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 2004 – April 2005

June 9, 2005

Preface

This is the Market Surveillance Panel's first report as a panel of the Ontario Energy Board and our 6th monitoring report since the IESO-administered markets opened three years ago, May 1, 2002. It provides highlights of market outcomes over the period November 1, 2004 to April 30, 2005.

With the change in reporting relationship our mandate is now described in the OEB's By-Law #3. We continue to be supported by the IESO's Market Assessment Unit in discharging these responsibilities. An agreement between the Board and IESO, the Protocol, sets out the arrangements to make this work. The Board's Electricity Market Surveillance web page summarizes these developments and provides links to the By-Law and Protocol at http://www.oeb.gov.on.ca/html/en/industryrelations/electricitymarketsurveillance.htm

This report follows the structure established in our previous reports. Chapter 1 and the Statistical Appendix provide the basic data on market outcomes over the period. Chapters 2 and 3 highlight market results we believe noteworthy, including the status of matters commented on in past reports and an assessment of some of the changes introduced into the market since our last report. The final chapter comments on the new policy environment for the IESO-administered markets and the implications for our role in the future.

As always we welcome comments on the structure and content of our monitoring reports. Our addresses for contact are:

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Chapter 1: Market Outcomes November 2004 to April 2005

1. *Introduction*

This chapter provides an overview of the main outcomes in the IESO administered markets over the period November 2004 through April 2005, and compares them with the corresponding period one year earlier. The chapter notes the following outcomes:

- Although the demand-supply balance improved as increases in demand were more than offset by new supply sources, electricity prices in the period under review were on average about 11.4 percent higher than a year earlier. The major factor underlying this increase appears to be higher prices for coal and natural gas, a continuation of the pressures evident in our last report that compared the summer of 2004 to the summer of 2003.[1] The level and composition of outages were also factor in November 2004 and April 2005. Both of these months have the highest year-over-year increase in price with April having the highest HOEP's across the period.

- Ontario became a net exporter of electricity, beginning in January 2005 and in increasing amounts until April when the flow was reversed. Net exports reflect the response of increased supply capacity in Ontario to prices in the New York market that had been consistently higher than Ontario prices, particularly in the off-peak hours. This ended in April when Ontario prices made it a more attractive destination.

- Prices of operating reserve were, in general, substantially lower through this period, compared with a year earlier, due primarily to the entry into the market of four new dispatchable loads starting in November of 2004.

[1] See the Panel's December 2004 Report. "Market Surveillance Panel Monitoring Report on the IMO-Administered Electricity Markets, May-October 2004."

- One of the impacts of the increased nuclear capacity in this period is that oil and gas-fired generation set the price less frequently than in the past and greater reliance was placed on coal-fired plants. This contributed to a shift in the frequency distribution of prices, with prices falling more often in the $30-60 range, representative of coal-fired generation. Although coal set the price more frequently, the biggest increase in fuel source actually used to produce electricity came from nuclear power. In both November and April we saw significant generator outages, both planned and forced. Typically these two months have significant levels of planned generator outages in preparation for the upcoming winter and summer peaks. Significant forced outages in the same period led to a very tight domestic supply cushion and an increased reliance on imports.

The Chapter also re-examines two issues that we have raised on previous occasions:

- The discrepancy between pre-dispatch prices and real time prices is reviewed again. We are pleased to be able to report that considerable progress continues to be made on narrowing the gap between these prices. In particular, the IESO is forecasting demand more accurately and this is contributing to more credible market signals.

- We also review again net revenue calculations that we first introduced in our June 2004 report.[2] We extend the analysis in this chapter to examine an additional year of data and to provide an assessment of the adequacy of net revenues from the market to support investment in new gas-fired generation.

2. *Ontario Energy Price*

As Table 1 - 1 indicates, the monthly HOEP was substantially higher in November, December, March and April than in the previous reference period. The largest change was in April when the average HOEP was $16/MWh higher than a year earlier. The HOEP was lower in January and February 2005 than it was in those months in 2004, but the big decline was on-peak, as the off-peak prices for those months were virtually identical. On balance, the higher prices outweighed

[2] See pp. 22-26 in our June 2004 report.

the lower prices in January and February; for the period as a whole the average HOEP was $5.66 (about 11.4 percent) greater than the HOEP of a year earlier.

Table 1 - 1: Average HOEP, On-Peak and Off-Peak, November - April

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	40.45	52.28	50.29	61.94	32.59	43.82
Dec	44.42	50.82	54.55	59.84	36.08	43.40
Jan	66.22	57.90	84.76	68.99	50.94	49.53
Feb	52.74	49.58	64.46	56.51	42.77	43.29
Mar	48.90	59.87	57.33	67.86	40.65	53.29
Apr	45.92	61.93	55.04	69.57	37.95	55.24
Average	49.82	55.48	61.07	64.14	40.17	48.19

There has been a marked change in the frequency distribution of the HOEP over the November - April period compared with the previous year. Figures 1 - 1 through 1 - 3 below plot the frequency of price outcomes for the HOEP, on average, and for the on-peak and off-peak periods. In general, there are far fewer occurrences of very low prices (in the $20-30 range). This is true on average and for both on-peak and off-peak prices. The forces leading to this result appear to be higher fuel prices. As shown in section 11 below, coal-fired units – rather than oil and gas units, dominated price setting in this period reflecting the extension of the offer curve. The higher coal prices than a year ago however led to reduced frequency of prices in the $20-30 range. Overall, the distribution of prices has become more concentrated about the $40-60 price range.

Figure 1 - 1: Frequency Distribution of HOEP, November 2004 - April 2005

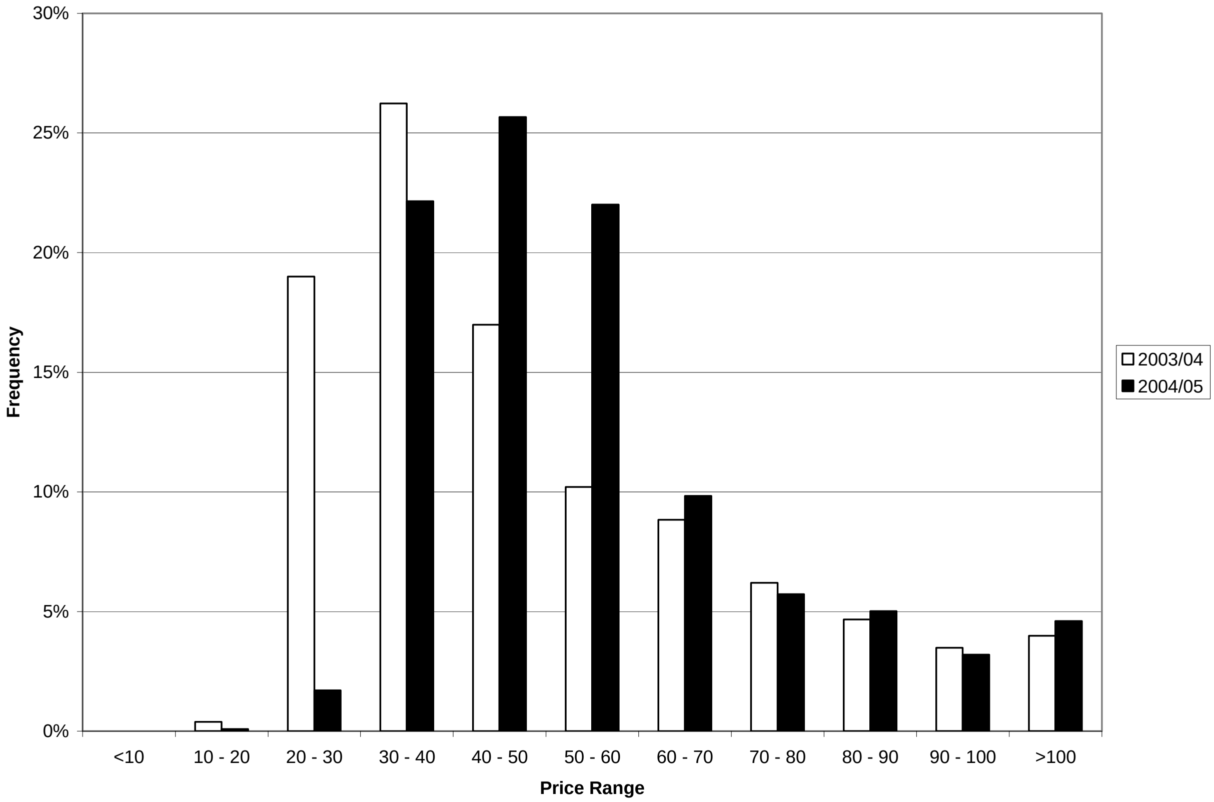


Figure 1 - 2: Frequency Distribution of HOEP, Off-Peak, November 2004 - April 2005

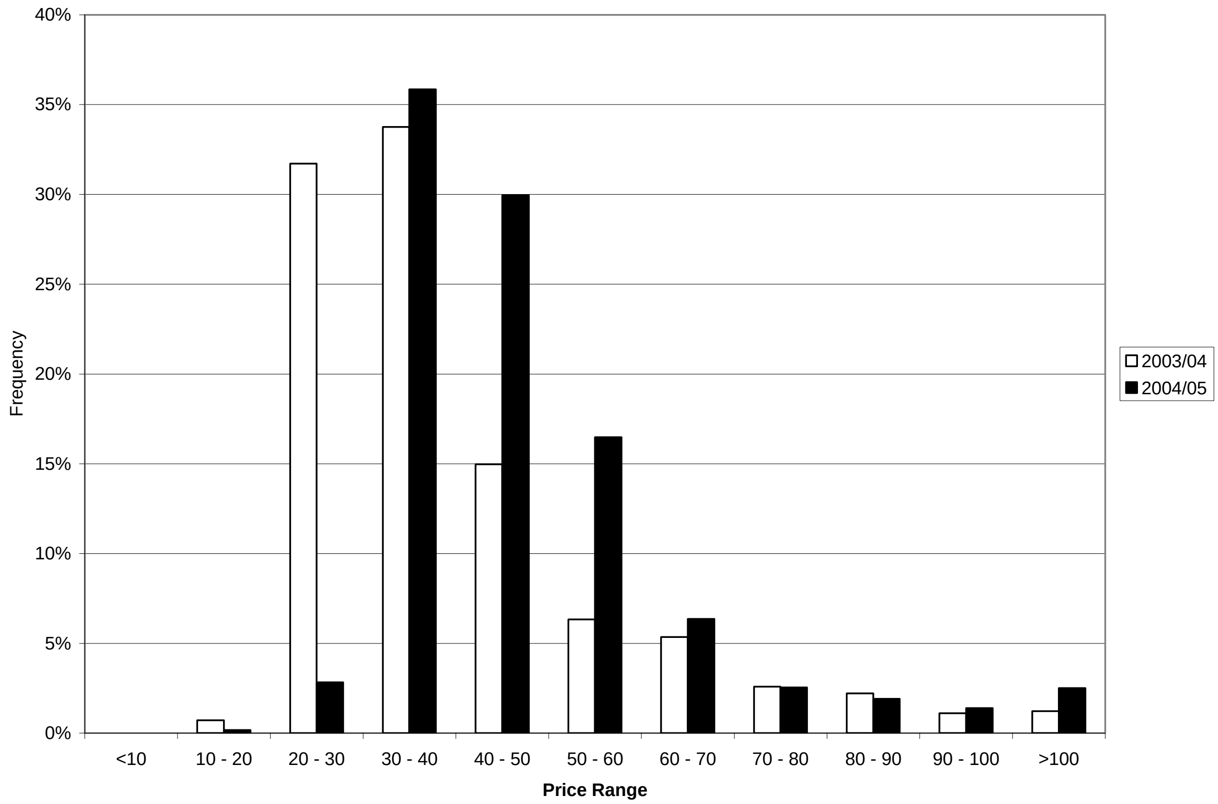
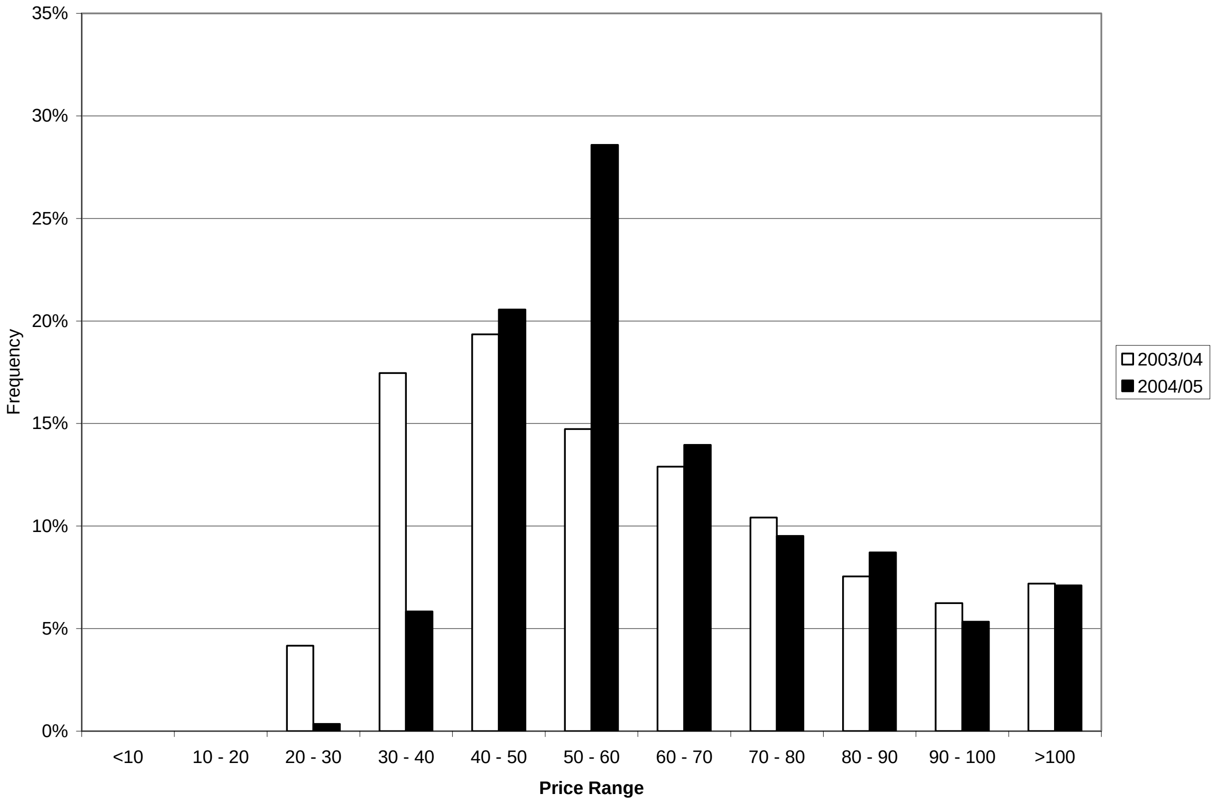


Figure 1 - 3: Frequency Distribution of HOEP, On-Peak, November 2004 - April 2005



3. *Demand*

Ontario energy demand over the reference period was, on average, 1.2 percent higher than a year earlier, and was also higher in all months of the period under review except for January and February 2005. As noted previously, on-peak prices in January and February were also lower. The lower demand and prices in January may have been weather-related as temperatures in January 2005 averaged about 4.9 degrees (centigrade) warmer than in January 2004. Although February 2005 was slightly colder than 2004, February 2004 was a leap year and the demand data are not adjusted for the extra day.

While Ontario demand rose slightly in April, exports declined by almost half in April 2005. This decline, related to higher prices, led to lower total market demand in April and had a moderating impact on the growth of demand (2.59 percent) over the period.

