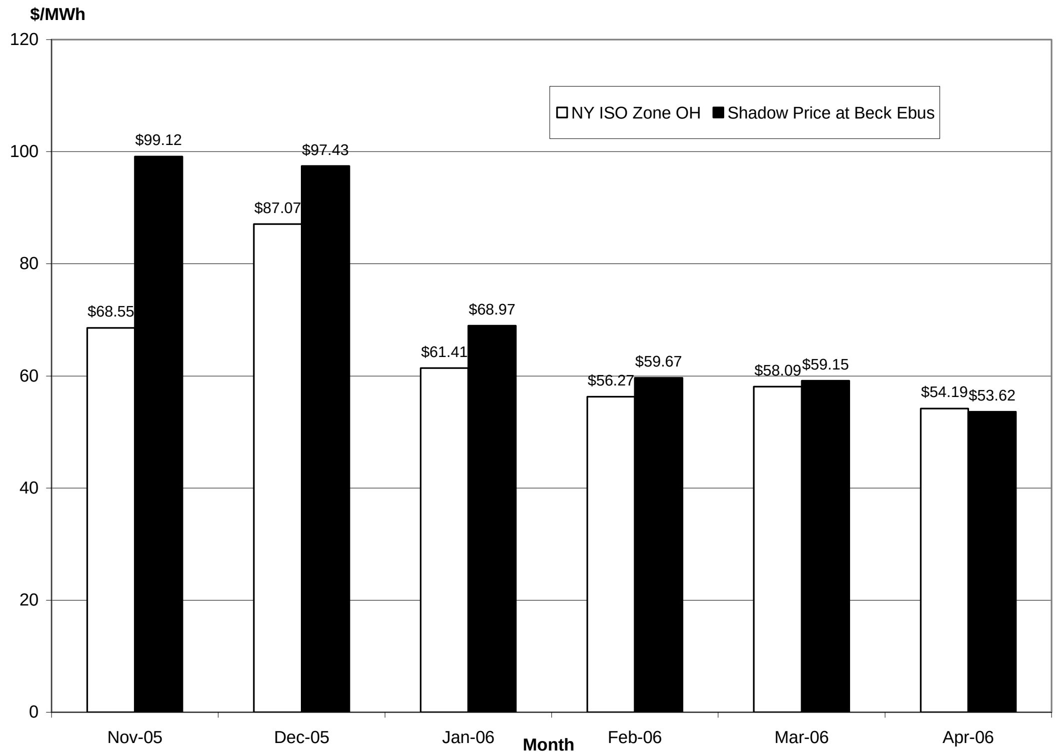
Imports and exports generally respond to price differences between adjacent markets and also contribute to price convergence. As Table 1-14 shows, Ontario was a net exporter in aggregate in all months in 2005/2006 although imports were slightly greater than exports on-peak in December 2005. It should be noted that Ontario's position as a net exporter in this period is a complete reversal from the previous six months, May through October 2005, where it was a net importer. When Ontario is a net exporter this puts upward pressure on the Ontario market price while the reverse is true when Ontario is a net importer.

Table 1-14: Net Exports from Ontario On-Peak and Off-Peak (MWh), November-April

	Off-peak		On-peak		Total	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
November	(267,649)	148,094	(329,824)	25,506	(597,473)	173,600
December	(8,289)	200,714	(139,370)	(13,734)	(147,659)	186,980
January	45,765	192,403	25,133	228,771	70,898	421,174
February	91,037	373,280	176,943	269,661	267,980	642,941
March	180,736	433,664	138,701	246,164	319,437	679,828
April	(187,057)	671,257	(207,975)	372,724	(395,032)	1,043,981

Normally, trade flows from lower price to higher price areas. This tends to equalize prices although transaction costs, transmission costs, transmission limitations and other factors may prevent full equalization. Given Ontario's position as a net exporter into New York during the period November 2005 – April 2006, it follows that the market price in Ontario should be lower than in New York. This is true of the HOEP (see Section 11 following) but it turns out that it is not true of the shadow price of power in the area of Ontario from which exports to New York flow. As shown in Figure 1-9, the shadow price in the area of Ontario adjacent to the intertie with New York, represented by the Beck Ebus, has generally been higher than the price on the New York side. In essence, exports to New York have been flowing from a higher price to a lower price area. This anomaly and its implications are discussed in greater detail in Chapter 2.

Figure 1-9: Beck Ebus Shadow Price vs. New York Price
November 2005 – April 2006 ($/MWh)



10.1 Analysis of Trade Flows between Ontario and New York

In past reports, the Panel has commented on neighbouring electricity prices and their subsequent effects on trade flows with Ontario. The Panel has directed the MAU to develop a more robust methodology to examine these trade flows. In this section we present an analysis of the trade flows (as measured by net exports) between Ontario and New York. Our approach focuses on the estimation of a reduced form econometric model for net exports. In this preliminary model we attempt to capture the responsiveness of trade flows to foreign demand (modeled by the New York price) while controlling for the effects of exogenous domestic supply conditions. This econometric approach allows us to infer the marginal impact of the New York price on the level of trade flows between Ontario and New York. Initial results are reported in Table 1-15.

Table 1-15: Estimation Results
January 2004 – April 2006

Variable	Coefficient	Std. Error	t-Statistic	P-value
Constant	875.63	772.76	1.13	25%
Nuclear Supply	0.39	0.03	14.50	0%
Hydroelectric Supply	0.56	0.25	2.28	4%
Ontario Demand	-0.28	0.05	-5.96	0%
New York price	11.28	4.79	2.35	3%
Natural Gas price	-45.42	18.19	-2.50	2%

This analysis shows the value of net exports is an increasing function of the New York price. This is indicated by the positive and statistically significant coefficient on the New York price. The model as specified, explains 90 per cent of the variability in net exports. The elasticity of net exports with respect to the New York price is 0.53.[10] In other words, a 10 percent increase in the New York price results in roughly a 5 percent increase in net exports, other things equal.

Based on these preliminary results the Panel has further instructed the MAU to extend this analysis to peak and off-peak trade flows between Ontario and New York.

10.2 Intertie Congestion

As the Ontario demand/supply condition improved in 2005/2006, transmission lines became less frequently congested in the import direction and more frequently congested in the export direction. This is shown in Table 1-16. Exports to New York were more frequently congested but this not yet a big issue: the number of hours with export congestion rose from 8 hours in 2004/2005 to 56 in 2005/2006. Imports from Michigan, were much less congested.[11] In contrast, import transmission from Minnesota became more congested compared to a year ago possibly because import capacity was frequently derated to 40 or 65 MW in 2005/2006 while during last year it was generally 90 MW.

[10] This is evaluated at the means of the New York price and net export.
[11] Phase shifters (PARs) were activated in March 2005 and consequently lowered the import/export capacity. For a detailed discussion, see the Panel's December 2005 report at pp. 79-82 and pp.100-101 and also section 2.3 of Chapter 3 of this report.

Table 1-16: Number of Hours with Interface Congestion, November–April*

	Import								Export			
	Michigan		New York		Minnesota		Manitoba		Michigan		New York	
	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006
Nov	23	11	0	0	14	30	2	1	0	0	1	2
Dec	14	15	0	0	2	17	1	1	0	0	1	4
Jan	11	6	0	0	3	13	1	0	0	0	2	6
Feb	6	1	0	0	3	18	2	0	0	0	1	3
Mar	15	5	0	0	1	26	0	1	1	0	3	13
Apr	30	0	0	0	7	13	7	0	0	4	0	28
Total	99	38	0	0	30	116	12	3	1	0	8	56

*Unconstrained Sequence

11. *Wholesale Electricity Prices in Neighbouring Markets*

Ontario has four neighbouring electricity markets: New York, PJM, New England and MISO, encompassing Michigan, Manitoba, Minnesota and all or part of 13 other U.S. states.

Ontario has historically been a net importer from Michigan and a net exporter to New York. While not directly linked to Ontario, both PJM and New England certainly influence the Ontario price as traders are active in all of these markets to arbitrage market opportunities.

Prices in these markets generally move in the same direction although intertie traders cannot fully arbitrage away price differences between markets due to factors such as:

- transmission constraints
- required bid-lead time
- imperfect information and
- scheduling protocols

Figures 1-10 to 1-12 compare the average, average peak and average off-peak HOEP with the neighbouring market prices. The HOEP continues to be much lower than NYISO, ISO-NE, and PJM in both on and off-peak hours as shown in Figures 1-11 and 1-12. The HOEP was higher than the Michigan price in November, December and

January, but lower than Michigan in April and on-peak in February and March. (It was marginally higher off-peak for these two months.) Somewhat lower prices from the Michigan direction are expected as it tends to be a coal-based region that may benefit from lower coal transportation costs than the Ontario coal-fired generators.

Figure 1-10: Average HOEP Relative to Neighbouring Markets November 2005 – April 2006

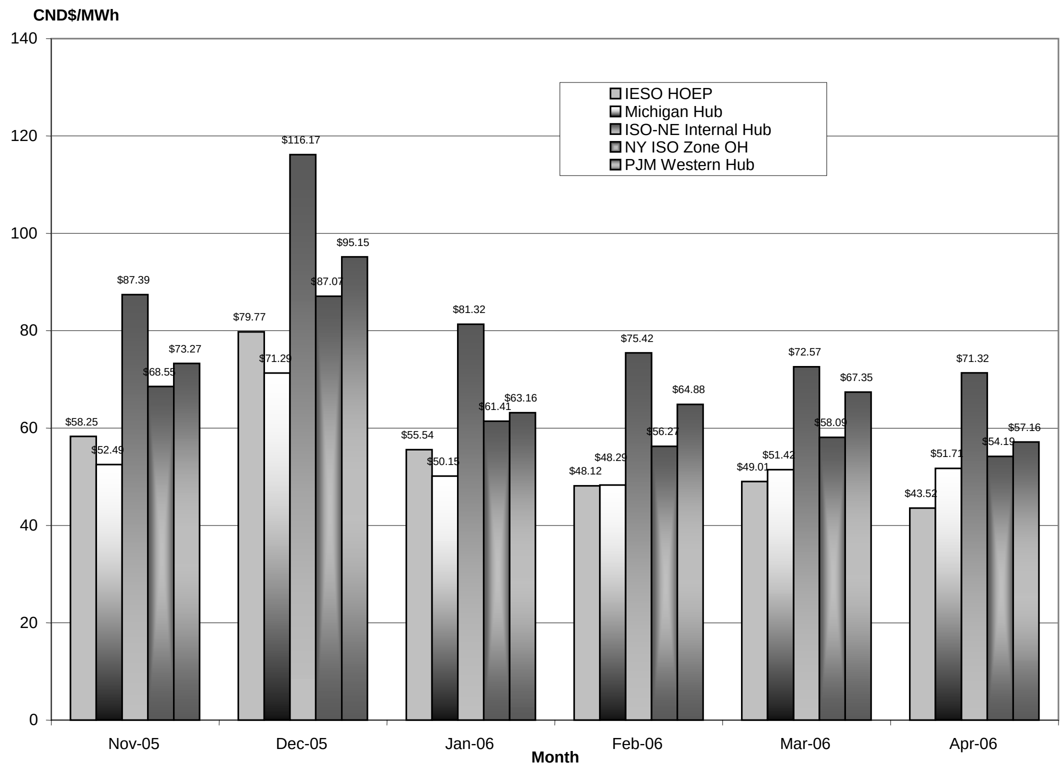


Figure 1-11: Average HOEP Relative to Neighbouring Markets, On-Peak, November 2005 – April 2006

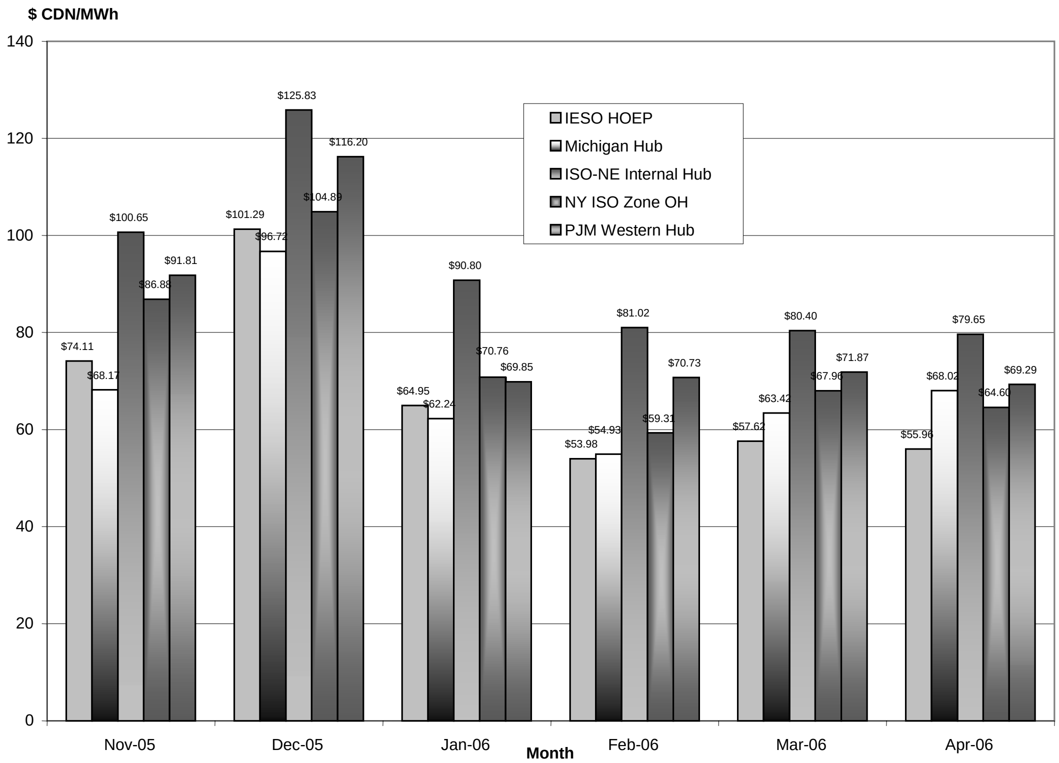
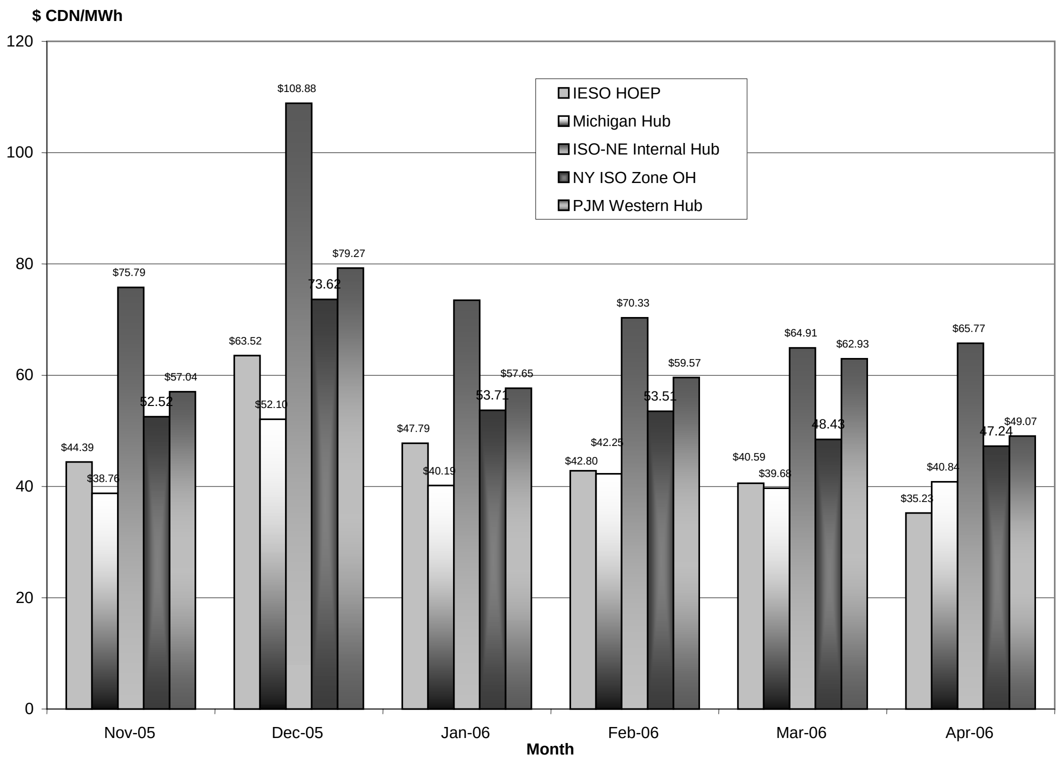


Figure 1-12: Average HOEP Relative to Neighbouring Markets, Off-Peak, November 2005 – April 2006



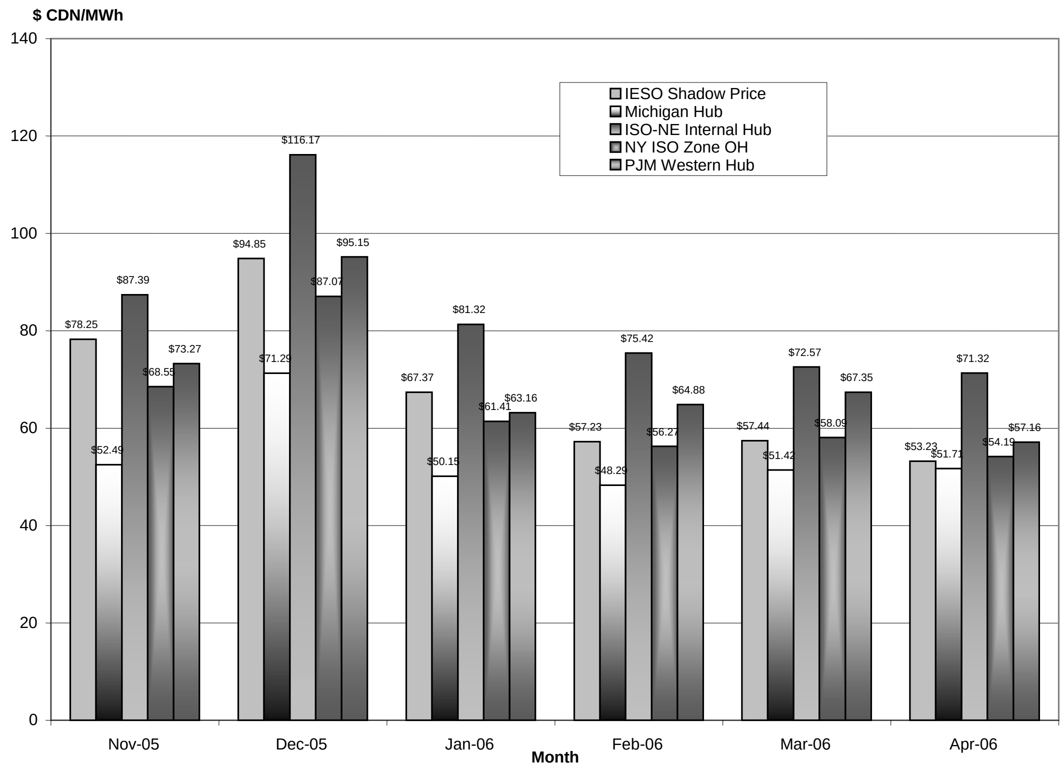
The HOEP is an Ontario-wide price that reflects the influence of low cost but bottled-in generation. The Richview shadow price is normally viewed as being more representative of the average marginal price of supplying energy in the province, taking into consideration transmission congestion and losses.[12] Richview is a node located in the Greater Toronto Area.

Ontario's average monthly prices represented by Richview are higher than the HOEP in each month, by varying amounts, as much as $20.27/MWh in November 2005 and as little as $1.83/MWh in January 2006. When we compare Richview shadow prices with those zones in neighbouring markets representative of the marginal energy costs for possible transactions with Ontario, Ontario's appearance as a lower production cost region changes. Based on monthly average HOEP, Ontario tends to be the lowest or

[12] Recall that the HOEP assumes that there are no transmission losses or congestion. Later in the chapter, Sections 16, Internal Zone Prices and CMSC by Internal Zone, give more information on the different price formulations.

second lowest priced area, whereas based on monthly average Richview prices Ontario exhibited the second, third or fourth lowest marginal production costs in the group with equal frequency. This is shown in Figure 1-13.

Figure 1-13: Average Richview Shadow Price Relative to Neighbouring Markets, November 2005 – April 2006



12. *Price Setters*

The percentage of time in the November through April 2004/5 and 2005/6 periods that a given fuel type set the market clearing price is set out in Tables 1-17 to 1-19.

Table 1-17 shows that coal-fired generation continues to be the dominant price setter throughout the period and at somewhat higher levels than a year earlier. The percentage of time that coal set the real-time price increased in all months except December, while the percentage of time that gas and water set the price fell in most months. The largest change was in the month of January in which coal increased its price setting share by

23 percent. In December natural gas-fired generation set price almost one quarter of the time. This is consistent with higher energy prices in that month.

Table 1-17: Share of Real-time MCP Set by Resource (%), November 2005 – April 2006

	Coal		Nuclear		Oil/Gas		Water	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
Nov	66.65	71.28	0.00	0.00	13.67	12.33	19.69	16.39
Dec	74.17	60.82	0.00	0.00	9.55	23.11	16.28	16.07
Jan	60.48	83.57	0.00	0.00	21.04	5.63	18.48	10.79
Feb	79.14	85.25	0.00	0.00	8.10	3.76	12.76	10.99
Mar	60.57	72.82	0.00	0.00	15.50	9.15	23.93	18.03
Apr	58.80	64.76	0.00	0.00	18.21	8.08	22.99	27.17

The on-peak figures for price setting shown in Table 1-18 repeat the pattern described above. The continuing importance of coal as a price setter reflects an increase in nuclear capacity, the traditional base-load supplier in the province. In essence, the increase in base-load capacity reduced the need to rely on high cost gas-fired generation, leaving coal generation as the marginal supplier more frequently. This does not imply that more coal-fired generation was used, only that it was marginal rather than inframarginal.

Table 1-18: Share of Real-time MCP Set by Resource (%), On-Peak, November 2005 – April 2006

	Coal		Nuclear		Oil/Gas		Water	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
Nov	52.60	57.05	0	0	24.26	24.15	23.14	18.80
Dec	62.23	45.30	0	0	16.62	40.79	21.16	13.91
Jan	45.47	78.60	0	0	36.58	10.02	17.95	11.38
Feb	71.12	80.72	0	0	13.32	6.32	15.56	12.96
Mar	46.64	59.33	0	0	25.87	15.87	27.49	24.80
Apr	43.43	67.30	0	0	27.73	17.37	28.84	15.33

The same general pattern prevailed in off-peak hours but Table 1-19 shows the traditional weakness of Oil / Gas and a surprisingly large share for hydroelectric generation in April 2006 compared to a year earlier.

Table 1-19: Share of Real-time MCP Set by Resource (%), Off-Peak November-April

	Coal		Nuclear		Oil/Gas		Water	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
November	79.11	83.58	0	0	4.31	2.11	16.57	14.31
December	84.05	72.40	0	0	3.65	9.91	12.29	17.68
January	71.86	87.62	0	0	9.03	2.06	19.10	10.32
February	86.44	89.37	0	0	3.38	1.42	10.19	9.21
March	72.01	85.84	0	0	6.84	2.66	21.14	11.49
April	72.26	63.09	0	0	9.70	1.96	18.04	34.95

13. *Operating Reserve Prices*

Tables 1-20 and 1-21 provide a comparison of monthly off-peak and on-peak operating reserve prices for each of the three classes of reserve.

Table 1-20: Operating Reserve Prices ($/MWh), Off-Peak November 2004 – April 2006

	10N		10S		30R	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
November	0.86	0.84	3.86	3.02	0.79	0.84
December	0.79	1.55	2.66	3.56	0.68	1.51
January	0.82	0.66	3.39	3.06	0.82	0.66
February	0.46	0.86	3.44	2.85	0.46	0.86
March	1.28	1.54	5.04	4.23	1.28	1.44
April	4.28	4.22	7.14	6.25	4.17	4.15

Operating reserve prices declined in some months and increased in others. There is no clear trend. January and April 2006 posted lower prices compared to a year earlier for all categories of OR in both off-peak and on-peak periods. Ten minute spin prices off-peak were lower in all months except December.

Table 1-21: Operating Reserve Prices ($/MWh), On-Peak November 2004 – April 2006

	10N		10S		30R	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
November	4.85	6.21	6.49	7.09	4.74	5.80
December	3.92	7.83	4.70	8.95	3.88	7.61
January	6.13	3.36	7.53	3.82	5.99	3.34
February	4.12	2.30	5.13	2.35	3.48	2.26
March	3.90	6.71	4.22	8.51	3.90	5.81
April	14.22	10.91	14.52	12.8	13.89	10.48

14. *One-Hour Pre-dispatch Price and HOEP*

The difference between either the three-hour ahead or the one-hour ahead pre-dispatch price and the real-time price is a measure of accuracy of price signals in the market. Inaccurate or unreliable pre-dispatch prices can lead to inefficient production decisions and can cause real-time scheduling inefficiencies. As will be pointed out in Chapter 3, they also detract from the IESO's TDRP.[13] Table 1-22 shows that the gap has increased in all months except January. The average monthly difference of 41 percent in April 2006 is the highest reported since January 2004.

Table 1-22: Measures of Difference between 1-Hour Ahead Pre-Dispatch Prices and HOEP, November-April

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		**Maximum Difference**		**Minimum Difference**		**Standard Deviation**		**Average Difference as a % of the HOEP**	
	2004/ 2005	**2005/ 2006**	**2004/ 2005**	**2005/| 2006**	**2004/ 2005**	**2005/ 2006**	**2004/ 2005**	**2005/ 2006**	**2004/ 2005**	**2005/ 2006**
November	11.12	14.62	70.28	109.30	(43.60)	(95.91)	15.74	24.08	23.86	30.18
December	8.33	17.99	89.97	115.80	(198.00)	(170.50)	18.53	29.64	18.82	31.06
January	10.57	7.76	108.60	98.88	(91.70)	(54.91)	15.62	15.46	20.47	15.99
February	6.52	8.32	65.08	85.36	(259.00)	(58.70)	14.43	12.23	14.56	18.80
March	9.55	10.25	57.98	92.99	(325.00)	(89.00)	18.01	15.45	18.71	24.13
April	10.28	7.74	82.78	107.75	(102.00)	(622.00)	16.79	29.19	21.15	40.88

[13] See Chapter 3, section 4

In previous reports we have identified the factors that contribute to the gap between the pre-dispatch and real-time prices as:

- demand forecast error
- variation in the performance of self-scheduling and intermittent generation
- out-of-market control actions and
- failure of scheduled imports and exports in real-time

All but failed intertie transactions show improvements or are likely to have had a negligible impact on the price gap. We review the data for each in turn. Included is an expanded discussion of self-schedulers that provides a preliminary review of the potential future impact of wind generation.

14.1 Demand forecast error

Table 1-23 shows the absolute percentage forecast difference has improved in all months for all measures compared to one year earlier. The average forecast difference for peak demand values, one hour ahead is now under 1 percent compared to 1.01 percent a year earlier and 1.19 percent in the immediately preceding period, May-October 2005. This compares very favourably to the typical standard of 2 percent for the other system operators that are members of the Northeast Power Coordinating Council (NPCC). The IESO continues to make refinements to its forecasting ability, the latest being the testing of an econometric model for day ahead forecasts that provides a confidence band to signal a need to re-evaluate underlying forecast assumptions.

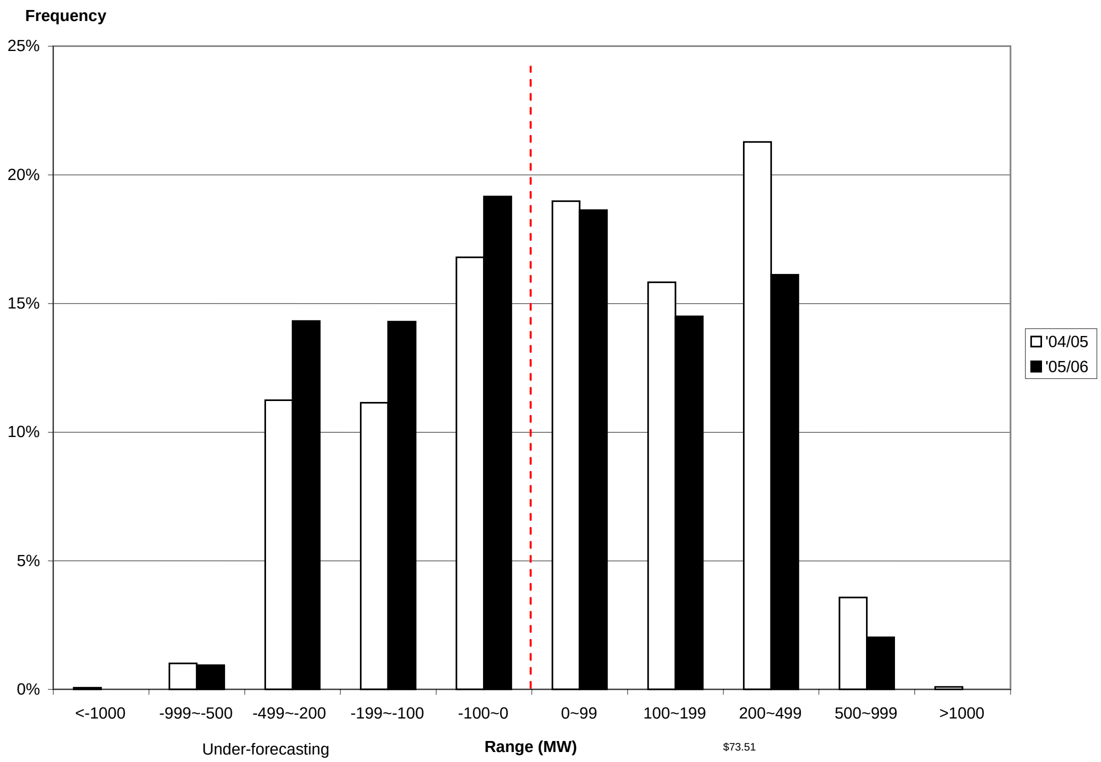
Table 1-23: Forecast Error in Demand
November 2005 - April 2006[14]

	Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1- Hour Ahead		3- Hour Ahead		1- Hour Ahead	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
November	2.29	2.03	2.12	1.84	1.29	1.21	1.05	0.97
December	2.38	1.97	2.10	1.79	1.53	1.22	1.25	0.95
January	2.11	2.09	1.88	1.81	1.30	1.39	1.01	1.09
February	1.92	1.89	1.70	1.69	1.19	1.18	0.91	0.93
March	1.76	1.78	1.62	1.61	1.11	1.06	0.86	0.86
April	1.97	1.87	1.79	1.67	1.27	1.16	0.99	0.94
Average	2.07	1.94	1.87	1.74	1.28	1.20	1.01	0.96

A dimension of forecast error in the past was the issue of bias in the forecast of demand, even on a peak-to-peak basis. Figure 1-14 now shows close to an even distribution in the frequency of over-forecasting and under-forecasting errors for the current period. This continues the pattern reported for the immediately preceding period, May-October 2005.

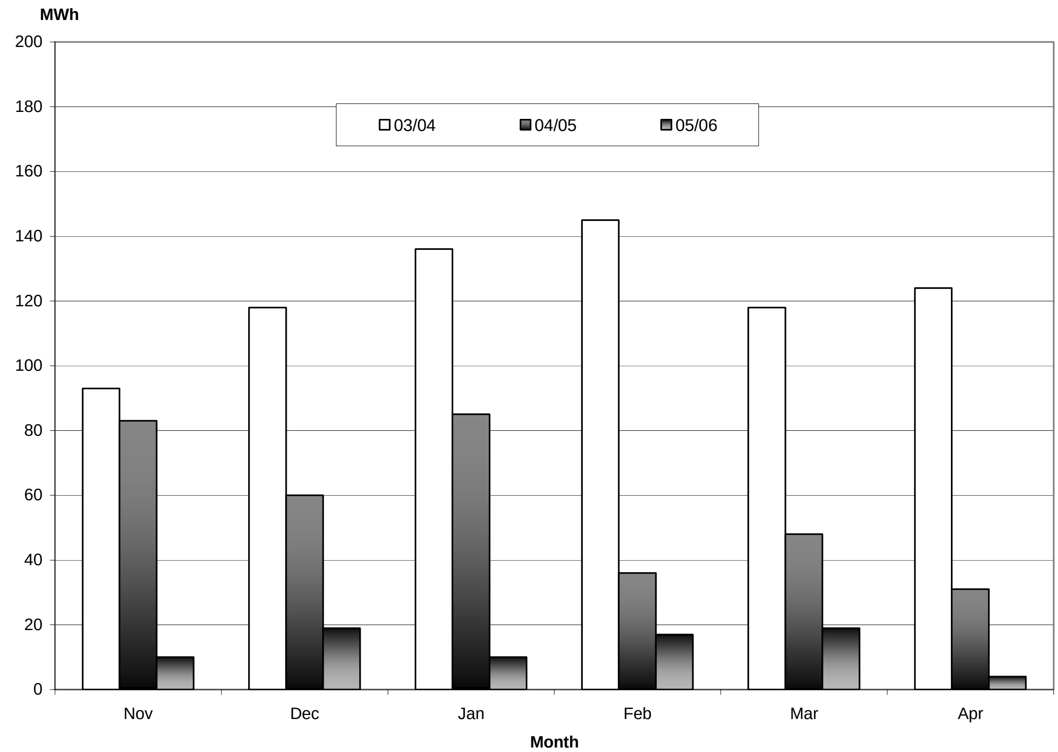
[14] The 2004-2005 numbers published in our June 2005 report differ slightly because demand did not include dispatchable loads. Since our last report, we have included dispatchable and non-dispatchable load values.

Figure 1-14: Frequency Distribution of Ontario Demand Forecast Error Comparing November-April



Another view of the tendency towards over-forecasting demand is obtained by examining the average values of the difference between the forecast pre-dispatch value and the actual peak demand in the hour. Figure 1-15 shows the monthly mean of the 1-hour ahead minus the real-time peak demand for each month. We have included data from the past two similar periods to portray the remarkable improvement in reducing the bias in the IESO’s demand forecast.