Table 1 - 2: Monthly Energy Demand (TWh) November - April

	Ontario Demand*			Exports			Total Market Demand		
	2003/2004	2004/2005	% Change	2003/2004	2004/2005	% Change	2003/2004	2004/2005	% Change
Nov	12.38	12.61	1.86	0.36	0.62	72.22	12.74	13.24	3.92
Dec	13.31	14.01	5.26	0.64	0.91	42.19	13.95	14.92	6.95
Jan	14.72	14.63	(0.61)	0.85	1.13	32.94	15.57	15.75	1.16
Feb	13.08	12.77	(2.37)	0.53	1.00	88.68	13.62	13.77	1.10
Mar	13.21	13.52	2.35	0.60	0.94	56.67	13.81	14.47	4.78
Apr	11.76	11.86	0.85	0.93	0.50	(46.24)	12.69	12.36	(2.60)
Total	78.46	79.40	1.20	3.91	5.10	30.43	82.38	84.51	2.59

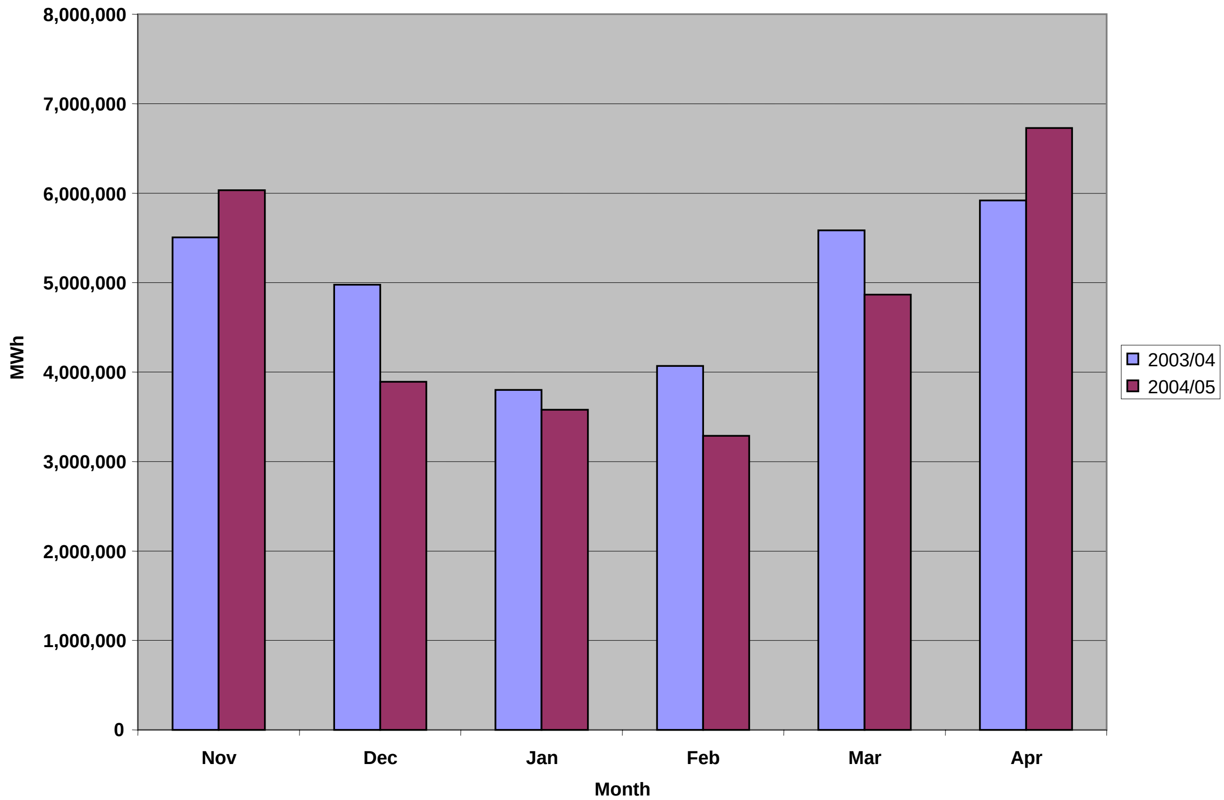
*Includes dispatchable loads

4. *Outages*

Generators go on outage either for maintenance of their plant equipment or because of sudden equipment failure that forces them from service. Typically planned outages are taken in shoulder months of the year – spring and fall – when market demand and price tend to be lowest. Generation outages – either planned or forced – can have a significant impact upon the market clearing price.

The following Figure 1 - 4 shows the combined planned and forced outages over the period November to April in 2003-2004 versus 2004-2005.

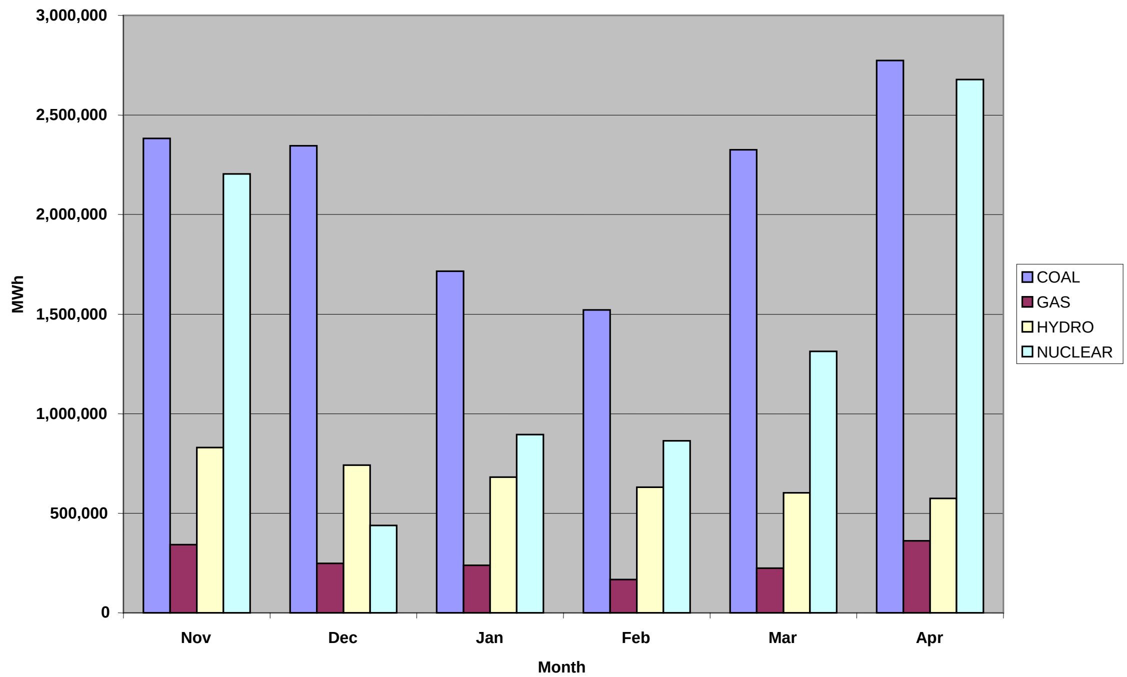
Figure 1 - 4: Total Outages both Planned and Forced, November 2004 - April 2005



Outages are an important part of the supply story in several months across the period. In both November and April the high levels of outages contributed to negative supply cushions and an increased reliance on imports. While the total volume of outages can be an indicator of supply conditions the nature of the generator on outage is also of great importance. A hydroelectric generator that is simply providing one hour of energy per day when forced out of service has a different market impact than a nuclear generator which is providing energy across all hours.

Figure 1 – 5 breaks down by fuel type the amount of generation on outage during the period November 2004 through April 2005. The impact of an outage to an infra-marginal generator is to push up the Market Clearing Price. An outage to an extra-marginal generator has no effect on price. Outages to nuclear units, which are infra-marginal, always have a price effect. In both November and April we observe major volumes of nuclear outage and would expect a price effect. The shift share analysis in section 6 illustrates the price impact of these outages.

Figure 1 - 5: Outages by Fuel Type November 2004 - April 2005



When there is a recurring forced outage, the IESO will ask for a report within 48 hours of the reasons why a forced outage may have recurred and what the participant will be doing to prevent future occurrences.

The MSP has asked the MAU to refine its ability to undertake a statistical review of outages as well as to ensure that all forced outages that contribute to anomalous price events over $200 are consistently reviewed with the participant.

5. *Supply – Supply Cushion*

In our first report the Panel developed a measure to indicate the overall tightness of supply and demand in the Ontario market.[3] This 'supply cushion' is a measure of unused energy that is available for dispatch in a particular hour. It is the ratio (expressed in %) of the difference

[3] See Our October 2002 report pp. 53-60.

between energy offered by Ontario generators and energy (plus operating reserves) required to satisfy demand relative to energy (plus operating reserves) required to satisfy demand. Observation, as well as statistical analysis since market opening, has shown that when the supply cushion falls below 10 percent one can expect upward pressure on price and probable price spikes. Because the energy offers used to construct the supply cushion are those of Ontario generators only, the supply cushion can be negative on occasion. When this occurs it means that Ontario demands can be satisfied only by net imports.

Table 1 - 3 below shows the real-time domestic supply cushion calculations for the November - April reference period and the same months in the previous year. November and April were the only two months in which the supply cushion was lower. April has the lowest supply cushion, 7.70 percent, for the period and also the highest incidence of hours with a negative supply cushion, 82. By contrast, in April 2004 there was only one hour that experienced a negative supply cushion.

The overall trends in the supply cushion reflect primarily the addition of generating capacity in the Ontario market. The return of the Bruce G3 unit on March 29, 2004 added 750 MW of capacity that was only minimally reflected in the year earlier numbers. In July, 2004 Brighton Beach came on stream, adding 560 MW and the Iroquois Falls facility (30 MW) began production in March of 2004. As well, dispatchable load offers of supply increased from roughly 320 MW to 465 MW through this period, as four loads became dispatchable.

Two aspects of the supply cushion results warrant some further explanation. The much higher incidence of negative hours, and the relatively low supply cushion in November, reflect a substantially higher than normal level of outages for that month. Table A - 4 in the Statistical Appendix shows total outages in November 2004 of 6.03 TWh, compared with 5.51 TWh in November 2003. With forced outages reflecting the unanticipated removal from service of 3 units at a nuclear station for a period of seven days.

The tighter supply cushion in November was reflected in higher prices in November 2004 compared with November 2003. We did not, however, see price spikes as imports appeared to be available at competitive prices to meet the Ontario demand. Net imports in November 2004 totaled 551 GWh, up from 364 GWh in November 2003.

April had the tightest supply cushion across the period and this was reflected in the highest period-over-period increase in price. April 2005 with the highest incidence of negative hours and the relatively low supply cushion reflected a substantially higher-than-normal level of outages, both planned and forced. Table A - 4 in the Statistical Appendix shows total outages in April 2005 of 6.73 TWh compared with 5.92 TWh in April 2003. At one point in April there was 11,900 MW of generation on planned and forced outage, roughly 40 percent of installed capacity.

The second aspect of the supply cushion that warrants comment is the observation that, notwithstanding the improved supply-demand balance picture represented by the supply cushion, average prices were higher in 2004-2005 than they were in 2003-2004. There is no inconsistency here since the supply cushion simply measures energy on offer at all price levels versus energy required to meet demand. The supply cushion indicates whether equilibrium is likely to result on the elastic portion of the offer curve, or on the inelastic portion. But it says nothing about the level of the offer curve. During the reference period, there was a greater propensity to establish equilibrium on the elastic portion of the offer curve, but the offers were more expensive because of higher costs due to higher fuel prices.

Table 1 - 3: Real-time Domestic Supply Cushion, November - April

	Average Supply Cushion %		**Negative Supply Cushion # of Hours**	
	2003/2004	**2004/2005**	**2003/2004**	**2004/2005**
Nov	11.40	9.56	24	61
Dec	12.20	13.55	35	29
Jan	11.10	12.93	53	1
Feb	10.70	14.96	27	2
Mar	11.60	14.91	36	0
Apr	13.43	7.70	1	82

6. *Shift Share Analysis to Explain Changes in HOEP*

In previous reports, the Panel has employed the technique of shift share analysis to isolate the respective impacts of changes in various possible causal (exogenous) factors on year-to-year differences in the monthly HOEP.[4] The shift share analysis reported here isolates the effect of the change in an exogenous component of either supply or demand on the monthly average HOEP by asking what the average HOEP for a given month in 2003-2004 would have been if the 2004-2005 value of the exogenous factor concerned were substituted for its 2003-2004 value. The measurable exogenous factors that could explain changes in the HOEP include:

- shifts in Ontario demand;
- changes in the available capacity of base-load nuclear generation;
- changes in supply from self-scheduling generators;
- changes in the supply of water available to hydroelectric generators.

All of these factors change HOEP but are largely insensitive to it. The shift share analysis is a helpful analytic tool to quantify the respective effects on the HOEP of certain measurable supply and demand shifts. It does not quantify the effects of all supply and demand shifts and it cannot explain the entire year-to-year change in the monthly HOEP. Among the other possible explanatory factors are:

- changes in fuel/emissions cost
- forced outages
- changes in bid strategy
- changes in the arbitrage opportunity between Ontario and surrounding markets affecting the levels of imports and exports.

In the Statistical Appendix Tables A - 12 and A - 13 provide data on the changes in the hourly average values for each of the exogenous demand and supply factors identified above. The data

[4] This technique is explained in the Panel's December 2003 report.

are reported for both off-peak periods and on-peak periods. Tables 1 - 4 and 1 - 5 present the monthly results of the shift share analysis for off-peak and on-peak periods.

Table 1 - 4: Estimated Impacts on 2003-2004 Average Monthly Off-Peak HOEP of Setting the Exogenous Variables at 2004-2005 Levels ($/MWh)

Factors	Nov	Dec	Jan	Feb	Mar	Apr
Ontario Demand	0.20	2.69	(2.50)	(0.63)	1.50	(1.93)
Nuclear Supply	(3.19)	(7.87)	(6.52)	(3.83)	(1.33)	8.26
Self-scheduling Supply	0.20	(0.97)	0.41	(0.50)	0.33	0.94
Hydroelectric Supply	2.25	2.79	(2.33)	(1.62)	(0.82)	0.81
Total Effect from Above Factors	(0.54)	(3.36)	(10.94)	(6.59)	(0.32)	8.09
Observed Difference in HOEP	11.34	8.34	(0.06)	(0.75)	12.76	13.00
Residual Effect	11.88	11.71	10.88	5.83	13.08	4.91

Table 1 - 5: Estimated Impacts on 2003-2004 Average Monthly On-Peak HOEP of Setting the Exogenous Variables at 2004-2005 Levels ($/MWh)

Factors	Nov	Dec	Jan	Feb	Mar	Apr
Ontario Demand	0.79	6.31	(4.95)	(2.19)	0.46	(0.70)
Nuclear Supply	(5.46)	(17.95)	(10.35)	(9.54)	(5.90)	13.52
Self-scheduling Supply	(0.53)	(0.78)	(0.14)	(3.18)	(0.03)	2.80
Hydroelectric Supply	2.21	5.10	1.39	(1.33)	1.58	(3.44)
Total Effect from Above Factors	(2.99)	(7.31)	(14.06)	(16.24)	(3.89)	12.18
Observed Difference in HOEP	12.17	5.01	(14.21)	(6.30)	9.70	18.15
Residual Effect	15.16	12.32	(0.15)	9.94	13.59	5.97

The shift share analysis provides the following insights:

- Ontario non-dispatchable load (demand) was lower in January 2005 than in January 2004 and this had the effect of reducing the HOEP. Table 1 - 5 shows that had on-peak non-dispatchable load been as low in January 2004 as it was in January 2005, the monthly average HOEP in January 2004 would have been $4.95 lower. Demand was higher in December 2004 than in December 2003. Table 1 - 5 shows that had on-peak demand in December 2003 been as high as it was in December 2004, the average HOEP in December 2003 would have been $6.31 higher.

- Base-load nuclear supply was higher in 2004-2005 (except for April) than in 2003-2004 and this had the effect of reducing the HOEP for all months in the 2004-2005 period (except April). The shift share analysis provides an estimate of the price effect of this increase in nuclear supply. According to Table 1 - 5, for example, if nuclear supply had been as high in January 2004 as it was in January 2005, the on-peak HOEP in January 2004 would have been $10.35 lower. In April of 2005 with a significant number of planned and forced outages, the nuclear supply is actually lower than in April 2004. This had a price increasing effect. If everything else were held equal, the on-peak HOEP would have been $13.52 higher in April 2004 if nuclear supply had been at its April 2005 level.

- Hydroelectric supply was lower in November and December, 2004 than in the corresponding months in 2003. This had the effect of increasing the HOEP. For example, if hydro supply had been as low in December 2003 as it was in December 2004, the on-peak HOEP in December 2003 would have been $5.10 higher.

While the shift share analysis can explain some of the price difference between 2003-2004 and 2004-2005, the relatively large residual effects imply that factors other than those included in the shift share analysis are also at work. As previously mentioned, these factors could include:

- changes in fuel prices
- forced outages of non-nuclear plants
- changes in offer strategies
- changes in prices in neighbouring markets.

In the next section, estimates of the possible impact of changing fuel prices on the HOEP are reported.

7. *Changes in Fuel Prices*

In our previous monitoring report we reviewed changes in coal and gas prices over the period and indicated how coal prices could have affected energy prices in the market. That analysis looked at unit specific heat rates to determine an upper and lower range, based on the least efficient and most efficient coal-fired units in Ontario. A comparable analysis is provided below in which the impact on energy prices is estimated assuming a generic heat rate for all coal-fired and gas-fired units. The approach taken here differs from the shift share analysis but also attempts to explain some of the changes to the average monthly HOEP year-over-year.

Table 1 - 6 shows the changes in coal and natural gas prices from November 2004 to April 2005, relative to the price in the previous year. Coal prices are the monthly average price for NYMEX Over-the-Counter Price for the Central Appalachian Region. Gas prices are monthly average Henry-Hub Spot Prices.

Table 1 – 6: Average Monthly Fuel Prices, November 2004 – April 2005

	Coal Price (NYMEX - $ CDN/MMBtu)			**Natural Gas Price (Henry-Hub Spot Price - $ CDN/MMBtu)**		
	2003/2004	**2004/2005**	**% Change**	**2003/2004**	**2004/2005**	**% Change**
Nov	1.93	2.93	51.8	5.88	7.13	21.3
Dec	2.13	3.05	43.2	8.12	8.03	(1.1)
Jan	2.32	3.06	31.9	7.85	7.53	(4.1)
Feb	2.57	2.94	14.4	7.18	7.58	5.6
Mar	2.85	2.97	4.2	7.17	8.45	17.8
Apr	2.76	3.04	10.1	7.63	8.83	15.7

Coal prices are higher each month, having stabilized around $3.00 per MMBtu compared to the steady increase in the previous year. This resulted in a much higher percentage increase in earlier months compared to the previous year, and smaller changes later in the period. Gas prices appear to be somewhat higher than last year, although because of the monthly volatility half the months have exhibited little change in price (marginal increases or decreases) while the other half had price increases of 16 percent to 21 percent.

These fuel price changes can be translated into estimates of production cost changes at generic coal-fired and gas-fired plants. Generic heat rates and variable Operations and Maintenance (O&M) costs are assumed for each fuel type as shown in Table 1 - 7.[5] Heat rates for new coal and gas-fired steam plant are assumed to be 9,000 BTU per KWh and 7,000 BTU per KWh respectively. Since these heat rates reflect operation from new plant run as base-load (i.e. around the clock) it is quite reasonable to consider less efficient operation (for older plant and non base-load operation). The results of a sensitivity case are provided later, showing the effect of a higher (less efficient) assumed heat rate.

In this table the MAU has included a variable O&M cost. There may well be other variable costs, such as transportation costs and emissions adders. The costs below can only be considered indicative of production costs and do not necessarily reflect costs or pricing for Ontario plant. However, since the variable O&M component is held constant, the production cost difference can be attributed entirely to the fuel price change and assumed heat rates. This means that even if the level of the production cost is not accurate, the change in production cost shown in the table still captures only the change implied by the fuel price change.

Table 1 - 7: Estimated Production Cost Impact of Fuel Prices Changes, November - April

	Estimated Coal-fired Production Cost ($CDN/MWh)			**Estimated Gas Fired Production Cost ($CDN/MWh)**		
Heat Rate	**9,000 BTU/KWh**			**7,000 BTU/KWh**		
Variable Cost	**$4.62/MWh**			**$3.07/MWh**		
	2003/2004	**2004/2005**	**Change**	**2003/2004**	**2004/2005**	**Change**
Nov	21.99	30.99	9.00	44.23	52.98	8.75
Dec	23.79	32.07	8.28	59.91	59.28	(0.63)
Jan	25.50	32.16	6.66	58.02	55.78	(2.24)
Feb	27.75	31.08	3.33	53.33	56.13	2.80
Mar	30.27	31.35	1.08	53.26	62.22	8.96
Apr	29.46	31.98	2.52	56.48	64.88	8.40

[5] The heat rate and variable O&M costs are taken from a recent report by the Canadian Energy Research Institute (CERI) – "Levelized Unit Electricity Cost Comparison of Alternate Technologies for Base-load Generation in Ontario"; August 2004. CERI expressed O&M costs in 2003 $CDN and assumed these were constant in real terms. In the analysis here we apply these costs without adjusting for inflation. CERI also

The table indicates that coal-fired production costs (for the identified components of cost) yield typical costs of $32 per MWh, representing monthly increases ranging from $1 to $9 per MWh, and an average increase of about $5.15 compared to the previous year. For gas production, cost estimates are $53 to $65 per MWh in the past 6 months, which are up to $9 per MWh higher than the corresponding months in the previous year. The average monthly increase for gas production costs was $4.34 per MWh, year-over-year.

Such production cost changes likely have affected HOEP prices and could explain some of the increase in the HOEP seen in the last six months. Table 1 - 16 and 1 - 17 later in this chapter show the portion of time different fuel types set price on-peak and off-peak. The next Table 1 - 8, estimates how HOEP could have been affected relative to last year by assuming the monthly production cost change calculated above and the portion of time the fuel type set the price in the 6 monthly periods last year. The calculation assumes: i) that the increased production cost implied by the fuel price change is reflected as an equivalent change in the offer price, and ii) that this does not alter the portion of time the generation sets the energy price.

Table 1 - 8: Potential Impact of Production Cost Changes on HOEP, On-Peak, November - April

	Coal		Gas		
	Production Cost Change ($/MWh)	**% Time Marginal (2003/2004)**	**Production Cost Change ($/MWh)**	**% Time Marginal (2003/2004)**	**Combined HOEP Impact ($/MWh)**
Nov	9.00	57.28	8.75	36.46	8.35
Dec	8.28	54.79	(0.63)	30.68	4.34
Jan	6.66	20.65	(2.24)	54.03	0.17
Feb	3.33	40.48	2.80	45.90	2.63
Mar	1.08	50.03	8.96	29.63	3.20
Apr	2.52	53.00	8.40	16.07	2.69

For example in November, the estimated combined HOEP impact was calculated as: $9.00 * 57.28% + $8.75 * 36.46% = $8.35 per MWh. This is a weighted average impact on HOEP. Note, because other fuel types were marginal about 6 percent of the time and no cost

assumed base-load operation. Average heat rates could be higher in practice if units are starting and stopping daily and running at below maximum output, which is more typical for intermediate and peaking operation.

increase is assumed for these, the combined HOEP impact is actually less than the individual coal and gas production cost changes. Hydroelectric generation opportunity costs may be contributing to higher HOEP also, although this is not captured in the above calculation. To the extent that hydroelectric opportunity costs rise because of coal and gas price effects in other hours, the prices may also be higher when hydroelectric is on the margin. So the actual impacts of coal and gas prices on average HOEP may well be higher than indicated here.

The calculation in the above table shows on-peak HOEP may have risen due to fuel prices as much as $8 per MWh on a monthly basis, with an average monthly impact of $3.56 per MWh. The next Table 1 - 9, shows that off-peak HOEP could have been affected from almost $1.40 to $8 per MWh, with a somewhat higher monthly average impact of $3.81 per MWh.

Table 1 - 9: Potential Impact of Production Cost Changes on HOEP, Off-Peak, November - April

	Coal		Gas		
	Production Cost Change ($/MWh)	**% Time Marginal (2003/2004)**	**Production Cost Change ($/MWh)**	**% Time Marginal (2003/2004)**	**Combined HOEP Impact ($/MWh)**
Nov	9.00	82.67	8.75	6.30	7.99
Dec	8.28	65.48	(0.63)	7.86	5.37
Jan	6.66	54.38	(2.24)	22.61	3.12
Feb	3.33	79.59	2.80	9.99	2.93
Mar	1.08	70.48	8.96	6.94	1.38
Apr	2.52	71.32	8.40	3.32	2.08

As mentioned above, these results are based on heat rates which may be more appropriate for new base-load units. To test the effect of less efficient operation, the analysis was redone using heat rates of 9,500 and 7,500 BTU/KWh for the coal and gas units respectively.[6] This leads to a larger impact on HOEP, about $0.22 per MWh on average over all months, i.e. $3.78 per MWh on-peak and $4.03 per MWh off-peak.

[6] These were heat rates used when assessing net revenue analysis for new entrants in PJM's State of the Market report published by the Market Monitoring Unit in March 2005.

These calculations provide some additional insights into understanding HOEP differences in the review period relative to the previous year. The earlier shift share analysis quantified potential impact on average monthly HOEP due to year-over-year changes, but led to a relatively large residual effect not explained by the exogenous variables. Given the fuel prices impacts above another portion of these residual quantities can be explained. Table 1 - 10 identifies the residual from the shift share analysis and how the unexplained change in average HOEP is reduced after considering the fuel price impacts.

Table 1 - 10: Shift Share Residual Adjusted for Fuel Price Impacts, November - April

	On-peak			Off-peak		
	Shift Share Residual ($/MWh)	**Impact of Fuel Price ($/MWh)**	**Net Residual ($/MWh)**	**Shift Share Residual ($/MWh)**	**Impact of Fuel Price ($/MWh)**	**Net Residual ($/MWh)**
Nov	15.16	8.35	6.81	11.88	7.99	3.89
Dec	12.32	4.34	7.98	11.71	5.37	6.34
Jan	(0.15)	0.17	(0.32)	10.88	3.12	7.76
Feb	9.94	2.63	7.31	5.83	2.93	2.90
Mar	13.59	3.20	10.39	13.08	1.38	11.70
Apr	5.97	2.69	3.28	4.91	2.08	2.83
Average	9.47	3.56	5.91	9.72	3.81	5.90

Accounting for fuel prices lowers the net residuals in all months, on-peak and off-peak. The average residual drops from about $9.60 to $5.90 on-peak and off-peak. The net residual is still fairly high in some months and more than $10 per MWh in March, both on-peak and off-peak. As concluded earlier, there are clearly other factors contributing to these residuals. As we continue to refine our analytical techniques we hope to be able to explain an even greater part of the period-to-period variations we observe in the market.

8. *Wholesale Electricity Prices in Neighbouring Markets*

Three other electricity markets operate in the Northeast United States as ‘neighbours’ to Ontario. Figures 1 - 6 to 1 - 8 compare monthly average prices, including off-peak and on-peak over the period under review. New York is one of Ontario’s largest electricity trading partners and although there is no direct trade with New England and PJM, all four markets are linked in the sense that perturbations in one, such as loss of a large generator, affect market outcomes in the others to some degree.

This relationship is reflected in the figures below with the Ontario price persistently lower compared to New York's, particularly in the off-peak period for all but April. In a frictionless market, one would expect arbitrage to result in the virtual elimination of price differences but the electricity market is far from frictionless. Transmission constraints between markets limit trade and scheduling protocols may lead to failed transactions. As well, imports and exports are selected in the hour-ahead dispatch and not in real-time, further limiting the ability to arbitrage away differences in real-time prices. Nevertheless, the general correlation between price differences and trade flows suggests that arbitrage does take place, and that changes in the HOEP can be explained in part by changes in prices in New York and other markets.

It is worth noting that MISO introduced a wholesale market, with spot price determination, effective April 2005. The bulk of our imports come from the southwest and future reports will include the MISO spot prices.

Figure 1 - 6: Average HOEP Relative to Neighbouring Markets, November 2004 – April 2005

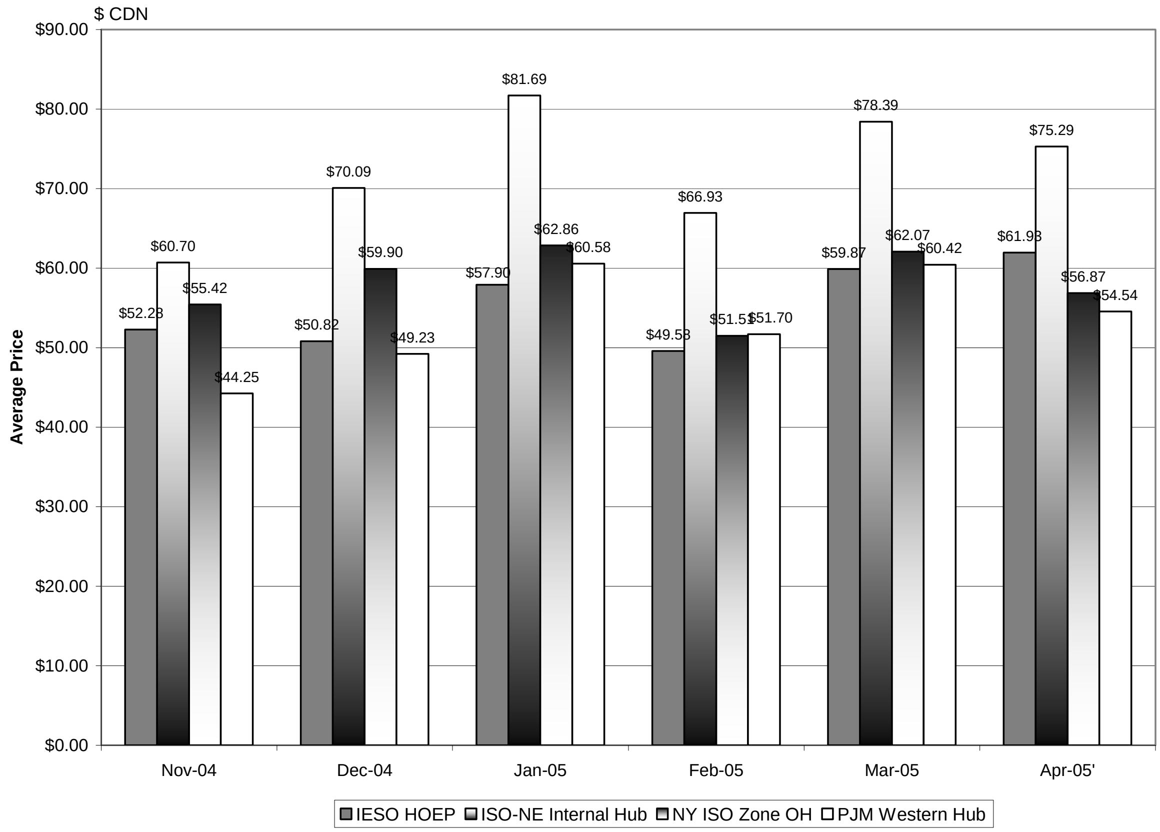


Figure 1 - 7: Average HOEP Relative to Neighbouring Markets, On-Peak, November 2004 – April 2005