Figure 1-15 Mean Forecast Error in Ontario Demand, One-Hour Ahead Pre-Dispatch Minus Peak Demand in the Hour, November–April



14.2 Performance of Self-Scheduling and Intermittent Generation

Figure 1-16 shows the average monthly difference between the offers of self-scheduling units and their actual delivered quantities in the current period compared to a year earlier. The magnitude of the differences continues to be small and thus has little impact upon the pre-dispatch to real-time HOEP price gap.

Figure 1-16 Average MW Difference between Self-Schedulers Offered and Delivered Quantities, November 2005 – April 2006

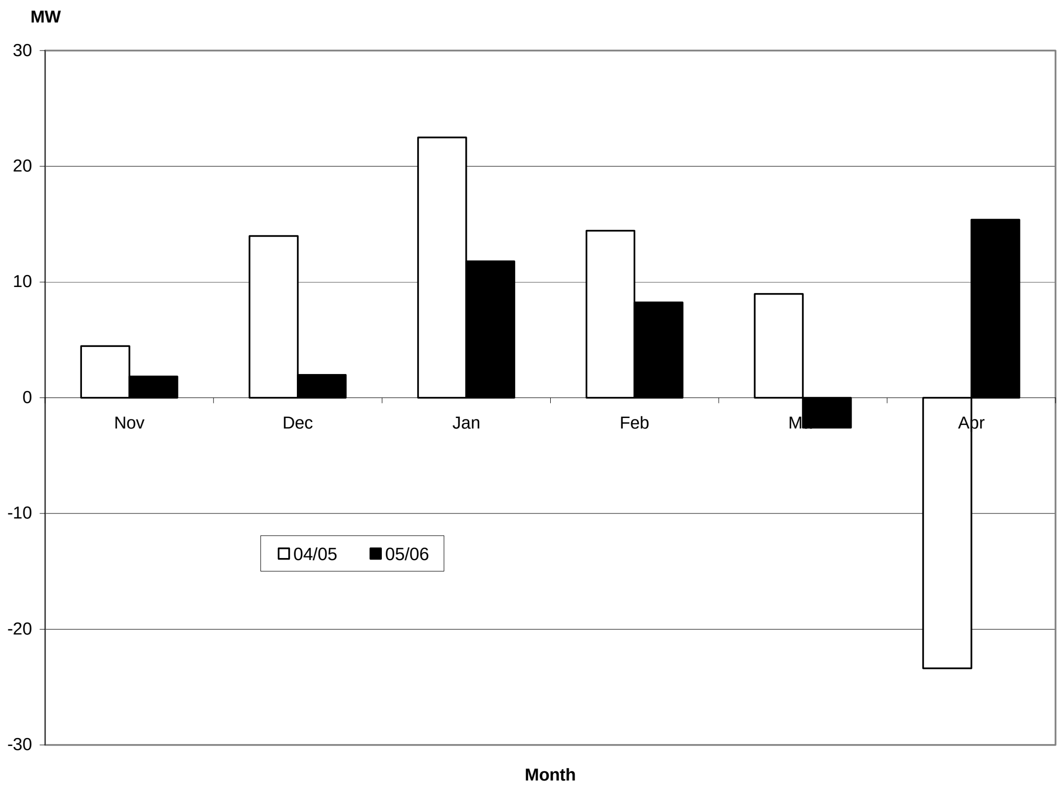


Table 1-24 shows the small average monthly absolute difference, ranging between 19-40 MW.

Table 1-24: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, November-April

	Total MW Pre-dispatch		Maximum Over-production (MW)		Maximum Under-production (MW)		Average Absolute Difference (MW)		Absolute Failure Rate (Abs Difference/MW Pre-dispatch) (%)	
	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006
Nov	784,062	670,401	229	185	149	164	36	33	3.42	3.72
Dec	809,100	638,461	223	233	119	109	34	30	3.24	3.64
Jan	839,424	645,993	205	141	118	81	30	26	2.62	3.09
Feb	766,811	618,271	224	134	168	89	32	19	2.95	2.10
Mar	822,583	767,993	177	132	119	102	23	29	2.11	2.85
Apr	710,274	636,415	148	175	190	126	33	40	3.78	5.44

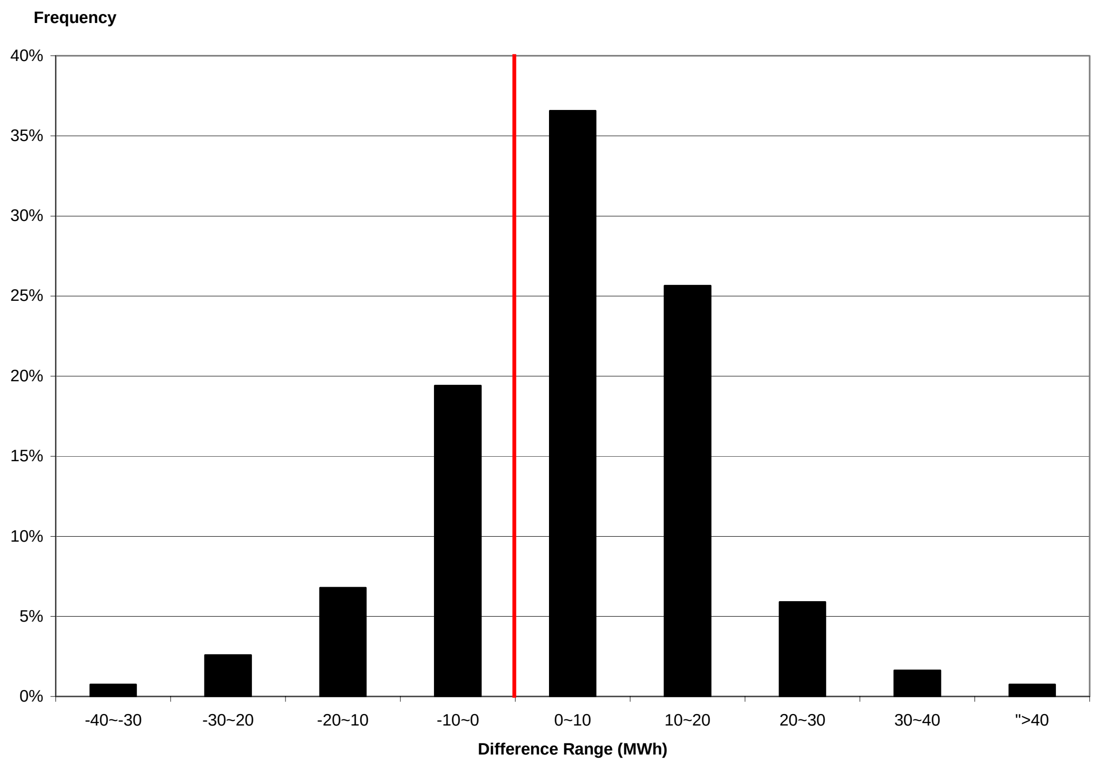
Performance of Wind-Power Generation

While self-scheduling error continues to be small, the size and makeup of the self-scheduling and intermittent portion of the Ontario market is quickly changing. Intermittent and self-schedulers represent an hourly average supply of 816 MW. Wind-power is beginning to have an impact on the Ontario market. While presently small, the roughly 100 MW of wind-power will be quickly ramping up to over 700 MW of installed capacity by October 2007 with a further amount to be specified by the Ontario Power Authority. These intermittent generators provide offers as to their expected performance in real-time. Decisions in pre-dispatch are made based upon these offers.

The MAU reviewed the performance of one wind project that was being put into service during the period covered by this report - see Figure 1-17. This review showed that the ability to generate was typically over-forecast and that the percentage error involved is significant. In total, wind generators forecast 44,829 MWh in the one hour ahead pre-dispatch during the period, but only delivered 37,390 MW in real-time, representing an over-forecast of 17 percent.

While the sample is very small, it would be a concern to the Panel if the forecast error that has been observed to date were to continue to prevail within the larger future population of wind generators. A forecast error such as this can lead to supply and demand inefficiencies as well as reliability problems.

Figure 1-17: Distribution of One Wind-Power Generators' Shortfalls (One Hour Ahead Pre-dispatch – Real-time), February–April, 2006



14.3 Out-of-Market Control Actions

The use of out-of-market control actions and its effects on market prices have been extensively discussed in previous reports. The IESO implemented the final tranche of 400 MW Control Action Operating Reserve (CAOR) only in real-time on November 23, 2005, with 200 MW at $75/MWh and the other 200 MW at $100/MWh. The present state of play is that pre-dispatch has 400 MW of CAOR.

Since the implementation of additional CAOR, we have observed only two hours with a manual OR reduction during the period: one in Hour 19 December 6, 2005, and the other in Hour 8, April 21, 2006. Both were mistakes that had no material impact on price. The April incident is described section 2.6 of Chapter 2.

The data in Table 1-25 suggest that the impact of manual reductions on OR requirements is no longer an important contributor to the discrepancy between pre-dispatch and real-time prices.

Table 1-25: Percentage of Intervals with Manual Operating Reserve Reductions* (Market Schedule)

	No Reduction		>1 MW and <200 MW		≥200 MW and <400 MW		≥400 MW and <800 MW		≥800 MW	
	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006
Nov	98.8	98.97	0.41	0.42	0.64	0.5	0.16	0.13	0	0
Dec	99.45	99.87	0.18	0	0.37	0.13	0	0	0	0
Jan	97.16	100	0.82	0	1.21	0	0.63	0	0.19	0
Feb	99.63	100	0.04	0	0.25	0	0.09	0	0	0
Mar	99.37	100	0.19	0	0.25	0	0.19	0	0	0
Apr	96.11	99.98	1.06	0	1.71	0.02	0.88	0	0.23	0
Avg	98.42	99.77	0.45	0.08	0.65	0.13	0.23	0.03	0.07	0

*Market Schedule

14.4 Real-Time Failed Intertie Transactions

Failed imports and exports remain a significant contributing factor to the differences between pre-dispatch prices and the HOEP. The data summarized in Tables 1-26 and 1-27 show little improvement in the incidence of either failed imports or failed exports, with average monthly failure rates similar to those experienced a year earlier.

Table 1-26: Incidents and Average Magnitude of Failed Exports from Ontario, November 2005 – April 2006

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
Nov	353	503	975	850	227	224	11.37	9.17
Dec	395	461	950	1098	257	221	10.00	8.95
Jan	392	543	1160	1132	230	216	7.41	8.92
Feb	421	541	830	1190	254	282	9.66	12.33
Mar	458	527	765	975	201	260	8.88	10.02
Apr	318	123	913	750	194	273	10.91	12.31

*Incidents of less than 1MW are excluded
**Average is based on those hours where failure occurred

Table 1-27: Incidents and Average Magnitude of Failed Imports into Ontario, November 2005 – April 2006

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
Nov	339	273	1134	539	135	112	3.6	3.15
Dec	259	293	1074	667	124	141	2.94	4.64
Jan	285	212	896	910	147	126	3.83	3.32
Feb	207	211	817	525	148	107	4.02	4.85
Mar	305	174	526	405	132	102	6.08	3.13
Apr	296	35	735	421	132	119	4.18	4.37

*Incidents of less than 1MW are excluded
**Average is based on those hours where failure occurred

More detailed data on import and export failures is provided in the Statistical Appendix, Tables A-40 through A-45.

Intertie transaction failures are the most important of the four factors contributing to the continuing discrepancy between real-time and pre-dispatch prices. The IESO plans to respond to this problem by introducing, effective June 2006, a real-time settlement charge for all failed transactions deemed to be within the control of market participants. The Day Ahead Commitment Process (DACP), to be introduced at the same time, may also improve the success rate of import transactions. The Panel will monitor the impact of these initiatives with interest.

15. *Hourly Uplift and Components*

As shown in Table 1-28, total hourly uplift charges were largely of the same order as those a year earlier. OR payments were $4 million less, offset by CMSC which was $3 million higher. The hourly uplift charges for the period compare favourably to the May-October 2005 period when total payments of $400 million were $185 million higher. This is another indicator of the transition from record demand levels and the associated grid congestion.

Table 1-28 Total Hourly Uplift Charge November -April ($ Million)

	Total Hourly Uplift		IOG		CMSC		Operating Reserve		Losses	
	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006	2004/ 2005	2005/ 2006
November	38	40	7	7	11	11	4	4	17	18
December	33	52	4	9	9	13	3	4	18	26
January	37	34	5	3	11	11	3	2	19	18
February	24	25	2	2	6	8	2	1	14	14
March	35	28	3	4	11	8	3	2	18	15
April	46	36	5	1	15	15	8	6	18	13
Total	**213**	**215**	**26**	**26**	**63**	**66**	**23**	**19**	**104**	**104**

Section 16 provides a detailed commentary on CMSC payment issues during the period.

16. *Internal Zone Prices and CMSC Payments*

As reported in earlier Panel Reports, Ontario has two real-time sequences:

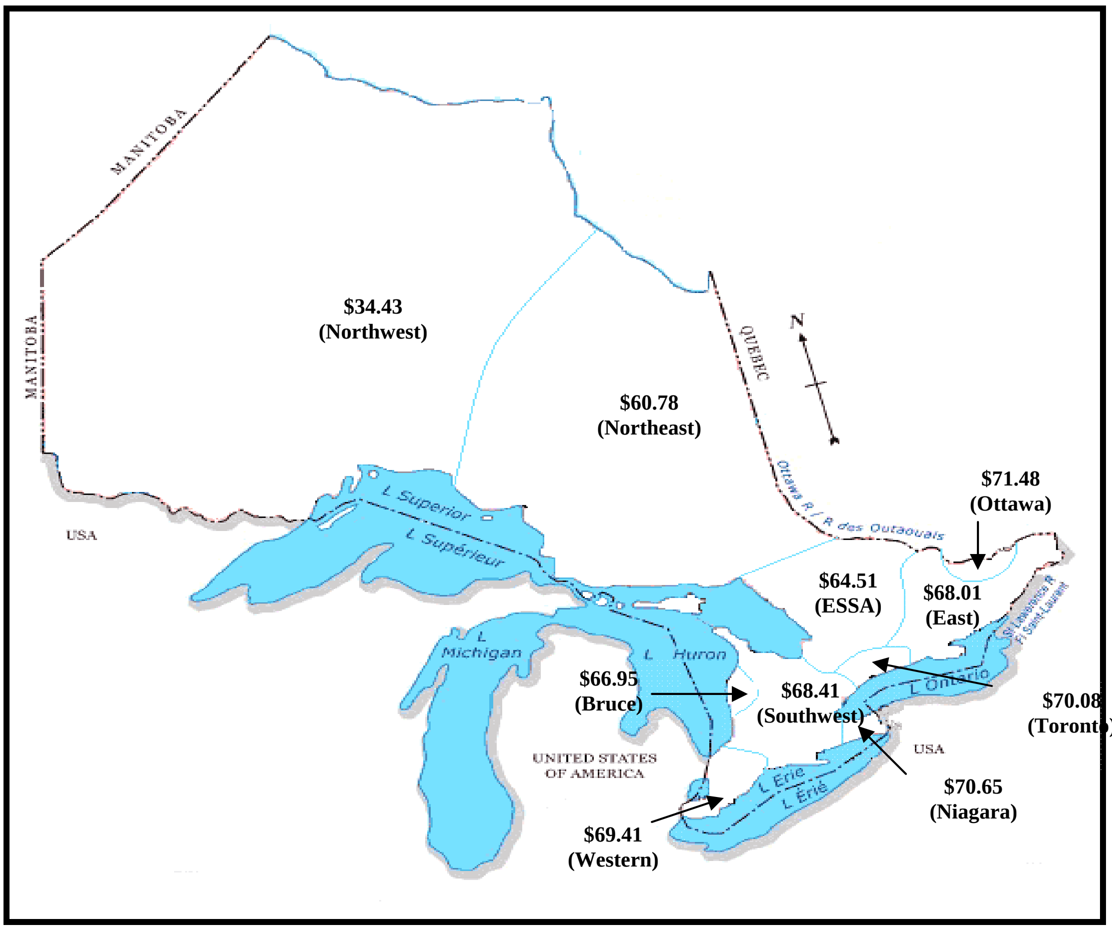
- an unconstrained sequence that determines the uniform price which generators receive and loads pay, assuming a transmission system with no constraints i.e., ‘bottle-necks’
- a constrained sequence that dispatches resources as well as calculates shadow prices at specific generator and load locations, taking into account constraints at all nodes.

The shadow price is the true cost of supplying the next MWh of energy at each node taking into account transmission congestion and losses. CMSC payments made to generators and loads result from the price differences between the two sequences at each node.

Figure 1-18 aggregates 300 nodal prices in Ontario into ten internal zones. Typically the nodes within each of these zones tend to exhibit the same characteristics due to the major transmission interfaces among them. Differences in prices between zones provide an indication of the congestion between zones

As the Panel observed in its last report, prices in central Ontario from Ottawa to the Western zone are relatively close to each other, suggesting that transmission congestion is not often a major issue amongst these zones. Although congestion is infrequent, during critical periods congestion in these areas can have a major impact upon reliability. On the other hand, the zonal price in the Northwest is $34.43/MWh, reflecting the frequent congestion on the transmission lines from the Northwest to southern Ontario as well as transmission losses. Although the average Northwest zonal price is the same as it was in May–October 2005 period, the remaining zonal prices have dropped by about $30 for reasons discussed earlier.

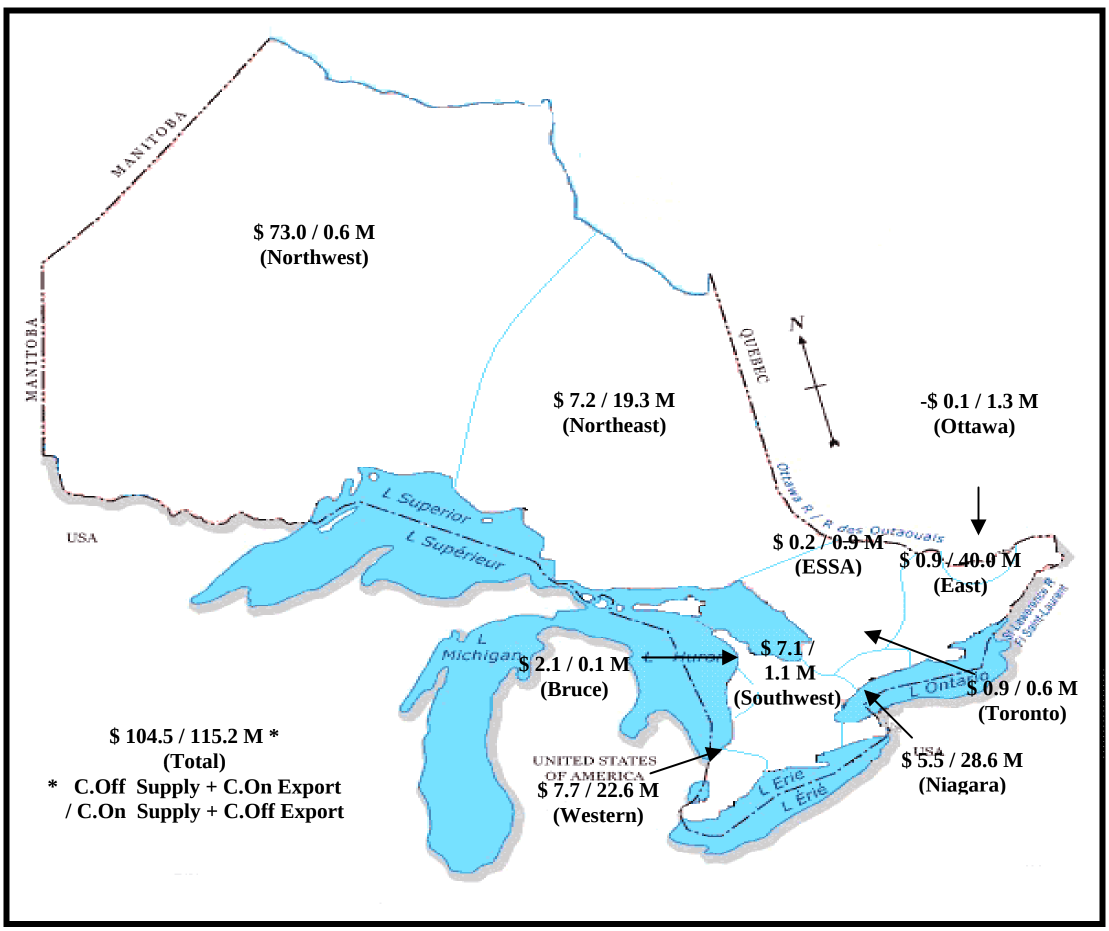
Figure 1-18: Average Internal Zonal Price, November 2005 – April 2006



CMSC and nodal prices are linked because a large component of each is induced by transmission constraints. CMSC is an indicator of the transmission congestion that exists within Ontario.

Figure 1-19 shows two sets of CMSC payments for each internal zone for the 12-month period ending April 2006. The first value is the sum of CMSC payments for constrained off generation, imports and constrained on exports. The second value is the sum of CMSC payments for constrained on generation, imports and constrained off exports. CMSC for imports and exports is attributed only to the zone to which the intertie is connected. Aggregating CMSC in this manner is a broad brush approach to understanding where congestion is occurring.

Figure 1-19 Total CMSC Payments by Internal Zones
May 2005 - April 2006



In the four zones in the southern part of Ontario which have interties, there are large payments to constrain on supply or constrain off exports - amounting to $23 million for the Western zone, $29 million for Niagara, $40 million for the East zone and $1 million for Ottawa. Of the total $93 million for these, some $66 million is for imports or exports. Since imports and exports cannot have self-induced or multiple ramp rate induced CMSC, all of the import and export CMSC can be attributed to internal transmission limits. In southern Ontario, this can be the result of local transmission interfaces but from our experience a very large portion of constrained-on supply is induced in response to the resources constrained off in the Northwest.

The zonal prices in the Figure 1-18 are not closely correlated with the CMSC payments in Figure 1-19. While it is easy to see the link between the low zonal price in the Northwest and the high CMSC payments there, in the Ottawa area CMSC for constrained on imports or constrained off exports is only $1 million even though its average nodal price is the highest among all zones. This is because CMSC payments are influenced not just by nodal price differences but also by the magnitude of the quantities constrained on or off.

The data above is the total CMSC over the last 12 months. In Table 1-29, we compare CMSC for the last 6 months against the same period a year earlier. Again, data are aggregated by zone as in the above figure, with the same assumptions.

Table 1-29: CMSC Payments by Internal Zone, November 2005 – April 2006

Internal Zone	Constrained Off Gen & Import Constrained On Export		Constrained On Gen & Import Constrained Off Export	
($ M)	Nov 04 - Apr 05	Nov 05 - Apr 06	Nov 04 - Apr 05	Nov 05 - Apr 06
Bruce	0.4	1.7	0.0	0.0
East	0.4	0.3	4.9	4.6
Essa	0.0	0.1	0.2	0.2
Niagara	2.2	2.7	8.0	10.7
Northeast	4.4	2.2	2.3	6.4
Northwest	17.1	17.0	0.6	0.4
Ottawa	0.0	0.0	0.0	0.3
Southwest	2.7	2.5	0.1	0.6
Toronto	1.5	0.6	0.7	0.4
Western	2.1	2.4	5.8	8.1
Total	30.8	29.5	22.6	31.7

Although we can identify CMSC payments associated with zones and often whether these are due to import/export constraints, it is not possible to associate these costs with specific interfaces or transmission lines (except for the E-W tie line) at this time. However, in the absence of nodal pricing we recommend (Chapter 4) that work be undertaken to associate the CMSC payments noted above with specific transmission interfaces. Such an effort would allow a more informed discussion of the necessity of transmission upgrades and investment decisions.

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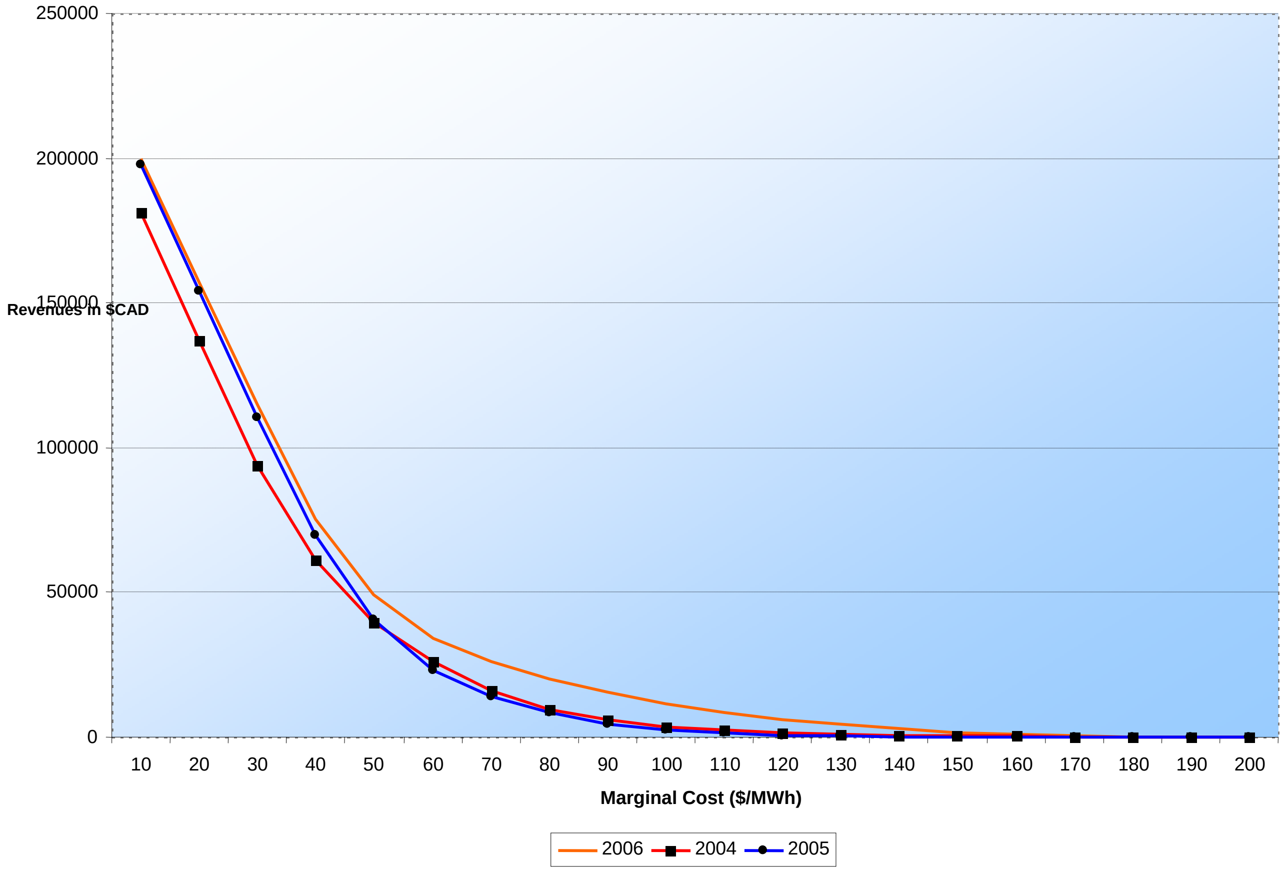
17. *Net Revenue Analysis*

Once again we asked the MAU to carry out a simple analysis to estimate the level of net revenues received by a generator in the Ontario market over the period. The analysis adopts the approach used in past Panel reports. Essentially a generator is assumed to produce energy whenever the hourly Ontario energy price (HOEP) in any hour exceeds the identified marginal cost of the generation. The net revenues or contribution margin received over the period are the sum of the hourly energy revenues minus the variable cost obtained by the generator. Results for the period November to April, on a year over year comparison, are summarised in Table 1-30 and Figure 1-20.

Table 1-30: Net Revenues, November-April Per MW

Marginal Cost ($/MWh)	2006 ($)	2005 ($)	2004 ($)
10	200,011	197,544	181,120
20	157,341	154,102	137,141
30	115,687	110,681	94,005
40	79,050	69,895	61,029
50	54,029	40,816	39,634
60	39,310	23,308	26,272
70	29,952	14,145	15,984
80	23,413	8,618	9,378
90	18,397	4,562	5,821
100	14,314	2,448	3,537
110	11,137	1,306	2,372
120	8,677	629	1,429
130	6,544	327	797
140	5,151	191	494
150	3,991	136	372
160	3,145	95	271
170	2,615	85	200
180	2,101	75	170
190	1,748	65	122
200	1,500	55	89

Figure 1-20: Net Revenues November 2003 – April 2006.



These results indicate that net revenues per MWh in 2006 were higher than in 2005 and 2004 for every level of marginal cost[15] To facilitate comparisons, the MAU estimated the marginal cost of a 7,500 Btu gas-fired generator over the period November to April, 2004 to 2006.[16] Results shown in Table 1-31 indicate that on average such a generator would have a cost of $60 in 2004, $66 in 2005 and $112 in 2006. The escalating marginal cost reflects the rapid rise in the cost of natural gas over the three periods. As a result the generator would have recovered net revenues of $26,272 in 2004 compared to $14,145 in 2005 and $11,137 in 2006.

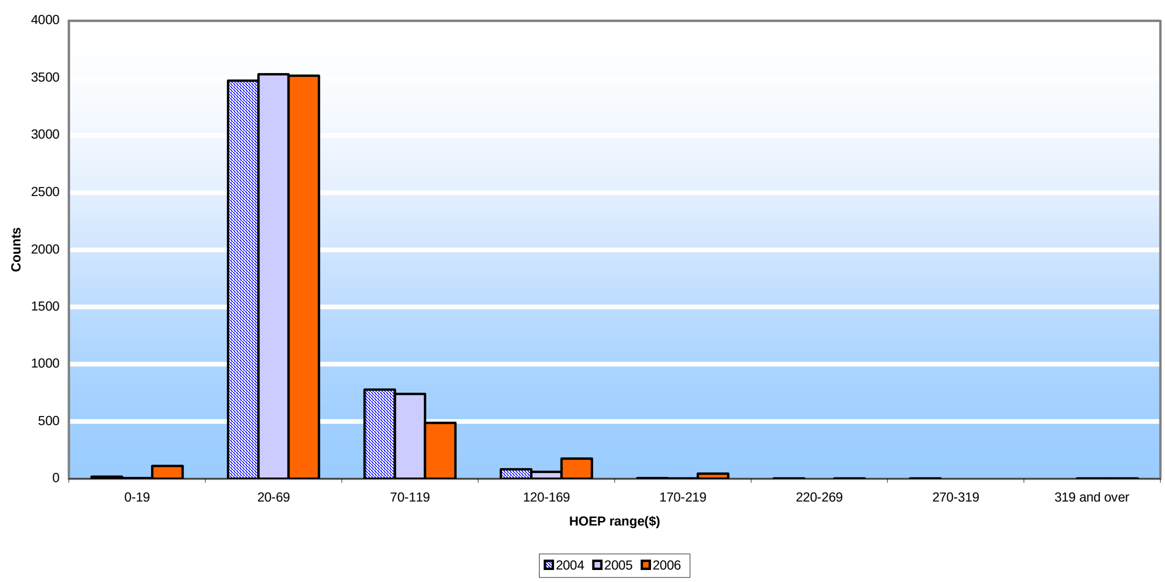
[15] In this section, the period year represents the period from November of the previous year to April of the current year. For example, year 2006 refers to the period November 2005 to April 2006.
[16] It would be misleading to compare the net revenues of the same marginal cost generator across all three periods without accounting for the rising cost of natural gas. After factoring the cost of natural gas, note how the increase in marginal cost substantially reduced the net revenues from the energy market.

Table 1-31: Marginal Cost of a 7,500 Btu Gas-Fired Generator, 2004-2006

	Average Henry Hub Natural Gas Spot Price in $ CDN	**Marginal Cost ($/MWh)**	**Net Revenues**
Nov. 2003-April 2004	$8.01	$60	$26,272
Nov. 2004-April 2005	$8.78	$66	$14,145
Nov. 2005-April 2006	$14.96	$112	$11,137

The higher net revenues in 2006 are mostly attributed to an increased frequency of high energy prices in the market in 2006 compared to 2005 and 2004. In particular there were 176 hours where the HOEP fell in the $120-$169 range in 2006 compared to 60 hours in 2005 and 83 hours in 2004. In 2006 the HOEP was between $170 and $219 in 45 hours compared to 3 hours in 2005 and 5 hours in 2004. These trends are reflected in the histograms of the HOEP in Figure 1-21 below.

Figure 1-21: Histogram of HOEP, November 2004 - April, 2006



Chapter 2: Analysis of Market Outcomes

1. *Introduction*

The Market Assessment Unit (MAU), under the direction of the Market Surveillance Panel, monitors the market for 'anomalies'. Anomalies are actions by market participants and market outcomes that fall outside of predicted patterns or norms.

The MAU reviews all 'high priced hours' to identify the critical factors leading to the high prices and reports its findings to the Panel. For the purpose of this report, 'high priced hours' are defined as all hours in which the HOEP was greater than $200/MWh or the hourly uplift exceeded the HOEP. The MAU also reviews all 'low priced hours' and reports its findings to the Panel. For the purpose of this review, a 'low priced hour' is defined as any hour in which the HOEP was less than $20/MWh.[17]

In addition, the MAU monitors for any other events that appears to be anomalous, even though they may not meet the 'bright-line' price tests, and reports its findings to the Panel.

With respect to high priced hours, there were 6 hours during the period November 2005 through April 2006 in which the HOEP was greater than $200/MWh. The following section describes the circumstances of these 6 hours. There was no hour during the review period in which the hourly uplift exceeded the HOEP.

Regarding low priced hours, there were 112 hours in the period November 2005 to April 2006 in which the HOEP was less than $20/MWh. Section 3 of this chapter reviews the factors typically driving the prices in these hours.

In its review and analyses of high priced and low priced hours and other anomalous events, the MAU did not find any event which suggested that there was gaming or abuse of market power by any market participant.

[17] The $200/MWh price limit is chosen based on the fact that the highest cost of a fossil generation unit is typically no higher than $200. The lower $20/MWh limit is chosen based on the fact that this reflects a lower bound for the cost of a fossil unit.

2. *Analysis of High Priced Hours*

The MAU regularly reviews all hours when the HOEP exceeds $200/MWh and when the hourly uplift exceeds the HOEP. The objective of this review is to understand the market dynamics that led to the 'high prices' and determine whether any further analysis of either flaws in the design of the market or the conduct of market participants is warranted.

Table 2-1 shows the number of high priced hours monthly since market opening. There were 6 hours in which the HOEP exceeded $200/MWh during the period November 2005 to April 2006. In the same period in the previous year (November 2004 to April 2005), there were 3 hours in which the HOEP exceeded the $200/MWh.

Table 2-1: High Priced Hours by Month, 2003-2006

	HOEP>$200			
	2003	**2004**	**2005**	**2006**
Jan	1	3	0	0
Feb	15	0	1	0
Mar	24	0	1	0
Apr	4	1	0	4
May	0	0	3	n/a
Jun	4	0	3	n/a
Jul	0	0	15	n/a
Aug	0	0	25	n/a
Sep	1	0	21	n/a
Oct	1	0	4	n/a
Nov	0	0	0	n/a
Dec	0	1	2	n/a

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

- Real-time demand is much higher than the pre-dispatch forecasts of demand

- One or more imports fail real-time delivery
- One or more generating units that appear to be available in pre-dispatch become unavailable in real-time as a result of a forced outage or derating

Each of these factors has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion.[18] Spikes of the HOEP above $200 are most likely to occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[19]

Occurrences of High Priced Hours

The 6 hours in the review period when the HOEP exceeded the $200 level are as follows:

- December 11, 2005 Hour 18 ($221)
- December 14, 2005 Hour 8 ($369)
- April 1, 2006 Hour 12 ($210)
- April 3, 2006 Hour 9 ($254)
- April 3, 2006 Hour 10 ($218)
- April 21, 2006 Hour 8 ($1,118)

In all six cases the supply cushion was below the 10 percent level. In three cases real-time demand was higher than the pre-dispatch forecast of demand, imports failed in real-time and inframarginal domestic generation was unavailable in real-time. In one case, failed imports and the forced outage of a unit contributed to the high HOEP and in another case higher than forecast real-time demand and failed imports drove up the HOEP. In the hour with the highest HOEP, the loss of inframarginal supply and an

[18] The supply cushion is explained on pp. 11-16 of the March 2003 report. It is a measure of the amount of unused energy that is available for dispatch in a particular hour and is expressed as a percentage derived arithmetically as:

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

EO = total amount of available energy offered
ED = total amount of energy demanded
OR = operating reserve requirements.

[19] Analysis by the MAU shows that the HOEP is 10 times more likely to be above $200 when the real-time supply cushion falls below 10 percent than when it is higher than 10 percent.

accident at a base-load plant contributed to the high price. The specific circumstances surrounding each of these high price events are discussed below.

The high price events in April reflect two recurring themes during the freshet period: first many peaking hydroelectric units were running for energy throughout the day. This meant that the offer curve became steeper as less peaking supply was available. As a result, any demand shock could result in significant price increase if the market cleared on the steep portion of the supply curve. Second, pre-dispatch market prices were usually low and high-cost gas-fired generators tended to shut down. This made the supply curve above the pre-dispatch price even steeper.

Table 2-2: Supply Cushion for High Priced Hours
December 2005 – April 2006

		Supply Cushion		Energy Price	
Date	**Hour**	**Pre-dispatch (%)**	**Real-time (%)**	**Pre-dispatch ($)**	**HOEP ($)**
December 11	18	18	2.5	181	221
December 14	8	21	3.0	199	369
April 1	12	26	5.0	72	210
April 3	9	23	2.7	70	254
April 3	10	23	3.3	76	218
April 21	8	24	7.0	78	1,118

2.1 December 11, 2005 Hour 18

In this hour the HOEP rose to $221/MWh.

Pre-dispatch market conditions

Pre-dispatch Ontario demand was projected at 20,707 MW with a pre-dispatch price of $181/MWh. There were 531 MW of hydro power and 45 MW of gas-fired generation priced between $181 and $350. All coal units were committed to full capacity. The market was a net exporter of energy with net exports of 345 MW. The supply cushion was 18 percent.

Real-time market conditions

Real-time Ontario demand averaged 20,290 MW with a peak of 20,443 MW that was 264 MW lower than pre-dispatch demand. Failed imports amounted to 242 MW. The supply cushion dropped to 2.5 percent. The HOEP reached $221. Lower than anticipated real-time demand (264 MW) would have the effect of decreasing real-time prices; failed imports (242 MW) tend to increase market prices. These two effects, other things equal, have a neutral effect on the HOEP. In the present case, the HOEP was higher than pre-dispatch. This indicates there were other factors that led to the high price. It turns out there was a fossil unit with offers in pre-dispatch that did not show up in real-time.

15:09 Pre-dispatch Run

The unit involved was coming back from a planned outage which was expected to end at 15:58. The unit initially had offers for Hours 18 to 24. At 14:54, just before the closure of the offer window,[20] the market participant felt that the unit would not be available for Hour 18 and as a result the market participant deleted existing offers for Hour 18. Mistakenly, however, the market participant re-inserted new offers at 14:54:34 (34 seconds later) for the unit for Hour 18. Instead of inserting new offers for Hours 20 to 24, the offers were re-inserted for Hours 18 to 24. As a result, the unit was selected in the 15:09 pre-dispatch run for Hour 18. However, the unit's output was set at zero in the 15:09 pre-dispatch schedule because the outage scheduler (which houses outage information) indicated to the DSO that the unit was unavailable.

16:09 Pre-dispatch Run

The outage terminated at 15:58 and the unit was available at 16:04 in the DSO. The unit was economical and it was selected in both pre-dispatch schedules (unconstrained at 16:09 and constrained at 16:15). This is because the unit was now no longer on an outage and there were offers submitted for Hour 18 (in error at 14:54:34). Absent this error,

[20] Participants can make changes to their offers until 2 hours before the dispatch hour. In this case the participant had until 14:59 (just before hour ending 16) to make changes for hour ending 18. See Market Rules Chapter 7, section 3.3.3.

there would have been no offers for Hour 18 and the unit would not have been in the market schedule for the 16:09 run.

In real-time, the unit's breaker was open because it was not ready to synchronise to the grid for Hour 18 and therefore it could not produce any energy.[21] The unit's output was zero.

Assessment

Because the unit was inadvertently in the pre-dispatch market schedule but not in the real-time market schedule, this had the effect of depressing the pre-dispatch price relative to the real-time price. In real-time, the market expected energy to be produced from the unit but instead had to obtain energy from higher cost resources. As a result the HOEP increased to $221 in Hour 18.

The outcome of the market participant's error was that the unit was not available in real-time and the market price rose. The MAU performed an analysis to determine the price impact of the participant's action. Had the unit been available in real-time, other things equal, the HOEP in Hour 18 would have been $166 instead of $221.
This incident is under investigation by the IESO's Compliance Unit to determine if a market rule was breached.

2.2 December 14, 2005 Hour 8

The HOEP in the hour reached $369/MWh.

Pre-dispatch Market Conditions

In pre-dispatch, demand was projected at 21,093 MW with a price of $199/MWh. Net imports amounted to 1108 MW. At a market price of $199 all available coal generation was fully scheduled. Between $200 and $400, offers from gas and oil generation

[21] For Hour 19, the unit was removed from both pre-dispatch schedules.

amounted to 542 MW and offers from hydroelectric generation totalled 523 MW. The pre-dispatch supply cushion was 21 percent.

Real-time Market Conditions

In real-time, demand averaged 20,703 MW and was never above the pre-dispatch level in any interval. In fact, peak demand was 21,042 MW. Failed imports of 216 MW and the forced outage of a gas-fired generator towards the end of the hour resulted in a supply disruption. The real-time supply cushion dropped to 3 percent. As a result, there was a shortage of conventional operating reserve from intervals 8 to 11 and the market turned to CAOR. The MCP reached a maximum of $610 in interval 11 while the HOEP jumped to $369. The loss of the generator was caused by problems with a synchronising breaker.

The loss of inframarginal supply from this gas-fired generator was a factor that contributed to the price spike. To examine the effect of this supply loss, the MAU conducted a simulation analysis. Had the pre-dispatch output from the generator been available in real-time, the HOEP in the hour would have been $185 instead of the observed $369.

Removal of Offers

The gas-fired generator was forced out in Hour 8; however the unavailability of another gas-fired generator in real-time (when it was picked up in the pre-dispatch constrained schedule) also contributed to the high HOEP. This second generator had both energy and reserve offers in the market for Hour 8 until 06:30 when these offers were deleted. In the final pre-dispatch run for Hour 8 (06:09), the unit was picked up for 36 MW of energy, 20 MW of 10S and 61 MW of 30R. In real-time, the unit did not start. When the first gas-fired generator was eventually forced out, the IESO made a call and requested an as soon as possible start for the second. This unit began producing in the beginning of hour ending 10. This raises the question why the unit was absent in real-time given that it was selected in the pre-dispatch constrained schedule.

<u>Assessment</u>

The operator of these generators re-evaluates its offer strategy as it gets more information on market conditions. The continuous addition and deletion of offers implies that the unit must be ready to start within a two hour notice. For Hour 8, however, the operator did not update its offers until 06:33 which is after the final unconstrained pre-dispatch run for Hour 8 (around 06:14). This meant the unit was deemed available to the market and it was in fact constrained on for 36.6 MW of energy in the pre-dispatch constrained schedule for Hour 8. After the pre-dispatch run, the operator realised that the unit could not make it for HE 8 and decided to delete the offers. Since the usual offer window was now closed, it had to request permission from the IESO to make the change within the mandatory offer window. The IESO removed the unit's offers for Hour 8 and therefore the unit was not available in real-time for Hour 8.

These actions were consistent with the relevant market manuals and market rules. The fossil unit in question was ABNO (available but not operating) requiring in the order of 2 hours to be ready to synchronise to the grid once scheduled in pre-dispatch. However, in keeping with the usual practice, it had placed offers for the hour prior (hour 8) in case it synchronized earlier than the start of hour 9 so that it would not run afoul of the market rule prohibiting generating without valid offers. As soon as the operator realized that the unit would not be ready for hour 8, it advised the IESO and thus satisfied the operating status notification obligation in the market rules. Therefore, when this matter was reviewed by the IESO's Compliance Unit no breach of the market rules was found.

The cause of the doubling in HOEP was the forced outage of the first fossil unit rather than the loss of 36 MW offered by the second unit. The MAU examined the circumstances of this event and has no reason to believe that it was other than a genuine operational event. Regarding the second failure, occurrences of this nature are relatively rare and in this case had a minimal impact on efficiency and increasing the HOEP. As a result we do not recommend any changes to the rules. These events may increase in the future as a result of the availability of more base-load supply leading to 'two-shifting' of fossil units that are then put into ABNO status. We have asked the MAU to keep us apprised if this behaviour becomes more prevalent in the future.

2.3 April 1, 2006 Hour 12

In Hour 12 the HOEP increased to $210/MWh.

Pre-dispatch Market Conditions

Demand was projected at 15,876 MW with a price of $72. Net exports were 723 MW and the pre-dispatch supply cushion was 26 percent. A number of fossil and nuclear units were on planned outages, accounting for approximately 4,700 MW. Typically major planned maintenance is undertaken on generators in periods when demand is lower such as the spring. Between $73 and $200, offers from hydroelectric generation amounted to 849 MW and there were 100 MW of coal generation in that price range. About 592 MW of hydroelectric generation were offered above $200 and there were only 14 MW of gas-fired generation above $200.

Real-Time Market Conditions

In real-time, demand reached a maximum of 16,245 MW and averaged 16,178 MW over the hour. With failed imports of 261 MW and the higher than forecast demand, the market had to find up to 631 MW of supply to meet demand. The supply curve was very steep as reflected in a real-time supply cushion of 5 percent. The market turned to the peaking hydroelectric supply to satisfy demand and it cleared on the steep portion of the supply curve. As a result the HOEP reached $210/MWh in the hour.

2.4 April 3, 2006, Hour 9

In this hour the HOEP reached $254/MWh.

Pre-dispatch Market Conditions

Demand was projected at 18,269 MW with an associated price of $70. Net exports amounted to 778 MW and the pre-dispatch supply cushion was 23 percent. Similar to the previous event, a number of fossil and nuclear units were on planned outages, amounting to approximately 3,300 MW. Between $78 and $200, there was 99 MW of hydroelectric supply in the offer stack and some 671 MW were offered between $200 and $2000. About 55 MW of gas-fired generation and 100 MW of coal generation were offered between $78 and $400.

Real-Time Market Conditions

In real-time, average demand came in at 18,310 with a peak of 18,372 MW. There were no failed imports in the hour. The forced outage of a nuclear unit from interval 2 onwards resulted in a loss of 416 MW of energy. In addition, the output of two fossil units was reduced by a total of 200 MW due to mechanical problems and many inframarginal units were on planned outages. As a result, the supply cushion fell to 2.7 percent. The supply shock caused the market to clear on the steep portion of the supply curve using hydroelectric supply offered above $200. The HOEP jumped to $254, $184 above the pre-dispatch price.

2.5 April 3, 2006, Hour 10

The HOEP increased to $218/MWh in the hour.

Pre-dispatch Market Conditions

Demand was projected at 18,320 MW with a price of $76. Net exports amounted to 661 MW. The supply cushion was 23 percent. A number of fossil and nuclear units were on planned outages, amounting to approximately 3300 MW. Again, the offer curve was very steep.

Real-Time Market Conditions

In real-time, demand averaged 18,363 MW with a peak of 18,451 MW. There were no failed imports in the hour. The loss of the nuclear unit in Hour 9 continued to have repercussions in Hour 10.[22] The market had to find 416 MW of lost base load supply. This came from coal and hydroelectric generation. The HOEP was driven up to $218 because in six intervals the market clearing prices were set by peaking hydroelectric units with offers above $200.

2.6 April 21, 2006, Hour 8

In this hour, the HOEP increased to $1,118/MWh and was eventually administered to $699.65/MWh. We first describe the events as they happened in real-time. Then we discuss the reasons behind the price correction.

Pre-dispatch market conditions

Demand was projected at 16,632 MW with a price of $78. Net exports scheduled amounted to 2,383 MW. Between $78 and $200, there were 36 MW of water, 15 MW of gas, and 40 MW of coal and import offers amounted to 561 MW. Above $200, there were 20 MW of gas, 164 MW of water and 1466 MW of imports. A number of gas, coal and nuclear units were on planned outages, approximately 4,200 MW. The pre-dispatch supply cushion was 24 percent. There were substantial import offers to meet any potential demand or supply shock.

Real-time market conditions

In real-time, Ontario demand averaged 16,738 MW with a peak demand of 17,123 MW in interval 8. Net exports were 2,233 MW. Demand came in higher than forecast in seven out of the twelve intervals as shown in the table below. The higher real-time price was the result of higher than forecast demand and a reduction in supply caused by two events.

[22] The unit tripped at 08:10, at approximately the same time that the pre-dispatch schedule is run for hour ending 10. As a result the pre-dispatch sequence still scheduled the unit in the market for HE 10. In real-time the unit's output was zero.

Table 2-3: Demand and Prices, April 21, Hour 8

Interval	MCP ($/MWh)	Real-time Demand Minus Pre-Dispatch Demand (MW)
1	275	(124)
2	370	(38)
3	450	6
4	1,280	119
5	2,000	250
6	1,280	124
7	370	(14)
8	300	(10)
9	1,998	292
10	2,000	491
11	2,000	216
12	1,100	(43)
Average	1,119	106

These events were:

- the unavailability of two fossil-fired units in real-time
- the loss of communication/telemetry with a hydroelectric generating station and the subsequent loss of Automatic Generation Control supply from a hydroelectric station[23]

The two fossil-fired units were selected in the pre-dispatch schedules to provide both energy and operating reserve. In real-time, each unit's output was zero. Both units had updated their offers just prior to the last pre-dispatch run for HE 8 (at 04:54). This indicated to the IESO that these units were available and ready for HE 8. In real-time, one of the fossil units failed to start and the other was slow to start. This had the effect of decreasing energy supply in real-time by 640 MW, 10S supply by 100 MW and 30R supply by 300 MW.

[23] Automatic Generation Control or AGC means the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between load and the output from generation facilities.

The loss of communication with the hydroelectric generating station was caused by a cable cut. The lack of communication between the IESO system and this station meant that this station unit could not effectively provide AGC support to the electrical grid. As a result the IESO had to find alternative sources of AGC. It turned out that 4 fossil-fired generators were available to provide AGC. Together these units provided 150 MW of AGC starting in interval 11 and 12. This implies that 150 MW of energy were not available to the market but instead were used for AGC. This had the effect of reducing supply by 150 MW in real-time in intervals 11 and 12.

Altogether, the combined supply reduction represented a large negative supply shock to the market. The market cleared at different points along the steep portion of the supply curve and this helps to explain the observed prices. In intervals 1 and 2, demand came in less than forecast and prices were set by the bids of peaking hydroelectric generation. From interval 3 to 6, demand started to pick up. Price in interval 3 was set again by peaking hydroelectric generation. In interval 4, demand increased by 119 MW and the market used the bid of a dispatchable load to solve for the price. In interval 5, demand rose by 250 MW and exceeded supply by 81.4 MW at the $2,000 ceiling price (known as a reserve deficit). The market was equilibrated by reducing reserve requirements by 81.4 MW and the MCP was set at $2,000 by a peaking hydroelectric unit. In interval 6, demand dropped relative to interval 5 and the price was set lower by a dispatchable load. In intervals 7 and 8, demand dropped further and peaking hydroelectric set the price. In intervals 9 to 11, demand suddenly increased and demand exceeded supply by 7 MW, 204.7 MW and 148 MW respectively. The reserve requirement was again reduced by the amount of the shortfall and the price was set by the bid of a dispatchable load in interval 9, by a peaking hydroelectric unit in interval 10 and by CAOR offered as energy at $2,000 in interval 11. Finally, in interval 12 demand dropped slightly and there was no reserve deficit. The price was set by the bid of a dispatchable load.

<u>Assessment</u>

The MAU analysed the impact of the two fossil-fired generators units on the market. Had these units been removed from the pre-dispatch schedule, the pre-dispatch price would have been $98 instead of $78 and 538 MW less exports would have been scheduled with no change to imports. This means that in real-time, market demand would have been reduced by 538 MW, other things equal. This in itself would have reduced the shortages in the market. The MAU also simulated what the price would be in interval 5 when there was a shortage in the market assuming these fossil units been available in real-time. The simulation indicates that the price in the interval would have been $87 instead of $2,000.

The IESO ended up administering the prices in intervals 5, 6, 9 and 11. In those intervals there was no information available on the output from this major hydroelectric station due to the failed telemetry. As a result, the IESO had to estimate what demand was in those intervals. In doing so the IESO overestimated demand as well as the degree of shortage in the market. As a consequence, market prices were overstated. The revised HOEP was reduced to $699.65. Table 2-4 below shows the original and the administered prices in the relevant intervals. The IESO also mistakenly lowered the reserve requirement in intervals 1 and 2. However this error did not materially affect market prices and no price correction was required.

Table 2-4: Intervals of Administered Prices, April 21, Hour 8

Interval	Original MCP ($/MWh)	Administered MCP ($/MWh)
5	2,000	1,100
6	1,280	320
9	1,998	350
11	2,000	650

It is also worth pointing out two other events that occurred as a result of this price spike. First, in this hour almost $250,000 of negative constrained off payments occurred, primarily related to constrained off exports in pre-dispatch that would have faced a high HOEP in real-time. This oddity is a consequence of the two market systems (unconstrained and constrained) that exist in Ontario and it is further explored in Chapter 4. Second, a price responsive non-dispatchable load cut consumption by 30 MW in the hour.[24] Typically a 30 MW reduction in demand does not have a large impact on market prices. In this case however the price impact was as much as $200 as shown in Table 2-5. Furthermore, absent the load reduction, the reserve deficit in some intervals in the hour would have been worse than what were observed.

Table 2-5: Price Impact of Load Reduction in Hour 8, April 21, 2006

Interval	Original MCP $/MWh	Simulated MCP $/MWh	Difference $/MWh
1	275	320	45
2	370	425	55
3	450	650	200
4	1,280	1,280	0
5	2,000	2,000	0
6	1,280	1,280	0
7	370	456	86
8	300	320	20
9	1,998	1,998	0
10	2,000	2,000	0
11	2,000	2,000	0
12	1,099	1,099	0
Average	**1,118.6**	**1,152.5**	**33.9**

3. *Analysis of Low Priced Hours*

A 'low priced hour' is any hour in which the HOEP was less than $20/MWh. As Table 2-6 indicates, there were 112 hours during the period November 2005 to April 2006 for which the HOEP was less than $20. During the same months a year earlier, there were 4 low priced hours. The lowest HOEP since market opening occurred on April 15, 2005 in Hour 3. In this hour a negative market clearing price prevailed in one interval. Section 3.1 below reviews this hour and explains the meaning of a negative MCP.

[24] This plant is non-dispatchable but it has the ability to re-organize production to avoid high electricity prices.

Table 2-6: Number of Hours with HOEP Less than \$20/MWh, November 2002 - April 2006

	# Hours HOEP <\$20/MWh
November 2002 to April 2003	3
November 2003 to April 2004	17
November 2004 to April 2005	4
November 2005 to April 2006	112

The MAU has found that, in general, a HOEP below \$20 occurs in hours when at least one of the following occurs:

- Ontario demand is less than 15,000 MW. This typically occurs in the overnight hours, on holidays or during the spring/fall seasons.

- Base-load supply is augmented by the supply from a number of hydroelectric facilities that become 'run-of-river' facilities due to the abundance of water from the spring run-off. This occurs most frequently during the spring time months of April, May and June but it can occur at other times.

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

<u>Occurrences of Low Priced Hours November 2005 – April 2006</u>

The MAU's review of these low priced hours indicates that they were mainly a result of low Ontario demand in combination with failed exports and over-forecast of demand. When real-time demand is this low, base-load generation may be sufficient to meet it. Table 2-7 summarises the results by month and Table 2-12 in the Appendix to the Chapter has detailed hourly statistics on these hours.

Table 2-7: Summary of Low Priced Hours, November 2005 – April 2006

Delivery Month	Failed Net Exports (MW)	Real Time Demand (MW)	Pre-dispatch Demand (MW)	HOEP $/MWh	Pre-dispatch Price $/MWh
November	300	14055	14709	$16	$35
December	247	13661	14094	$15	$35
January	352	15231	15632	$14	$34
February	465	14018	14435	$15	$32
March	468	13372	13595	$16	$31
April	356	12953	13146	$11	$24

3.1 April 15, 2006 Hour 3

The lowest HOEP since May 2002, $4/MWh, occurred in this hour.

<u>Pre-dispatch Market Conditions</u>

Demand was projected at 11,581 MW with a price of $12.72. Net exports were 1,927 MW. The pre-dispatch supply cushion was 49 percent.

<u>Real-time Market Conditions</u>

In real-time, demand averaged 11,491 MW with a peak of 11,599 MW. Failed exports amounted to 354 MW. The real-time supply cushion was 22 percent. The price in 11 out of the 12 intervals was set by a base-load hydroelectric generation with offers between $4 and $5. In the last interval of the hour, three hydroelectric units came back from forced outages. These units had negative offers in the market schedule. One of them set the price at $-0.88/MWh. The HOEP for the hour was $4/MWh.

<u>Assessment</u>

The Ontario market design allows market participants to submit negatively priced offers. Offers are stacked and the market price is determined by the intersection of market demand with the offer curve. In the first 11 intervals of the hour, the price was $4 and was set by base-load hydroelectric generation. In interval 12, a few hydroelectric units came back from forced outages. The additional supply from these hydroelectric units that became available in interval 12 was all priced below zero and was quickly selected in the market schedule ahead of the generation priced at $4. One of these units was the marginal unit with a negative offer price. As a result a negative price was determined for interval 12.

While negative offers are allowed and low market prices are welcomed by loads, negative bids can raise their own efficiency issues. Market participants may have contracts that pay them a fixed price for each MW produced. Provided this fixed price is above their incremental cost, these market participants have an incentive to run regardless of the market price and they may submit negative offers to ensure that they are selected in the market schedule. There is a risk that in submitting such offers, the market participant involved may displace another unit with a lower incremental cost but which may not be on a fixed-price contract. If this is the case, the market outcome is inefficient because a higher cost unit is selected ahead of a lower cost one. It is also conceivable that competitive bidding among market participants on this type of fixed-price contract could result in market prices below the incremental cost of production. To avoid these inefficiencies, the design of these fixed-price contracts should be such as to induce the market participants involved to base their offers on their incremental costs. We comment further on this in Chapter 4.

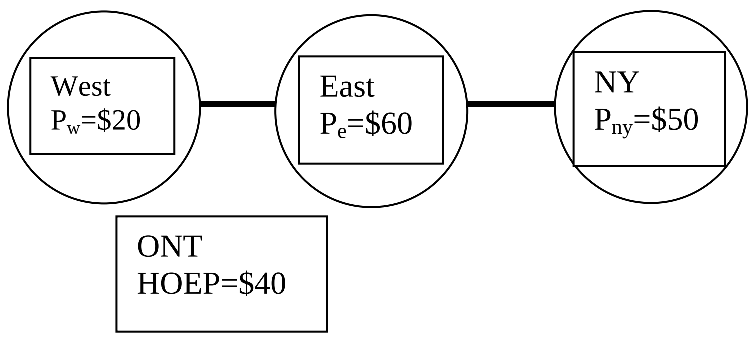
4. *Other Anomalous Events*

4.1 Inefficient Net Exports over the New York Interface

In the course of its monitoring activity, the MAU has found that energy is frequently exported (net of imports) from Ontario to New York when the incremental cost of producing the energy in Ontario is higher than the New York delivered price (which is presumably the incremental cost of producing in New York less any transactions cost). A net trade flow from Ontario to New York when prices in Ontario are higher than delivered prices in New York is inefficient. Further analysis points to the uniform pricing model employed in Ontario as the cause of this inefficient trade flow. As is explained below, the problem is that exporters from Ontario to New York pay the lower HOEP rather than the higher relevant shadow price at the New York interface.

Absent physical constraints preventing the flow of imports/exports between Ontario and New York, arbitragers should bid/offer exports/imports so that energy flows towards the jurisdiction with the highest prices. Such trade should occur until price differences are minimal. Evaluating the extent of arbitrage in the Ontario electricity market is complicated by the fact that different market participants pay or are charged different prices (shadow prices for CMSC payments and HOEP). It is also complicated by the fact that scheduling decisions (and payment obligations to importers) are made in two different time frames (pre-dispatch and real-time). The following stylized example is offered to illustrate these issues.

Figure 2-1: Stylized Example of Pricing Zones



Assume Ontario is divided into 2 nodes or zones, the West and the East and that there is congestion between the East and West so that the prices in the 2 zones (the nodal prices) differ. The price in each zone is established as the incremental cost of supplying the next MW of energy within the zone (based on offers and bids). The price in the West is $20 while the price in the East is $60 and the HOEP is assumed to be $40. Dispatchable market participants are then compensated for differences between their offers/bids and the HOEP through Congestion Management Settlement Credits (constrained on or constrained off payments). Generators in the West will be paid a constrained off payment (the lost opportunity for selling at the HOEP) and generators in the East will be paid a constrained on payment (to encourage them to run when their cost is higher than the HOEP).

Assume now that import/export activity was permitted between New York and Ontario (no congestion on the interface). At first glance, there would appear to be an arbitrage opportunity for an exporter to buy power at the HOEP and sell to New York. Assuming an export would incur a transmission charge of t = \$5, the exporter stands to earn a return of R = P_{ny-t} - HOEP = \$50-\$5-\$40 = \$5. This would suggest that if there were no congestion on the interface, arbitrage would lead to exports from Ontario to New York.

It would be inefficient however, if this export were to occur (i.e., to physically flow from Ontario to New York). While the exporter would pay only \$40 for the exported energy, it would be supplied from a generator in the East whose incremental cost was \$60. That is, a \$60 generator would be producing to supply a load in New York that would otherwise have been supplied by a generator with an incremental cost of \$50.

What should the exporter bid and would this export actually physically flow? Presumably, the exporter would not want to pay more than the New York delivered price. That is, the exporter should be willing to pay (bid) no more than B = P_{ny-t} = \$50-\$5 = \$45. If the exporter bid higher than this, it would risk buying at a price that was higher than what he would receive in New York. But, if the exporter's bid was B = \$45, the exporter would be constrained off. An export from Ontario to New York would be supplied from the East zone. Given that the export bid (its willingness to pay) is lower than \$60 (the cost of the next MW), the export would be uneconomic and would not be scheduled in the constrained dispatch. In this case, the export would not physically flow to New York. Instead, the exporter would receive a constrained off payment equal to the difference between its bid price and the HOEP. That is, CO = B - HOEP = \$45-\$40 = \$5.

How would an importer from New York likely offer? Importers would be willing to offer energy from New York into Ontario as long as the price they receive in Ontario is greater than P_{ny-t}. That is, they should offer O = P_{ny-t} = \$55. With these offers, they would not be selected in the unconstrained sequence but would be constrained on as their offer price is lower than the incremental generation cost in the East. These imports would physically flow from New York to Ontario.

In sum, in this example the physical flow of energy (measured as the constrained schedule) is from the lower price market to the higher priced market. That is, the physical trade flow should be efficient. It is not distorted by the HOEP which makes it appear as if Ontario is the lower priced market. In addition, in the absence of congestion and other impediments to trade, allowing both imports and exports on the Ontario - New York interface should result in a convergence of prices between the East zone and New York. Imports from New York (offered at \$55) would be constrained on in the East and would physically flow from New York to Ontario. This would cause P_e to fall towards \$55 and P_{ny} to rise towards \$55 (imports from New York to Ontario represent demand in New York that would cause P_{ny} to rise). At the same time, exports would be scheduled in the unconstrained schedule, but constrained off in the East. The scheduling of exports to New York in the unconstrained schedule would cause the HOEP to rise. The changes in HOEP and P_{ny} would in turn cause importers and exporters to adjust their optimal import offer or export bid. This dynamic adjustment process would continue to the point that, in equilibrium, absent any constraints on the interties, all arbitrage opportunities would dissipate. The key point is that, at least in theory, there should not be any inefficient trade flows.

A review of price and net export data between Ontario and New York appears to suggest that, contrary to theoretical expectations, inefficient trade flows (net exports) are frequently occurring between Ontario and New York. The nodal price at the Beck Ebus represents the incremental cost of supplying the next MW at the Beck Ebus node.[25] The Beck Ebus node is the node closest to the New York interface and in this respect it is the

[25] A nodal price includes the incremental cost of generation (based on offers and bids) plus the cost of delivery to that node (i.e., losses and internal transmission congestion). Nodal prices in the province can differ for two reasons: losses and transmission congestion. First, due to the physical characteristics of the transmission system, energy is lost as it is transmitted from generators to loads. Additional generation must be dispatched to provide energy in excess of that consumed by load. Second, transmission congestion prevents lower cost generation from meeting the load; higher cost generation must be dispatched in its place.

best reflection of the cost of supplying another MW of export from Ontario to New York. As discussed in the simple example above, when the Beck Ebus price is higher than the delivered price to New York, it implies that a higher cost generator in Ontario would be producing to supply a load in New York when this load could have been supplied by a New York generator with a lower incremental cost.

Figure 2-2 provides an indication of the prevalence of inefficient net exports from Ontario to New York. It plots the percentage of hours in a month in which the Beck Ebus shadow price (RT_s) was greater than the New York zone OH price (P_{ny}) less transmission charges (t) so (RT_s-$P_{ny\text{-}t}$>0) and Ontario was a net exporter (in the constrained sequence) to New York.[26] Table 2-13 in the Appendix to this chapter also provides this data. As Figure 2.2 indicates, inefficient net exports occur as frequently as 38.6 percent of the hours in the month of October 2005. Also, the frequency of inefficient exports appears to have increased since January 2004.

[26] The New York zone OH price is the higher of the hour ahead price (HAM) or the real-time price. The higher of the two prices was selected because exporters from Ontario to New York are provided a guarantee much like our IOG that assures them their offer price in NY's hour ahead Balancing Market Evaluation (BME) market. The transmission charge was assumed to be $5 Cdn. All New York prices were converted to Canadian dollars using the Bank of Canada daily exchange rate. Hours in which there was congestion on the New York interface were eliminated from the data set as in these hours there would be a physical impediment to arbitrage.