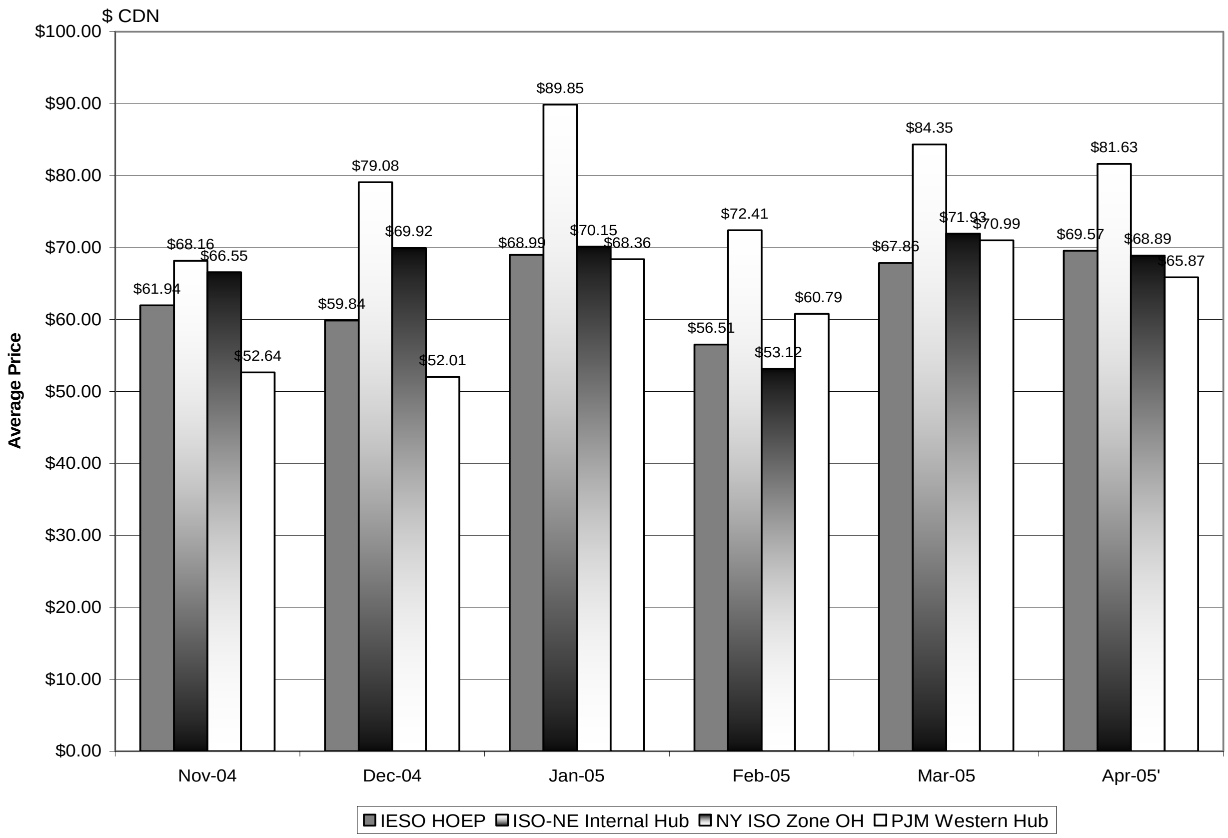
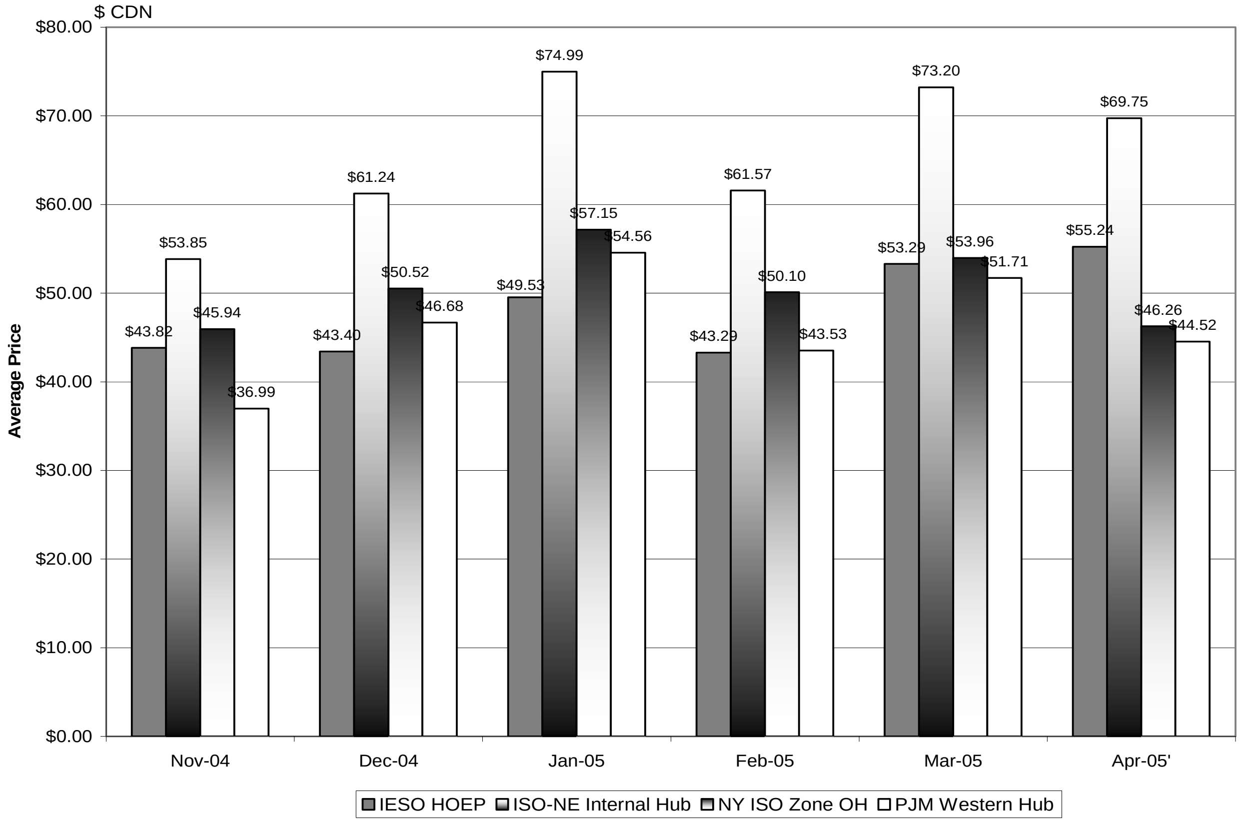


Figure 1 - 8: Average HOEP Relative to Neighbouring Markets, Off-Peak, November 2004 – April 2005



9. *Imports and Exports*

As Table 1 - 11 shows Ontario became a net exporter in January of 2005 but reverted to its position as a net importer in April.

This was not the first time Ontario was in a net export position. Indeed, Table A - 27 in the Statistical Appendix shows that we were net exporters from April 2004 through August 2004, but became net importers for the balance of 2004. The return to a net export position in January 2005 appears to be heavily influenced by net exports to New York in the off-peak period, which almost doubled in the first three months of 2005 compared with the first three months of 2004 (from 816.4 GWh to 1,560.7 GWh). This is consistent with both the improvement in the supply-demand balance and with the persistent differential in Ontario/NY prices, particularly in the off-peak period. A significant reversal took place in April and higher prices made exports from Ontario much less attractive.

Table 1 - 11: Net Exports (Unconstrained Schedule) from Ontario, On-Peak and Off-Peak (MWh), November – April

	Off-peak		On-peak	
	2003/2004	**2004/2005**	**2003/2004**	**2004/2005**
Nov	(222,416)	(267,649)	(142,459)	(329,824)
Dec	(97,079)	(8,289)	(249,784)	(139,370)
Jan	(32,596)	45,765	(174,322)	25,133
Feb	(66,647)	91,037	(239,477)	176,943
Mar	(12,848)	180,730	(67,594)	138,701
Apr	223,503	(187,057)	156,329	(207,975)

* Note: positive indicates net exports, negative means net imports

Net exports disaggregated by intertie zone are reported in Table 1 - 12. It shows generally the Michigan zone exports more to Ontario than it imports from Ontario. Conversely the New York zone typically imports more energy from Ontario than it exports to Ontario. In general these trends continue to illustrate the typical flows of electricity that have characterized the surrounding markets over the past few years. Relatively cheap power flows through the Michigan ties towards higher priced markets in New York and New England. The Province of Quebec traditionally imports more than it exports, and did so over the 6 month period, although it is a net exporter in 3 of these months. As stated earlier the high level of outages of Ontario plant in April reversed these trade flows.

Table 1 - 12: Net Exports by Intertie Zone, On-peak and Off-peak (MWh),

November 2003 - April 2005

		MB		**MI**		**MN**		**NY**		**PQ**		**Total**	
		2003/ 2004	**2004/ 2005**	**2003/ 2004**	**2004/ 2005**	**2003/ 2004**	**2004/ 2005**	**2003/ 2004**	**2004/ 2005**	**2003/ 2004**	**2004/ 2005**	**2003/ 2004**	**2004/ 2005**
Nov	Off-peak	35,337	(91,322)	(315,166)	(505,593)	(19,276)	(25,987)	64,236	345,862	12,453	9,391	(222,416)	(267,649)
	On-Peak	27,590	(44,627)	(233,029)	(392,112)	14,191	(6,954)	52,654	172,774	(3,865)	(58,905)	(142,459)	(329,824)
Dec	Off-peak	(4,756)	(71,745)	(368,345)	(490,941)	(21,277)	(5,960)	279,993	534,224	17,306	26,133	(97,079)	(8,289)
	On-Peak	23,182	(28,511)	(307,020)	(369,984)	8,820	638	38,355	272,146	(13,121)	(13,659)	(249,784)	(139,370)
Jan	Off-peak	47,417	(83,274)	(478,193)	(505,930)	(9,368)	(9,634)	362,750	582,224	44,798	62,379	(32,596)	45,765
	On-Peak	19,653	(11,102)	(360,104)	(309,798)	9,281	561	137,987	342,623	18,861	2,849	(174,322)	25,133
Feb	Off-peak	(58)	(87,214)	(343,790)	(373,185)	(12,848)	(13,077)	235,612	512,923	54,437	51,590	(66,647)	91,037
	On-Peak	(9,846)	(18,891)	(254,483)	(138,236)	(4,572)	(2,941)	1,245	328,061	28,179	8,950	(239,477)	176,943
Mar	Off-peak	(32,320)	(98,570)	(254,269)	(215,581)	(2,674)	(9,107)	218,068	465,577	58,351	38,411	(12,848)	180,730
	On-Peak	(60,968)	(5,868)	(171,537)	2,513	39,964	6,413	88,026	181,778	36,921	(46,135)	(67,594)	138,701
Apr	Off-peak	(22,784)	(93,740)	(293,157)	(320,697)	5,485	(16,867)	476,240	229,204	57,719	15,043	223,503	(187,057)
	On-Peak	(39,026)	(70,506)	(136,673)	(134,908)	40,690	(14,836)	251,952	(91,203)	39,386	(78,928)	156,329	(207,975)

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

10. *Operating Reserve Prices*

Tables 1 – 13 and 1 - 14 provide a comparison of average operating reserve prices for each of the three classes of reserve for each period.

Table 1 - 13: Operating Reserve Prices ($/MWh), Off-Peak Periods, November - April

	10N		10S		30R	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	2.32	0.86	3.69	3.86	2.04	0.79
Dec	1.81	0.79	4.33	2.66	1.25	0.68
Jan	1.42	0.82	3.96	3.39	1.23	0.82
Feb	0.43	0.46	3.46	3.44	0.43	0.46
Mar	0.91	1.28	3.35	5.04	0.91	1.28
Apr	3.58	4.28	6.10	7.14	3.39	4.17

Table 1 - 14: Operating Reserve Prices ($/MWh), On-Peak Periods, November - April

	10N		10S		30R	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	10.97	4.85	11.26	6.49	6.86	4.74
Dec	9.11	3.92	9.58	4.70	4.79	3.88
Jan	8.13	6.13	10.02	7.53	6.22	5.99
Feb	4.60	4.12	5.81	5.13	4.39	3.48
Mar	9.43	3.90	10.01	4.22	9.39	3.90
Apr	16.07	14.22	16.46	14.52	14.98	13.89

There are two main factors that influenced the year-to-year changes in operating reserve prices:

- The IESO purchased an additional 200 MW of ten-minute non-spinning reserve during the peak delivery hours 7 through 21 in 2003. As detailed in the previous report this supplemental reserve requirement was removed from the market mid-January 2004. The lower reserve requirement should lead to lower observed prices in November, December of 2004 and (to a lesser extent) January 2005. The table suggests that this expected result did occur.

- Dispatchable loads traditionally bring to the market not only additional offers for energy, but also for operating reserve. By November 2004, four new dispatchable loads had entered the market providing an additional 145 MW of ten non-spin and 30-minute reserve. This increase in supply should also exert downward pressure on price. The overall impact of the dispatchable loads on the OR market can be seen from Tables A - 45 and A - 46 in the Statistical Appendix, which show that the share of OR provided by dispatchable loads has essentially doubled.

April OR prices are traditionally higher because less hydroelectric resources are available for OR as these plants are scheduled for energy. This was true in both periods as shown above.

11. *Price Setters*

The percentage of the time in both periods that a given fuel type set the market clearing price in the real-time market (in both on-peak and off-peak hours) is shown in Tables 1 - 15 to 1 - 17.

Table 1 - 15: Share of Real-time MCP Set by Resource (%), November - April

	Coal		Nuclear		Oil/Gas		Water	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	71.31	66.65	0	0	19.72	13.67	8.97	19.69
Dec	60.58	74.17	0	0	18.26	9.55	21.16	16.28
Jan	38.96	60.48	0	0	36.92	21.04	24.12	18.48
Feb	61.42	79.14	0	0	26.63	8.10	11.95	12.76
Mar	60.27	60.57	0	0	18.33	15.50	21.40	23.93
Apr	62.70	58.80	0	0	9.33	18.21	27.98	22.99

As Table 1 - 15 indicates the percentage of time in which oil/gas generators set the price fell substantially, with the exception of April where it doubled. This reduction for all months but April is seen in both on and off-peak periods as shown in Tables 1 - 16 and 1 - 17.

Table 1 - 16: Share of Real-time MCP Set by Resource (%), Off-Peak, November - April

	Coal		Nuclear		Oil/Gas		Water	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	82.67	79.11	0	0	6.30	4.31	11.03	16.57
Dec	65.48	84.05	0	0	7.86	3.65	26.67	12.29
Jan	54.38	71.86	0	0	22.61	9.03	23.01	19.10
Feb	79.59	86.44	0	0	9.99	3.38	10.42	10.19
Mar	70.48	72.01	0	0	6.94	6.84	22.58	21.14
Apr	71.32	72.26	0	0	3.32	9.70	25.36	18.04

The decline in oil/gas is most apparent in on-peak hours for January 2005, compared with January 2004, where the frequency with which coal-fired generation set the price more than doubled, as the importance of oil, gas and hydro as price setters correspondingly declined. This trend to greater reliance on coal as a price setter, due in large part to the extension of the elastic part of the supply curve as a result of increased nuclear capacity, appears to be one of the driving forces behind the observation that prices are tending to cluster in the $30-$60 range, the typical price range for coal-fired offers.