Figure 2-2: Percentage of Hours with Inefficient Net Exports to New York, January 2004 – January 2006

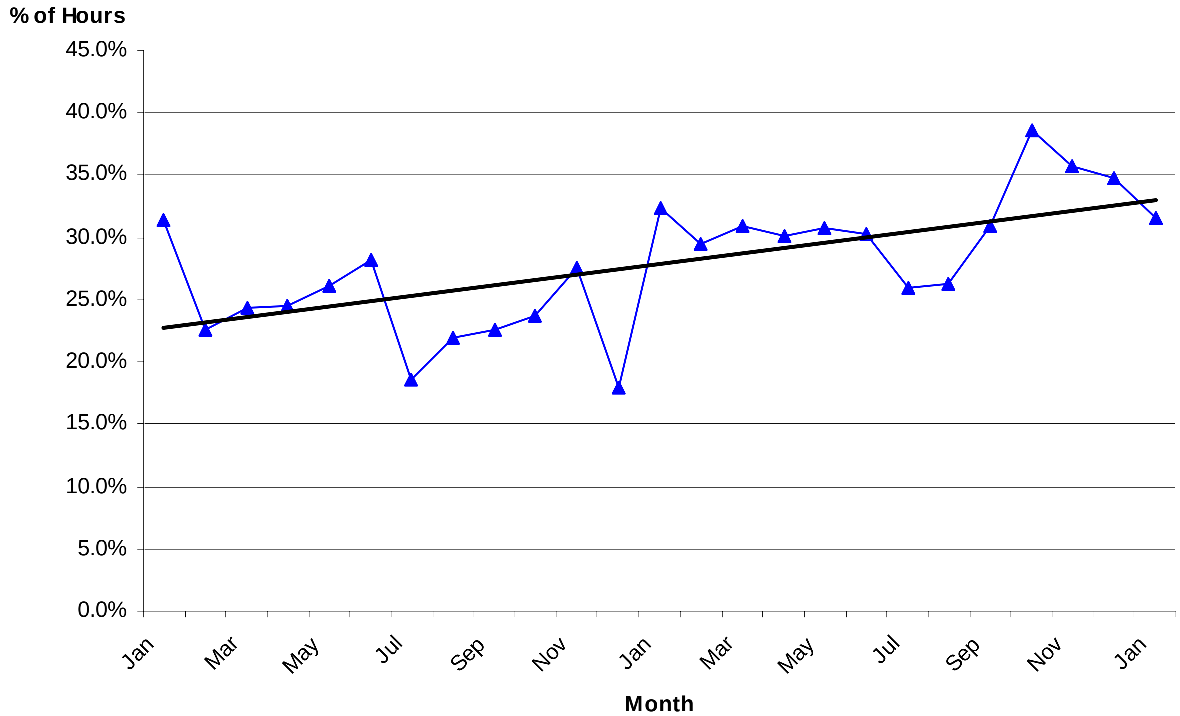
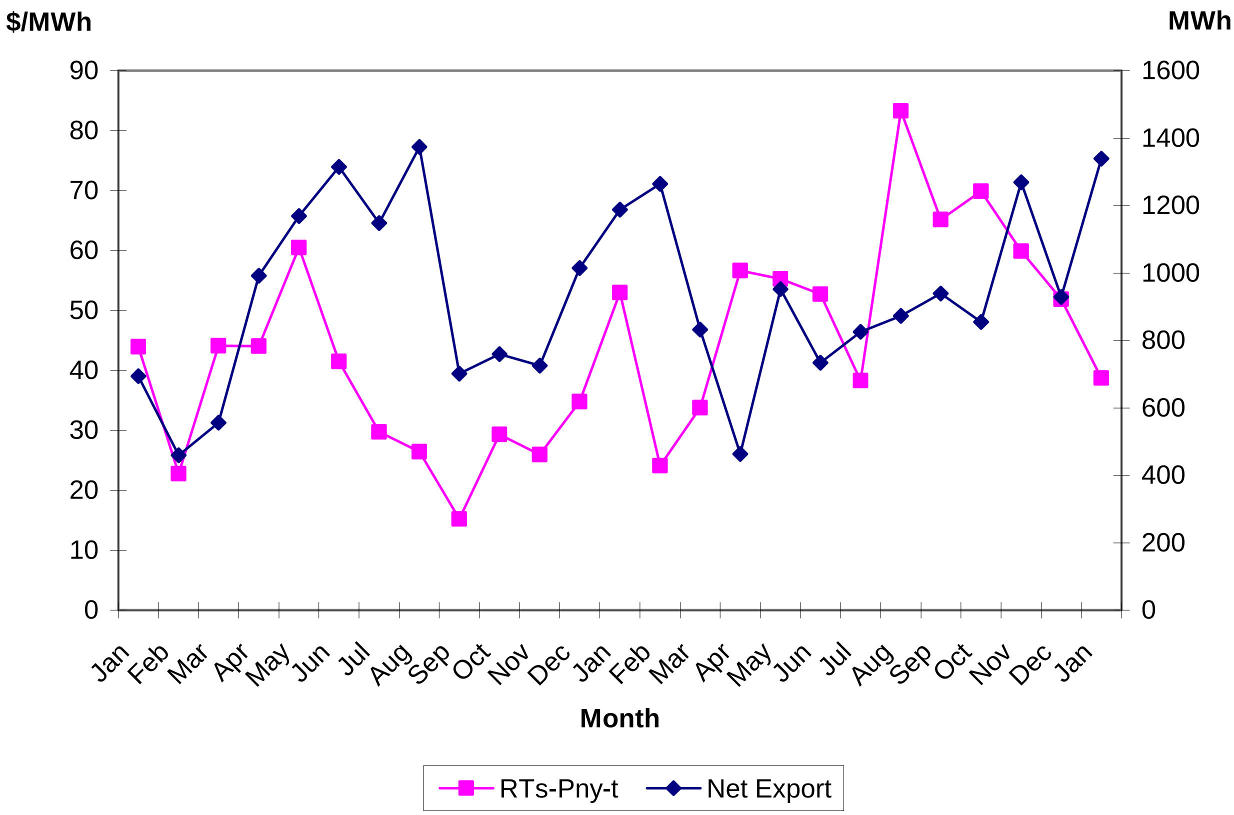


Figure 2-3 plots the average hourly price differences between the real-time Beck Ebus shadow price and the delivered price in New York for those hours in which there was inefficient trade flow identified. It also plots the average hourly net exports to New York when trade was inefficient. Figure 2-3 suggests that when there are inefficient trade flows, Ontario to New York price differences (net of delivery cost) are substantial, typically in the $40 range but as high as $84 last August. Figure 2-3 also indicates that the average hourly net exports when there is inefficient trade flow is substantial as well; typically in the neighbourhood of 1,000 MWh.

Figure 2-3: Average Hourly Price Differences and Net Exports, January 2004 – January 2006



This apparently inefficient arbitrage is extensive and contrary to our theoretical expectations. There may be other explanations for it. One possibility is that the timing difference between schedules and payment decisions for imports and exports may explain the appearance of inefficient trade flows.[27] In other words, what may be *ex ante* efficient (i.e. efficient scheduling of net imports in the pre-dispatch) may be *ex post* inefficient (inefficient in real-time).

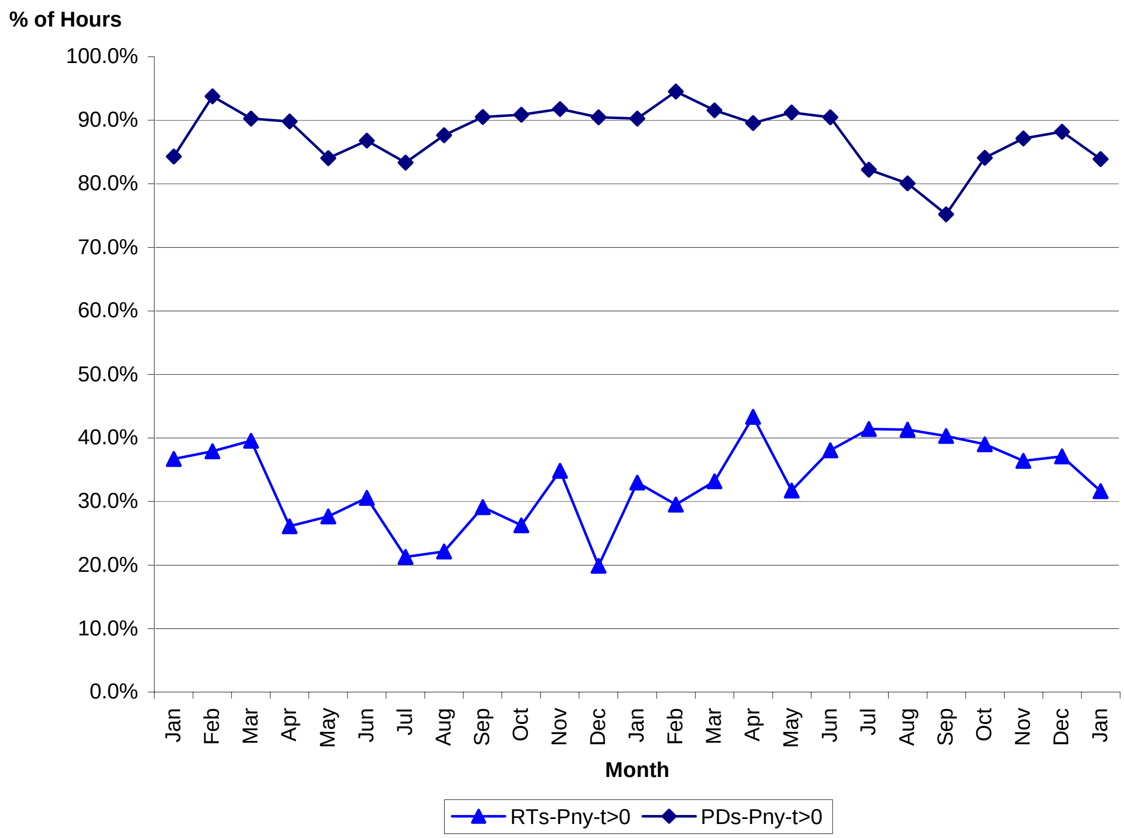
[27] In his 2002 report to the New York ISO Board of Directors and Management Committee, David Patton, the Independent Market Monitor for the New York ISO, indicated that the lack of convergence between the hour ahead market and real-time market prices had caused external transactions (exports and imports) to be scheduled inefficiently. See http://www.ksg.harvard.edu/hepg/Papers/Patton_NY_review_summer02_10-15-02.pdf

Assuming that exporters and importer bids and offers reflect the New York price plus delivery charges as discussed above (i.e. bids converge to P_{ny-t} and offers converge to P_{ny+t}), net exports will be physically scheduled to flow (in the pre-dispatch constrained schedule) whenever *ex ante* P_{ny-t} is greater than the pre-dispatch Beck Ebus nodal price (PD_s) and exporters expect that P_{ny-t} >HOEP. When this is the case, arbitragers will expect a profit opportunity from buying from Ontario to sell to New York. At the same time, the pre-dispatch will indicate that the cost of supplying the export (represented by PD_s) is less than the exporter's bid and the exporter's expectation of the delivered price to New York. When $P_{ny-t} > PD_s$ and P_{ny-t} >HOEP net exports to New York appear to be efficient in an *ex ante* sense.

However, due to unexpected changes from pre-dispatch to real-time, it may be the case that the cost of serving the exports (the real-time nodal price at Beck Ebus) increases so that in an *ex post* sense, we have inefficient physical trade flows. Since the exports are scheduled one hour in advance and are fixed regardless of the real-time prices, we must accept this inefficiency. Note also, that since the exporter never actually pays the real-time nodal price and instead pays the HOEP, it does not have to factor the possible spike of the real-time nodal prices in its bidding evaluation. It need only concern itself with real-time spikes in the HOEP. Therefore, as long as the HOEP does not spike as much as the real-time nodal price, there may be a tendency for *ex ante* efficient trade to appear as *ex post* inefficient trade.

Figure 2-4 provides a perspective on the likelihood that net exports are scheduled *ex ante* efficiently but are *ex post* inefficient.

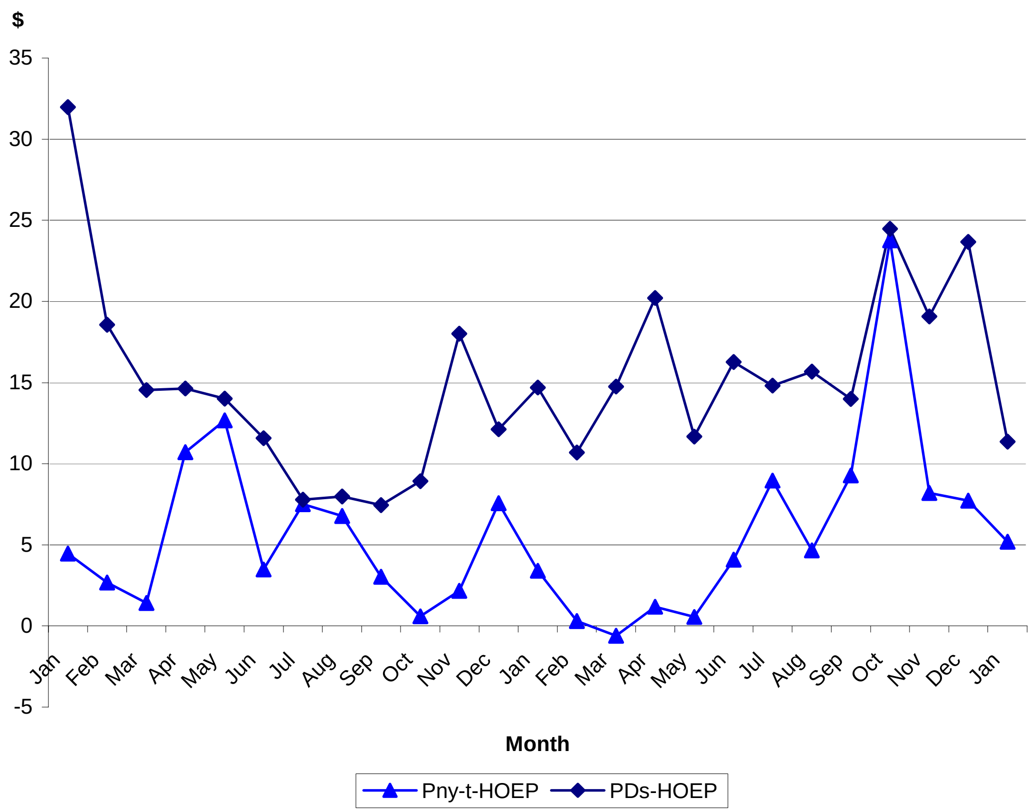
Figure 2-4, Comparison of Pre-dispatch vs Real-time Price Differences, January 2004 – January 2006



The first series illustrates the frequency in which the hourly real-time nodal price at Beck is higher than the delivered price of exports to New York. This occurs in roughly 30 percent to 40 percent of the hours. The second series illustrates the frequency in which the hourly pre-dispatch nodal price at Beck is higher than the delivered price to New York. This occurs very frequently; in generally more than 80 percent of the hours and often above 90 percent of the hours. Figure 2-4 indicates that if exports were to bid no more than the delivered price to New York, they should rarely be scheduled in the pre-dispatch constrained sequence; energy should almost never physically flow towards New York. That is, rarely would a net export to New York be *ex ante* efficient and hence rarely would *ex post* inefficient exports exist. This implies that the conjecture that the apparent inefficient trade flows that surface in real-time can be explained by unanticipated changes in the real-time nodal price is untenable. Furthermore, since in most hours there are net exports to New York scheduled in the pre-dispatch constrained sequence, most export bids must be much higher than the delivered price to New York (P_{ny-t}) and higher than the Beck Ebus pre-dispatch nodal price.

The implication is that exporters are generally bidding to avoid being constrained off, that is, to ensure that the energy they have purchased actually flows. As the analysis in Figure 2-5 suggests, the strategy of bidding to avoid being constrained off is profitable. However, the potential return to an exporter from bidding above the HOEP but below the Beck Ebus pre-dispatch nodal price and being constrained off would appear to be even larger. The first series in Figure 2-5 plots the expected return from buying energy from Ontario at the HOEP and selling to New York. This series indicates that the return is generally positive but rarely higher than $8. In this sense, there seems to be a reasonable level of convergence between the HOEP and the delivered price to New York. The second series plots the potential average hourly return from being a constrained off export. This average return is always positive and rarely less then $10. It is generally considerably higher than the return from actually delivering energy to New York.

Figure 2-5:
Comparison of Expected Return to Exports for Delivered Energy to New York vs Being Constrained Off, January 2004 – January 2006



Overall Assessment

The analysis summarized in Figures 2-4 and 2-5 implies that exporters are most likely focusing on price differences between the New York delivered price and the HOEP. They are bidding in a manner to assure that they are scheduled in the pre-dispatch constrained sequence rather than bidding in a manner that reflects the New York delivered price and getting constrained off. We also see that price difference between the HOEP and the New York delivered price are reasonably small on average suggesting arbitrage pressures. One possible explanation for this bidding behaviour may be that our analysis has failed to capture other potential factors affecting exporters' bidding incentives. For example, while the Beck Ebus shadow price is frequently higher than the New York delivered price, it may be difficult to predict how much higher this price may be and hence lowering bids to the point where the exporter could be assured to be constrained off may lead to frequent situations where the exporter fails to be scheduled at all. In this case, the exporter may be aiming for the lower but more likely achievable return (which is actually delivering to New York at the HOEP).

Another risk may be that bidding low in Ontario with the expectation of being constrained off may lead to situations where the exporter is actually scheduled to flow to New York (in the constrained sequence). But as this scheduling may be unexpected, it may not have scheduled a corresponding import into New York. This could lead to the exporter being imposed a penalty charge for its failure in New York that would overwhelm any potential expected gains from being constrained off.

For these and possibly other reasons, arbitrage between Ontario and New York is focused on the HOEP. The result is inefficient exports and the effective extension of the cross-subsidy inherent in Ontario's uniform price regime to New York loads. This problem has been exacerbated by market rules that, other things being equal, would have reduced the HOEP relative to prices in the constrained schedule. For example, the 12 times ramp rate assumption, which has the appearance of systematically lowering the HOEP (i.e., because it removes ramp effects in price), may simply lead to more exports than would otherwise occur.

Our analysis in this section focuses on one of the inefficiencies that are caused by the uniform price regime. The uniform price regime by its very nature also distorts consumption and generation decisions within Ontario. In this respect, an obvious way to reduce these inefficiencies is to adopt nodal pricing or at least some form of location-based pricing. Further discussion of this possibility appears in Chapter 4.

5. *Other Issues Arising from Monthly Monitoring Reports*

5.1 Simultaneous Import/Export CMSC

In January 2006, the MAU observed trades where a market participant's import was constrained off and its export was constrained on in the same hour on the same interface. While it is common to observe a market participant importing on one interface and exporting on another in the same hour, this does not normally occur on the same interface. On investigation, it was determined that during the period November 2005 through April 2006 there were approximately 17,000 MWh of simultaneously constrained import and export offers involving $0.5 million in constrained off payments. The MAU undertook an analysis to understand why a participant would be importing and exporting on the same interface in the same hour and how such a strategy could be profitable.

Normally, an arbitrager exports when the Ontario price is low (compared to external prices) and imports when the Ontario price is high. In a market with Locational Marginal Pricing (LMP), a trader can be successful in at most one trade -- either the import (when the domestic price is higher than the import offer) or the export (when the domestic price is lower than the export bid) or none (when the domestic price is between import offer and export bid). The situation in the Ontario market is different. The Ontario market has two price sequences, a uniform price and a constrained price. These two different price sequences can lead to two directly opposite arbitrage opportunities at the same time. A trader can profit from both arbitrage opportunities at the same time.

To illustrate the potential profitability of simultaneously making offers to import and export on the same intertie, assume that the unconstrained pre-dispatch price in Ontario is $100/MWh while the pre-dispatch price in the constrained schedule is $30. In other words, the zone involved is congested and the cost of producing power in this area is significantly lower than the uniform price for Ontario. In the trader's home market, the price is assumed to be $50. For simplicity, assume also that transaction costs and transmission charges are zero.

Under these assumptions there are two different arbitrage opportunities that could be pursued at the same time. These are:

1. importing into Ontario, buying out of the trader's home market at $50/MWh and selling into the Ontario unconstrained market at $100, yielding a profit of $50; or
2. exporting from Ontario, buying out at the constrained price of $30 and selling to the trader's home market at $50, yielding a $20 profit.

To take advantage of both arbitrage opportunities at the same time, the trader could offer imported energy at a price of $60. In this case, the import offer would be accepted in the unconstrained schedule as it is cheaper than the unconstrained pre-dispatch price of $100 but it would not be accepted in the constrained schedule as cheaper ($30) domestic generation exists in the congested zone. Thus, the import would be constrained off and receive a constrained off payment of $40/MWh, ($100 - $60 /MWh).

At the same time, the trader could also bid to export energy at a price of $40 /MWh. In this example, the export bid would not be accepted in the unconstrained schedule as the $100 unconstrained pre-dispatch price is higher than the exporter's bid. The export bid would be accepted in the constrained schedule; however, as $30 domestic generation exists in the congested zone that could be exported. Thus, the import would be constrained on and would purchase the MW at its bid price of $40/MWh. The trader would receive a profit of $10/MWh (buy at $40/MWh from Ontario and sell at $50/MWh in the other market). Recognising an arbitrage opportunity and buying out of a highly congested area would be the efficient response

In this example, the trader would receive a constrained off payment of $40 on its import offer plus a $10 profit on its export transaction for a total of $50/MWh. The profitability of this strategy would be greatest on interties such as the Northwest, where large gaps exist between the constrained and unconstrained pricing schedules.

Traders would face risks in pursuing a strategy such as this. If the price in the neighbouring market falls below the ($30) Ontario constrained price, the trader could face a loss on the export

The traders are simply responding to price signals in the constrained and unconstrained markets. In particular, they are willing to:

1. sell into Ontario at the uniform price (pre-dispatch HOEP) when it exceeds the price in their home market;
2. buy from the Ontario constrained market at prices below the price in their home market.

The strategy of traders to offer to import and to export simultaneously on the same interface is rational given the existence of both unconstrained and constrained price schedules in the Ontario market. In an LMP system, there can only be one transaction that can be successful, the efficient transaction based upon the constrained price schedule. It is not clear what the benefits to the Ontario market are from providing a payment to inefficient responses to the uniform schedule that are constrained off.

On rare occasions, the MAU has also observed similar but opposite behaviour. In these instances, constrained areas have a pre-dispatch shadow price higher than the pre-dispatch HOEP. In this case, simultaneous import and export offers can be structured so as to lead to a constrained off export payment and constrained on imports.

In both cases it would appear the export or import that is responding to the constrained price is efficient. However, paying the constrained off payment for an offer that is responding to the HOEP does not appear to enhance efficiency. Once again, we discuss possible remedies for this and other anomalies caused by the uniform price formulation in Chapter 4.

5.2 Intertie Congestion and Transmission Rights

Imports and exports are important for both market efficiency and system reliability. One requirement for import and export decisions to be efficient is for energy prices to reflect the economic consequences of intertie transmission constraints.

The Ontario market is divided into 14 zones, of which 13 are called ‘external zones’ and the Ontario zone. An external zone is actually a node in the Ontario market that acts as a proxy for the external market or jurisdiction, and represents the limited transmission capability linking Ontario with an external market or jurisdiction. The Ontario zone is the core of the IESO-administered system and covers all domestic generation and loads.

When an interface reaches its maximum capacity, the transmission lines involved are congested and the price at the external zone differs from the price in the Ontario zone. Under these circumstances, an importer or exporter faces the risk that power it has contracted to buy or sell may not flow. For example, when an importer has a supply contract with an Ontario load and the import transmission line is congested to the point that its power cannot be delivered, the importer would have to buy power from Ontario generators at a higher price than from the price prevailing in the relevant external markets in order to meet its contractual obligation. An importer or exporter may face other, related risks when the intertie is congested. For example, even if the power does flow for an importer, it is paid the lower zonal price for its energy rather than the higher HOEP which domestic generation is paid.

Another form of price risk for importers arises if there are transmission constraints within Ontario as well as congestion at the intertie itself. In this case an import may be accepted in the unconstrained schedule but not in the constrained schedule, i.e. it may be constrained off. The resulting constrained off payment to the importer is the difference between the lower zonal price and the importer’s offer price rather than the difference between the HOEP and the trader’s offer price as would be the case for a domestic generator. In this case, intertie congestion poses a risk of a reduced constrained off payment.

An intertie trader may hedge these intertie congestion risks by purchasing Transmission Rights (TR). A TR holder is entitled to a payment equal to the congestion-induced price difference between an external zone and the Ontario zone. For instance, a TR holder who has 100 MW of TR for exports on the New York interface during the year 2005 would be entitled to 100 times the Intertie Congestion Price (ICP) (which in this case is the price at the New York zone minus the price in the Ontario zone) or zero, whichever is greater in each hour of 2005.[28] Thus, the payment to a TR holder is a revenue stream for the period in which the TR is awarded. In this example, the TR holder would be hedged against the risk of export congestion on the New York intertie.

The major Ontario interfaces (e.g., the New York and Michigan interfaces) have become increasingly congested since market opening, which implies an increasing risk associated with bilateral contracts for intertie traders. The percentage of hours in which the transmission line on a given interface is congested on either the export or import direction is shown in Table 2-8. It is apparent that there is an upward trend in both import and export congestion on the main interties. For example, on the Michigan interface, the incidence of import congestion increased steadily from 2 per cent in 2002 to 21 per cent in 2005. This upward trend may be the result of greater competition among intertie traders to arbitrage Ontario-Michigan price differences or reduced transmission capability, or a strategy change of traders to target CMSC payments.

[28] The actual TR payout is based on real-time price differences between the zones, which equals ICP except when one of the prices is limited by plus or minus $2,000 (the Maximum Market Clearing Price). We continue to use the reference to ICP as an approximation in the discussion below.

Table 2-8: Percentage of Hours with Transmission Congestion, 2002-2006

		2002	2003	2004	2005	2006*
Export	**New York**	0	2	3	6	13
	Michigan	0	0	0	0	1
	Manitoba	0	0	0	0	0
	Minnesota	0	0	0	0	1
	PQDA	0	0	0	0	0
	PQHZ	1	0	5	6	3
Import	**New York**	1	1	0	1	0
	Michigan	2	9	11	21	3
	Manitoba	1	0	1	2	0
	Minnesota	6	1	15	19	17
	PQXY	0	0	0	0	0
	PQBE	1	0	0	0	0
	PQPC	1	0	0	0	0
	PQDA	2	0	0	0	0
	PQDZ	1	1	0	1	0

* Data for 2006 are up to April 30

The increasing incidence of transmission congestion should have two effects. First, payments to TR holders should increase and the TR auction price should increase in anticipation of this. Second, congestion rents should increase.

Regarding auction prices, revenue from the sale of TR rights should tend to equality with payments to TR holders. In an efficient TR market, a buyer of 1 MW of TR should be willing to pay the present value of the future revenue stream for 1 MW of TR payments, adjusted for the risk associated with the uncertain revenues.

The principle of user pay implies that it is reasonable to expect that the TR should be self-funding.[29] There are two possible interpretations of the self-funding principle. The first is that payments to TR holders for energy that flows should tend to equality with congestion rents over time. According to this interpretation, congestion rents and TR payments should tend to be equal since the purpose of the TR is to provide an opportunity to traders to recover lower energy revenues induced by congestion. This equals the

[29] All markets with TR or the equivalent face a design issue about self-funding. Whenever there is congestion with real flows below maximum capability there is a possibility of a congestion rent shortfall. Some designs allow a pro-rating for TR payments to create the equality between rents and payouts, but this implies that the TR does not cover the full risk to traders. The current IESO TR market design includes TR auction payment as part of the self-funding calculation.

congestion rents. The second interpretation of the self-funding principle is that TR payouts should equal the sum of congestion rents and constrained off payments foregone by importers as a result of intertie congestion. According to this interpretation, TR should also be available to be used to hedge against the risk that constrained off payments will be reduced by intertie congestion. TR associated with the constrained off amount are self-funded in the sense that uplift would be higher if constrained off payments were based on the HOEP rather than the lower, congestion-induced zonal price.

Transmission Rights Prices and Purchases

The IESO conducts two types of auctions: a long-term auction and a short-term auction. The long term auction is held every three months (usually in February, May, August and November) and the short term auction every month. A winner of an auction pays a uniform price that clears the auction run based on participants' offers to buy and MW offered for sale by the IESO. In the long-term auction TR are sold for a period of 12 months, while in the short-term auction the TR period is one month.

Tables 2-9 and 2-10 list the average long-term and short-term prices and the ICP by interface. The average long-term price is the sum of TR-weighted average prices divided by the total number of hours in the year and the average ICP is the sum of hourly ICP divided by the total number of hours in the year. Similarly, the short-term auction price is the sum of short-term (TR weighted) prices divided by 720 hours (for simplicity). If there was no short term auction for a month (due either to the sale of all available rights as long term TR, or changing conditions which reduced availability), the month is excluded from the calculation of the short-term average price.

It is apparent from the tables that TR prices have in general been significantly lower than the corresponding ICP, implying that the purchase of TR rights has been highly profitable. In the case of import TR on the Michigan interface, for example, the long-term TR price was less than half of the actual ICP, implying that the TR holders received more than $2 for every $1 investment in long-term transmission rights. The same is true of the short-term rights. This would appear to imply a speculative opportunity.

The tables show that ICP is not always larger than the corresponding TR price. This is somewhat more common for exports than imports and more common on the Quebec interties. For most of these the ICP was close to zero indicating little or no congestion, and TR prices which tended to be low were somewhat speculative on the chance there might be congestion. (Such ties tend to have trade in one direction.) However, higher TR prices than the ICP have also been observed on an intertie in the year following a high TR payout, with less intertie congestion occurring in the second year. These results are not surprising, and indicate there is uncertainty regarding the level of congestion for the coming period.

Table 2-9: Import TR Price and ICP ($/MWh), 2003-2005

	Long Term Import						Short Term Import					
	2003		2004		2005		2003		2004		2005	
Source	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**
Manitoba	0.73	1.16	0.24	0.19	0.35	1.05	1.49	1.88	2.49	2.29	11.38	12.80
Michigan	0.56	1.87	1.08	1.82	1.59	3.76	6.74	10.46	17.40	21.64	23.20	45.70
Minnesota	0.20	0.22	0.43	4.45	1.03	7.87	0.39	0.33	19.75	53.92	1.33	0.46
New York	0.62	0.61	0.34	0.01	0.31	0.98	2.94	5.99	5.36	0.08	2.15	11.89
PQBE	0.14	1.89	0.02	0.06	0.02	0.03	0.14	0.00	0.23	0.76	0.17	0.42
PQDA	0.09	2.66	0.02	0.00	0.01	0.00	1.06	32.19	0.28	0.05	0.20	0.00
PQDZ	0.14	0.46	0.05	0.00	0.02	0.04	0.50	0.00	0.17	0.00	0.13	0.11
PQPC	0.04	0.24	0.02	0.00	0.01	0.00	0.11	0.00	0.19	0.00	0.14	0.01
PQXY	0.03	0.09	0.06	0.00	0.01	0.01	0.22	0.00	n/a	n/a	0.01	0.13

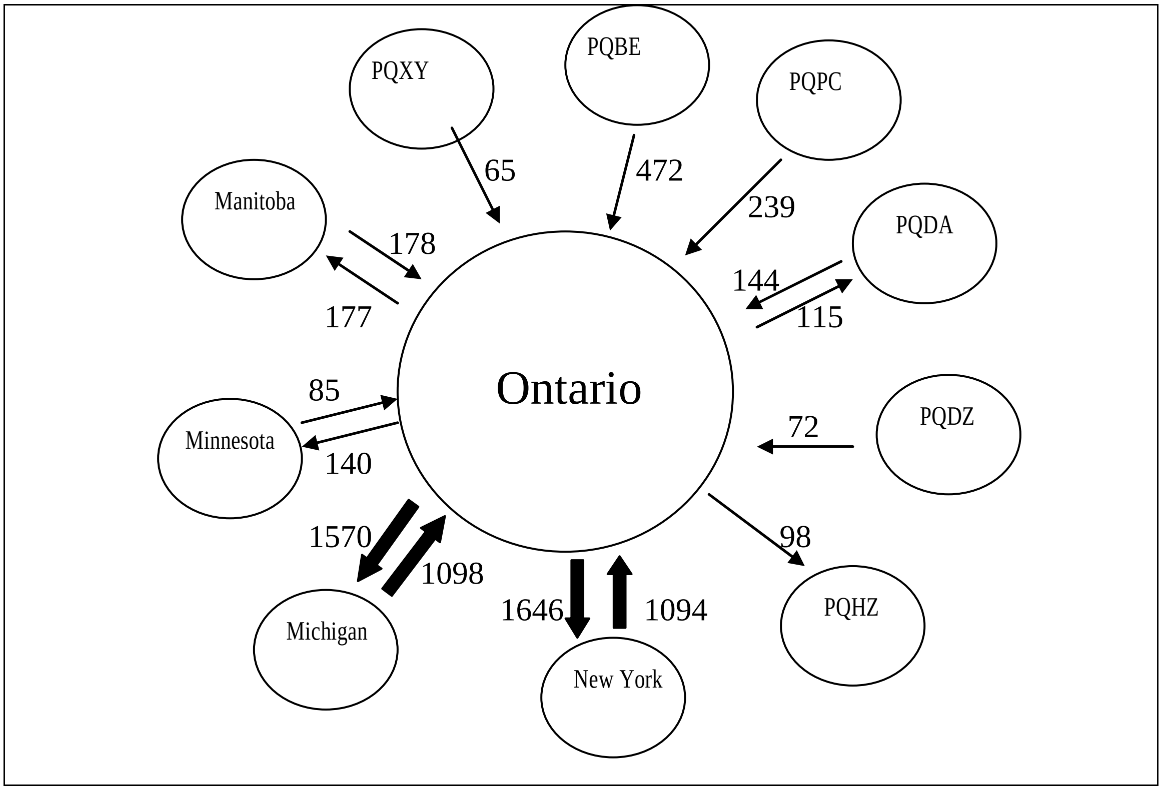
Table 2-10: Export TR Price and ICP ($/MWh), 2003-2005

	Long Term Export						Short Term Export					
	2003		2004		2005		2003		2004		2005	
Sink	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**	**Price**	**ICP**
Manitoba	0.01	0.03	0.18	0.00	0.06	0.02	0.17	0.00	1.16	0.01	0.48	0.20
Michigan	0.04	0.00	0.02	0.11	0.04	0.04	0.05	0.00	1.35	0.08	0.36	0.45
Minnesota	0.16	0.71	0.08	1.95	0.18	0.01	0.04	0.00	1.20	23.78	0.56	0.00
New York	0.22	0.60	0.51	0.50	0.77	2.17	1.02	5.48	8.07	4.02	13.53	26.42
PQHZ	0.03	0.00	0.10	1.75	1.91	6.40	0.31	0.00	0.30	4.58	11.53	53.20
PQDA	0.05	0.43	n/a	0.11	0.05	0.00	n/a	n/a	0.06	0.00	0.10	0.00

In spite of these counter-examples, overall payouts exceed revenue from the auction by a factor of 2 to 1, as can be seen in the next Table 2-11 (comparing column A with the sum of C and D) with no indication that the quantities are converging. In an efficient market, the TR price should tend to the ICP over time. The large discrepancy observed in the Ontario market might indicate a high degree of uncertainty regarding future payouts.

Figure 2-6 shows the average transmission rights purchased (long term plus short term) in 2005 by interface. The pattern of TR sold is consistent with the historical trade flows and import or export limits at the interties. Ontario generally imports from Quebec and Manitoba and exports to New York. Contrary to this pattern, Ontario was a net importer from Michigan in 2005 but the volume of import TR sold was much lower than the export TR sold. This was the result of import capability being much less than export capability. As a whole, the total export TRs sold on all interfaces were greater than the total import TR.

Figure 2-6: Average Transmission Rights Purchases (MW), 2005



Self-Funding of TR Payments

In compliance with the Market Rules, the IESO maintains a TR Clearing Account. Table 2-11 summarizes the revenues and payouts in the account. 'TR Payout' is the amount that the IESO paid to the TR holders, 'Congestion Rent' is the amount that the IESO collected,[30] 'Short Term Auction' is the revenue from selling short-term TRs and 'Long Term Auction' is the revenue from selling long-term TRs. As a whole, the IESO has accumulated an account balance of $42.44 million dollars in 2003 through 2005.[31] The IESO Board is authorized to disburse funds from the TR Clearing account to energy consumers in Ontario at such times it determines appropriate.