Table 1 - 17: Share of Real-time MCP Set by Resource (%), On-Peak, November - April

	Coal		Nuclear		Oil/Gas		Water	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	57.28	52.60	0	0	36.46	24.26	6.25	23.14
Dec	54.79	62.23	0	0	30.68	16.62	14.53	21.16
Jan	20.65	45.47	0	0	54.03	36.58	25.32	17.95
Feb	40.48	71.12	0	0	45.90	13.32	13.62	15.56
Mar	50.03	46.64	0	0	29.63	25.87	20.34	27.49
Apr	53.00	43.43	0	0	16.07	27.73	30.93	28.84

Note however, that coal's share of on-peak price setting declined by almost 10 percentage points in April while oil/gas increased by more than this amount. The increase in the frequency of price setting by oil and gas units in April can be attributed to the major outages to both nuclear and coal plant that were discussed in section 4 above.

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

In past reports the Panel has noted that there is a persistent discrepancy between pre-dispatch and real-time prices. In our last report we noted a reduction in this discrepancy. While it is unrealistic to expect pre-dispatch and real-time prices to match perfectly a narrowing of this discrepancy is welcomed.

Generators and loads require a reliable pre-dispatch signal to plan their production. In some markets these signals are delivered through a day ahead market. In Ontario, the signal is derived from pre-dispatch market prices refreshed hourly to the dispatch hour. The convergence of the pre-dispatch and real-time price is a sign that demand-supply conditions in the market are being accurately projected.

As Table 1 - 18 indicates the difference between the one-hour ahead pre-dispatch and real-time price is persistent but continued to decline from 2003-2004 to 2004-2005 both in terms of the average differences and percentage differences.

Table 1 - 18: Measures of Difference 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 % of the HOEP	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	6.88	11.13	74.23	70.28	(56.49)	(43.59)	11.45	15.83	19.64	23.91
Dec	15.89	8.30	70.15	89.97	(83.54)	(198.31)	19.28	18.56	44.71	18.76
Jan	23.28	10.58	780.39	108.62	(99.55)	(91.66)	52.01	15.60	42.75	20.48
Feb	15.90	6.53	62.16	65.08	(38.20)	(258.61)	16.20	14.42	36.05	14.55
Mar	10.46	9.53	57.54	57.98	(92.83)	(325.26)	12.92	18.06	24.79	18.65
Apr	12.00	10.28	57.45	82.78	(191.93)	(101.66)	14.74	16.76	31.25	21.13
Avg	14.07	9.39	183.65	79.12	(93.76)	(169.85)	21.10	16.54	33.20	19.58

In the past reports four factors that affect the difference between pre-dispatch and HOEP have been identified. These are:

- demand forecast error (pre-dispatch versus real-time)

- variations in the performance of self-scheduling and intermittent generation (pre-dispatch versus real-time)
- the failure of scheduled imports and exports in real-time, and
- out-of-market control actions, which are typically taken in real-time.

In the absence of these four factors, the pre-dispatch prices on which loads, generators and importers base their decisions will be reliable indicators of the real-time prices they expect to pay or receive.[7] Decisions made in pre-dispatch will turn out to be efficient in real-time.

The role played by each of these factors is discussed below.

Demand Forecast Error

Since participants in the Ontario market must make their supply and demand decisions in advance, accurate demand forecasts are essential if the market is to operate efficiently. In other markets transparency in demand forecast comes from loads signaling consumption levels through their bids via a day ahead market. In Ontario, without a day ahead market, it is necessary for the IESO to forecast the consumption of all non-dispatchable load which makes up roughly 98 percent of all Ontario load. Inaccurate demand forecasts contribute to either excess capacity being on-line or shortages in real-time with adverse consequences for both market efficiency and reliability.

A review of the last six months shows that the reduction in the demand forecast error noted in our last report has continued. Table 1 - 19 shows that the mean absolute percentage forecast difference between pre-dispatch and real-time demand has continued to decline. In the Ontario design, the bid/offer window closes two hours ahead of pre-dispatch. Loads and generators bidding in the market make their final bid decisions based upon the 3-hour pre-dispatch. The IESO in turn makes choices about imports and exports at the one-hour ahead pre-dispatch point.

[7] Pre-dispatch prices are not expected to ever match real-time prices since there are design differences between the pre-dispatch and real-time schedules. These include, for example, the use of peak demand rather than average demand as a forecast for all intervals of the hour in pre-dispatch and the assumption in real-time of a 12-times ramp rate. These design differences notwithstanding, however, it is still the case that the pre-dispatch price is the best indication of real-time prices available to the market and the smaller the difference between them, the more efficient will be the decisions of market participants.

At both the 3-hour ahead and 1-hour ahead time points the absolute percentage forecast demand difference has continued to decline. One-hour ahead pre-dispatch demand forecast differences are now in the order of 1 percent.[8]

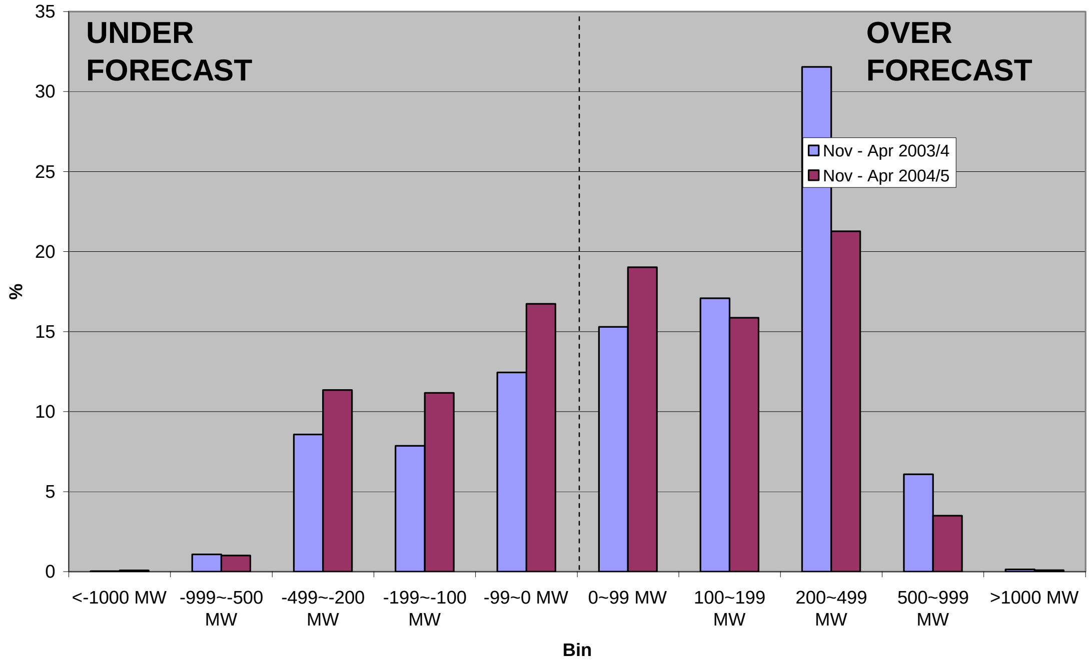
Table 1 - 19: Forecast Error in Ontario Demand, November - April

	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		1-hour		3-hour		1-hour		3-hour		1-hour		3-hour		1-hour	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	408	390	383	364	241	225	207	185	2.49	2.35	2.33	2.18	1.44	1.33	1.23	1.09
Dec	478	441	441	392	282	289	229	238	2.82	2.42	2.57	2.15	1.65	1.57	1.32	1.29
Jan	484	409	466	369	297	255	253	201	2.82	2.17	2.72	1.94	1.55	1.33	1.31	1.04
Feb	441	357	408	320	254	225	208	174	2.43	1.97	2.24	1.76	1.37	1.22	1.12	0.94
Mar	434	314	404	292	271	203	226	159	2.57	1.80	2.38	1.67	1.57	1.14	1.30	0.89
Apr	399	314	376	289	259	210	222	164	2.57	2.04	2.4	1.88	1.62	1.32	1.38	1.03

In previous reports we have looked simply at the demand forecast error absolute differences, as above. This report also reviews the tendency to consistently over-forecast demand, even on a peak-to-peak basis. When we review the data in Figure 1 - 9 we see a marked reduction in the tendency to over-forecast demand in the current period compared with the same period one year ago.

[8] Typically electricity markets in the North-East Power Coordinating Council (NPCC) are setting a standard of Mean Absolute Demand Forecast Difference accuracy of 2%.

Figure 1 - 9: Frequency Distribution of Ontario Demand Forecast Error Comparing November - April



Another way to look at the tendency towards over-forecasting is through the average values of the forecast difference between pre-dispatch and peak demand. Table 1 - 20 provides the mean of the forecast differences each month, representing the average bias in the monthly forecasts. In all months the forecast bias is positive but has dropped substantially, on a MW and percentage basis, for both 3-hour ahead and 1-hour ahead forecasts. The average bias across the last six months has dropped to about half the level of the average from a year earlier, now being about 60 MW, or about 0.3 percent and 0.4 percent for 1-hour ahead and 3-hour ahead respectively.

Table 1 - 20: Mean Forecast Error in Ontario Demand, November - April

	Mean forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean forecast difference: pre-dispatch minus average demand divided by the peak demand (%)			
	3-hour		1-hour		3-hour		1-hour	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	102	95	93	83	0.64	0.55	0.57	0.47
Dec	132	79	118	60	0.80	0.44	0.69	0.32
Jan	133	105	132	85	0.71	0.53	0.69	0.42
Feb	166	50	145	36	0.91	0.27	0.75	0.18
Mar	119	51	118	48	0.73	0.29	0.70	0.26
Apr	126	30	124	30	0.81	0.23	0.77	0.20
Avg	130	68	122	57	0.77	0.39	0.70	0.31

While it is important to continue to monitor demand forecasting accuracy and bias, we are pleased at the improvements that have been made to the forecasting process and the results achieved. The IESO has been responsive to the concerns we have expressed and has worked with the MAU to revise their forecast methodology in particular instances that the Panel identified. We will continue to review both forecasting methodologies and results and where we identify specific issues that can further improve demand forecasting we will make appropriate recommendations to the IESO.

Performance of Self-Scheduling and Intermittent Generation

Table 1 - 21 shows the average absolute hourly discrepancy between the offers of self-scheduling units and the actual delivered quantities. While the absolute failure rate associated with self-scheduling units is higher than the demand forecast error the magnitude and difference continues to be so small that it has a little impact upon the difference between the hour ahead pre-dispatch price and the HOEP.

Table 1 - 21: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities

	Total MWh Pre-dispatch		Maximum Overproduction (MW)		Maximum Underproduction (MW)		Average Absolute Difference (MW)		Absolute Failure Rate (Abs Difference/MW Pre-dispatch) (%)	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	964,681	784,062	277	229	139	149	36	36	3.08	3.42
Dec	863,853	809,100	405	223	140	119	36	34	2.74	3.24
Jan	1,080,865	839,424	1,317	205	834	118	32	30	3.00	2.62
Feb	834,172	766,811	644	224	250	168	35	32	3.25	2.95
Mar	1,174,221	822,583	724	177	131	119	54	23	3.95	2.11
Apr	760,221	710,274	262	148	113	190	29	33	1.89	3.78

*Note: the failure rate is the average of hourly absolute failure rate

<u>The Role of Import Offers and Export Bids in both Pre-dispatch and Real-Time</u>

The data in Table 1 - 22 show a rise in the export failure rate suggesting we should see an increase in the price gap. As we have discussed in previous MSP reports failed imports and exports are a significant contributing factor in the difference between pre-dispatch prices and HOEP. Other things being equal failed exports reduce the HOEP relative to the pre-dispatch price.

Table 1 - 22: Incidents and Average Magnitude of Failed Exports from Ontario November - April

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	255	353	737	975	163	227	10.40	11.37
Dec	265	396	903	950	196	257	7.54	10.00
Jan	281	393	1214	1160	170	229	5.13	7.41
Feb	236	421	740	830	154	254	6.39	9.66
Mar	280	458	675	765	138	201	6.03	8.88
Apr	299	319	977	913	190	194	5.77	10.91

*Note: the incidents with less than 1 MW excluded
** Note: Average is based on those hours where failure occurred

The incidents of failed imports are also increasing. In the opposite direction failed imports increase the HOEP relative to the pre-dispatch price and at times will impact reliability. When imports fail the IESO has to replace them with more expensive generation or take control actions to ensure a reliable operation.

Table 1 - 23: Incidents and Average Magnitude of Failed Imports into Ontario, November - April

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	154	347	682	1134	107	130	2.23	3.55
Dec	183	270	861	1074	124	116	2.25	2.86
Jan	262	298	1233	896	139	138	3.34	3.76
Feb	142	219	654	817	102	136	1.70	3.90
Mar	140	334	700	503	96	116	1.93	5.83
Apr	104	317	463	735	85	117	1.59	3.97

*Note: the incidents with less than MW excluded
** Note: Average is based on those hours where failure occurred

A further break down of import and export failures by on and off-peak is provided in the Statistical Appendix, Tables A - 40 through A - 44.

We continue to be concerned over the failure rate associated with imports and export failures, and especially so since it appears to have worsened. This is an issue that we intend to explore further.

<u>Out-of-Market Control Actions</u>

The use of out-of-market control actions and their subsequent impact on market prices has been extensively discussed in previous reports and are commented on again in Chapters 2 and 3. In general, the use of control actions to meet reserve requirements results in depressed real-time prices and has historically been an important factor in the discrepancy between pre-dispatch and real-time prices. In response to Panel recommendations, the IESO has taken a number of actions that have resulted in reduced use of out-of-market control actions, and in pricing out-of-market reserves. Table 1 - 24 below shows that the use of out-of-market control actions continued to decrease in the period under review. While the frequency and use of out-of-market control actions has reduced substantially due to the efforts of the market, they can still be an important factor during critical events when appropriate price signals are important for supply–demand response.

Table 1 - 24: Percentage Intervals with Manual Operating Reserve Reductions (Market Schedule),November - April

	No Reduction		>1 MW and <200 MW		>200 MW and <400 MW		>400 MW and <800 MW		>800 MW	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	99.53	98.80	0.29	0.41	0.19	0.64	0.00	0.16	0.00	0.00
Dec	98.51	99.45	0.25	0.18	0.82	0.37	0.43	0.00	0.00	0.00
Jan	96.55	97.16	0.75	0.82	1.85	1.21	0.65	0.63	0.20	0.19
Feb	98.67	99.63	0.59	0.04	0.56	0.25	0.18	0.09	0.00	0.00
Mar	96.66	99.37	1.22	0.19	1.89	0.25	0.22	0.19	0.00	0.00
Apr	97.52	96.11	0.84	1.06	1.34	1.71	0.07	0.88	0.22	0.23
Avg	97.91	98.42	0.66	0.45	1.11	0.65	0.26	0.23	0.07	0.07

*Note: The manual OR reduction exclude those incidents where the reduction is simply in response to an OR activation as specified in section 7.4.5 of Chapter 7 of Market Rules

13. *Hourly Uplift and Components*

Total hourly uplift charges declined slightly to $196 million in 2004-2005 compared to the earlier period. As can be seen in Table 1 – 25, operating reserve payments fell almost 50 percent and Intertie Offer Guarantee (IOG) payments also declined significantly; however, these declines were offset by increases in Congestion Management Settlement Credit (CMSC) payments and transmission line losses.

The lower IOG payments generally reflect the continuing decline in the discrepancy between pre-dispatch and real-time prices and the more favourable supply conditions within Ontario. As noted in last year’s report, January 2004 was an unusually cold month and so the one month decline in IOG payments of $10 million in January 2005 was the result of this year’s more temperate conditions. Even though the imports of April 2005 were higher than 2004, the IOG payments per MWh are lower and are a reflection of the reducing gap between the pre-dispatch and real-time prices.