[30] TR payout is the TR awarded times the ICP. Congestion rent is the actual power flow times the ICP. Thus if the actual power flow is different from the TR awarded, the congestion rent collected by the IESO would be different from the payout to TR holders.
[31] The balance is $45 million for 2002 through 2005.

Table 2-11: Transmission Rights Account Summary ($ million)

Year	TR Payout (A)	Congestion Rent (B)	Congestion Rent Shortfall (B-A)	Short Term Auction (C)	Long Term Auction (D)	Balance (E = B+C +D-A)
2003	$29.23	$24.44	($4.79)	$0.80	$15.61	$11.62
2004	$30.01	$28.12	($1.89)	$2.83	$18.46	$19.40
2005	$89.69	$63.64	($26.05)	$8.07	$29.15	$11.42
Total	$148.93	$116.20	($32.73)	$11.70	$63.21	$42.44

TR payouts have exceeded congestion rent by $32.73 million over these three years. If the volume of TRs sold on each interface is close to the actual average flow of power when the intertie is congested, the congestion rent collected by the IESO should be roughly equal to the payout to TR holders. The large shortfall indicates that the volume of TRs sold must be greater than the actual flow on at least some interfaces.

The quantity of TRs offered by the IESO is based on the transmission capability of each intertie in the absence of transmission constraints elsewhere on the grid. Indeed, the quantity of TRs sold matches the unconstrained capability very well on most interfaces. Due to the uniform price system in the Ontario market, internal constraints and loop flows (especially the Lake Erie loop flow), the actual power flow on some main interfaces, such as Michigan and New York, is less than their unconstrained capability.[32] As a consequence, the quantity of TRs offered for sale leads to payouts to TR holders which exceed the congestion rent collected by the IESO.

While the excess of TR payments over congestion rents collected is inconsistent with the first interpretation of the self-funding principle, it is not necessarily inconsistent with the second which is that TR payouts should equal the sum of congestion rents and constrained off payments foregone by importers as a result of intertie congestion. In other words, if congestion at the interties led to constrained off CMSC payments which were some $33 million lower (over the 3 years), TR sales would have been self-funding in this broader sense. Unfortunately, it is difficult to recalculate what CMSC would have

[32] Other factors may also contribute to reduced flows, to a lesser degree, including failed intertie transactions.

been without intertie congestion. We have asked the MAU to explore this further to determine some means for assessing what portion of the $33 million figure may be due to internal constraints or other causes

This analysis leads the Panel to conclude that there are two issues with the TR market as it is presently operating. First, the quantity of TR offered for sale by the IESO exceeds the MW that can actually flow and this results in payouts to TR holders that exceed the congestion rent that is actually collected. TR payouts may or may not exceed the sum of congestion rents and constrained off payments foregone by importers. This requires more analysis. Also, there appears to be some debate about which interpretation of the self-funding principle is preferable from the perspective of market design and some further discussion of this may be useful. If the broader interpretation of the self-funding principle is appropriate and it is determined that the TR market is not self-funding, this can and, in our view, should be corrected by limiting the quantity of TR offered and/or creating a transparent mechanism to deal with this under-funding.[33]

The second issue is that the prices paid for TR are often well below their expected value (anticipated payout) effectively diverting congestion rents to TR holders and ultimately resulting in a higher uplift.[34] This apparently enduring speculative profit opportunity is not a characteristic of an efficient market but the reasons for this inefficiency remain unclear. It is also worth some additional study.

[33] Equality of auction payments and TR payouts imply that in Table 2-11 Column A should equal column B plus reductions in CMSC payments.
[34] Assuming the equality between auction payments and TR payouts column C plus column D should equal column A in Table 2-11. If this were the case, the account balance column E (which equals B+C+D-A) should equal B congestion rents. According to the self-funding principle, payouts (column A) should (roughly) equal congestion rents (column B) or congestion rents plus the reduction in CMSC payments. By design, some portion of congestion rents are intended to accrue to the IESO on behalf of domestic consumers in the market, while reduced CMSC flows immediately to all consumers as reduced uplift

Appendix to Chapter 2

Table 2-12: Low Price Hours, November 2005 to April 2006.

Delivery Date	Delivery Hour	Failed Net Exports	Real Time Demand (MW)	Pre-dispatch Demand (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)
November 12, 2005	16	575	15,190	15,597	14	35
November 13, 2005	8	0	13,115	13,752	14	32
November 13, 2005	9	100	13,951	14,640	17	35
November 21, 2005	6	524	13,963	14,847	19	38
Average		**300**	**14,055**	**14,709**	**16**	**35**
December 29, 2005	5	297	13,449	13,697	16	31
December 29, 2005	6	197	13,874	14,490	14	38
Average		**247**	**13,661**	**14,094**	**15**	**35**
January 01, 2006	16	225	16,104	16,732	14	34
January 10, 2006	4	557	14,737	14,869	13	32
January 10, 2006	5	275	14,853	15,294	16	36
Average		**352**	**15,231**	**15,632**	**14**	**34**
February 05, 2006	4	529	13,476	13,527	18	30
February 05, 2006	5	297	13,402	13,611	20	30
February 05, 2006	6	435	13,545	13,864	17	30
February 05, 2006	7	435	13,929	14,472	13	30
February 05, 2006	8	460	14,459	15,120	13	30
February 05, 2006	9	635	15,296	16,018	13	40
Average		**465**	**14,018**	**14,435**	**15**	**32**
March 13, 2006	4	468	13,372	13,595	16	31
April 02, 2006	7	620	13,179	13,327	16	37
April 04, 2006	1	630	14,034	14,279	18	33
April 04, 2006	2	547	13,791	14,035	13	28
April 06, 2006	1	469	14,263	14,304	18	32
April 06, 2006	2	294	13,945	14,098	14	30
April 06, 2006	3	208	13,839	13,828	14	20
April 06, 2006	4	275	13,900	14,188	17	32
April 7, 2006	1	616	13,574	13,795	13	25
April 7, 2006	2	489	13,262	13,484	13	14
April 7, 2006	3	585	13,153	13,160	13	14
April 7, 2006	4	615	13,237	13,637	13	32
April 7, 2006	5	401	13,824	14,391	16	32
April 7, 2006	24	494	14,318	14,672	18	35
April 9, 2006	17	930	15,266	15,316	14	35
April 9, 2006	18	600	15,196	15,187	14	29
April 10, 2006	1	350	13,344	13,382	16	28

Table 2-12: Low Price Hours, November 2005 – April 2006 - Continued

Delivery Date	Delivery Hour	Failed Net Exports	Real Time Demand (MW)	Pre-dispatch Demand (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)
April 10, 2006	2	150	13,197	13,169	16	16
April 10, 2006	3	425	13,209	13,131	19	29
April 10, 2006	24	335	13,943	14,095	14	28
April 11, 2006	5	200	13,718	14,484	19	36
April 11, 2006	23	350	14,615	15,318	18	38
April 11, 2006	24	343	13,687	14,034	12	28
April 12, 2006	1	352	13,145	13,532	13	33
April 12, 2006	2	318	12,914	13,238	12	27
April 12, 2006	3	217	12,759	12,914	13	27
April 12, 2006	4	50	12,831	13,152	15	30
April 12, 2006	24	-50	13,790	14,244	13	29
April 13, 2006	1	279	13,303	13,455	13	14
April 13, 2006	2	519	13,040	13,116	5	13
April 13, 2006	3	500	12,882	12,906	8	13
April 13, 2006	4	260	12,931	13,091	13	14
April 13, 2006	5	0	13,537	14,164	20	34
April 13, 2006	23	411	14,085	14,896	5	37
April 13, 2006	24	500	13,044	13,541	5	30
April 14, 2006	1	400	12,452	12,308	4	5
April 14, 2006	2	100	12,098	12,057	7	8
April 14, 2006	3	150	11,885	11,772	7	7
April 14, 2006	4	124	11,856	11,731	9	8
April 14, 2006	5	337	11,999	11,892	6	12
April 14, 2006	6	303	12,358	12,426	8	18
April 14, 2006	7	0	12,905	13,355	15	41
April 14, 2006	24	375	12,351	12,576	13	30
April 15, 2006	1	449	11,865	11,958	5	13
April 15, 2006	2	300	11,585	11,751	8	12
April 15, 2006	3	354	11,491	11,581	4	13
April 15, 2006	4	364	11,414	11,507	4	10
April 15, 2006	5	0	11,589	11,832	9	13
April 15, 2006	6	200	12,111	12,511	5	25
April 15, 2006	7	97	12,833	13,370	5	37
April 15, 2006	8	100	13,763	14,312	8	30
April 15, 2006	23	182	13,310	13,673	13	26
April 15, 2006	24	300	12,532	12,657	19	25
April 16, 2006	1	193.5	12,022	11,984	13	15
April 16, 2006	2	400	11,697	11,815	8	17
April 16, 2006	3	375	11,568	11,451	10	16
April 16, 2006	4	375	11,525	11,427	5	10
April 16, 2006	5	472	11,660	11,593	5	12
April 16, 2006	6	258	11,879	11,978	9	20

Table 2-12: Low Price Hours, November 2005 – April 2006 - Continued

Delivery Date	Delivery Hour	Failed Net Exports	Real Time Demand (MW)	Pre-dispatch Demand (MW)	HOEP ($/MWh)	Pre-dispatch Price ($/MWh)
April 16, 2006	7	175	12,358	12,543	16	29
April 16, 2006	8	217	13,214	13,662	14	40
April 16, 2006	13	669	14,001	14,179	14	39
April 16, 2006	14	555	13,818	13,939	12	32
April 16, 2006	15	415	13,679	13,721	19	30
April 16, 2006	17	482	13,645	13,700	6	32
April 16, 2006	18	483	13,457	13,519	5	22
April 16, 2006	19	216	13,621	14,001	8	40
April 16, 2006	23	400	13,360	13,486	5	27
April 16, 2006	24	496	12,632	12,603	6	14
April 17, 2006	1	298	12,278	12,157	13	26
April 17, 2006	2	308	12,089	12,004	13	20
April 17, 2006	3	373	12,016	12,040	12	20
April 17, 2006	5	423	12,661	12,875	9	37
April 17, 2006	23	481	14,363	14,906	6	26
April 17, 2006	24	350	13,463	13,942	6	13
April 18, 2006	1	575	12,938	12,867	4	12
April 18, 2006	2	500	12,653	12,649	4	12
April 18, 2006	3	453	12,590	12,386	5	12
April 18, 2006	4	413	12,695	12,848	4	24
April 18, 2006	5	0	13,338	13,989	8	36
April 18, 2006	24	160	13,434	13,742	15	30
April 19, 2006	3	363	12,502	12,383	16	30
April 19, 2006	4	406	12,612	12,599	18	32
April 19, 2006	23	836	14,278	14,831	5	32
April 19, 2006	24	460	13,281	13,708	4	13
April 20, 2006	1	349	12,723	12,961	12	13
April 20, 2006	2	480	12,426	12,647	12	14
April 20, 2006	3	258	12,221	12,478	5	11
April 20, 2006	4	544	12,263	12,761	11	28
April 21, 2006	1	393	12,770	12,872	7	18
April 21, 2006	2	323	12,482	12,588	4	18
April 21, 2006	3	321	12,245	12,399	4	12
April 21, 2006	4	0	12,296	12,796	13	30
April 22, 2006	4	304	11,742	11,818	8	29
April 22, 2006	5	511	11,941	12,062	5	31
Average		**356**	**12,953**	**13,146**	**11**	**24**

Table 2-13: Inefficient Net Exports (NX), Hours, Frequency, Volume & Returns January 2004 – January2006

Year	Month	Number of Hours	% of Hours RT_S-P_{NY-T} >0	% of Hours RT_S-P_{NY-T} >1 & NX>0	% of Hours Return to Delivered Export>0	% of Hours Return to Constrained Off Export>0	Expected Return on Delivered Export Avg. P_{NY-T}-HOEP ($)	Expected Return on Constrained off Export PD_S-HOEP ($)	% of Hours PDs-P_{NY-T} >0 and NX>0	Avg. Hourly NX (MW)
2004	Jan	733	36.7	31.4	61.0	84.3	4.46	31.98	61.7	684
2004	Feb	691	37.9	22.6	57.0	93.8	2.68	18.56	54.1	334
2004	Mar	738	39.6	24.4	53.5	90.2	1.42	14.54	59.2	368
2004	Apr	705	26.1	24.5	75.5	89.8	10.7	14.64	55.7	966
2004	May	665	27.7	26.2	75.5	84.1	12.67	14.01	56.2	1,265
2004	Jun	674	30.6	28.2	65.6	86.8	3.48	11.58	65.3	1,316
2004	Jul	677	21.3	18.6	69.9	83.3	7.5	7.78	49.8	1,185
2004	Aug	705	22.1	22.0	67.4	87.7	6.78	7.98	62.4	1,495
2004	Sep	707	29.1	22.6	62.4	90.5	3.04	7.44	55.7	553
2004	Oct	735	26.3	23.7	60.4	90.9	0.6	8.92	66.1	725
2004	Nov	715	34.8	27.6	55.5	91.7	2.16	18.01	68.4	684
2004	Dec	734	19.9	18.0	69.1	90.5	7.57	12.13	60.9	1,117
2005	Jan	728	33.0	32.3	60.3	90.2	3.41	14.69	71.3	1,256
2005	Feb	657	29.5	29.5	49.2	94.5	0.31	10.69	80.8	1,315
2005	Mar	723	33.2	31.0	56.0	91.6	-0.6	14.75	81.1	847
2005	Apr	718	43.3	30.1	55.7	89.6	1.19	20.21	61.4	377
2005	May	716	31.7	30.7	64.2	91.2	0.55	11.68	69.0	1,103
2005	Jun	702	38.0	30.3	59.3	90.5	4.1	16.27	52.6	784
2005	Jul	659	41.4	25.9	59.8	82.2	8.97	14.81	49.3	558
2005	Aug	622	41.3	26.2	62.9	80.1	4.66	15.68	40.4	654
2005	Sep	605	40.3	30.9	57.7	75.2	9.27	13.99	48.1	831
2005	Oct	528	39.0	38.6	61.9	84.1	23.77	24.48	65.0	969
2005	Nov	709	36.4	35.7	63.9	87.2	8.2	19.08	67.6	1,327
2005	Dec	712	37.1	34.7	60.1	88.2	7.72	23.67	71.1	970
2006	Jan	696	31.6	31.6	58.8	83.9	5.2	11.35	66.5	1,459

Chapter 3: Summary of Changes to the Market since the Last Report

1. *Introduction*

This chapter summarizes changes in the market since our last report. Section 2 reports on the status of issues raised in previous reports. Section 3 reviews other material changes that have occurred in the market. In Section 4, we provide an assessment of the Transitional Demand Response Program (TDRP). Other demand response programs are now being planned. It is hoped that the analysis of the TDRP will provide those involved with some guidance.

2. *Status of Matters Identified in Previous Reports*

2.1 The Treatment of Manual Reductions in Operating Reserve.

The use of out-of-market control actions and its effects on market prices have been extensively discussed in previous reports. On November 23, 2005, the IESO created the final tranche of real-time 400 MW Control Action Operating Reserve (CAOR), with 200 MW at $75/MWh and the other 200MW at $100/MWh. Concurrently, the IESO introduced a new procedure that precludes the manual reduction of operating reserve requirements in the event of shortages.[35] This procedure will reduce the incidences of counter-intuitive market prices during times of serious shortage. We have long advocated this measure and we commend the IESO for having adopted it. During the period November to April 2006 there were 71 intervals in which all or part of this new tranche of CAOR was utilised.

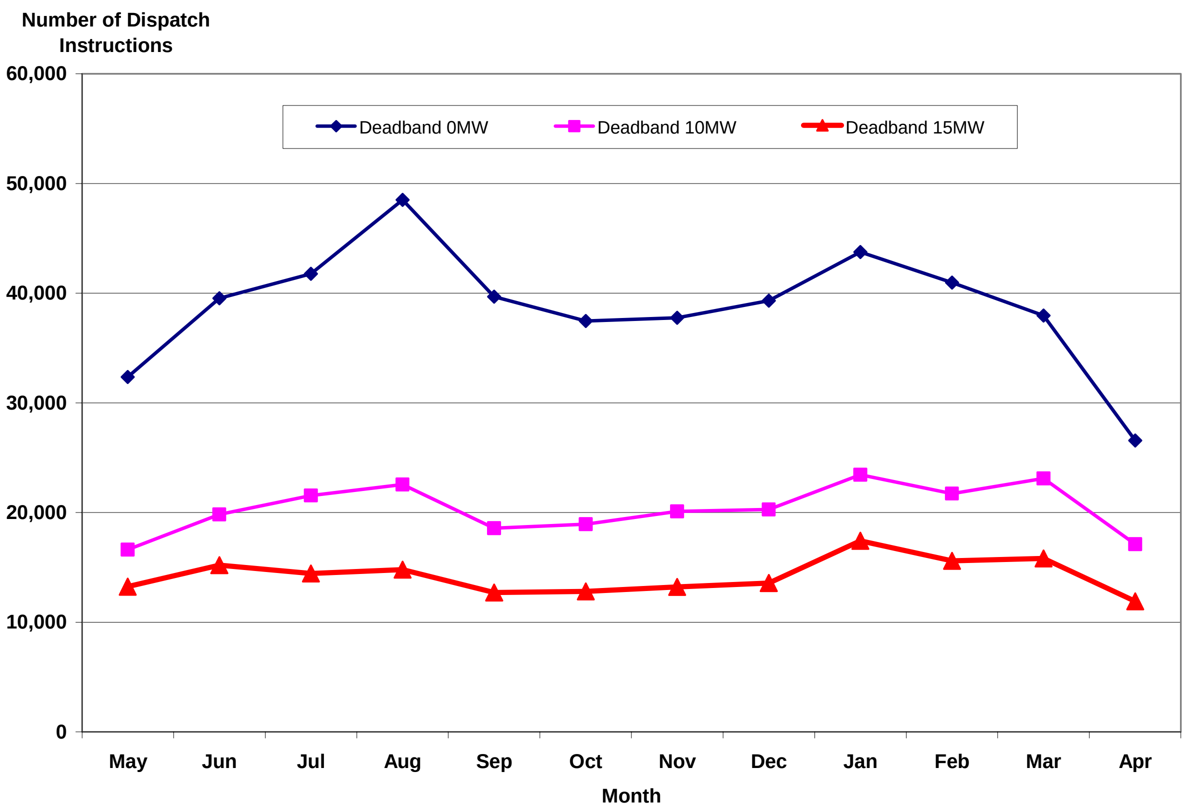
We have asked the MAU to continue to monitor the CAOR to determine if the present volumes and prices of CAOR are appropriate and it's impact upon both the market and reliability.

[35] Since the creation of the final tranche of CAOR there have been two hours in which there was a manual OR reduction, one of which is discussed in Chapter 2.

2.2 IESO Measures to Reduce Dispatch Volatility

In previous reports, we acknowledged participants' concerns about the volatility of dispatch instructions and its impact on the efficiency of generators. In our last report we outlined some of the measures the IESO was taking to deal with it. In this section we update our assessment of the situation.

Figure 3-1: Monthly Total Fossil Dispatch Instructions by Compliance Deadband May 2005 – April 2006



The IESO has put into place the following measures, some as pilots and some as permanent measures:

- In January 2006 the compliance deadband was increased from 10 MW to 15 MW on a trial basis. Figure 3-1 illustrates the number of dispatch instructions on a monthly basis that fossil generators would be required to be followed depending upon the compliance deadband. With the increase in this deadband from 10 MW to 15 MW in January 2006, fossil generators dispatch instructions that must be followed in the period from January 2006 through April 2006, have reduced by an average of 6,000 dispatch instructions per month. After receiving favourable participant comments, on May 8, 2006 the IESO's Compliance Interpretation Bulletin was changed to permanently accommodate the 15 MW deadband.

- For multi-unit station aggregates, the IESO plans to introduce a 'replacement offer program' to help manage unit contingency events. Replacement offers would allow a unit operator to run a replacement unit when the unit that received a dispatch instruction is forced out of service. In February 2006, this program was tested on four hydroelectric compliance aggregates where the management of contingency events is considered an issue. The four hydroelectric compliance aggregates under the pilot were at Abitibi Canyon, Mattagami, Michipicoten and Mackay. In the opinion of the participants, these pilots were successful. Rule changes will be introduced leading to full implementation later in the summer.

- A pilot project for watershed aggregation was developed to allow generators on a cascade river to aggregate dispatch instructions and redistribute them across the river system to maximise the efficiency of the river system. The pilot program was instituted on two watersheds. Initial reports from the participants have welcomed the pilot program in allowing more efficient dispatch of their resources. In addition, the IESO is exploring a pilot test program for compliance aggregation with a large (over 300 MW) dispatchable fossil facility. A cogeneration facility had been invited to participate in the pilot, but was unable to accommodate the test. The target by the IESO is to complete this test in June.

In general, the pilots have proven successful in the opinion of participants; however for full implementation the IESO systems will need a number of enhancements/changes. These include changes to the rules and settlement systems to accommodate CMSC and changes to the IESO Control Room monitoring tools. It is expected that these changes will be complete by summer 2006.

It appears that the combination of increased compliance deadbands and the pilot programs are having a positive impact on dispatch efficiency. By reducing the number of dispatch instructions that generators must respond to is anticipated that it will reduce generation adjustment cost. We will continue to monitor these initiatives and report on them.

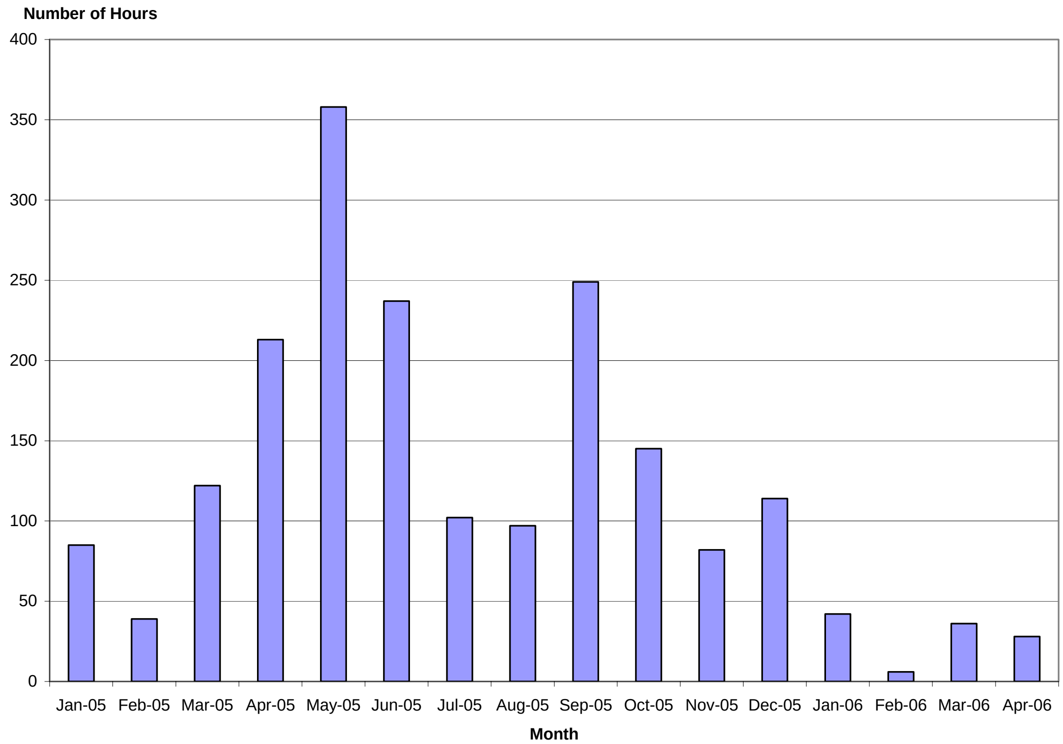
2.3 Reduced MISO Intertie Limits

As we noted in our December 2005 report, the average import capability of the Michigan intertie was reduced in March 2005 by approximately 400 MW. This reduction coincided with and resulted from the placing in-service of two phase shifters (PARS) between Ontario and Michigan at the Lambton Generating Station. Effectively, the Michigan interface was de-rated, thus limiting both imports and exports and increasing the frequency of congestion at the interconnection. This congestion has increased the hourly Ontario energy price (HOEP).

It was originally understood that the PARS would be the limiting element on the interconnection, but their phase angle regulating capability was expected to more than off-set this reduction. That is, by controlling inadvertent parallel power flows that may at times impede import capability, a greater number of transactions could be scheduled across the New York / Michigan interfaces. Unfortunately, until an agreement for operation of the PARS between Hydro One and the International Transmission Company in Michigan can be reached, the PARS cannot actually be used in anything but emergency conditions and it simply increases congestion without the corresponding benefit of controlling inadvertent parallel power flows.

The following figure illustrates the number of hours of import / export congestion on the Michigan interface since January 2005. Not surprisingly, because of the dominance of imports from Michigan into Ontario over this interface, imports accounted for 99 percent (1,915 hours) of the total 1,998 congested hours during this period.

Figure 3-2: Number of Hours of Import / Export Congestion Ontario - Michigan Interface, Monthly, January 2005- April 2006



The MAU undertook to provide an analysis to the IESO on the financial impact to the Ontario Electricity Market of the installation of the Michigan PARS.

In order to estimate the financial impact on the real-time market of increased congestion on the Michigan-Ontario interface several points need to be understood:

- If congested import MW are fully replaced by import MW on a different interface there is no price impact associated with reduced Michigan supply. One must remember that in real-time all imports are placed at the bottom of the offer stack. By replacing one group of import MW with another group of import MW there is no impact on the shape of the real-time offer curve and in turn the HOEP.

- If congested MW are fully replaced by internal offers there is a 'full' price impact associated with reduced Michigan supply. In this case the real-time offer curve has shifted to the left and thus there is a full impact upon the HOEP.

- If the congested MW are partially replaced by internal offers or imports there is a partial price impact associated with the internally replaced MW.

The estimated increase in the HOEP resulting from increased congestion on the Michigan-Ontario interface averaged \$2.59/MWh during the period March 2005 though January 2006.[36] Given the fixed price contracts and rebate provisions existing in the market this price increase would have resulted in a net transfer of \$90 million from loads to generators.

Since January 2006 there has been little congestion on the Michigan interface due to high availability of supply and low demand as described in Chapter 1. The IESO is presently studying potential options for operation of the phase shifters.

3. *New Matters to Report*

3.1 Regional Reserve Sharing

On January 4, 2006 the Northeast Power Coordinating Council (NPCC) Regional Reserve Sharing (RRS) program became effective. The program allows participating NPCC members to assist each other in meeting their 10-minute reserve requirement and

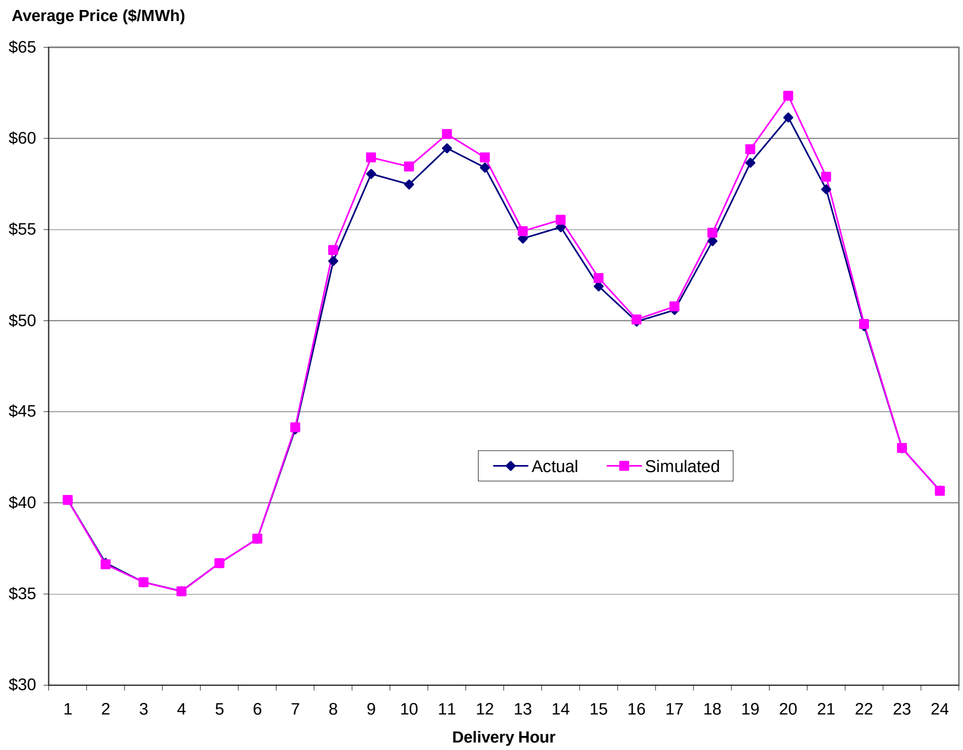
[36] The large estimated increase in HOEP was mainly due to the tight supply/demand condition in summer 2005. Given the steep supply curve, several hundred MW increase in supply would have led to a significant drop in the real time price.

to receive reserve sharing energy as an extension of the NPCC Shared Activation of Reserve (SAR). Each member may count 50 MW towards their 10 minute non-spinning operating reserve requirement. The RRS reserve energy is activated following termination of SAR and each area may receive up to 100 MW of reserve energy for 60 minutes. As a result, the IESO lowered its reserve requirement from a normal level of 1,418 MW to 1,368 MW.

Since then, the IESO has occasionally increased the operating reserve requirement back to 1,418 MW when the shared operating reserve was deemed to be undeliverable due to interface congestion or other internal or external reliability concerns.

As is well known, the Ontario market clearing price (MCP) is a co-optimisation between energy and operating reserve. As a consequence, a reduction in demand for operating reserves should be expected to reduce the energy price. To estimate the impact on the real-time price, the MAU ran a simulation for the period of January - April 2006 assuming the OR requirement had not been reduced and holding everything else equal. Figure 3-3 illustrates the average actual and simulated prices. Simulation results indicate that the reduction in the OR requirement has had minimal impact on off-peak prices. This is an expected result considering the large available supply of OR in off-peak hours where energy demand is low. But simulation results do indicate that there has been a relatively large impact on the on-peak price. On average the reduction in the OR requirement as a result of the RRS program has lowered the HOEP by $0.36/MWh. Given the fixed price contracts and rebate provisions existing in the market, the price lowering can be translated into a $4 million net transfer from generators to loads.

Figure 3-3: Average Actual Price vs. Average Simulated Price, January–April 2006

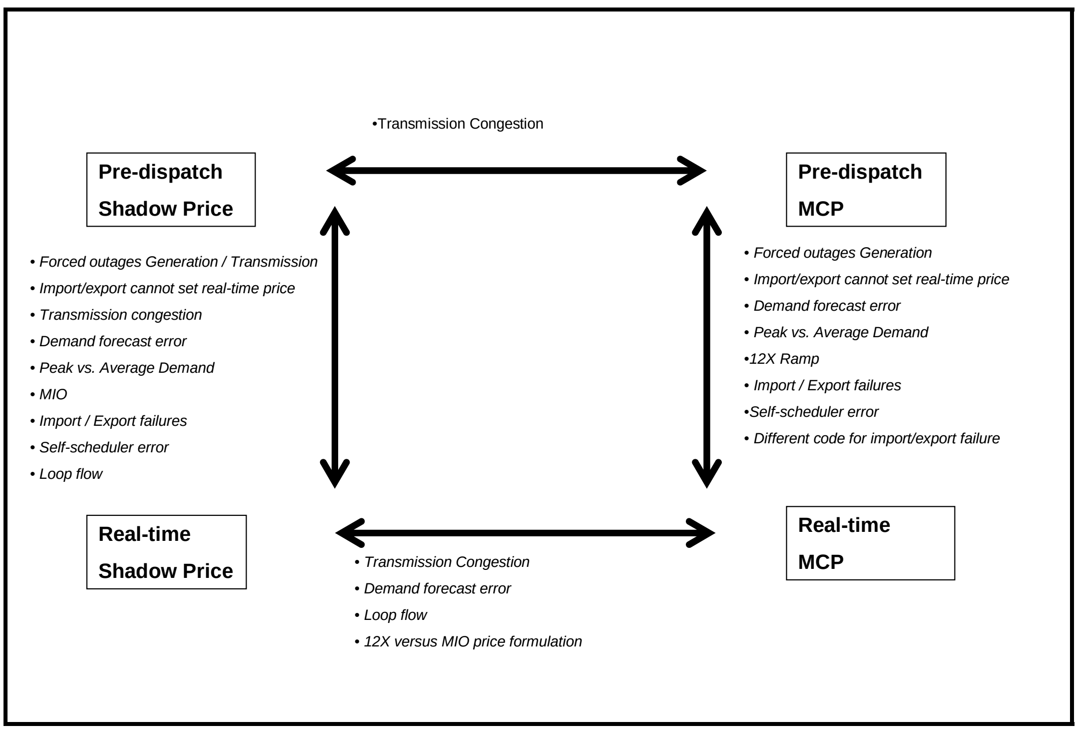


3.2 Discerning the Impact of Transmission Congestion on Price

The design of the Ontario market provides for two price sequences both in the pre-dispatch and the real-time dispatch. The unconstrained sequence calculates the MCP which ignores internal transmission constraints and other reliability constraints and assumes a 12 times ramp rate on generation units. The constrained sequence takes into account all constraints and incremental losses and calculates a locational price (or shadow price) at each generation or consumption point. This locational price is the incremental value of producing one more MW at the generation point or cost of consuming one more MW at the consumption point.