Table 1 - 25: Total Hourly Uplift Charge, November - April

	Total Hourly Uplift $ Millions		IOG $ Millions		CMSC $ Millions		Operating Reserve $ Millions		Losses $ Millions	
	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005	2003/2004	2004/2005
Nov	25	38	1	7	7	11	6	4	10	17
Dec	31	33	8	4	4	9	5	3	13	18
Jan	53	37	15	5	14	11	5	3	20	19
Feb	33	24	8	2	6	6	3	2	16	14
Mar	32	35	4	3	7	11	6	3	16	18
Apr	31	46	3	5	6	15	9	8	14	18
Total	205	196	39	25	44	58	34	19	89	97

We attribute the significant reduction in operating reserve payments to an increase in supply of operating reserve from dispatchable loads and energy from increased base-load generation supply displacing higher priced generators.

In our previous report we noted significant changes in monthly losses; again we see similar differences in November and December of 2004 compared to the previous year. The IESO has indicated that while they have investigated this to determine the cause of the difference they have not yet found an explanation for the difference and will continue to explore the issue.

14. *Net Revenue Approximation and Investment Adequacy*

Our June 2004 report provided a simple analysis of what we called Net Revenue, representing the hypothetical revenue available to meet fixed costs. This was a rough approximation calculated as the amount by which energy payments would have exceeded specified levels, where these levels might equate to average or marginal costs of generation. It has been a year since that analysis, allowing comparison with an additional year of market price data.

The earlier report identified the numerous limitations of such analysis. Moreover, it did not address the question whether such net revenues would be sufficient to attract new investment.

Drawing from a recent report by CERI[9] the MAU has now performed additional analyses to assess whether current levels of energy prices would be sufficient to sustain entry by a new gas-fired generator.

As with the previous assessment, we are interested in your feedback regarding the usefulness of this type of information.

Hypothetical Revenue Available to Meet Fixed Costs

As described in the previous report, a net revenue or hypothetical revenue analysis estimates the difference between market revenues and the variable costs incurred from producing the energy. The margin between the revenues and variable costs contributes to the recovery of a generator's fixed costs.

In the analysis presented here all variable costs are represented by a single cost per MWh, referred to as the base level. A generation facility is assumed to produce energy and receive energy payments if HOEP for an hour exceeds the assumed base level. The difference between HOEP and the base is treated as net revenue. These are summed for a 12-month period to yield the annual net revenue estimate. For example, referring to Table 1 - 26 a facility with $40 per MWh variable costs would be attributed a hypothetical net revenue of $119,529 in the 2004 period (from May 2004 to April 2005). This represents the sum of HOEP less $40 over all hours where HOEP exceeds $40 per MWh.

In using this data the limitations of the analysis should be kept in mind:

- Actual variable costs will change over the year – due to fuel price changes, the number of hours a unit is run daily and even the output level at which the unit is run.

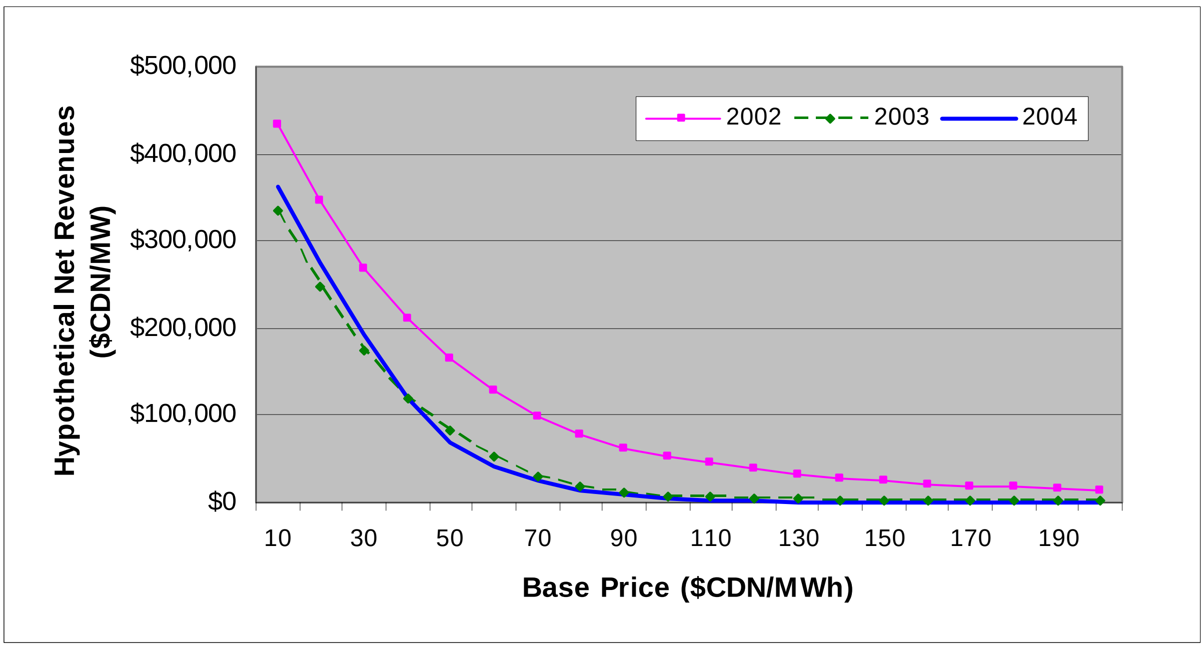
[9] Canadian Energy Research Institute "Levelized Unit Electricity cost comparison of alternate technologies, for base-load generation in Ontario", August 2004.

- Additional revenues might be received for providing ancillary services or as the result of being constrained on in the dispatch.

- A facility is unlikely to be able to produce in all hours where HOEP is higher than the base level, due to forced and planned outages, because there are too few consecutive hours to justify the unit's start-up, the higher prices were distributed in different hours of a day, or there was insufficient advance indication of the production opportunities.

The tables and figures below present data for three years. The period May 2002 to April 2003 is referred to as 2002, May 2003 to April 2004 as 2003 and May 2004 to April 2005 as 2004.[10] The values represent the revenue attracted by 1 MW.[11]

Figure 1 - 10: Hypothetical Net Revenues to Meet Fixed Costs by Year



This figure clearly shows how results from 2003 and 2004 are similar and well below hypothetical net revenues implied by 2002 HOEP prices, in all base price ranges. The 2003 and

[10] Prices during the market suspension from August 14 to 23 in 2003 are omitted, leading to an understatement of net revenues for the period.
[11] Data for the first two years are slightly revised, relative to the previous report

2004 data appear to diverge only a little in the $10 to $30 per MWh and $50 to $70 per MWh, ranges. The corresponding table provides more detailed data for comparison.

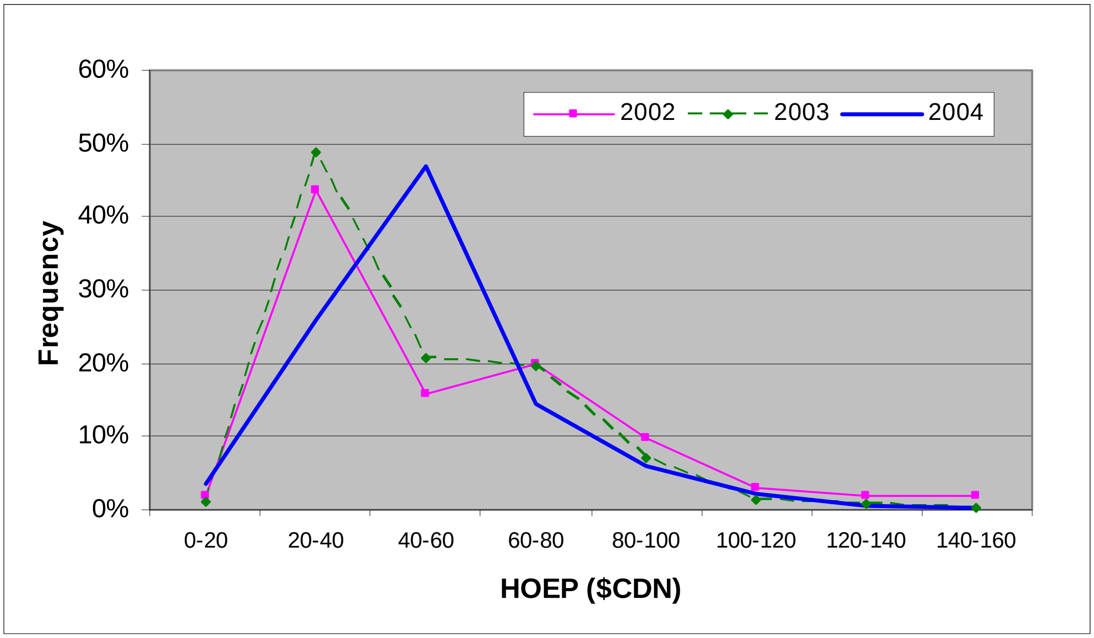
Table 1 - 26: HOEP Revenues above Base Level

Base Level ($ per MWh)	**Energy Payments above Base Level ($ CDN per MW)**			**Percentage (%) Change ($ CDN)**		
	2002	**2003**	**2004**	**2004 to 2002**	**2004 to 2003**	**2004 to 2003**
10	433,912	333,920	361,296	(17)	8	27,376
20	346,952	248,420	275,373	(21)	11	26,952
30	267,388	173,498	192,796	(28)	11	19,298
40	211,140	120,319	119,529	(43)	(1)	(790)
50	166,131	81,830	69,720	(58)	(15)	(12,110)
60	127,771	51,874	40,614	(68)	(22)	(11,260)
70	98,000	30,088	24,849	(75)	(17)	(5,238)
80	77,405	17,421	14,799	(81)	(15)	(2,622)
90	62,920	11,161	8,481	(87)	(24)	(2,680)
100	52,616	7,720	4,805	(91)	(38)	(2,915)
110	44,873	5,776	2,743	(94)	(53)	(3,033)
120	38,329	4,406	1,653	(96)	(62)	(2,754)
130	32,870	3,459	1,128	(97)	(67)	(2,331)
140	28,239	2,846	858	(97)	(70)	(1,989)
150	24,432	2,424	697	(97)	(71)	(1,727)
160	21,550	2,138	598	(97)	(72)	(1,540)
170	19,362	1,930	523	(97)	(73)	(1,407)
180	17,561	1,747	458	(97)	(74)	(1,289)
190	16,073	1,585	417	(97)	(74)	(1,167)
200	14,780	1,435	387	(97)	(73)	(1,047)

2004 hypothetical net revenues are on the order of 10 percent higher (up to $27,000) than comparable 2003 values, up to a base level of $30 per MWh. Between $50 and $60 base levels the 2004 net revenues fall significantly below the 2003 values, between 15 percent and 22 percent or by about $12,000 annually. Above $70 per MWh, 2004 values stay below 2003, by less than about $3,000 although this appears large on a percentage basis.

The explanation for the large difference between 2002 versus 2003 and 2004 is the higher frequency of HOEP prices in the higher price ranges for 2002. Differences between 2003 and 2004 can also be seen as related to the frequency distribution of HOEP.

Figure 1 - 11: Distribution of Ontario HOEP by Year



The decline in net revenues from 2002 is attributed to the lower frequency of occurrence of higher prices, and lower average prices. 2002 had a significant number of hours with price occurrences in the $60-80 range and in the ranges above that. There were 107 hours in 2002 when the HOEP exceeded or equalled $200 compared to 10 hours in 2003 and 3 hours in 2004. The slight further decline in net revenues from 2003 to 2004 in the centre of the price ranges is due to more shifting of prices to below the $60 range from higher levels. Average price for 2004 is higher than 2003, so net revenue at the low price range is also higher.

Revenue Adequacy Assessment

The above section addressed the question of the hypothetical net revenues that might be available to meet fixed costs given the assumed base level and energy prices observed since market opening in 2002. It does not indicate whether such revenues would be adequate to meet the fixed costs which may be incurred for a generating unit. This section provides some indication whether market prices to date would be sufficient to sustain new generation by estimating an Internal Rate of Return (IRR) for new entry. The analysis takes published data about the cost of new generation in Ontario and hypothetical net revenues to determine an IRR for the project.

In 2004 the Canadian Energy Research Institute (CERI) reported on the costs of new generation capacity in Ontario.[12] In their study CERI identified the characteristics of a new combined cycle gas turbine similar to the 580 MW plant recently built Brighton Beach facility, as set out in the following table. The MAU has adopted this plant description for the purpose of the revenue adequacy assessment below.

Table 1 - 27: CERI Gas-Fired Plant Assumptions

$ CDN (2003)	BASE CASE ASSUMPTIONS
Plant	580 MW $711/KW capital cost (50% in each year prior to operation) 30 year life
Operation & Maintenance	Fixed Cost $15.38/KW/yr Variable Cost $3.07/MWh
Operation	Heat Rate 7000 BTU/KWh Annual Capacity Factor: 90%
Fuel	$6.47 per MCF (in 2005) Escalating at 1.8% (real) to 2025 then constant

CERI reviewed different technology options as base-loaded generation, assuming that each ran with 90 percent annual capacity factor in the base case. In our analysis below the number of hours run comes from comparing historical market prices in each hour and the average running cost of the generator. This is essentially equivalent to the hypothetical net revenue calculation performed in the previous section. The annual capacity factor and hypothetical net revenues are results of the comparison with the observed hourly prices.

We also departed somewhat from the CERI work by assuming the initial year of operation was 2004. All costs in the CERI analysis were expressed in real terms (2003 $ CDN). Except for fuel costs these were constant costs, that is, independent of the start date. However for a start date of 2004 we had to modify the assumed fuel costs, and used the average price of gas observed at the Henry Hub in 2004. These prices were adjusted by the daily US-CDN exchange rate and the average over the year was translated to 2003 $ CDN. Combined with the 7,000 BTU/MWh heat rate for the plant, the resulting average fuel cost was $51.31 per MWh. Adding in variable O&M of $3.07, the total variable running cost was calculated as $54.38 per MWh.

For the first year of operation the plant is assumed to face the prices observed from May 2004 to April 2005. This resulted in a hypothetical revenue available to meet fixed costs of $54.8 million over the 12 months, with the plant running for only 34 percent of the year. Given fixed O&M costs for the year are $15.38 per KW, the hypothetical net revenue for the year is $39.4 million per MW installed.

In order to estimate IRR, annual revenue amounts are required. This could require simulating market prices in future years, which would require a host of assumptions. We simplify this by assuming that the annual net revenue will be the same (in real terms) for each of the 30 years of plant operation. This is equivalent to saying each year as fuel prices escalate in real dollars, market prices each hour increase by the same amount. In each hour the difference between the market price and the variable cost would remain the same as in the initial year, and annual net revenues would be identical (in real dollars).

To summarize, for the IRR calculation capital costs are $355 per KW in each of the two years before initial operation, and net revenue in each of the 30 years of operation is $39.4 million per MW installed. These assumptions and calculations yield a before-tax IRR figure of 3.5 percent. Required rate of return for an investment will vary considerably for any potential investor. However at 3.5 percent, few if any investors would be attracted to such a project. Of course, this result is dependent on the assumptions. If projected costs were lower or market prices higher the IRR would increase.

[12] Levelized Unit Electricity lost… report title found at footnote 5, page 16..

PJM also performs net revenue adequacy analysis. In the recent assessment[13] for new generation facilities they conclude that net revenue has been below levels required to cover the full cost of new plant, more so for new peaking plant. This is consistent with the above assessment based on the last 12 months of energy prices in Ontario.

As in our previous net revenue section, the Panel welcomes comments as to how to improve the usefulness of such analysis.

[13] PJM State of the Market, March 2005.