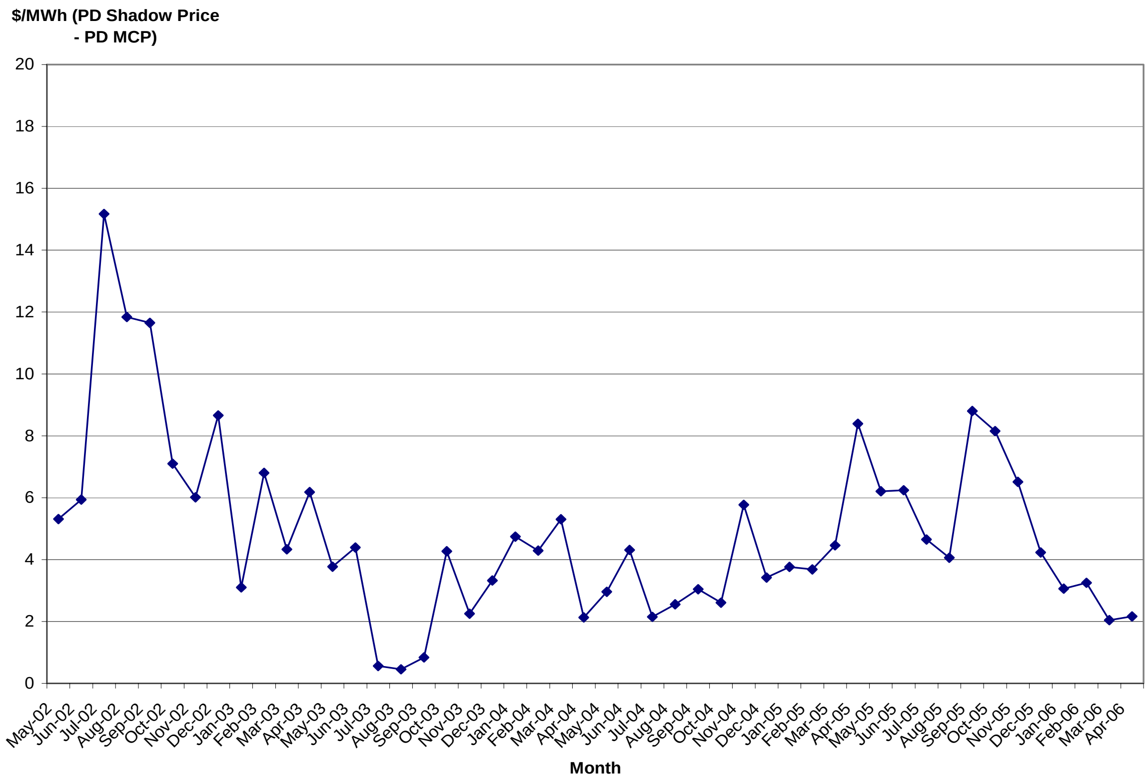
The IESO market algorithm also calculate the shadow price at the Richview bus, which is the reference price of the Ontario system and an indicator of supply and demand conditions in the constrained model. Because the inputs **(**e.g. starting points) and constraints for each run (i.e. the pre-dispatch constrained, the pre-dispatch unconstrained, the real-time constrained and the real-time unconstrained) are generally different, the MCP and Richview shadow prices are different. Figure 3-4 summarizes the main factors that cause the price difference between the two sequences (constrained and unconstrained) in pre-dispatch and real-time and what causes differences between the pre-dispatch and real-time sequences. For instance, transmission congestion dominates the price difference between the pre-dispatch shadow price and the pre-dispatch MCP while there are many factors that contribute to the differences in the other price pairs: between shadow prices in pre-dispatch and real-time; between the real-time shadow price and MCP; and between the MCP in pre-dispatch and real-time.

Figure 3-4: Major Causes of Price Differences between MCP (Unconstrained Sequence) & Shadow Price (Constrained Sequence)



In the case of all these price differences except the one between the pre-dispatch and real-time MCP, transmission congestion plays a significant role. To see the impact of transmission congestion, the simplest way is to look at the price difference in the pre-dispatch between the Richview shadow price and MCP because transmission line congestion is the dominant contributor to this price difference. Figure 3-5 depicts the average monthly difference between the pre-dispatch shadow price and pre-dispatch MCP since market opening. One can see that the difference was highest in 2002 summer and lowest in 2003 and 2004. The price difference increased again in summer 2005. The large differences in those months are highly related to the tight market conditions, which tend to lead to large CMSC payments.

Figure 3-5: Monthly Average Difference: PD Shadow Price minus PD MCP



3.3 Constrained Off CMSC Payments in Designated Zones

In our last review of the market we reported on a specific cause for anomalous CMSC payments.[37] These resulted from participants structuring their bids and offers into known congested zones with the apparent expectation of being constrained off and receiving a

[37] See our December 2005 report, pp. 71-72

stream of CMSC payments, with little likelihood of delivering energy into the Ontario market. We explained that traders could offer energy into a congested zone within Ontario at a price between the pre-dispatch uniform price and the lower nodal price in the area. This leads to the import being selected in the market schedule but being constrained off because the offer is above the constrained (nodal) price. Similarly, export transactions could be bid at a price high enough to be accepted in the market schedule but constrained off because of a higher nodal price resulting from congestion in the zone.

At that time we asked the MAU to bring this matter to the attention of the IESO's Market Rules group to consider amendments that would restrict CMSC payments in the circumstances outlined above. In November 2005, the IESO initiated a process to address the issue.[38]

Since November there have been several meetings with the Technical Panel and with stakeholder groups to develop an approach for dealing with the issue. The current proposal recommends the identification of zones across Ontario in which congestion is fairly common and allows the review of persistent and significant CMSC payments in these areas for possible adjustment, based on the actual costs or lost opportunities of the market participant involved. In order to maintain equitable treatment between internal and external resources, the proposed reviews would apply to generators and dispatchable loads as well as imports and exports.

Rule modifications are expected to be implemented sometime this summer. Until then, the MAU's continued monitoring, together with forbearance on the part of market participants contacted by the MAU, appear to have reduced the magnitude of these CMSC payments.

[38] Further details are provide at http://www.ieso.ca/imoweb/consult/consult_se10.asp

3.4 Urgent Rule for the Removal of Constrained Off Payments to Linked Wheels

A linked wheeling-through transaction allows a market participant to move energy through Ontario from one jurisdiction to another (e.g. from Michigan through Ontario to New York) without the risk of: (i) the energy being retained in Ontario and (ii) exposure to the Ontario market price. With a linked wheeling-through transaction, market participant risk and potential for reward is limited to the source and destination markets. In late February 2006, the MAU observed a series of constrained off payments, approximately $0.5 million, for a linked wheel, transmitting power from the MISO market through to the New York ISO. The outcome of paying CMSC payments for a linked wheel as well as CMSC payments at the same time for both the import leg of the transaction and the export leg appeared anomalous. Typically CMSC payments have been construed as providing some benefit to the Ontario market while a linked wheel provides no benefit to the Ontario market and has no market risk associated with the market.

The MAU sought our advice on this issue. The Panel agreed that linked wheeling through transaction eligibility for CMSC payments was not consistent with the intent of the market design. We were also of the opinion that eliminating CMSC for these transactions would not affect market participant behaviour in regard to these transactions or other intertie transactions.

The IESO approached the market participant confidentially to advise that an urgent rule would be introduced shortly and to request that it forgo the relevant CMSC payments and return past payments that had already accrued. The market participant agreed to forego future CMSC payments for a transitional period until the rule was amended. A local market power review is underway regarding past CMSC payments to the participant in question.

On April 7, 2006 the IESO Board passed an urgent rule eliminating constrained off payments to linked wheels.

4. *The Transitional Demand Response Program*

Overview

In June 2003 the IESO Board of Directors endorsed the development of a Transitional Demand Response Program (TDRP). The main objective of this program was to help market participants overcome specific barriers to demand response in the short-term and increase the level of demand responsiveness in the Ontario electricity market over the medium and long term. The program is available to authorized market participants – individual loads with interval meters, embedded loads with interval meters represented by an aggregator, non-interval metered loads represented by an aggregator. Some specific barriers highlighted during the consultation process were: a) the discrepancy between pre-dispatch and real-time prices; b) infrastructure costs, c) the difficulty of measuring demand response by customers without interval meters d) the retail price freeze which discourages demand response and, e) a lack of awareness of demand response technologies and options.

Under the program, demand response must be greater than 0.25 MW and no more than 5 MW for each project. The TDRP is limited to a total of 100 MW. Participants are eligible to receive TDRP payments until the program expires in April 2007. Participants monitor pre-dispatch forecast prices on the IESO website, if the three hour ahead pre-dispatch price exceeds $120/MWh, the participant can choose to reduce demand in that hour. They do so by submitting the appropriate form to the IESO. The participant is paid the three hour pre-dispatch price for each MW of reduced demand. The maximum 3 hour pre-dispatch price to be used by the IESO in settlement calculations is $500/MWh. In other words the price cap under the TDRP is $500/MWh. Demand reduction is measured against a baseline demand in the case of participants with interval meters. Those without meters submit a measurement and verification plan from which the demand response can be reliably determined.

Participation Rate

Since April 2005 16 participants have applied for the program. Out of those, 14 were accepted, representing 22 projects and 66.8 MW approved for the TDRP. Out of those 14 participants, 8 participants representing 31.05 MW of demand response have actively participated in the TDR program. The effective participation rate (in terms of MW) is 46.5 percent and 57.1 percent (in terms of participants). No participant has left the program. Table 3-1 shows on a monthly basis, the energy curtailed by all active participants in 2005.

Of those projects that have active participants, demand reductions range from shutting down non-critical equipment to controlled lighting, cooling, heating and refrigeration, to using load displacement and embedded generation. Over the period April 2005 to December 2005, there was a total of 4,192 hours when TDRP was activated, that is, where the 3 hour ahead pre-dispatch price exceeded $120/MWh. Of those, there were 3,761 hours where TDRP payments were made, amounting to $1,155,962. The maximum hourly load reduction was 20 MW on October 14, 2005 in Hour 13.

Table 3-1: TDRP Demand Curtailed, June-December 2005

	MWh
Jun	64
Jul	483
Aug	1,568
Sep	2,032
Oct	1,569
Nov	514
Dec	1,088
Total	7,318

Evaluation of the TDR Program

To evaluate the TDR program, we first derive an estimate of the average value of electricity consumption by the market participants.[39] We do so because there is no information on the value of consumption foregone by the loads because there are no bids associated with the loads' reductions. We then compare the estimated consumption value with the domestic generation cost of supply. Our analysis indicates the average consumption value for the market participants to be $273. We use the real-time Richview nodal price as a proxy for the domestic generation cost.[40]

If in real-time the Richview price turns out to be equal or greater than $273 then the *ex-ante* decision to reduce consumption was efficient and there is a net gain to the market. This is because the value of the consumption is less than or equal to the resource cost to supply this consumption. If on the other hand the Richview price in real-time is lower than $273, then some participants who had reduced consumption (in response to the higher 3 hour ahead pre-dispatch price) would have been better off consuming electricity in that hour. This may represent a net loss to the market, for example in the case when the domestic generation cost to supply that consumption is lower than the value of the consumption foregone.[41]

The overall benefit to the market is the difference between the net gain that is realized when the Richview price exceeds $273 (and participants correctly reduced consumption)

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[39] Without specific prices at which they are willing to go away, it is difficult to infer the value of electricity consumption to the market participants. Our simple approach focuses on the fact that a participant should be willing to go away if it is paid the difference between its valuation and the HOEP in the hour. Let V be consumption value of the market participant. Assume P is the average price received by participants. Then we posit that *ex ante*, in any given hour, the participant is indifferent in relation to consumption when V minus the expected HOEP equals P. Then the value of electricity consumption to the market participant is given by ***V= P + Expected (HOEP).*** We then derive estimates of P and the expected HOEP using regression analysis. P is derived by examining the correlation between the 3 hour ahead price and load reductions submitted. Expected HOEP is calculated using a weighted 3 hour ahead price. We found P was $155 and expected HOEP was $118.

[40] Most of the participants are located in south west Toronto which makes the Richview price a reasonable proxy for the supply cost.

[41] The assumption here is that the additional supply required to satisfy demand is of a small magnitude and it would come solely from domestic generation, i.e. no additional imports are needed. Also the price effect following the demand reduction is assumed to be small such that no additional exports are scheduled.

and the net loss that is realized when the Richview price is lower than $273 (and participants had incorrectly reduced consumption).

Over the period June-December 2005, there were 3,745 hours where TDRP was triggered. Out of those hours, there were 400 hours where the Richview price was higher than $273 and during this period participants reduced consumption by a total of 711 MWh. Since the supply cost was above the value placed by participants on the consumption value, there is a benefit to the market and this amounted to $342,240.

There were 3,345 hours in which the Richview price was lower than or equal to $273/MWh. During this period participants reduced consumption by 6,607 MWh and the consumption benefit foregone amounted to $982,457. The benefits and losses are summarized in Table 3-2.

Table 3-2: TDRP Benefit and Loss, June - December 2005

	Richview Price <$273	**Richview Price >$273**
Benefit	n/a	$342,240
Loss	$982,457	n/a
MWh Curtailed	6,607	711

The overall net benefit/loss to the market is the difference between columns 2 and 3 in the table. This amounts to a net loss of $640,217. Costs for administering the program and assessing the voluntary compliance of the TDRP customers are on top of these estimates. One reason that the program has reduced rather than increased market efficiency in many instances is that program participants make their decision to forego consumption based on the three hour ahead pre-dispatch price and this price often overstates the actual tightness of the market in real-time. Improving the accuracy pre-dispatch price projection would reduce the frequency with which program participants incorrectly choose to forego or not to forego consumption.

<u>Performance of the Near Term Pre-Dispatch Prices in Projecting the HOEP</u>

In this section we analyse the price projection performance of the 1, 2 and 3 hour ahead pre-dispatch prices.

The MAU examined the projecting performance of the 3 hour ahead pre-dispatch price, the 2 hour ahead price and the 1 hour ahead pre-dispatch price since market opening.[42] Our analysis indicates that the 2 hour ahead pre-dispatch price is marginally better than the 3 hour ahead price whereas the 1 hour ahead pre-dispatch price is better than either the 3 hour ahead pre-dispatch price or the 2 hour ahead pre-dispatch price. The 3 hour ahead pre-dispatch price tends to overstate the HOEP more frequently that the other 2 pre-dispatch prices as shown in column 2 of Table 3-3. For example, over the period June to December 2005 (5,136 hours), the 3 hour ahead price predicts that the HOEP will be above $120 in 1,335 hours when in reality it is above $120 in only 690 hours, which can lead to a 50 percent error in the TDRP consumption decision.

While, as reported in Chapter 1, the IESO has improved its Ontario Demand forecasts, there continue to be significant issues with price projections. The Panel has noted in previous reports that seams issues and transaction failures can contribute significantly to this error. With the real-time transaction settlement charge to be implemented in June 2006, it is hoped that a reduction in failures will contribute to an improvement in price projections.

Table 3-3: Tendency for Pre-Dispatch Prices to Overstate HOEP

	PD > $120 and HOEP <$120 (Number of Hours/%)	PD > $120 and HOEP > $120 (Number of Hours/%)	PD > $120 (Number of Hours/%)
1 Hour	537 (43.8%)	690 (56.2%)	1,227 (24.0%)
2 Hours	546 (44.4%)	682 (55.6%)	1,228 (24.0%)
3 Hours	645 (48.3%)	690 (51.7%)	1,335 (26.0%)

[42] Detailed results are available from the MAU upon request.

Recommendations for Program Improvement

- Improvements in the price projection performance of the pre-dispatch price can potentially enhance the net benefit of programs such as TDRP. It should be noted that at 3 hours prior to the dispatch hour, not all consumption and supply decisions are fully understood as the market does not close until 2 hours ahead. Technically the use of the 1 hour or the 2 hour ahead pre-dispatch price signal as the trigger price will enhance net benefit combined with other improvements in the market such as reductions in transaction failures.
- In the future, the design of demand response programs should consider allowing participants to nominate their own threshold/strike prices at which they prefer to 'sell' their load back. In a recent review of its demand response program, NYISO found that participants did not find it difficult to nominate their own strike prices.[43] The IESO could then rank the nominated strike prices and select the least cost bids to call upon. Nominated strike prices also provide information upon the consumption value of each participant. This will make it easier to evaluate the program in the future.

Overall Assessment

The analysis above shows that the TDR program has reduced market efficiency in the sense that the value of foregone consumption by program participants has exceeded the cost of generation. Whether it has assisted loads in becoming more responsive to market signals remains to be determined. In this regard, an assessment of the extent to which the TDRP has helped participants to develop the necessary infrastructure to engage in demand response would be useful.

We have suggested some measures that would reduce the negative impact that the TDR program has had on the efficiency of the market. We wish to emphasize, however, that the accuracy of price projections and the determination of strike prices are but two of the issues that arise in assessing the benefits of demand responsiveness programs. Subsidizing customers to reduce their consumption may contribute to the efficiency of

[43] http://www.nyiso.com/public/webdocs/products/demand_response/drp_evaluation/2003/executive_summary.pdf

the market if the price these customers would have paid for the MW they choose to forego is less than the actual cost of production of these MW. It has always been our preference, however, to deal with possible inefficient consumption directly by allowing the prices paid by customers to reflect the actual cost of service.

5. *Contracts and the Spot Market*

In our previous two reports we discussed the implications for the market of the increasing portion of supply that was being provided at regulated prices or through fixed price contracts. In this section we update our calculation of the portion of supply that remains exposed to the spot market and discuss the implications of the fixed-price contracts for the prices paid by Ontario consumers.

There are a large and growing number of contracts with provincial government agencies, regulatory regimes and other arrangements governing the payments made to generators for supply into the Ontario market. The market opened with some contracts held by the OEFC, the non-utility generation (NUG) contracts, arranged in the late 1980's and 1990's and currently representing about 1,900 MW of capacity. In the last few years we have seen the majority of remaining generation moved in a similar direction with arrangements which fix the price of their energy. This includes OPG's prescribed assets (10,000 MW) and non-prescribed assets (about 11,000 MW), the Bruce Power refurbishment (1,550 MW now and up to 3,000 MW in future),[44] Clean Energy Supply (CES) contracts (1,955 MW in total with 117 MW GTAA now in-service), the Lennox Reliability must-run (RMR) contract with the IESO (2,100 MW), early mover contracts for Brighton Beach, TransAlta's Sarnia generation and others (over 1,100 MW), and renewable energy contracts (about 100 MW now in-service.). More generation is expected to be contracted and come into service in the next few years including new plant such as the Portlands project (550 MW in Toronto) and imports from Manitoba (400 MW).

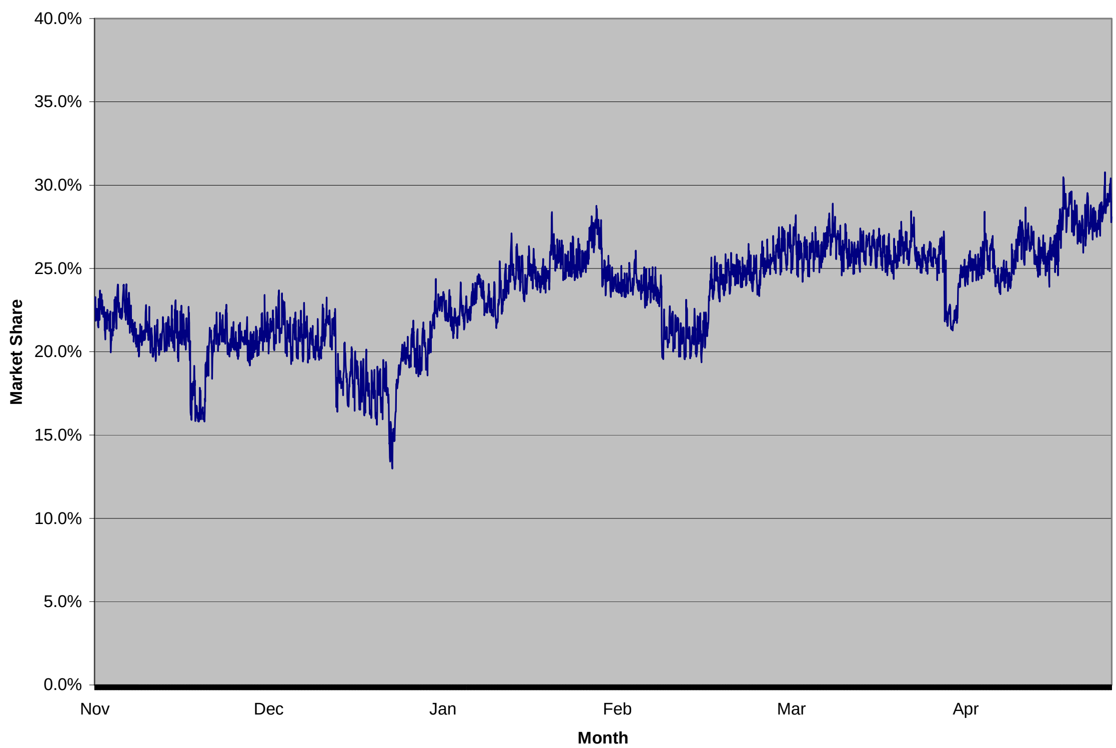
[44] Bruce A has a guarantee of a minimum average price of $45/MWh supplied.

As noted in our last report, one implication of this is that new generation in Ontario is expected to be developed only through provincial government procurement processes for the foreseeable future. From a reliability perspective this provides some certainty regarding additional supply arriving when needed to meet capacity requirements. To some extent, new procurement has been achieved through competitive processes, namely the CES contracts, with contract terms set out in advance and prices being established as part of the competition. An increasing number of supply arrangements are being made through one-on-one processes typically mandated by the government for reliability or other policy reasons, such as coal replacement. These include the Bruce arrangement, early mover contracts, Goreway and the anticipated Portlands and Manitoba contracts. Another single-source contract is the RMR for the Lennox plant, although this had public scrutiny as a result of an OEB review.

Two further aspects of the increasing importance of contracts we explore below are how much generation is left receiving spot market prices and the net effect of these government procurement and regulatory arrangements on prices paid for consumption.

As it did for the Panel's last report, the MAU has reviewed each hour's production to identify how much is not under contract. This represents the supply that gets and keeps the HOEP. Figure 3-6 presents the hourly results for the last 6 months, focusing on domestic production only.

Figure 3-6: Ontario Domestic Generation Without Fixed Pricing as a Percent of Ontario Production November 2005 – April 2006



The implied hourly spot market share in this period ranged from a high of 31 percent of Ontario generation, to a low of 13 percent with an average of 23 percent over all hours. Compared with the 6 months prior to this, the high and low are 3 to 4 percentage points lower, although the average is only 1 percentage point lower, indicating only a modest decline in the relative size of the spot market share. Equivalently, we can look at the absolute amount of Ontario generation that was remunerated at the spot price; this ranged from 2,100 MW to 5,970 MW and averaged 4,290 MW over the period. These data indicate the maximum absolute quantity continues to fall, as observed in the last report, reflecting the early mover arrangements, while the average and minimum quantities remain about the same.

Another way to view the spot market is to include imports. During the November 2005 - April 2006 period, there was an average of about 880 MW supplied by imports, ranging from zero up to 2,880 MW in a given hour. Including imports increases the share of the spot market to an average of 27 percent with an hourly high of 35 percent and low of 19 percent

The fixed price arrangements and contracts also have an effect on payments by consumers. Rebates or additional charges to domestic consumers are invoiced at the end of each month (as the Global Adjustment) and are assigned proportionally to the monthly energy consumption. Since the adjustment is unrelated to the time of consumption, loads which do not fall under the Regulated Price Plan should continue to be guided by the market price as a signal for consumption.[45] For example, consuming off-peak rather than on-peak will not change the monthly energy consumed or the global adjustment for a given customer, but that customer continues to pay less for the off-peak energy.

Since loads are being served by a blend of supply with and without fixed prices, a rise in the MCP is partially offset (hedged) because of the contracts. The amount of the offset is similar but not quite the same as the implied market shares above. To estimate the impact for the November 2005 to April 2006 period, we observe there was about 61.2 TWh (= million MWh) corresponding to production under fixed-price arrangements (although not all contracts were in effect at the time), while at the same time there was about 75.5 TWh of Ontario consumption.[46] Assuming $1 per MWh higher prices each hour, Ontario consumers would receive rebates averaging $0.81. Similarly, consumers would only benefit in the amount of 19 cents if the market price were to decline by a dollar, because of reduced rebates to generators. The actual amount can be higher or lower than this depending on a variety of assumptions in the calculations.[47]

[45] About half of domestic consumption is covered by the Regulated Price Plan (RPP)
[46] Ontario Domestic Demand less estimated losses of 2.2 percent
[47] The results are not necessarily robust and applicable to other historical or future scenarios. The reported proportion rebated, as well as supply receiving spot market prices, is based on the historical data. For this calculation we have assumed a price change of $1 each hour. If price increases were higher in hours with lower portions of fixed price energy, the average rebate would be lower. Similarly, if prices were higher because of increased gas costs, there would be less of a price hedge to the extent that contracts prices account for gas price changes; in that situation there would be no price hedge for gas-fired generation. Also, applying specific contract arrangements could lead to other results.

Chapter 4: The State of the IESO-Administered Markets

1. *Introduction*

This is our 8th consecutive report on the performance of the IESO-administered market in which we conclude that the market has operated well within the parameters set for it. We examined participant behaviour, market operations and market outcomes from the perspective of economic efficiency. An efficient market should produce competitive prices that reflect the underlying supply and demand conditions and support reliable operations. We are satisfied that this was achieved over the six-month period of November 2005 through April 2006.

Our review shows that the challenges that led to increased prices during the summer of 2005 - high loads, low resource levels and high gas prices - receded during the last six months. The average HOEP dropped back to $55.88 per MWh, about the level seen a year ago. At the same time, prices in some hours reached record low levels, with the market price in one interval in April actually falling below zero. Lower domestic loads and increased hydroelectric availability during the spring run-off period contributed to the low prices, but so did relatively high levels of failed exports. In other words, these price movements are consistent with underlying market forces. Although the MAU was in contact with participants at several instances regarding anomalous market outcomes during the period, we found no evidence of the abuse of market power and rule changes were initiated to address some specific issues with congestion payments.

The next two sections of this concluding chapter comment on ways that the market's usefulness can be protected and improved. The first provides some simple guidelines to ensure that future supply contracts provide the correct incentives to bid into the market. The second describes the limitations of the Ontario market's current uniform pricing construct and recommends eliminating constrained off payments by themselves or as part of a move to locational pricing.

2. *Future Supply Agreements*

During this past six months we have seen continued contracting of generation by the Ontario Power Authority (OPA). The IESO also entered into, the first reliability must run (RMR) contract. It is highly unlikely that new generation would come to Ontario without the protection of an OPA contract for the foreseeable future. This means that investment decisions are now centrally determined as part of the government procurement process and underscores the importance that the supply arrangements support the operation of the market as the driver of efficiency in the sector.

We would be concerned if the Ontario Power Authority OPA entered into fixed supply agreements akin to the old and discredited Power Purchase Agreements. When those agreements were made there was no spot market in operation that provided dynamic price signals of the cost of energy in the province. The circumstances are different now. We have a well-established and transparent wholesale market and we believe there are concrete benefits to be obtained if future procurement and other regulated price contracts are designed so as to support dispatch efficiency by ensuring that generators have the incentive to offer at prices related to cost. To the best of our knowledge, the CES contracts and early mover contracts entered into by OPA are designed so as to maintain dispatch efficiency. Supply arrangements that are organized as ‘contracts for difference’ (CFD) also preserve the incentives for generators to offer at prices relate to cost. The CFD is a trade contract in which the purchaser pays the seller the difference between the contract price and the spot market price. It insulates the parties from spot price volatility while also connecting them to the full incentive of real-time market prices.

We note, however, that the financial arrangements for OPG’s prescribed and non-prescribed assets and the Lennox RMR contract may under certain circumstances provide incentives for inefficient bidding. For OPG’s prescribed and non-prescribed assets, fixing the contract price but not the contract output can lead to instances when OPG has a financial incentive to run the plant even if the market price is less than incremental cost.

This could lead to a loss of efficiency if a lower cost supplier is displaced and the market price is less than the incremental cost of generation. In the case of the Lennox RMR contract, a contractual payment of cost plus a portion of the MCP may create a similar incentive although the contract seeks to limit the potential for these excursions to special circumstances. We will continue to monitor the implementation of these arrangements to identify any such problems.

We have seen some recognition of the importance of market processes in OPA's procurement of supply through the CES contracting process which featured a competition for the selection of new generation or demand management projects, and standardized contracts. Where there are multiple potential suppliers, we encourage OPA to continue using competitive selection processes.

For any future contracting we encourage the OPA to continue in the direction of maintaining the market price as a signal for supply whether this involves arrangements for generation or demand response within Ontario, or supply from outside the province. The point is that market incentives are a more effective means to promote efficiency than oversight by market monitors or regulators.

It will come as no surprise that we encourage the eventual restoration of either the energy market or a specialized capacity market as the mechanism to spur investment in the province.

3. *Limitations of Uniform Pricing*

An aspect of market evolution in which the Panel has taken a particular interest is locational pricing and all it entails. Uniform pricing and CMSC were introduced as part of the original market design for Ontario as transitional measures with the expectation that some form of locational pricing would be adopted in the not too distant future. It was known from the outset based on experience elsewhere that uniform pricing would result in inefficiencies and distortions in the market that would require a number of administrative fixes. Nevertheless, this was considered acceptable as a temporary situation.

In earlier reports and a discussion paper on constrained off CMSC, the Panel has identified many anomalous outcomes associated with CMSC and uniform pricing. In this report we have noted several more anomalous and/or inefficient results. We expect that we have not yet uncovered the last of these.

Consequently, the Panel is recommending that some aspects of market design be changed to deal with these issues and prevent further similar problems. The Panel has often noted that locational pricing offers greater efficiency than is possible with uniform pricing and once more recommends a move in that direction.

<u>Market Issues Reported to Date</u>

In this report we have identified several market flaws or oddities related to uniform pricing or CMSC. Some are new while others are recurrences of previously observed phenomena:

- In Chapter 2 we explained how uniform pricing has resulted in inefficient exports to New York. When the NYISO price is above HOEP but below the nodal price exports tend to flow but are inefficient since the incremental cost of generation in New York – represented by the NYISO price – is less than the incremental cost of supply in Ontario, as indicated by the nodal price.
- We also described in Chapter 2 how market participants can simultaneously receive constrained on payments for imports and constrained off payments for exports.
- Constrained off exports can be assessed large charges (negative CMSC) when no transaction takes place. For example, on April 21, we observed that real-time prices spiked because of an unexpected shortage and constrained off exports were assessed large negative CMSC payments, even though there was no physical export flow.

- In Chapter 3 we reported on a Market Rule change that was necessary to deal with CMSC payments as the result of participants targeting the price range between the nodal price and uniform price when there was little likelihood of a transaction actually taking place.
- An urgent rule was required to deal with inappropriate constrained off CMSC which was being paid to linked wheels. When system conditions led to cutting linked wheels in February, very large CMSC payments were created because linked wheels are required to bid and offer at the Maximum Market Clearing Price (minus or plus $2,000/MWh).

The Panel has always viewed constrained off CMSC as susceptible to gaming, because a payment is made when no transaction takes place, begging the questions of whether a transaction was intended and what costs were avoided or opportunities lost. Other problems have been reported and discussed in several earlier reports and the 2003 consultation on CMSC:

- Large negative offer prices for generation and imports (for example -$1,000 or -$2,000 per MWh) were leading to very large CMSC payments when these were constrained off. The CMSC calculation was modified to exclude compensation for the portion of the offer price below zero.
- We observed that continued deviation from dispatch by a facility induced constrained off conditions and CMSC payments. A Market Rule was introduced which allowed the IESO to review the conditions after the fact and adjust the CMSC for dispatchable load when it is self-induced as a consequence of dispatch deviations.
- Energy limited resources can be repeatedly constrained off and receive multiple CMSC payments for the same unit of constrained off energy. The local market power rules were changed to estimate an opportunity cost for the constrained off water resource and to provide for the use of this estimate in order to assess possible local market power and CMSC adjustments.

- We observed that because of scheduling protocols with the NYISO, imports or exports that could not possibly flow could be selected in the market schedule and be eligible for constrained off CMSC payments. A Market Rule subsequently enabled the limiting of market (unconstrained) schedules based on the limits shared with NYISO.

Each of these problems led to some enabling rule change, including an urgent rule change for negative price CMSC but in some cases the solution has been less than complete.

4. *Moving Forward*

In Chapter 1 we reported CMSC payments by zone although we did not relate these payments to specific constraints because of the difficulty associating CMSC payments with specific constrained transmission interfaces. This limitation was also noted in our 2003 Consultation as interfering with the ability to identify efficiency benefits for transmission enhancements. This continues to be the situation and we recommend the work be undertaken by the IESO. Such an effort would allow a more informed discussion of the necessity of transmission upgrades and investment decisions.

We also have a broader set of recommendations.

In 2003 the Panel suggested the elimination of constrained off CMSC payments but accepted arguments that the timing was not auspicious for a rule change of this magnitude. We are now of the opinion that conditions are such that it is time to eliminate constrained off payments, by themselves or as the result of a move to locational pricing, ideally associated with the development of a Day Ahead market. New CMSC issues continue to emerge leaving a sense that there may be more to discover. Reticence over changing the market structure because of the possibility of scaring away new investment is no longer a concern for the foreseeable future with the procurement role now taken on by OPA. Load and generation are largely protected by fixed price contracts. Finally, constrained off CMSC payments have risen well beyond earlier levels.

Over the 4 years of the market, constrained off CMSC has grown in absolute terms and in comparison to constrained on payments. This can be seen in the following table which shows constrained off CMSC for the last year of operation as $163 million compared with $75 million in the first year. Moreover, in the first year constrained off payments were about 58 percent as large as constrained on payments, while in this last year they were almost 200 percent.

Table 4-1: Annual CMSC Payments ($ Million), 2002-2006

CMSC	Constrained Off	Constrained On	Total[48]
Year 1	75	131	233
Year 2	64	28	105
Year 3	82	24	125
Year 4	163	82	260

There are no longer persuasive reasons to postpone initiatives that could deal with these issues. In light of the flaws and inefficiency identified and the expected continuation and emergence of new problems, we see this as an opportune time to modify the market design. The market has the potential to maximize the efficiency for supplying electricity in Ontario. The right modifications to market structure at this time can contribute toward the achievement of this goal.