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. There were three hours during the period November 2004 to April 2005 in which the HOEP was greater than $200/MWh. There were no hours during the review period in which 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.[14] There were four hours in the period November 2004 to April 2005 in which the HOEP was less than $20/MWh.

In addition, the MAU monitors for any other events that appear to be anomalous, even though they may not meet the 'bright-line' price tests, and reports its findings to the Panel. Section 4 of this chapter reports on two such events. A market design issue raised in one of the MAU's monthly reports and of relevance to market efficiency is discussed briefly in section 5.

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

2. *Analysis of High Priced Hours*

The MAU regularly reviews all hours where the HOEP exceeds $200/MWh and where 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 over the past years. There were three hours in which the HOEP exceeded $200/MWh during the period November 2004 to April 2005. In the same period in the previous year (November 2003 to April 2004), there were four hours in which the HOEP exceeded $200/MWh.

Table 2 - 1: High Priced Hours, Monthly, November 2003 – April 2005

	HOEP>$200		Hourly Uplift Above HOEP	
	2003/2004	2004/2005	2003/2004	2004/2005
Nov	0	0	0	0
Dec	0	1	0	0
Jan	3	0	0	0
Feb	0	1	1	0
Mar	0	1	0	0
Apr	1	0	0	0

In our previous reports, we noted that a HOEP greater than $200 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
- Real-time provision of energy by self-scheduling and intermittent generators is less than scheduled in pre-dispatch

[14] 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.

- 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.[15] 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. When the real-time supply cushion falls below the 10 percent level, generally all of the offers from Ontario's traditional price setting generating units have been accepted to provide energy to meet Ontario demand. At this point, the market must turn to the more expensive Ontario offers: the offers of combustion turbine units (CTUs), peaking hydroelectric units that did not expect to run, or dispatchable loads, all of which tend to be offered at prices above $200.

Occurrences of High Priced Hours

There were three hours in the review period where the HOEP exceeded the $200 level.

- December 5, 2004 Hour 19 ($254.58)
- February 17, 2005 Hour 19 ($338.61)
- March 5, 2005 Hour 19 ($394.11)

Tables 2 - 13 to 2 - 14 in the Appendix to this chapter present some key statistics summarising the market conditions during these three hours. As shown in Table 2 – 2, in all three cases the supply cushion was well below the 10 percent level. In all three cases real-time demand was higher than the pre-dispatch forecast of demand. In two cases imports failed in real-time and in two cases infra-marginal domestic generation was derated in real-time. The specific circumstances surrounding each of these three high price events are discussed below.

[15] The supply cushion is explained at pp. 11-16 of our 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.

Table 2 - 2: Supply Cushion for High Priced Hours

Date	Hour	Pre-dispatch Supply Cushion (%)	Real-time Supply Cushion (%)
05-Dec-04	19	18.30	3.30
17-Feb-05	19	11.50	1.10
05-Mar-05	19	15.20	1.60

2.1 December 5, 2004 Hour 19

The HOEP during hour 19, December 5, 2004 was $254.58 while the MCP reached $401 in interval 3 of the hour. The pre-dispatch price of $59 did not indicate any supply strain for this hour. In fact, the pre-dispatch supply cushion was 18 percent which is reasonable by pre-dispatch standards. In real-time, however, peak demand was 682 MW higher than projected in pre-dispatch and imports in the amount of 157 MW failed. This higher than anticipated demand combined with the failed imports to drive the supply cushion down to 3.3 percent. When the supply cushion is this low, peaking hydroelectric generation becomes the marginal supplier. Indeed, peaking units set the MCP in most intervals in hour 19, resulting in a HOEP of $254.58. The HOEP would have been much higher had the IESO not reduced the reserve requirement from 1,418 MW to 700 MW. Had the IESO not reduced the reserve requirement manually, the market would have been short by the amounts shown in the far right hand column of Table 2 - 3 below. The DSO would have equilibrated supply and demand by reducing the reserve requirement by the amount of the shortage and setting the price at the bid of the marginal supplier which in this case was a dispatchable load bidding at $1,999.[16] Thus, absent manual intervention by the IESO, the MCP during intervals 1 – 4 and 6 – 8 would have been $1,999. This is shown in Table 2 - 3 below.

[16] The current DSO does not permit dispatchable loads to set prices. In our simulation we remove that constraint and allow loads to set prices.

Table 2 - 3: Real-time Prices Compared to Simulated Prices, Hour 19, December 5, 2004

Interval	Energy MCP $/MWh	Simulated Energy MCP with full Reserve Requirement $/MWh	Reserve Shortage with Full Reserve Requirement (MW)
1	340.16	1,999.00	106
2	376.05	1,999.00	166
3	401.20	1,999.00	216
4	400.00	1,999.00	176
5	120.10	139.99	0
6	352.12	1,999.00	131
7	332.65	1,999.00	77
8	329.32	1,999.00	66
9	118.55	139.99	0
10	104.50	134.30	0
11	95.19	124.99	0
12	85.09	101.24	0
Average	**254.58**	**1,219.46**	**78.03**

The IESO's Market Pricing Working Group is currently studying the pricing of additional Control Action Operating Reserve (CAOR)[17] in the market. The proposal under study is to price an additional 400 MW of CAOR at $100/MWh for the first 200 MW and $150/MWh for the second 200 MW. The MAU has simulated the effect on the MCP of the availability to the market of 800 MW of priced CAOR at these prices and existing prices for the original 400 MW given no manual reserve reduction by the IESO. The results of this simulation are shown in Table 2 - 4. In this simulation, the DSO draws on the additional 400 MW tranche of priced CAOR as well as dispatching off infra-marginal dispatchable load to equate supply and demand. The MCP is higher than when this second tranche is priced at zero as is presently the case.

Once again the simulation results reinforce the need to allow the market to select additional CAOR based on its offer price. The Panel has consistently argued for this approach in previous reports.

[17] CAOR refers to procedures that the IESO can use to fulfill operating reserve requirement. These include; a) 3% and 5% voltage reductions on the IESO grid, b) disregarding the 30-minute reserve requirement for up to 4 hours and c) making exports recallable.

Table 2 - 4 : Simulated Prices with Additional CAOR, Hour 19, December 5, 2004

Interval	Energy MCP ($/MWh)	Simulated Energy MCP with full Reserve Requirement and additional CAOR ($/MWh)
1	340.16	372.12
2	376.05	446.05
3	401.20	471.20
4	400.00	450.00
5	120.10	159.99
6	352.12	422.12
7	332.65	363.48
8	329.32	360.15
9	118.55	141.99
10	104.50	134.30
11	95.19	124.99
12	85.09	101.24
Average	**254.58**	**295.64**

2.2 February 17, 2005 Hour 19

The HOEP in hour 19 on February 17, 2005 was $338.61. The MCP ranged from a low of $79.62 in interval 1 to a high of $1,830 in interval 8. Table 2 - 5 lists the MCPs for each of the 5-minute intervals in the hour. The factors that contributed to the high MCPs in this hour are discussed below**.**

Table 2 - 5: Data on Market Conditions, Hour 19, February 17, 2005

Interval	Actual MCP ($/MWh)	Pre-dispatch Demand minus real-time Demand (MW)	Total Reserve Requirement (MW)
1	80	272	1418
2	80	180	1318
3	82	78	1318
4	110	(44)	1118
5	115	(112)	1118
6	116	(147)	1018
7	120	(141)	1018
8	1830	(155)	990
9	520	(131)	946
10	450	(104)	946
11	450	(98)	946
12	110	87	946

Pre-dispatch Market Conditions

The pre-dispatch forecast of demand was 21,500 MW. Based on this demand and the offers available in the hour, the pre-dispatch price was $80 and all available fossil generation was scheduled to its capacity limits. This meant that there would be no spare capacity of fossil generation available to supply energy in the event of a positive shock in demand or a sudden loss of infra-marginal supply in real-time. Import offers not selected in pre-dispatch are also unavailable to supply additional energy in real-time. As a consequence, any change in real-time would require energy to be provided by peaking hydroelectric facilities. These facilities were all offered at prices well above the $80 pre-dispatch price. In particular, there were an additional 300 MW of hydroelectric supply offered for energy at prices between $80 and $240. All of the remaining hydroelectric resources were offered at prices in the $400 range. In short, the real-time offer curve was extremely price inelastic for output levels beyond the forecast level of demand.

Real-time Market Conditions

Upward pressure on the market price in real-time was the result of heavier than anticipated demand, failed imports and the derating of infra-marginal generating units.

As Table 2 - 5 indicates, real-time demand was higher than the pre-dispatch forecast in most intervals in the hour. As well, 151 MW of scheduled imports failed and the derate of several fossil plants further reduced supply by 315 MW.[18] These shocks meant that the market had to turn to additional, more costly hydroelectric resources.

In response to this tightening of supply, the IESO manually lowered operating reserve requirements gradually through the hour from 1,418 MW in interval 1 to 946 MW in intervals 9 – 12 as shown in Table 2 - 5. It carried out-of-market sources of reserve in order to meet its NERC and NPCC standards. By interval 8, the requirement for 30-minute reserve was reduced to 1 MW and only 10-minute spinning reserve and 10-minute non-spinning reserve were being carried. If the IESO had not reduced the reserve requirement, the shortage of operating reserve would have been as shown in the far right hand column of Table 2 - 6 below.

In order to understand the implications of this intervention we asked the MAU to simulate how the DSO would have dealt with this shortage had there been no manual intervention. Table 2 - 6 compares the actual MCP with what it would have been if the reserve requirement had not been (manually) reduced by the IESO and entered into the DSO. The DSO would have reduced the reserve requirement by the amount of the shortage and selected the bid of the marginal supplier, in this case a dispatchable load, resulting in MCPs of $1,999 for intervals 4 - 12.

The MAU also carried out a second simulation to assess what would have happened if the second tranche of CAOR had been priced as under discussion with the IESO's Market Pricing Working Group and the IESO had not lowered the reserve requirement.[19] Table 2 - 7 shows the DSO would have set prices more representative of the tight supply conditions during the hour, but far below the levels that would have arisen had the market been forced to clear with no manual intervention and no price ascribed to out-of-market actions, i.e., the $1,999 prices shown in Table 2 - 6.

[18] In an effort to understand the events that led to the high price in the hour, the MAU, acting for the Panel, requested and obtained further information on the nature of these derates from the market participant.

Table 2 - 6: Real-time Price Compared to Simulated Prices, Hour 19, February 17, 2005

Interval	Energy MCP ($/MWh)	Simulated Energy MCP with full Reserve Requirement ($/MWh)	Reserve Shortage with Full Reserve Requirement (MW)
1	79.62	79.62	0
2	79.93	79.93	0
3	82.07	110.00	0
4	110.09	1,999.00	47
5	115.47	1,999.00	109
6	116.10	1,999.00	147
7	120.02	1,999.00	147
8	1,830.00	1,999.00	333
9	520.00	1,999.00	315
10	450.00	1,999.00	360
11	450.00	1,999.00	347
12	110.00	1,999.00	19
Average	338.61	1,521.71	152

Table 2 - 7: Simulated Prices with New CAOR Prices, Hour 19, February 17, 2005

Interval	Actual Energy MCP ($/MWh)	Simulated Energy MCP with full Reserve Requirement and additional CAOR ($/MWh)
1	79.62	99.62
2	79.93	99.93
3	82.07	102.07
4	110.09	130.09
5	115.47	135.47
6	116.10	186.10
7	120.02	186.10
8	1,830.00	1,930.00
9	520.00	520.00
10	450.00	1,950.00
11	450.00	600.00
12	110.00	129.48
Average	338.61	505.74

[19] Recall the proposal under discussion for the remaining 400 MW is that 200 MW would be priced at $100/MWh and the remaining 200 MW at $150/MWh.

2.3 March 5, 2005 Hour 19

The HOEP for delivery hour 19 on March 5, 2005 reached $394.11. The peak in the hour MCP spiked to $1,950 in interval 8. The reasons for both the high HOEP and the MCP spike are discussed below.

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

The pre-dispatch peak demand forecast was 18,335 MW. The pre-dispatch supply cushion was 15 percent. Scheduled net exports were 574 MW. The pre-dispatch price was $69. All available fossil units were selected in the pre-dispatch schedule. Offers from Ontario generators not accepted in pre-dispatch included one offer from a gas-fired generator to provide 230 MW at $85 as well as offers from peaking hydroelectric facilities at prices ranging from $160 to $2,000.

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

Real-time demand was higher than had been forecast in pre-dispatch during seven intervals in hour 19 (see Table 2 - 8). Peak demand came in at 18,657 MW, some 322 MW higher than the pre-dispatch forecast. In addition, a fossil plant which had been derated earlier in the day but was declared by the market participant to be available for hour 19 and thus scheduled in pre-dispatch to supply 350 MW turned out to be unavailable in real-time. The combined effect of higher than anticipated demand and the reduction in the amount of infra-marginal supply available in real-time was to reduce the real-time supply cushion to 1.6 percent. As a result, the market cleared on the steep portion of the supply curve.

Table 2 - 8 : Summary of Market Conditions by Interval, Hour 19, March 5, 2005

Interval	Actual Energy MCP ($/MWh)	Pre-dispatch Demand Minus Real-time Demand (MW)	Total Reserve Requirement (MW)
1	57	435	1,418
2	84	311	1,418
3	90	204	1,418
4	100	124	1,418
5	100	64	1,418
6	110	(42)	1,418
7	520	(175)	1,418
8	1,950	(219)	1,418
9	429	(322)	1,418
10	429	(322)	1,318
11	429	(322)	1,318
12	429	(322)	1,318

MCP's During the Hour

The MCP's for each 5-minute interval during the hour are reported in Table 2 - 8. The MCP at the start of the hour was $57. By interval 7, load was exceeding the pre-dispatch forecast by 175 MW and the MCP had climbed to $520. In interval 8, load exceeded the pre-dispatch forecast by 219 MW and of the MCP spiked to $1,950 (the bid of a dispatchable load). In interval 9, there was a reserve shortage. The DSO reduced reserve requirements by the amount of the shortage and set the MCP at the bid of the marginal Ontario generator ($429) rather than the offer of the marginal Ontario bidder (dispatchable load at $1,999) as it is now being corrected to do.

The MCP was administered at $429 for the last three intervals. A consequence of the process of setting an administered price is that there is essentially no data on the behaviour of the market during the last three intervals of hour 19.

Impact on Real-time Prices

The respective impacts of the unanticipated increase in real-time demand and the derating of infra-marginal generation in real-time on the MCP during the first 8 intervals of hour 19 have been estimated by the MAU using simulation analysis. The first simulation (Test 1 in Table 2 -

9) shows what the MCP would have been if the derate occurred but real-time demand had been accurately forecast in pre-dispatch. Comparing the column headed "Test 1" with the column headed "Actual Energy MCP" shows that the under-forecasting of demand in pre-dispatch increased the MCP between $1 and $1,600 depending on the interval. The very large price impact in interval 8 is the result of the market clearing at the steepest portion of the supply curve during this interval.

The second simulation (called "Test 2" in Table 2 - 9) shows what the MCP would have been during the first 8 intervals given no derate but real-time demand exceeding the pre-dispatch forecast. Comparing the column headed "Test 2" with the column headed "Actual Energy Price" shows that the derate increased the MCP by between $1 and $1,865, depending on the interval.