We have always seen locational pricing as providing the most efficient signals for the market. Full nodal pricing may offer the greatest efficiencies but alternatives – two-zone pricing or simply eliminating constrained off CMSC – could be implemented if these are needed to ease the transition. These options for consideration by the IESO are sketched below:

[48] As reported in the Statistical Appendices e.g. Table A-16. "Total" represents all CMSC, including CMSC for OR and some energy CMSC which due to label assignment issues were not attributable to constrained on or constrained off categories.

a) Eliminate constrained off CMSC payments

In general terms, this is simply the removal of all constrained off CMSC. It deals with some of the CMSC issues identified above, but does not provide the full efficiencies of locational pricing, except that it does provide a signal for locating new generation outside areas with surplus.[49]

Eliminating constrained off CMSC has been criticized as leading to higher market prices. The MAU has assessed the possible HOEP impact of this change under two scenarios – one which removed constrained off fossil units in the Northwest when determining market price, and a second scenario which had the further removal of constrained off imports and exports.[50] Table 4-2 summarizes the estimated HOEP change, and the impact to Ontario consumers after adjustment for regulated and other generation with contracted fixed prices. The adjustment is assumed to be 25 percent.[51]

[49] One of the design variations is whether there could be a type of TR market for internal congestion, allowing participants to hedge their risk of being constrained off.
[50] Details of the analysis can be provided on request.
[51] In chapter 3 we identified that fixed price arrangements with generators created a hedge on about 81 percent of the price increase for Ontario demand. Because there was some uncertainty in this figure, here we use a more conservative value of 25 percent for the unhedged portion (rather than 100-81 = 19 percent.

Table 4-2: HOEP Impact of Removing Constrained Off Supply November 2005 – April 2006

Scenario	HOEP Impact ($/MWh)	Adjusted for contracts etc. Net Impact - 25%
Removal of NW Fossil	$4.17	$1.04
Plus removal of imports less exports	$4.80	$1.20

For 150 TWh of consumption the adjusted figures amount to between $155 million and $180 million per year. However, the removal of constrained off CMSC could lower uplift by roughly $60 million to more than $100 million a year (the annual figures net of the current CMSC recovery), and would offset some of the impact on consumers from the higher HOEP.

b) Zonal Pricing – Two Zone Model

There could be one zone in the Northwest and one for the rest of Ontario, exhibiting separate prices. Intra zonal congestion management would still require CMSC payments. One possible implementation maintains constrained and unconstrained schedules, treating the Northwest something like another intertie zone.[52]

The two zone model may provide most of the pricing signal advantages of locational pricing because it captures the most restrictive transmission constraint in the province. However, with the planned removal of coal generation in the Northwest, the importance of the East-West transmission constraint and consequent pricing differences between the Northwest and the rest of Ontario may not be as great in future, while flows may even reverse direction. Still, there would be efficiency gains, as the result of the right pricing signals, at those times

[52] The alternative would be using only a constrained model and developing representative nodal prices within each zone. Suitable designs would have to be investigated.

when there is pricing divergence. For example, with current conditions, the two zone model could resolve most of the identified efficiency related export issues.

c) Nodal Pricing

The NYISO provides a possible design with nodal prices for generation, and a single price for load in a zone based on an average of nodal prices. This provides the full efficiency benefits of nodal pricing while offering some simplification for pricing for wholesale loads.

A nodal pricing design could lead to average prices as indicated in Figure 1-18, but with other changes to generation taking place, in particular the closing of coal plant, we don’t anticipate as much difference between prices in the northern and southern parts of the province. Under this approach there would be no constrained off CMSC and potentially only a residual constrained on CMSC, possibly as payments for reliability must run units.

5. *Conclusion*

A well-functioning spot market constitutes a solid basis on which to continue to develop market-based structures and rules that can ultimately achieve efficiency in consumption and investment, as well as dispatch. Ontario, like other electricity markets, needs to continue to evolve to achieve these goals for the benefit of all Ontarians. We believe there is merit in the IESO conducting a review of options to reform the uniform price construct, perhaps in conjunction with renewed work on the development of a day ahead market.

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

Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2005 – April 2006

PUBLIC

June 2006

In some instances, the data reported in this Report has been updated or recalculated and therefore may differ from values previously quoted in our earlier reports.

List of Tables

*Table A-1: Monthly Energy Demand (TWh)**

	Ontario Demand**		Total Market Demand		Exports	
	2004 / 2005	2005 / 2006	2004 / 2005	2005 / 2006	2004 / 2005	2005 / 2006
May	11.58	11.32	12.80	12.31	1.21	0.99
Jun	11.84	13.03	12.95	13.78	1.12	0.75
Jul	12.56	13.67	13.69	14.40	1.11	0.73
Aug	12.49	13.58	13.78	14.41	1.28	0.83
Sep	12.03	12.15	12.52	13.06	0.49	0.91
Oct	11.85	11.87	12.40	12.80	0.56	0.93
Nov	12.23	12.08	12.86	13.20	0.62	1.12
Dec	13.65	13.37	14.57	14.41	0.91	1.04
Jan	14.23	13.20	15.36	14.39	1.13	1.20
Feb	12.37	12.17	13.38	13.26	1.00	1.09
Mar	13.08	12.78	14.02	14.01	0.94	1.23
Apr	11.41	11.09	11.91	12.40	0.50	1.32

* This data has been revised and is now from the unconstrained schedule.
** This is non-dispatchable demand only.

Table A-2: Average Monthly Temperature (°Celsius)*

	2002	2003	2004	2005	2006
Jan		(7.68)	(9.13)	(6.78)	0.30
Feb		(7.02)	(3.29)	(3.60)	(3.56)
Mar	0.39	(0.57)	2.26	(1.29)	1.21
Apr	7.27	5.53	6.88	8.18	8.36
May	11.21	12.23	13.31	12.14	N/A
Jun	19.18	18.53	17.78	22.54	N/A
Jul	24.14	21.71	20.65	24.09	N/A
Aug	22.63	21.85	19.57	22.53	N/A
Sep	20.09	17.12	18.40	18.33	N/A
Oct	9.16	9.04	10.85	11.01	N/A
Nov	3.18	4.91	5.29	5.06	N/A
Dec	(1.82)	(0.03)	(2.54)	(3.13)	N/A

*Table A-3: Number of Days Temperature Exceeded 30°C**

	2002	2003	2004	2005	2006
Jan		0	0	0	0
Feb		0	0	0	0
Mar	0	0	0	0	0
Apr	0	0	0	0	0
May	0	0	0	0	N/A
Jun	5	4	2	9	N/A
Jul	16	4	1	11	N/A
Aug	8	4	0	7	N/A
Sep	4	0	0	2	N/A
Oct	0	0	0	0	N/A
Nov	0	0	0	0	N/A
Dec	0	0	0	0	N/A

* Temperature is calculated at Toronto Pearson International Airport

*Table A-4: Outages (TWh), May 2004-April 2006**

	Total Outage		Planned Outage		Forced Outage	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	6.05	6.00	3.69	3.07	2.36	2.93
Jun	4.45	3.49	1.81	1.37	2.65	2.11
Jul	4.04	3.49	1.40	0.51	2.64	2.98
Aug	3.64	3.63	1.20	0.51	2.43	3.12
Sep	5.87	4.74	2.46	2.19	3.41	2.55
Oct	6.60	5.60	3.30	3.04	3.31	2.55
Nov	6.26	4.98	3.03	2.23	3.23	2.75
Dec	4.22	4.26	1.71	1.46	2.51	2.80
Jan	3.68	3.03	1.02	1.37	2.66	1.65
Feb	3.30	2.46	1.39	1.10	1.91	1.37
Mar	4.92	4.04	2.54	2.60	2.38	1.44
Apr	7.40	4.88	2.88	3.36	4.52	1.52

* There are two sets of data that reflect outages information. Past reports have relied on information from the IESO's outage database. This table reflects the outage information that is actually input to the DSO to determine price. The MAU has reconciled the difference between the two sets of data by applying outage types from the IESO's outage database to the DSO outage information.

Table A-5: Average HOEP, On and Off-Peak, May 2004-April 2006

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	48.06	53.05	61.93	63.78	37.60	44.21
Jun	46.69	65.99	60.15	83.57	33.81	49.19
Jul	45.58	76.05	55.55	102.84	37.38	55.84
Aug	43.51	88.24	52.81	118.49	35.84	61.08
Sep	49.57	93.70	59.17	123.65	41.16	67.50
Oct	49.11	75.92	57.48	101.37	42.80	56.71
Nov	52.28	58.25	61.94	74.11	43.82	44.39
Dec	50.82	79.77	59.84	101.29	43.40	63.52
Jan	57.90	55.54	68.99	64.95	49.53	47.79
Feb	49.58	48.12	56.51	53.98	43.29	42.80
Mar	59.87	49.01	67.86	57.62	53.29	40.59
Apr	61.93	43.52	69.57	55.96	55.24	35.23

Table A-6: Average Richview Slack Bus Price, On and Off-Peak
May 2004-April 2006

	Average Richview Slack Bus Price		Average On-Peak Richview Slack Bus Price		Average Off-Peak Richview Slack Bus Price	
	2004 / 2005	2005 / 2006	2004 / 2005	2005 / 2006	2004 / 2005	2005 / 2006
May	65.64	67.38	88.85	85.13	48.13	52.76
Jun	59.23	94.51	81.48	130.91	37.95	59.71
Jul	52.34	98.98	62.91	139.47	43.64	68.42
Aug	49.38	118.09	62.74	155.02	38.42	84.98
Sep	57.73	114.00	69.63	145.04	47.31	86.83
Oct	54.26	100.98	63.47	133.89	47.32	76.14
Nov	61.98	78.25	73.56	102.68	51.85	56.87
Dec	58.33	94.85	70.38	124.83	48.42	72.22
Jan	70.98	67.37	89.01	83.80	57.36	53.84
Feb	54.35	57.23	62.57	67.15	46.88	48.22
Mar	68.03	57.44	78.47	69.01	59.47	46.12
Apr	86.90	53.12	101.25	68.33	74.36	42.98

Table A-7: Ontario Demand (GWh) by Market Segmentation, May 2004-April 2006

	LDC's		Wholesale Loads		Generation		Metered Energy Consumption		Transmission Losses		Total Energy Consumption	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	9,466	9,409	2,003	1,880	155	175	11,625	11,465	211	280	11,836	11,745
Jun	9,586	11,235	1,995	1,750	165	170	11,746	13,155	300	344	12,046	13,499
Jul	10,332	11,662	1,897	1,726	177	193	12,405	13,581	365	514	12,770	14,095
Aug	10,300	11,412	2,008	1,895	178	208	12,487	13,515	259	517	12,746	14,032
Sep	9,958	10,041	1,989	1,854	157	197	12,104	12,092	266	461	12,370	12,553
Oct	9,709	9,828	2,123	1,766	167	177	11,998	11,771	217	416	12,215	12,187
Nov	10,172	10,233	2,020	1,709	188	165	12,380	12,107	221	334	12,601	12,441
Dec	11,714	11,497	1,984	1,728	194	197	13,892	13,422	90	324	13,982	13,746
Jan	12,053	11,185	1,988	1,752	199	188	14,239	13,124	380	473	14,619	13,597
Feb	10,494	10,425	1,793	1,555	153	164	12,441	12,145	291	423	12,732	12,568
Mar	11,010	10,787	1,931	1,756	181	174	13,122	12,717	372	483	13,494	13,200
Apr	9,525	9,231	1,844	1,658	181	154	11,550	11,043	278	470	11,828	11,513

Table A-8: Frequency Distribution of HOEP, May 2004-April 2006
(Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	<10.00		**10.01 - 20.00**		**20.01 - 30.00**		**30.01 - 40.00**		**40.01 - 50.00**		**50.01 - 60.00**		**60.01 - 70.00**		**70.01 - 100.00**		**100.01 - 200.00**		**> 200.01**	
	2004/2005	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**	**2004/2005**	**2005/2006**
May	0.54	0.00	8.87	1.48	15.59	1.88	15.59	22.04	**19.35**	**34.41**	15.46	10.62	9.95	13.04	9.68	13.71	4.97	2.42	0.00	0.40
Jun	0.83	0.28	10.83	3.19	8.19	5.42	14.31	14.44	**31.53**	**19.44**	17.36	11.81	4.86	8.33	8.61	17.78	3.47	18.89	0.00	0.42
Jul	0.81	0.13	8.60	0.40	10.62	6.18	15.46	17.20	**32.80**	9.81	12.10	10.48	9.81	7.39	9.54	23.12	0.27	**23.25**	0.00	2.02
Aug	0.00	0.13	10.08	0.27	7.26	3.49	20.97	16.40	**33.47**	11.02	14.38	10.22	8.20	6.59	5.51	15.59	0.13	**32.93**	0.00	3.36
Sep	0.14	0.00	1.94	0.00	5.56	1.81	18.75	15.42	**28.61**	10.69	23.33	11.25	13.19	4.72	7.92	13.89	0.56	**39.31**	0.00	2.92
Oct	0.00	0.00	0.00	1.21	2.28	1.34	**32.80**	14.78	18.82	24.19	29.17	10.89	9.54	7.26	6.99	14.11	0.40	**25.67**	0.00	0.54
Nov	0.00	0.00	0.00	0.56	3.33	2.64	**29.44**	20.56	27.50	**28.75**	14.03	17.08	7.36	8.19	15.56	12.64	2.78	9.58	0.00	0.00
Dec	0.00	0.00	0.00	0.27	3.49	0.81	**39.11**	10.89	20.70	22.98	17.88	14.52	4.97	9.27	8.74	12.90	4.97	**28.09**	0.13	0.27
Jan	0.00	0.00	0.54	0.40	3.09	1.34	17.88	11.02	20.30	**33.20**	**26.75**	29.44	10.35	11.96	14.52	7.80	6.59	4.84	0.00	0.00
Feb	0.00	0.00	0.00	0.89	0.15	1.79	25.74	17.41	**33.78**	**47.62**	27.08	18.45	6.55	9.38	6.10	3.72	0.45	0.74	0.15	0.00
Mar	0.00	0.00	0.00	0.13	0.00	2.55	5.24	30.65	28.49	**31.85**	**29.57**	15.86	16.26	10.08	16.94	6.85	3.36	2.02	0.13	0.00
Apr	0.00	5.97	0.00	7.22	0.00	9.72	16.11	**26.81**	**23.75**	20.69	17.08	12.64	12.92	9.31	21.39	5.97	8.75	1.11	0.00	0.56
May-04 Apr-05	0.19	N/A	3.41	N/A	4.96	N/A	20.95	N/A	**26.59**	N/A	20.35	N/A	9.50	N/A	10.96	N/A	3.06	N/A	0.03	N/A
May-05 Apr-06	N/A	0.54	N/A	1.34	N/A	3.25	N/A	18.14	N/A	**24.55**	N/A	14.44	N/A	8.79	N/A	12.34	N/A	15.74	N/A	0.87

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2004-April 2006
(Percentage of Hours within Defined Range)

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	0.13	0.13	8.47	0.54	12.77	2.28	16.40	16.94	15.59	**35.75**	**17.20**	11.02	11.69	12.37	11.29	16.80	6.45	3.76	0.00	0.40
Jun	0.69	0.14	9.86	3.33	8.19	4.17	12.92	12.50	**29.31**	19.17	17.36	11.25	7.64	9.17	9.17	17.78	4.72	**22.08**	0.14	0.42
Jul	0.67	0.13	7.80	0.40	9.81	3.90	13.71	13.17	**30.51**	12.63	12.63	10.22	12.50	6.99	11.29	23.52	0.94	**26.48**	0.13	2.55
Aug	0.00	0.27	9.54	0.13	7.26	3.09	17.47	12.63	**33.06**	11.42	14.92	10.62	11.69	6.59	5.91	15.46	0.13	**35.35**	0.00	4.44
Sep	0.14	0.14	1.94	0.00	4.03	0.97	17.50	9.86	**27.36**	13.75	17.92	11.11	20.42	5.83	10.00	14.17	0.69	**41.11**	0.00	3.06
Oct	0.13	0.13	0.00	0.67	2.15	1.34	27.02	10.22	20.43	23.92	**28.90**	12.63	12.23	7.93	8.20	14.38	0.94	**28.09**	0.00	0.67
Nov	0.14	0.14	0.00	0.56	2.50	2.22	**25.69**	18.19	19.31	**24.44**	22.92	19.03	8.47	10.56	17.36	13.47	3.61	11.39	0.00	0.00
Dec	0.13	0.13	0.00	0.27	3.09	0.54	**33.20**	10.35	21.10	19.22	20.30	14.11	6.72	11.16	9.81	14.38	5.65	**28.90**	0.13	0.94
Jan	0.13	0.13	0.40	0.40	2.96	0.40	14.25	10.62	18.41	23.52	**28.63**	**33.87**	11.69	15.99	15.32	9.14	8.20	5.91	0.00	0.00
Feb	0.15	0.15	0.00	0.60	0.15	0.89	13.84	13.39	**38.99**	**46.43**	29.61	22.02	9.23	9.97	7.14	5.65	0.74	0.89	0.15	0.00
Mar	0.13	0.13	0.00	0.13	0.00	1.61	2.42	24.46	**27.02**	**34.54**	26.48	16.53	20.70	11.16	18.95	9.14	4.17	2.15	0.13	0.13
Apr	0.14	5.97	0.00	6.53	0.00	8.19	11.25	19.86	22.50	**26.11**	16.53	10.56	13.47	10.83	**24.86**	9.72	11.25	1.67	0.00	0.56
May-03 Apr-04	0.22	N/A	3.17	N/A	4.41	N/A	17.14	N/A	**25.30**	N/A	21.12	N/A	12.20	N/A	12.44	N/A	3.96	N/A	0.06	N/A
May-04 Apr-05	N/A	0.68	N/A	1.18	N/A	2.48	N/A	14.11	N/A	**23.20**	N/A	15.63	N/A	9.65	N/A	13.35	N/A	18.55	N/A	1.16

* Bolded values show highest percentage within month.

Table A-10: Total Hourly Uplift Charge ($ Millions), May 2004-April 2006

	Total Hourly Uplift		IOG*		CMSC**		Operating Reserve		Losses	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	36	32	2	3	9	11	8	3	17	16
Jun	29	53	1	5	9	21	4	1	15	25
Jul	47	87	1	12	4	43	4	1	39	31
Aug	26	110	1	20	7	55	1	1	16	33
Sep	28	62	1	7	9	24	1	1	16	30
Oct	24	56	2	8	7	23	1	4	15	22
Nov	38	40	7	7	11	11	4	4	17	18
Dec	33	52	4	9	9	13	3	4	18	26
Jan	37	34	5	3	11	11	3	2	19	18
Feb	24	25	2	2	6	8	2	1	14	14
Mar	35	28	3	4	11	8	3	2	18	15
Apr	46	36	5	1	15	15	8	6	18	13

* The IOG numbers are not adjusted for IOG offsets, which was implemented in July 2002. IOG offsets are reported in Table A-15.

** Numbers are adjusted for Negative Price CMSC Revision and Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments. Local Market Power Adjustments are reported in Table A-19.

Table A-11: Operating Reserve MCP ($/MWh), May 2004-April 2006

	10N		10S		30R	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	8.66	3.27	10.90	5.77	8.20	3.20
Jun	3.97	1.21	5.93	3.11	3.77	1.21
Jul	3.60	0.73	5.62	4.29	3.47	0.73
Aug	0.88	0.53	3.27	5.74	0.87	0.53
Sep	1.06	0.40	3.54	5.99	1.02	0.40
Oct	0.54	2.63	2.93	5.80	0.54	2.55
Nov	2.72	3.35	5.08	4.92	2.63	3.16
Dec	2.20	4.25	3.58	5.88	2.12	4.13
Jan	3.11	1.88	5.17	3.40	3.04	1.87
Feb	2.20	1.54	4.24	2.61	1.90	1.52
Mar	2.46	1.79	4.67	2.63	2.46	1.79
Apr	8.92	6.90	10.58	8.87	8.71	6.68

*Table A-12: Exogenous Factors, Off-Peak**

	Nuclear (Average Hourly MW)		Base-load Hydroelectric (Average Hourly MW)		Self-Scheduling (Average Hourly MW)		Lakeview (Average Hourly MW)		Ontario Demand (NDL) (Average Hourly MW)		Average HOEP ($)	
	04/05	05/06	04/05	05/06	04/05	05/06	04/05	05/06	04/05	05/06	04/05	05/06
Nov	7,574	9,180	2,004	1,738	913	734	192	0	15,092	14,835	40.71	42.68
Dec	9,846	9,448	1,910	1,743	919	683	0	0	16,547	16,160	41.06	66.50
Jan	9,603	9,950	1,863	1,759	942	679	219	0	17,355	15,871	47.79	46.06
Feb	9,523	10,639	1,959	1,789	965	755	129	0	16,781	16,364	43.24	41.94
Mar	9,097	10,040	2,183	1,951	931	848	143	0	16,150	15,551	51.00	40.69
Apr	6,565	9,432	2,121	1,911	826	667	40	0	14,160	13,742	47.82	28.01

* Off-Peak hours are defined as HE22 to HE7, inclusive, for all days of the week.

*Table A-13: Exogenous Factors, On-Peak**

	Nuclear (Average Hourly MW)		Base-load Hydroelectric (Average Hourly MW)		Self-Scheduling (Average Hourly MW)		Lakeview (Average Hourly MW)		Ontario Demand (NDL) (Average Hourly MW)		Average HOEP ($)	
	04/05	**05/06**	**04/05**	**05/06**	**04/05**	**05/06**	**04/05**	**05/06**	**04/05**	**05/06**	**04/05**	**05/06**
Nov	7,589	9,167	2,355	2,301	1,049	915	489	0	18,342	18,173	60.54	69.38
Dec	9,857	9,444	2,328	2,359	1,065	837	0	0	19,641	19,268	57.79	89.25
Jan	9,610	9,950	2,234	2,169	1,083	843	423	0	20,396	19,070	65.13	62.30
Feb	9,519	10,627	2,360	2,369	1,107	900	266	0	19,581	19,364	54.12	52.54
Mar	9,069	10,051	2,454	2,440	1,081	987	318	0	18,594	18,337	66.21	54.96
Apr	6,603	9,403	2,384	2,279	990	798	181	0	17,047	16,582	72.00	54.60

* On-Peak hours are defined as HE8 to HE21, inclusive, for all days of the week.

*Table A-14: IOG Payments, Top 10 Days, November 2005-April 2006**

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
2005/11/05	28,625	0.99	34.74	19,962
2005/12/13	17,363	0.66	38.19	24,933
2005/12/09	10,447	0.64	61.22	23,423
2005/12/12	12,318	0.57	46.48	24,576
2005/11/25	19,153	0.54	28.23	22,863
2005/11/23	19,480	0.53	27.29	23,130
2005/11/10	18,578	0.52	28.12	22,309
2005/12/16	21,383	0.51	24.06	23,555
2005/12/07	13,032	0.50	38.21	23,933
2005/12/17	20,008	0.49	24.71	21,872
	Total Top 10 days	5.95		
	Total for Period	24.57		
	% of Total Payments	25.14		

* Numbers are not netted against IOG offset for the ‘implied wheel’.

Table A-15: IOG Offsets due to Implied Wheeling

	IOG Offset ($'000)		IOG Offset (%)	
	2004/2005	2005/2006	2004/2005	2005/2006
May	81	259	4.61	10.14
Jun	98	477	6.88	8.97
Jul	135	652	11.63	5.52
Aug	154	1,118	16.47	5.51
Sep	70	844	5.76	11.37
Oct	409	716	26.75	8.86
Nov	376	836	5.45	11.20
Dec	260	642	6.51	7.54
Jan	438	258	9.14	9.74
Feb	61	59	3.13	3.34
Mar	331	68	9.95	1.85
Apr	469	55	8.88	3.98

Table A-16: CMSC Payments, Energy and Operating Reserve ($ Millions), May 2004-April 2006

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	5.95	10.87	1.65	1.96	8.22	12.92	1.35	1.06	9.57	13.98
Jun	5.71	13.55	1.56	6.83	7.75	22.46	1.18	0.37	8.93	22.84
Jul	4.40	29.77	1.65	17.15	6.47	48.66	1.02	0.24	7.49	48.90
Aug	5.60	28.63	1.28	25.56	7.13	56.20	0.53	0.09	7.66	56.29
Sep	7.17	17.04	2.35	7.22	9.92	25.89	0.53	0.13	10.45	26.02
Oct	5.91	17.27	1.22	5.18	7.62	23.52	0.13	0.69	7.74	24.21
Nov	7.56	8.14	3.07	3.53	11.46	12.53	0.80	0.94	12.26	13.48
Dec	7.70	7.46	2.36	4.77	10.65	13.46	0.58	0.92	11.23	14.38
Jan	9.01	7.26	2.36	3.10	11.96	11.94	0.52	0.45	12.48	12.39
Feb	6.28	5.98	1.34	2.56	7.91	9.36	0.77	0.35	8.69	9.72
Mar	7.04	6.11	2.02	2.15	11.91	8.86	0.45	0.45	12.36	9.31
Apr	9.87	11.23	3.57	2.15	14.48	14.78	1.80	1.19	16.28	15.96
May 04 -Apr 05	82.20	N/A	24.43	N/A	115.48	N/A	9.66	N/A	125.14	N/A
May 05 -Apr 06	N/A	163.31	N/A	82.16	N/A	260.58	N/A	6.88	N/A	267.48

* The sum for energy being constrained on and off does not equal the total CMSC for energy in some months. This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete. Note that these numbers are the net of positive and negative CMSC amounts.
** The totals for CMSC payments do not equal the totals for CMSC payments in Table A-10: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months. Neither table includes Local Market Power adjustments, shown in Table A-19.

Table A-17: Share of Constrained On Payments by Import and Domestic Suppliers (%)

	Domestic		Imports	
	2004/2005	2005/2006	2004/2005	2005/2006
May	63	78	37	22
Jun	69	81	31	19
Jul	83	39	17	61
Aug	78	29	22	71
Sep	49	75	51	25
Oct	79	63	21	37
Nov	49	55	51	45
Dec	57	62	43	38
Jan	67	52	33	48
Feb	44	46	56	54
Mar	41	42	59	58
Apr	58	36	42	64

Table A-18: Share of CMSC Payments Received by Top Facilities (%), May 2004-April 2006

	Share of Total Payments Received by Top 10 Facilities		Share of Total Payments Received by Top 5 Facilities	
	Constrained Off	Constrained On	Constrained Off	Constrained On
May 05	62.90	51.78	48.31	36.23
Jun 05	54.56	52.62	44.72	34.86
Jul 05	60.41	62.51	43.39	49.29
Aug 05	62.66	74.12	42.37	61.02
Sep 05	59.98	63.05	41.33	41.74
Oct 05	57.94	55.78	45.72	40.14
Nov 05	62.13	43.57	50.71	28.43
Dec 05	47.05	51.04	33.34	33.03
Jan 06	68.46	48.19	54.91	35.89
Feb 06	70.29	55.04	58.20	42.07
Mar 06	61.55	50.14	50.63	33.02
Apr 06	53.10	59.74	41.39	37.95
May 2004 – Apr 2005	59.19	48.97	45.00	33.70
May 2005 – Apr 2006	60.09	55.63	46.25	39.47

Table A-19: Local Market Power Investigation Statistics

	May 2002 to April 2003	May 2003 to April 2004	May 2004 to April 2005	May 2005 to April 2006*	Total
Number of LMP Investigations					
Terminated (no CMSC Adjustment)	50	26	36	7	119
Completed (CMSC Adjustment)	265	202	74	63	604
Pending	0	0	0	17	17
Total Initiated	315	228	110	87	740
Inquiry Cases Terminated	5	0	0	0	5
Inquiry Cases Completed	46	0	4	0	50
CMSC Adjustment ($ Millions)					
Completed Cases	6.30	3.34	3.26	0.86	13.78
Pending – Potential Adjustment	-	-	-	0.55	0.55

* Data for March and April, 2006 are not included.

Table A-20: Share of Real-time MCP Set by Resource (%), May 2004-April 2006

	Coal		Nuclear		Oil/Gas		Water	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	53	67	0	0	11	9	36	24
Jun	62	51	0	0	7	30	31	19
Jul	59	43	0	0	6	38	34	20
Aug	69	46	0	0	6	33	25	21
Sep	69	45	0	0	12	34	18	20
Oct	76	58	0	0	5	15	19	27
Nov	66	71	0	0	13	12	20	16
Dec	74	61	0	0	9	23	17	16
Jan	60	84	0	0	20	6	19	11
Feb	79	85	0	0	8	4	13	11
Mar	61	73	0	0	15	9	24	18
Apr	59	65	0	0	17	8	23	27

Table A-21: Share of Real-time MCP Set by Resource (%), Off-Peak, May 2004-April 2006

	Coal		Nuclear		Oil/Gas		Water	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	49	72	0	0	5	1	46	27
Jun	57	67	0	0	1	12	42	20
Jul	52	61	0	0	2	21	46	17
Aug	60	66	0	0	2	16	37	18
Sep	71	66	0	0	3	17	26	17
Oct	85	74	0	0	2	3	13	23
Nov	78	84	0	0	4	2	18	14
Dec	84	72	0	0	3	10	13	18
Jan	71	88	0	0	8	2	20	10
Feb	86	89	0	0	3	1	11	9
Mar	72	86	0	0	7	3	22	11
Apr	73	63	0	0	9	2	18	35

Table A-22: Share of Real-time MCP Set by Resource (%), On-Peak, May 2004-April 2006

	Coal		Nuclear		Oil/Gas		Water	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	58	61	0	0	19	18	23	21
Jun	68	34	0	0	13	48	19	18
Jul	69	18	0	0	11	59	20	23
Aug	80	23	0	0	10	51	10	25
Sep	67	21	0	0	23	54	9	25
Oct	62	36	0	0	10	30	28	33
Nov	53	57	0	0	24	24	23	19
Dec	62	45	0	0	16	41	21	14
Jan	46	79	0	0	36	10	18	11
Feb	71	81	0	0	13	6	16	13
Mar	47	59	0	0	25	16	28	25
Apr	44	67	0	0	27	17	29	15

Table A-23: Resources Selected in Real-time Market Schedule (%), May 2004-April 2006

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	3	8	10	8	12	17	6	7	30	28	52	48
Jun	5	8	9	6	13	22	6	8	25	21	55	49
Jul	4	8	8	5	14	22	6	8	25	19	54	51
Aug	5	7	10	6	16	22	5	8	22	17	56	53
Sep	9	8	4	7	18	20	7	7	25	17	50	56
Oct	8	8	5	8	23	19	8	6	24	21	45	53
Nov	10	7	5	9	21	17	7	6	26	24	46	52
Dec	8	6	7	7	18	20	7	6	22	23	53	51
Jan	7	6	8	9	22	20	7	5	22	22	49	53
Feb	6	3	8	8	21	18	7	5	22	22	49	54
Mar	5	4	7	9	21	16	7	6	23	24	49	54
Apr	8	2	4	11	18	11	8	6	32	29	42	54

Table A-24: Resources Selected in the Real-time Market Schedule (TWh), May 2004-April 2006

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear		Total*	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	0.41	0.93	1.21	0.99	1.52	1.95	0.76	0.79	3.72	3.34	6.53	5.69	12.53	11.76
Jun	0.65	1.05	1.12	0.75	1.65	2.85	0.77	1.01	3.15	2.80	6.82	6.44	12.39	13.10
Jul	0.57	1.06	1.11	0.73	1.90	2.96	0.82	1.14	3.36	2.57	7.11	6.99	13.19	13.65
Aug	0.69	0.94	1.28	0.83	2.14	3.08	0.72	1.16	2.93	2.31	7.43	7.29	13.22	13.84
Sep	1.03	0.95	0.49	0.91	2.12	2.55	0.83	0.89	2.90	2.10	5.83	6.96	11.68	12.51
Oct	0.95	0.99	0.56	0.93	2.72	2.35	0.90	0.79	2.85	2.55	5.23	6.48	11.69	12.16
Nov	1.22	0.94	0.62	1.12	2.53	2.19	0.88	0.81	3.04	3.01	5.46	6.60	11.91	12.61
Dec	1.06	0.85	0.91	1.04	2.53	2.74	0.94	0.88	3.09	3.27	7.33	7.03	13.75	13.92
Jan	1.05	0.78	1.13	1.20	3.25	2.78	1.04	0.75	3.14	3.08	7.15	7.40	14.58	14.01
Feb	0.73	0.44	1.00	1.09	2.71	2.38	0.93	0.70	2.90	2.96	6.40	7.14	12.94	13.18
Mar	0.63	0.55	0.94	1.23	2.84	2.21	1.00	0.86	3.13	3.28	6.76	7.47	13.72	13.83
Apr	0.90	0.28	0.50	1.32	2.10	1.36	0.87	0.70	3.66	3.68	4.74	6.78	11.37	12.52

*This is domestic generation, which is the sum of *Fossil-Coal*, *Fossil-Oil/Gas*, *Hydroelectric*, and *Nuclear*.

*Table A-25: Offtakes by Intertie Zone, On-peak and Off-peak (MWh), May 2004-April 2006**

		MB		MI		MN		NY		PQ	
		2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	Off-peak	0	0	21,592	16,353	9,138	280	668,221	511,177	31,115	59,461
	On-Peak	0	128	73,147	31,000	30,633	139	363,678	334,474	14,485	34,248
Jun	Off-peak	0	0	16,175	4,933	794	147	565,888	406,800	36,048	41,918
	On-Peak	0	184	44,143	36,405	7,465	610	417,033	229,136	27,585	27,417
Jul	Off-peak	0	0	21,568	20,219	2,085	409	608,976	505,227	41,731	41,977
	On-Peak	0	13	67,785	45,079	19,549	203	331,014	100,715	21,238	12,143
Aug	Off-peak	0	0	14,568	17,397	1,000	1,474	692,843	510,880	34,207	42,732
	On-Peak	0	0	74,885	43,185	400	970	447,670	183,081	16,535	28,678
Sep	Off-peak	0	0	8,458	4,152	0	1,146	285,404	602,683	12,600	54,665
	On-Peak	0	0	12,051	5,868	377	820	162,580	202,956	4,251	37,526
Oct	Off-peak	0	0	5,098	18,497	39	303	284,241	515,081	4,296	59,617
	On-Peak	0	0	13,662	19,215	1,888	187	243,433	279,983	2,583	33,938
Nov	Off-peak	0	0	896	8,845	0	617	373,843	583,318	22,774	58,291
	On-Peak	0	0	3,881	23,455	0	300	218,142	395,340	5,139	46,773
Dec	Off-peak	0	472	4,582	34,355	1,384	1,038	545,467	592,952	35,236	58,652
	On-Peak	4,671	8,543	7,947	60,676	4,213	1,100	296,391	240,503	14,987	38,591
Jan	Off-peak	477	0	3,176	5,791	0	157	601,117	596,785	68,034	54,543
	On-Peak	12,459	250	9,746	16,002	6,782	410	380,532	488,721	43,472	34,612
Feb	Off-peak	0	0	5,550	24,471	1,112	0	515,010	549,983	52,489	51,078
	On-Peak	7,204	74	38,252	58,541	4,252	217	336,718	366,894	40,360	34,060
Mar	Off-peak	29	0	23,643	19,166	2,224	118	497,216	639,453	57,167	47,787
	On-Peak	14,453	0	94,864	58,314	10,703	1,169	223,155	439,656	21,314	26,955
Apr	Off-peak	0	0	7,210	121,123	0	951	263,123	684,203	39,138	43,527
	On-Peak	0	26	33,854	109,300	152	529	146,265	347,253	14,285	12,208

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

*Table A-26: Injections by Intertie Zone, On-peak and Off-peak (MWh), May 2004-April 2006**

		MB		MI		MN		NY		PQ	
		2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	Off-peak	12,169	104,990	248,883	378,392	8,047	32,738	5,650	7,500	0	1,237
	On-Peak	31,634	81,372	74,405	258,089	9,401	22,503	15,338	16,112	545	22,452
Jun	Off-peak	43,718	88,762	313,700	334,001	20,193	26,446	4,634	27,795	96	18,512
	On-Peak	61,812	78,517	154,277	260,234	15,512	23,022	25,145	88,336	6,445	103,591
Jul	Off-peak	63,958	106,182	295,430	307,890	25,797	27,902	16,530	27,891	5,683	48,628
	On-Peak	14,288	72,496	78,344	200,680	5,895	24,375	17,577	126,258	46,895	119,781
Aug	Off-peak	73,522	101,796	352,551	271,676	27,778	29,387	25,378	31,557	6,659	29,174
	On-Peak	31,238	84,284	131,802	227,519	12,045	28,958	6,418	96,054	24,802	41,497
Sep	Off-peak	73,961	88,172	414,710	344,228	19,196	25,782	31,519	20,300	20,215	71
	On-Peak	38,403	67,792	286,478	293,601	8,256	21,075	40,357	78,148	100,997	15,385
Oct	Off-peak	78,755	83,580	361,366	432,958	23,639	13,959	4,489	12,896	46,985	312
	On-Peak	35,114	60,445	236,722	329,739	4,589	11,317	7,051	33,726	153,582	14,443
Nov	Off-peak	91,322	85,779	506,489	380,087	25,987	21,538	27,981	13,853	13,383	1,721
	On-Peak	44,627	61,058	395,993	308,131	6,954	17,551	45,368	28,585	64,044	25,036
Dec	Off-peak	71,745	82,790	495,523	333,200	7,344	22,031	11,243	32,480	9,103	16,254
	On-Peak	33,182	42,343	377,931	218,732	3,575	13,178	24,245	40,094	28,646	48,801
Jan	Off-peak	83,751	82,046	509,106	356,141	9,634	20,355	18,893	4,693	5,655	1,638
	On-Peak	23,561	61,843	319,544	201,464	6,221	15,902	37,909	12,877	40,623	19,139
Feb	Off-peak	87,214	57,494	378,735	174,417	14,189	15,522	2,087	3,593	899	1,221
	On-Peak	26,095	46,981	176,488	104,802	7,193	12,084	8,657	11,543	31,410	15,290
Mar	Off-peak	98,599	54,587	239,224	185,629	11,331	18,839	31,639	2,472	18,763	11,333
	On-Peak	20,321	49,823	92,301	130,077	4,290	20,378	41,377	16,033	67,449	63,621
Apr	Off-peak	93,740	65,462	327,907	91,920	16,867	5,807	33,919	9,691	24,095	5,679
	On-Peak	70,506	41,490	168,762	27,208	14,988	4,713	55,062	4,524	93,213	18,658

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

Table A-27: Net Exports (MWh)

Year	Month	On-Peak	Off-Peak	Total
2003	May	(179,189)	46,863	(132,326)
	Jun	(201,943)	(55,467)	(257,410)
	Jul	179,938	306,195	486,133
	Aug	(50,847)	148,178	97,331
	Sep	(322,343)	(167,701)	(490,044)
	Oct	(476,637)	(411,012)	(887,649)
	Nov	(142,459)	(222,416)	(364,875)
	Dec	(249,784)	(97,079)	(346,863)
2004	Jan	(174,322)	(32,596)	(206,918)
	Feb	(239,477)	(66,647)	(306,124)
	Mar	(67,594)	(12,846)	(80,440)
	Apr	156,329	223,503	379,832
	May	350,620	455,317	805,937
	Jun	233,037	236,563	469,601
	Jul	276,589	266,961	543,549
	Aug	333,185	256,730	589,915
	Sep	(295,232)	(253,139)	(548,370)
	Oct	(175,493)	(221,560)	(397,053)
	Nov	(329,824)	(267,649)	(597,473)
	Dec	(139,370)	(8,289)	(147,660)
2005	Jan	25,133	45,765	70,898
	Feb	176,943	91,037	267,980
	Mar	138,751	180,724	319,475
	Apr	(207,975)	(187,057)	(395,031)
	May	(539)	62,414	61,875
	Jun	(259,946)	(41,718)	(301,664)
	Jul	(385,437)	49,339	(336,099)
	Aug	(222,398)	108,893	(113,506)
	Sep	(228,831)	184,093	(44,738)
	Oct	(116,347)	49,794	(66,553)
	Nov	25,506	148,094	173,600
	Dec	(13,734)	200,714	186,980
2006	Jan	228,771	192,403	421,174
	Feb	269,666	373,287	642,953
	Mar	246,164	433,664	679,828
	Apr	372,724	671,245	1,043,969

Table A-28: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	9.56	2.70	89.29	62.46	(67.17)	(177.13)	15.72	17.20	28.42	10.21
Jun	6.32	9.31	56.29	68.73	(114.16)	(188.58)	14.04	19.15	24.00	21.99
Jul	5.12	14.46	45.73	305.94	(72.63)	(373.17)	11.49	41.90	18.63	28.28
Aug	4.80	20.70	37.70	787.29	(40.78)	(244.47)	8.10	64.38	17.56	30.26
Sep	4.77	12.30	40.83	175.45	(93.73)	(469.99)	9.07	39.90	13.19	23.93
Oct	4.97	14.82	51.93	152.39	(63.19)	(396.93)	10.82	40.25	11.47	30.64
Nov	14.04	15.59	95.30	133.49	(56.18)	(107.11)	18.43	28.53	29.00	31.25
Dec	11.81	19.94	124.97	128.93	(197.68)	(139.24)	22.58	32.23	24.22	32.25
Jan	12.97	7.83	135.59	95.15	(90.28)	(55.84)	18.83	16.72	24.63	15.52
Feb	7.17	7.10	56.14	91.97	(261.55)	(63.38)	15.39	13.21	16.49	16.31
Mar	9.18	8.58	66.13	98.99	(339.68)	(76.97)	19.73	16.97	18.30	20.14
Apr	10.00	3.71	103.76	223.01	(111.67)	(651.03)	19.10	31.42	21.07	30.78

Table A-29: Measures of Differences between 1-Hour Ahead Pre-dispatch Prices and HOEP

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	10.05	4.97	72.62	52.37	(62.19)	(175.32)	14.11	16.98	27.58	14.51
Jun	6.73	9.68	53.20	94.12	(108.31)	(238.58)	12.84	18.02	24.09	22.45
Jul	5.21	12.50	41.29	287.05	(71.62)	(417.67)	10.06	37.22	18.32	26.69
Aug	4.99	19.50	33.05	574.86	(36.79)	(267.59)	7.58	58.42	17.61	29.29
Sep	4.01	9.93	31.99	133.67	(93.98)	(474.82)	7.97	36.31	11.57	20.67
Oct	5.72	16.70	51.21	139.88	(45.55)	(372.26)	10.12	35.93	12.69	33.03
Nov	11.12	14.62	70.28	109.26	(43.59)	(95.91)	15.74	24.08	23.86	30.18
Dec	8.33	17.99	89.97	115.79	(198.31)	(170.48)	18.53	29.64	18.82	31.06
Jan	10.57	7.76	108.62	98.88	(91.66)	(54.91)	15.62	15.46	20.47	15.99
Feb	6.52	8.33	65.08	85.36	(258.61)	(58.70)	14.43	12.23	14.56	18.82
Mar	9.55	10.25	57.98	92.99	(325.26)	(89.21)	18.01	15.45	18.71	24.13
Apr	10.28	7.74	82.78	107.75	(101.66)	(621.55)	16.79	29.19	21.15	40.88

Table A-30: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2004 / 2005	2005 / 2006	2004 / 2005	2005 / 2006
May	1.69	(3.64)	10.71	3.83
Jun	0.39	(1.20)	7.95	7.96
Jul	(0.03)	(4.21)	4.66	8.53
Aug	0.91	(3.54)	5.43	8.87
Sep	(0.19)	(10.75)	2.83	0.59
Oct	1.45	(4.81)	4.58	8.42
Nov	2.66	1.79	9.05	10.93
Dec	(0.35)	(0.47)	5.48	9.53
Jan	1.98	0.29	7.28	5.24
Feb	(0.83)	2.98	5.59	9.29
Mar	(1.36)	2.31	5.71	10.98
Apr	0.83	(1.50)	7.24	20.88

* This is an average of hourly difference relative to hourly peak MCP

Table A-31: Average Monthly HOEP Compared to Average Monthly Peak Hourly MCP

	HOEP		Hourly Peak MCP		Peak minus HOEP	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	48.06	53.05	56.47	61.66	8.41	8.62
Jun	46.65	65.99	53.12	76.86	6.46	10.87
Jul	45.58	76.05	50.83	92.84	5.25	16.78
Aug	43.49	88.24	47.57	111.25	4.08	23.01
Sep	49.57	93.70	53.76	114.44	4.19	20.74
Oct	49.07	75.92	53.43	97.45	4.36	21.53
Nov	52.28	58.25	60.74	71.09	8.47	12.84
Dec	50.83	79.77	59.47	98.20	8.64	18.43
Jan	57.90	55.54	66.50	63.01	8.60	7.47
Feb	49.58	48.09	56.95	53.44	7.36	5.35
Mar	59.87	49.01	70.76	57.15	10.89	8.14
Apr	61.93	43.52	71.38	52.77	9.45	9.25

*Table A-32: Frequency Distribution of Difference Between 1-Hour Pre-dispatch and HOEP, May 2004-April 2006**

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)															
	< -$50.01		-$50 to -$20.01		-$20.00 to -$10.01		-$10.00 to -$0.01		$0.00 to $9.99		$10.00 to $19.99		$20.00 to $49.99		> $50.00	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	0.27	1.34	2.02	3.23	1.75	2.55	11.29	11.69	40.32	52.82	24.60	16.94	18.68	11.29	1.08	0.13
Jun	0.70	0.42	0.97	1.53	2.92	2.50	16.02	10.83	45.54	42.08	22.28	22.92	11.28	19.17	0.28	0.56
Jul	0.13	2.55	1.48	3.36	2.15	2.96	**20.43**	12.37	48.79	32.66	19.49	13.58	7.53	**25.67**	0.00	6.85
Aug	0.00	2.55	0.40	4.44	2.02	4.44	14.54	11.69	62.05	30.91	16.69	13.17	4.31	20.97	0.00	11.83
Sep	0.28	**4.17**	0.14	**7.08**	1.39	**4.72**	18.89	**14.44**	**63.89**	26.67	12.50	10.69	2.92	22.50	0.00	9.72
Oct	0.00	1.75	0.40	5.91	2.02	3.76	19.95	9.41	53.10	33.74	15.23	10.08	9.16	20.56	0.13	**14.78**
Nov	0.00	1.25	1.67	2.08	3.47	2.64	12.22	9.72	37.64	37.92	19.72	15.56	**23.06**	23.06	2.22	7.78
Dec	**0.81**	2.02	1.88	2.69	1.75	3.23	15.07	8.60	45.09	33.06	17.90	13.84	15.34	22.45	2.15	14.11
Jan	0.27	0.13	1.08	1.88	1.61	3.09	13.98	12.90	41.26	54.17	20.97	15.32	18.82	9.41	2.02	3.09
Feb	0.15	0.30	1.19	1.04	1.79	0.89	11.90	6.71	53.72	**59.17**	21.58	20.12	9.38	10.73	0.30	1.04
Mar	0.40	0.40	1.35	1.88	2.02	2.28	10.50	6.05	41.32	46.37	**25.84**	21.24	18.17	20.03	0.40	1.75
Apr	0.28	0.97	**2.08**	2.50	**3.61**	1.67	14.17	7.22	34.86	43.06	20.83	**27.64**	21.39	16.81	**2.78**	0.14

* Bolded values show highest percentage within price range.

Table A-33: Difference between 1-Hour Pre-dispatch and HOEP within Defined Ranges

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	84.14	81.18	0.54	0.00	15.32	18.82
Jun	78.97	84.72	0.42	0.00	20.61	15.28
Jul	75.40	78.76	0.40	0.00	24.19	21.24
Aug	81.83	76.88	1.21	0.00	16.96	23.12
Sep	79.17	69.58	0.14	0.00	20.69	30.42
Oct	77.63	79.17	0.00	0.00	22.37	20.83
Nov	82.64	83.89	0.00	0.42	17.36	15.69
Dec	80.35	83.47	0.13	0.00	19.52	16.53
Jan	82.80	81.85	0.27	0.13	16.94	18.01
Feb	84.97	91.06	0.00	0.00	15.03	8.94
Mar	85.73	89.25	0.00	0.13	14.27	10.62
Apr	79.86	87.50	0.00	0.14	20.14	12.36

Table A-34: Difference between 1-Hour Pre-dispatch and Hourly Peak MCP within Defined Ranges

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	59.68	59.41	4.57	4.30	35.75	36.29
Jun	59.89	64.31	1.39	2.08	38.72	33.61
Jul	52.69	53.23	3.36	1.88	43.95	45.89
Aug	58.41	52.28	2.96	2.15	38.63	45.56
Sep	56.67	43.61	1.94	3.47	41.39	52.92
Oct	56.60	51.34	2.83	2.69	40.57	45.97
Nov	60.42	63.19	1.94	2.50	37.64	34.31
Dec	59.35	58.60	1.35	2.42	39.30	38.98
Jan	59.01	62.10	4.57	2.42	36.42	35.48
Feb	63.39	75.56	3.42	2.09	33.18	22.35
Mar	58.82	70.83	3.63	2.96	37.55	26.21
Apr	58.61	71.81	2.50	2.08	38.89	26.11

Table A-35: Percentage Intervals with Operating Reserve Reductions Due to Shortage (Market Schedule), May 2004-April 2006

	No Reductions		>1 MW and <200 MW		>200 MW and <400 MW		>400 MW and <800 MW		>800 MW	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	94.49	98.44	1.12	0.48	3.24	0.65	1.15	0.43	0.00	0.00
Jun	97.50	98.70	0.38	0.09	1.10	0.47	1.02	0.65	0.00	0.08
Jul	99.01	98.97	0.04	0.60	0.64	0.12	0.30	0.30	0.00	0.00
Aug	99.47	99.81	0.20	0.19	0.32	0.00	0.00	0.00	0.00	0.00
Sep	99.75	100.00	0.05	0.00	0.00	0.00	0.21	0.00	0.00	0.00
Oct	100.00	98.81	0.00	0.02	0.00	0.63	0.00	0.41	0.00	0.12
Nov	98.80	98.97	0.41	0.42	0.64	0.50	0.16	0.13	0.00	0.00
Dec	99.45	99.87	0.18	0.00	0.37	0.13	0.00	0.00	0.00	0.00
Jan	97.16	100.00	0.82	0.00	1.21	0.00	0.63	0.00	0.19	0.00
Feb	99.63	100.00	0.04	0.00	0.25	0.00	0.09	0.00	0.00	0.00
Mar	99.37	100.00	0.19	0.00	0.25	0.00	0.19	0.00	0.00	0.00
Apr	96.11	99.98	1.06	0.00	1.71	0.02	0.88	0.00	0.23	0.00
AVG	98.40	99.46	0.37	0.15	0.81	0.21	0.39	0.16	0.04	0.02

Table A-36: Demand Forecast Error

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	353	308	319	274	232	228	190	171	2.30	2.01	2.07	1.77	1.47	1.44	1.20	1.07
Jun	371	530	338	466	283	363	231	259	2.24	2.92	2.05	2.55	1.66	1.93	1.36	1.36
Jul	428	573	380	466	319	424	258	288	2.53	3.11	2.24	2.54	1.83	2.25	1.49	1.53
Aug	405	418	359	368	298	315	238	224	2.40	2.22	2.12	1.96	1.70	1.64	1.36	1.16
Sep	373	325	344	280	249	248	203	190	2.26	1.89	2.07	1.63	1.45	1.40	1.18	1.08
Oct	318	270	303	245	204	203	172	156	2.00	1.67	1.90	1.51	1.25	1.22	1.04	0.94
Nov	395	347	366	314	226	209	185	167	2.29	2.03	2.12	1.84	1.29	1.21	1.05	0.97
Dec	443	360	393	327	289	224	238	175	2.38	1.97	2.10	1.79	1.53	1.22	1.25	0.95
Jan	410	381	368	329	256	256	201	202	2.11	2.09	1.88	1.81	1.30	1.39	1.01	1.09
Feb	360	352	321	315	227	222	173	175	1.92	1.88	1.70	1.68	1.19	1.18	0.91	0.92
Mar	318	315	293	285	205	189	159	155	1.76	1.78	1.62	1.61	1.11	1.06	0.86	0.86
Apr	315	296	288	265	211	187	164	152	1.97	1.87	1.79	1.67	1.27	1.16	0.99	0.94
AVG	374	373	339	328	250	256	201	193	2.18	2.12	1.97	1.86	1.42	1.43	1.14	1.07

*Table A-37: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges (%)**

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	3	1	20	16	16	17	17	18	15	18	13	15	14	15	1	1	57	52	43	48
Jun	6	12	19	30	15	15	13	14	14	10	12	8	18	10	3	1	53	71	47	29
Jul	9	12	21	26	11	13	15	12	12	11	10	9	18	14	4	3	56	63	44	37
Aug	7	5	21	21	12	12	16	15	14	15	10	12	16	17	4	3	56	53	44	47
Sep	4	1	19	13	11	12	18	18	18	16	10	13	15	22	3	4	53	44	47	56
Oct	1	0	17	8	18	12	20	18	19	22	10	18	13	20	1	1	56	39	44	61
Nov	3	2	24	15	17	15	21	18	16	20	9	16	10	14	0	1	65	50	35	50
Dec	7	2	23	18	15	15	15	17	13	20	10	13	14	15	3	0	60	52	40	48
Jan	5	3	25	18	16	12	18	18	15	15	10	14	10	17	1	3	64	51	36	49
Feb	2	2	17	17	18	14	19	19	18	17	12	14	12	14	1	1	57	54	43	46
Mar	2	2	20	14	16	16	20	20	21	21	11	14	10	12	0	0	58	52	42	48
Apr	2	1	18	14	14	15	21	20	18	22	14	16	11	13	1	0	55	49	45	51

* This data has been revised to include dispatchable loads.

*Table A-38: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities**

	Pre-Dispatch (MW)		Maximum Difference (MW)		Minimum Difference (MW)		Average Difference (MW)		Fail Rate (Difference/MW Pre-dispatch) (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	712,553	722,187	145.81	187.12	(118.30)	(61.18)	(5.70)	20.11	(0.42)	2.18
Jun	754,026	724,804	283.55	242.51	(91.13)	(43.18)	10.00	49.68	0.82	4.67
Jul	842,044	701,810	582.64	244.28	(282.74)	(70.56)	51.68	55.18	4.32	6.06
Aug	737,531	667,215	227.87	200.67	(53.35)	(167.25)	33.11	15.43	3.61	1.37
Sep	719,483	543,183	308.92	258.62	(103.57)	(62.01)	42.28	22.42	4.54	3.22
Oct	787,642	629,537	276.43	170.60	(97.43)	(275.80)	23.58	(1.27)	2.41	(0.12)
Nov	784,062	670,401	228.63	184.95	(149.38)	(164.43)	4.47	1.83	0.72	(0.26)
Dec	809,100	638,461	222.98	233.19	(119.34)	(108.64)	13.98	1.98	1.66	0.43
Jan	839,424	645,993	204.68	141.63	(117.83)	(81.23)	22.50	11.80	2.17	1.66
Feb	766,811	618,271	224.36	134.26	(167.67)	(89.06)	14.44	8.24	1.40	1.08
Mar	822,583	767,993	176.58	131.56	(118.60)	(102.08)	8.98	(2.59)	0.99	(0.22)
Apr	710,274	636,415	148.37	175.08	(190.30)	(126.48)	(23.37)	15.39	(2.64)	2.66
AVG	773,794	663,856	252.57	192.04	(134.14)	(112.66)	16.33	16.52	1.63	1.89

* Self-scheduled generators also include those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.

Table A-39: Discrepancy between Wind Generators' Offered and Delivered Quantities

	Pre-Dispatch (MW)	Maximum Difference (MW)	Minimum Difference (MW)	Average Difference (MW)	Fail Rate (Difference/MW Pre-dispatch) (%)
	2006	2006	2006	2006	2006
Feb	1,762	10.80	0.76	6.57	92.62
Mar	6,686	23.26	(17.76)	1.21	(37.43)
Apr	4,557	24.96	(26.01)	(3.62)	(864.77)
AVG	4,335	19.67	(14.34)	1.39	(269.86)

*Table A-40: Incidents and Average Magnitude of Failed Imports into Ontario**

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	117	355	388	650	77	168	2.18	6.07
Jun	272	348	864	916	120	190	4.81	5.94
Jul	261	349	545	1,110	124	192	5.39	5.95
Aug	319	301	667	1,025	96	188	4.23	5.70
Sep	293	316	509	885	91	173	2.53	5.43
Oct	293	335	482	810	131	134	3.88	4.33
Nov	339	273	1,134	539	135	112	3.60	3.15
Dec	259	293	1,074	667	124	141	2.94	4.64
Jan	285	212	896	910	147	126	3.83	3.32
Feb	207	211	817	525	148	107	4.02	4.85
Mar	305	174	526	405	132	102	6.08	3.13
Apr	296	84	735	421	132	104	4.18	3.10

* This data has been revised to exclude transaction failures of less than 1 MW.

*Table A-41: Incidents and Average Magnitude of Failed Imports into Ontario, On-Peak**

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	54	157	388	631	98	128	3.88	4.78
Jun	139	184	527	916	95	177	4.81	5.57
Jul	68	171	545	1,110	86	219	3.48	6.47
Aug	79	161	667	1,025	105	202	3.90	6.42
Sep	128	164	509	885	93	162	2.45	5.29
Oct	87	138	254	466	82	129	1.61	3.83
Nov	132	134	1,134	539	137	110	3.15	3.25
Dec	114	139	925	550	127	124	3.01	4.54
Jan	122	71	655	910	158	143	4.31	3.16
Feb	81	90	817	525	134	99	4.17	4.47
Mar	134	69	526	300	133	86	7.37	2.07
Apr	149	30	735	223	135	68	4.75	2.08

* This data has been revised to exclude transaction failures of less than 1 MW.

*Table A-42: Incidents and Average Magnitude of Failed Imports into Ontario, Off-Peak**

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	63	198	157	650	60	200	1.36	7.03
Jun	133	164	864	672	145	205	4.81	6.35
Jul	193	178	444	771	138	166	6.13	5.40
Aug	240	140	518	777	93	172	4.37	4.95
Sep	165	152	377	700	90	185	2.60	5.56
Oct	206	197	482	810	151	137	5.71	4.74
Nov	207	139	582	422	133	114	3.98	3.06
Dec	145	154	1,074	667	122	156	2.89	4.72
Jan	163	141	896	492	140	117	3.51	3.43
Feb	126	121	499	505	157	113	3.94	5.13
Mar	171	105	456	405	131	113	5.34	4.18
Apr	147	54	669	421	130	125	3.70	3.64

* This data has been revised to exclude transaction failures of less than 1 MW.

*Table A-43: Incidents and Average Magnitude of Failed Exports from Ontario**

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	434	483	958	991	185	267	6.20	11.55
Jun	460	457	1,104	1,128	208	238	7.92	12.71
Jul	460	337	950	1,350	192	275	7.35	11.34
Aug	452	368	1,052	1,478	230	226	7.52	9.16
Sep	373	341	920	1,000	205	241	13.61	8.28
Oct	387	477	964	1,188	232	231	13.93	10.63
Nov	353	503	975	850	227	224	11.37	9.17
Dec	395	461	950	1,098	257	221	10.01	8.95
Jan	392	543	1,160	1,132	230	216	7.41	8.92
Feb	421	541	830	1,190	254	282	9.66	12.33
Mar	458	527	765	975	201	260	8.88	10.02
Apr	318	543	913	1,000	194	291	10.92	10.68

* This data has been revised to exclude transaction failures of less than 1 MW.

*Table A-44: Incidents and Average Magnitude of Failed Exports from Ontario, On-Peak**

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	191	180	958	925	205	216	7.51	8.85
Jun	224	187	1,104	800	205	198	8.49	11.20
Jul	186	102	950	1,180	195	224	7.62	12.64
Aug	224	143	1,052	815	237	191	9.00	9.65
Sep	175	125	900	716	199	164	16.29	7.65
Oct	166	180	964	600	210	144	11.80	7.23
Nov	151	185	975	619	246	160	14.04	5.97
Dec	179	165	896	1,057	271	173	12.94	7.54
Jan	161	242	1,160	805	252	169	8.23	7.06
Feb	208	261	755	1,190	237	258	10.36	12.75
Mar	188	225	765	775	207	209	9.69	8.19
Apr	141	201	650	836	194	245	12.30	9.50

* This data has been revised to exclude transaction failures of less than 1 MW.

*Table A-45: Incidents and Average Magnitude of Failed Exports from Ontario, Off-Peak**

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	243	303	781	991	169	297	5.31	13.30
Jun	236	270	970	1,128	211	266	7.46	13.66
Jul	274	235	916	1,350	190	298	7.18	10.97
Aug	228	225	800	1,478	223	249	6.42	8.94
Sep	198	216	920	1,000	210	285	11.95	8.51
Oct	221	297	954	1,188	248	284	15.73	12.43
Nov	202	318	877	850	213	262	9.76	11.33
Dec	216	296	950	1,098	246	248	8.29	9.65
Jan	231	301	941	1,132	214	253	6.86	10.40
Feb	213	280	830	950	271	304	9.13	12.01
Mar	270	302	650	975	196	299	8.37	11.33
Apr	177	342	913	1,000	195	317	10.04	11.32

* This data has been revised to exclude transaction failures of less than 1 MW.

Table A-46: Shares by Fuel Type of Total Operating Reserve Requirements, Off-Peak Periods

	Dispatchable Load (% of Total Requirement)		Hydroelectric (% of Total Requirement)		CAOR (% of Total Requirement)		Fossil (% of Total Requirement)		Import (% of Total Requirement)		Export (% of Total Requirement)		Total (Average Hourly Value MW)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	14.11	30.09	69.03	61.38	0.24	0.26	16.25	7.82	0.36	0.25	0.00	0.20	1,409	1,413
Jun	13.02	32.08	80.13	61.76	0.04	0.01	6.71	5.92	0.11	0.12	0.00	0.10	1,418	1,418
Jul	10.27	25.20	82.15	68.79	0.11	0.00	6.90	5.35	0.57	0.62	0.00	0.05	1,403	1,410
Aug	14.62	18.83	76.06	75.24	0.01	0.00	8.61	5.52	0.70	0.41	0.00	0.00	1,393	1,395
Sep	18.95	18.56	72.40	74.65	0.00	0.00	8.45	6.67	0.19	0.12	0.00	0.00	1,373	1,399
Oct	19.33	15.00	70.99	78.94	0.00	0.02	8.08	4.97	1.59	0.00	0.00	1.07	1,417	1,460
Nov	23.67	20.27	68.50	74.56	0.08	0.00	7.50	4.95	0.28	0.00	0.00	0.21	1,538	1,430
Dec	20.89	18.74	73.50	74.37	0.02	0.31	4.40	4.85	1.12	0.00	0.00	1.62	1,479	1,430
Jan	25.11	22.10	69.70	73.33	0.05	0.00	4.90	4.34	0.27	0.00	0.00	0.10	1,414	1,375
Feb	26.62	23.53	68.50	72.02	0.01	0.06	4.80	4.16	0.03	0.00	0.00	0.06	1,418	1,368
Mar	27.10	23.57	66.30	70.63	0.08	0.11	5.80	5.50	0.75	0.00	0.00	0.00	1,416	1,368
Apr	28.87	25.05	59.50	61.29	0.41	0.73	10.4	11.25	0.57	0.28	0.28	1.19	1,407	1,367

Table A-47: Shares by Fuel Type of Total Operating Reserve Requirements, On-Peak Periods

	Dispatchable Load (% of Total Requirement)		Hydroelectric (% of Total Requirement)		CAOR (% of Total Requirement)		Fossil (% of Total Requirement)		Import (% of Total Requirement)		Export (% of Total Requirement)		Total (Average Hourly Value MW)	
	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006	2004/2005	2005/2006
May	12.91	23.63	49.31	64.31	2.06	0.85	33.96	7.15	1.76	2.14	0.00	1.92	1,391	1,413
Jun	10.53	24.56	68.76	68.66	0.37	0.16	19.28	5.05	1.06	1.01	0.00	0.54	1,400	1,395
Jul	8.44	19.49	70.14	73.47	0.31	0.14	17.63	4.82	3.48	1.65	0.00	0.42	1,403	1,402
Aug	13.45	18.56	78.08	76.07	0.00	0.14	7.66	4.25	0.81	0.30	0.00	0.67	1,403	1,387
Sep	17.05	19.70	75.02	75.11	0.02	0.05	7.25	4.79	0.65	0.10	0.00	0.24	1,376	1,398
Oct	18.64	16.17	76.24	75.90	0.01	0.42	4.90	5.71	0.21	0.17	0.00	1.60	1,417	1,463
Nov	20.52	19.31	70.70	68.53	0.83	0.79	6.40	7.95	1.55	0.06	0.00	3.29	1,520	1,524
Dec	20.71	19.98	73.70	65.23	0.38	1.37	3.90	8.09	1.33	0.62	0.00	4.22	1,431	1,430
Jan	22.47	22.44	70.50	65.61	0.94	0.35	5.00	4.88	1.09	2.65	0.00	3.90	1,399	1,370
Feb	23.63	23.40	70.21	59.40	5.20	0.24	5.30	5.36	0.27	7.02	0.03	4.37	1,412	1,367
Mar	22.95	22.99	72.50	61.94	0.43	0.30	3.90	6.69	0.24	3.09	0.00	4.64	1,412	1,368
Apr	24.15	25.15	53.50	49.61	3.27	1.21	18.2	20.28	0.8	0.84	0.03	2.49	1,398	1,367

Table A-48: Day Ahead Forecast Error (as of Hour 18)

Year	Month	Average Forecast Error (MW)	Average Absolute Error (% of Peak Demand)	No. of Hours with Forecast Error ≥ 3%	Percentage of Hours with Absolute Error ≥ 3%
2003	Jan	39	1.86	160	22
	Feb	169	1.78	111	17
	Mar	102	1.67	88	12
	Apr	45	2.14	195	27
	May	160	1.75	137	18
	Jun	140	2.10	155	22
	Jul	278	2.93	304	41
	Aug	211	3.40	222	42
	Sep	192	2.52	220	31
	Oct	96	1.61	108	15
	Nov	160	2.09	183	25
	Dec	224	2.27	207	28
2004	Jan	158	2.33	215	29
	Feb	337	2.16	176	25
	Mar	148	2.27	220	30
	Apr	166	2.36	223	31
	May	123	2.21	208	23
	Jun	0	2.35	221	36
	Jul	328	3.35	345	49
	Aug	223	2.74	288	39
	Sep	89	2.27	212	28
	Oct	85	1.74	125	20
	Nov	184	1.88	144	20
	Dec	146	2.40	213	29
2005	Jan	213	2.04	170	23
	Feb	188	1.69	118	18
	Mar	45	1.83	139	19
	Apr	82	2.09	186	26
	May	44	1.85	137	23
	Jun	255	3.13	299	36
	Jul	450	4.30	382	49
	Aug	220	3.03	299	39
	Sep	72	2.22	198	28
	Oct	56	1.75	133	18
	Nov	(67)	1.86	151	21
	Dec	(20)	1.78	139	19
2006	Jan	11	2.21	215	29
	Feb	(11)	1.76	120	18
	Mar	28	1.49	80	11
	Apr	0	1.88	143	20

Table A-49: Average One Hour Ahead Forecast Error

Year	Month	Peak Forecast Error (MW)	Average Absolute Error (% of Peak Demand)	No. of Hours with Forecast Error ≥ 2%	Percentage of Hours with Absolute Error ≥ 2%
2003	Jan	116	1.11	102	14
	Feb	78	1.09	101	15
	Mar	62	1.15	118	16
	Apr	65	1.26	145	20
	May	103	1.14	133	18
	Jun	68	1.28	152	21
	Jul	102	1.47	192	26
	Aug	74	1.49	142	27
	Sep	68	1.21	141	20
	Oct	78	1.20	130	17
	Nov	93	1.20	127	18
	Dec	118	1.28	159	21
2004	Jan	132	1.24	132	18
	Feb	145	1.10	106	15
	Mar	118	1.27	145	19
	Apr	124	1.36	165	23
	May	37	1.20	128	15
	Jun	29	1.37	170	23
	Jul	53	1.49	203	28
	Aug	48	1.36	179	21
	Sep	22	1.18	124	15
	Oct	21	1.04	107	13
	Nov	83	1.05	102	14
	Dec	60	1.25	146	20
2005	Jan	85	1.01	86	12
	Feb	36	0.91	58	9
	Mar	48	0.86	53	7
	Apr	31	0.99	85	12
	May	9	1.07	98	15
	Jun	148	1.36	160	23
	Jul	120	1.53	210	28
	Aug	30	1.16	127	21
	Sep	(52)	1.08	90	15
	Oct	(49)	0.94	70	9
	Nov	10	0.97	73	10
	Dec	19	0.95	74	10
2006	Jan	10	1.09	107	14
	Feb	17	0.92	59	9
	Mar	19	0.86	53	7
	Apr	4	0.94	73	10