Table 2 - 9: Real-time Prices Compared to Simulated Prices, March 5, Hour 19

Hour	Interval	TEST 1: Derate with no Demand Forecast Error ($/MWh)	TEST 2: No Derate but Real-time Demand is Higher than Forecasted ($/MWh)	Actual Energy MCP ($/MWh)
19	1	56	56	57
19	2	57	55	84
19	3	84	55	90
19	4	89	55	100
19	5	92	55	100
19	6	105	57	110
19	7	117	85	520
19	8	350	85	1,950
19	9	1,999	89	429

<u>The Derating of a Generating Unit in Real-time</u>

The Panel asked the MAU to determine if there were any communication issues between the IESO and the market participant that caused the generating unit involved in this event to be scheduled in pre-dispatch but unavailable in real-time. The MAU found that the market participant involved kept the IESO properly informed on the status of the derated unit. Although its return to service was uncertain, the prediction was that the unit would be available for hour 19. This prediction turned out to be incorrect. With the benefit of hindsight, of course, the generating unit involved would not have been scheduled in pre-dispatch and more imports (fewer exports) would have been selected in pre-dispatch. This would have reduced reliance on higher cost domestic generation in real-time.

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 - 10 indicates, there were four hours during the period November 2004 to April 2005 for which the HOEP was less than $20. During the same months in 2003 - 2004, there were 17 low priced hours

Table 2 - 10: Hours with HOEP <$20, November - April, 2003 – 2005

	Hours with HOEP less than $20 MWh	
	2003/2004	**2004/2005**
Nov	0	0
Dec	13	0
Jan	1	4
Feb	0	0
Mar	1	0
Apr	2	0

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 season.

- 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 place additional downward pressure on the HOEP. This can occur as follows:

- An over-forecast of demand can result in higher imports into Ontario and lower exports out of Ontario than are warranted by the true (real-time) Ontario supply and demand situation. Once scheduled, these imports and exports cannot be dispatched off in real-time even though they may be more expensive than some Ontario generators. As a consequence, if real-time demand is less than forecast, the market clearing price falls as the most expensive Ontario generators are dispatched off to re-establish supply-demand balance. This causes the real-time HOEP to be lower than it would have been had the load forecast been correct. When real-time demand is low enough that imports and base-load generation can meet it, the HOEP is set by base-load generators with offer prices below $20.

- An over-forecast of demand and thus of the real-time price for the hour incorrectly induces operators of fossil generating units to commit them by offering their minimum running levels at prices that will ensure that these units stay on-line. When the actual demand is lighter than forecast, these units stay on-line and base-load hydroelectric units are dispatched down to meet the lower than expected demand. These units set the price with an offer price below $20.

- When exports are scheduled in pre-dispatch, additional fossil generation facilities may be committed to remain on-line (through low offer prices at their minimum loading points) or additional imports may be scheduled in pre-dispatch to meet the export commitment. If large export transactions fail, there is suddenly an excess supply in the Ontario market. Imports scheduled in pre-dispatch cannot be dispatched off. Again, the market clearing price falls as Ontario generation is backed down to re-establish supply-demand balance. Given the failure of significant export transactions, Ontario base-load generation and pre-scheduled imports may be sufficient to satisfy demand. In this case the HOEP is set by base-load generation which is typically bid into the market at a relatively low price.

Occurrences of Low Priced Hours November 2004 – April 2005

The MAU's review of these low priced hours indicates that they were mainly a result of low Ontario demand. In two cases failed exports also contributed to the low prices (see Table 2 - 11). There was neither an over-forecast of demand nor excessive scheduling of imports in pre-dispatch. When demand is this low, base-load generation may be sufficient to meet it.

Table 2 - 11: Low Priced Hours, November 2004 – April 2005

Low Price Event	Energy Price	Pre-dispatch Ontario Demand (MW)	Real-time Ontario Demand (MW)	Failed Exports (MW)
January 1, 2005, Hour 5	$18.01	13,038	13,110	19
January 1, 2005, Hour 6	$18.83	13,048	13,051	19
January 2, 2005, Hour 2	$15.98	14,350	14,451	150
January 2, 2005, Hour 6	$19.47	13,992	14,221	150

4. *Other Anomalous Events*

Anomalous events need not be associated with unusually high or unusually low prices. Prices can also be anomalous if they are counter-intuitive, that is, if they are not reflective of conditions of abnormally tight supply or of abnormally abundant supply. Similarly, sudden and marked departures from established bidding patterns may be anomalous.

4.1 Apparent Change in Bidding Strategy – December, 2004

The MAU's monthly monitoring report brought to the attention of the Panel an event that appeared to be anomalous. The event was related to the bidding behavior of a market participant that was also on the Spare Generation On-line (SGOL) program. This program guarantees the recovery of start-up and speed no-load costs.[20] On December 14, 2004 the participant in question was offering the generating unit involved at prices that would recover its start-up and speed no-load costs despite the fact that it would be compensated for these costs through the SGOL program. At the Panel's instructions, the MAU discussed the bidding behaviour with the participant and the reasons for the apparently anomalous bid were explained. As a consequence of this discussion, the Panel decided that an analysis of the efficacy of the SGOL program was in order and it asked the MAU to undertake one. This analysis is presented in Chapter 3. The bidding behaviour that was thought to be anomalous has not recurred.

4.2 Failure of the HOEP to Reflect a Supply Emergency – April 7, 2005

The events of April 7, 2005 provide another example of the perverse effects of the use of out-of-market control actions on the operation of the market.[21] In this case, the use of control actions by the IESO drove the HOEP from $133 in hour 10 to $39 in hour 11, notwithstanding the declaration of an Energy Emergency Alert.

April 7, 2005 Delivery Hour 10

Hour 10 was characterized by real-time supply reductions in the form of: (1) failed imports in the amount of 543 MW and, (2) the forced outage of a 250 MW fossil generator after the last pre-dispatch run. These real-time shocks pushed up the MCP which reached a peak of $132 in interval 9. As the simulations in Table 2 - 12 show, the MCP would have risen much higher in some intervals had the IESO not engaged in a series of control actions during hour 10.

Supply conditions were much tighter in the constrained schedule than in the unconstrained schedule.[22] For example, generation at Beck 2 was constrained down 376 MW to respect Queenston Flow West (QFW) limits. The actual and anticipated supply/demand balance in the

[20] Start-up costs are primarily the fuel costs associated with warming up a unit to bring it online. Speed no-load costs are mainly the fuel costs associated with running the unit even when it is not producing any electricity.

[21] These are: a) carrying non-market sources of operating reserve, b) cancelling exports that were initially scheduled in pre-dispatch, c) purchasing additional imports from available offers after final pre-dispatch and d) purchasing emergency energy from a neighbouring market. A general review of the nature and consequences of out-of-market control actions is provided in Chapter 3.

[22] Constrained demand in real-time was higher than in pre-dispatch. Unconstrained demand on the other hand was lower in real-time than in pre-dispatch.

constrained schedule was actually so unfavourable that it led the IESO to initiate a series of control actions beginning in interval 1 of hour 10 and culminating in the declaration of an energy emergency during interval 5 of hour 10.

The actions the IESO took were to reduce the operating reserve requirement from 1,418 MW to 600 MW and to make 325 MW of exports to New York recallable.[23] While these actions 'eliminated' the reserve and energy shortages in intervals 1 and 2, the constrained schedule indicated that there would be an energy shortage during intervals 3 and 4. At 09:17, the IESO requested assistance from external markets to meet its energy demand. It received 440 MW of shared activation reserve,[24] 220 MW each from NYISO and PJM. There remained an energy shortage of roughly 317 MW. The IESO declared an Energy Emergency Alert at 09:21. The IESO cut 97 MW of exports, started the implementation of 5 percent voltage reduction[25] for all areas within Ontario except for the Northwest and Niagara areas and it also purchased emergency energy for intervals 11 (80 MW) and 12 (40 MW). The shared activation reserve was deactivated at 0947. By 0955 these actions had eliminated the shortages in the constrained schedule.

The actions taken to alleviate shortages in the constrained schedule are treated as reductions in demand in the unconstrained schedule and this depresses the HOEP. It is troubling that despite the fact that the Ontario market was in an emergency operating state, the highest MCP in hour 10 was less than $140. This is primarily because of the actions taken in the real-time constrained schedule, i.e. the shared activation reserve, the lowering of the reserve requirement and the 5 percent voltage reduction. These actions served to reduce real-time demand. In addition, the real-time unconstrained schedule also had net imports of 1,717 MW compared to 1,532 MW in the constrained schedule and both peak and average demand were lower than their pre-dispatch forecasts.

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[23] The reserve deficit was identified in the pre-dispatch constrained (PDC) run at 0807AM. The PDC scheduled 325 MW of CAOR. This provided the basis for the control room to identify export transactions as recallable. In real-time the reserve deficit was much higher than in pre-dispatch. As a result, the IESO lowered operating reserve requirements in real-time.

[24] NPCC Document C-19 provides operational guidelines during operating reserve shortages. Essentially there are five areas (New England, New York, Ontario, Quebec and the Maritimes) that have agreed to share resources whenever an area becomes deficient in operating reserve. The reserve is activated and shared with the reserve-deficient area. Shared activation reserve is treated as inadvertent energy and is available only for 30 minutes.

April 7, 2005 Delivery Hour 11

The market continued to operate under an emergency state in hour 11. At the start of the hour the IESO set the reserve requirement back up to 1,418 MW. This resulted in reserve deficits in the upcoming intervals. The IESO had already cut all exports for hour 11 and more imports were scheduled. Nonetheless, a reserve deficit was still indicated for 10:25. The IESO responded by purchasing 200 MW of emergency energy and this temporarily eliminated the reserve deficiency in the constrained schedule. For the rest of the hour, the IESO purchased up to 530 MW of emergency energy to meet operating reserve requirements.[26] The emergency energy purchases eliminated the need for the voltage reduction and it was eliminated beginning at 10:34.

During hour 11, there was voltage reduction; exports were cancelled and emergency energy was imported. As a consequence of these control actions by the IESO, the real-time unconstrained schedule in hour 11 never showed any shortages. The voltage reduction and export cuts lowered demand while emergency imports increased supply. Notwithstanding the state of emergency, the MCP never exceeded $41. The simulation in Table 2 - 12 shows that had it not been for the voltage reduction in the first six intervals of hour 11, the MCP would have been between $45 and $114, depending on the interval. Had it not been for the emergency purchases in the last six intervals, the MCP would have been between $39 and $114.

[25] Activation of voltage reduction is a manual process via phone contact with transmitters and distributors.

[26] Internal Manual 2.4; Procedure 2.4/5 "Adequacy and Operating Reserve" stipulates that if the IESO is deficient in 10-minute reserve and the deficiency was caused by a reportable event, the control room will restore the 10-minute reserve to the required level as soon as possible and within 90 minutes following the end of the allowable Disturbance Recovery Period of 15 minutes.

Table 2 - 12 : Real-time Prices Compared to Simulated Prices, Hours 10 and 11, April 7, 2005

		Simulated MCP ($)	Simulated MCP- with no control actions ($)
Hour	**Interval**	**Energy**	**Energy**
10	1	138.91	160.00
10	2	136.80	155.04
10	3	136.80	155.04
10	4	130.22	155.42
10	5	130.22	155.42
10	6	131.83	157.53
10	7	133.30	160.02
10	8	133.30	162.17
10	9	133.30	190.77
10	10	130.59	1999.00
10	11	126.87	161.80
10	12	131.46	1950
Average		**132.80**	**463.52**
11	1	40.13	110.09
11	2	39.87	95.09
11	3	40.64	113.40
11	4	40.38	111.84
11	5	38.60	45.00
11	6	39.36	114.20
11	7	36.51	39.62
11	8	38.53	60.30
11	9	40.24	114.20
11	10	40.88	114.88
11	11	39.60	111.84
11	12	40.88	95.09
Average		**39.64**	**93.80**

Impact of Control Actions on Real-time Prices

The simulation for hour 10 in Table 2 - 12 shows the combined effects on the MCP in hour 10 of reducing the reserve requirement from 1,418 MW to 600 MW, of using shared activation reserve, of purchasing emergency energy and of reducing voltage by 5 percent. The simulation shows that the MCP in hour 10 would have been between $18 and $1,870 higher if the reserve requirement had not been reduced and the control actions were not taken. For hour 10 as a whole, the HOEP came in at $133. Without these control actions, the HOEP would have been $464.

The simulation for hour 11 in Table 2 - 12 shows the effect on the MCP in hour 11 of the 5 percent voltage reduction during the first six intervals of the hour and the effect of the emergency imports during the last six intervals. The simulation shows that, had demand been higher by the amount of the voltage reduction during the first six intervals, the MCP would have been between $6 and $75 higher, depending on the interval. The simulation also shows that if emergency imports had not been added to supply at a zero price, the MCP would have been between $3 and $74 higher, depending on the interval. For Hour 11 as a whole, the HOEP came in at $39. Without the control actions, the HOEP would have been $94.

Implications for Market Design

The events of April 7th highlight several concerns regarding the impact that control actions can have on market outcomes, market signals and market efficiency.

The Panel has argued consistently that out-of-market actions blunt the price signals that are necessary to provide consumers and potential suppliers with valuable information about the scarcity value of the resource. The IESO practice of pricing some of the out-of-market actions is a welcome response but the events of April 7 clearly show that energy prices on that day failed to reflect the very serious supply/demand pressure that the energy market was facing. It is encouraging that the IESO immediately acted to begin a review of the events that led to the uninformative real-time prices of April 7, 2005.

Manual reductions in required operating reserves are not necessary for system reliability and, because they assume that reserves have no value in the marketplace, they have several perverse effects. They are typically implemented when demand conditions are tight, and thus reduce the actual reserves that can be called upon should a contingency arise at the very time that these reserves should be valued most highly because not having them would have more severe consequences. As well, they reduce both energy and reserve prices so that they do not reflect the actual scarcity position. This results in the absence of appropriate signals to load and generation that more operating reserve is required. Market signals are distorted and market efficiency is reduced.

The Panel is concerned that continued use of manual reductions in reserve requirements leads to price outcomes that can have adverse consequences for market efficiency. For example, if prices are continually reduced relative to what one would expect when demand gets tight, then:

- fossil generators may not come to market in a way that can provide timely operating reserve because they may anticipate that they will not cover their costs;

- loads may not make appropriate investments in control systems necessary to enable them to provide operating reserve if they expect that prices will not rise to allow them to recover the costs in a timely way;

- although imports are selected in pre-dispatch, the import gets the higher of the pre-dispatch or real-time price. If real-time prices are kept below values one would expect to see in times of scarcity, importers may be less willing to supply to the Ontario market – particularly if the demand tightness is general across neighbouring markets;

- as well, if demand tightness is general across neighbouring markets, exporters may feel they have a ‘one-way bet’ if experience suggests that manual interventions will prevent the Ontario price from rising. If this materializes then additional export demand can exacerbate the demand tightness in the Ontario market.

As we have recommended on previous occasions, and continue to recommend, market efficiency will be enhanced if out-of-market reserve actions are priced and brought within a market framework. While there is some debate as to what the ‘true’ scarcity price of operating reserve might be during episodes of supply shortage, it is clearly not zero

An additional source of concern to the Panel is the way in which voltage reductions and emergency imports are introduced into the DSO. Instead of being inserted into the real-time offer stack at a price that reflects their opportunity cost, these emergency sources of supply are treated by the DSO as a reduction in demand. As a consequence, these 'last resort' and presumably very costly sources of supply can never set the real-time price.

It seems logical to us that if the supply/demand balance is sufficiently tight to require voltage reductions and/or emergency imports the energy price ought to reflect this. One would think that an appropriate outcome would be for the prices of the emergency sources of supply to reflect their opportunity costs and for these prices to set the MCP in the interval, so that consumers and potential providers of peaking energy understand what the true scarcity cost of these resources is. This is not the case at present. Indeed, the way in which voltage reductions and emergency imports are introduced into the DSO actually results in a lower price than would obtain had there been no emergency. This seems to us to be counterintuitive and counterproductive and we have previously recommended that the IESO should take action to incorporate emergency imports into the pricing algorithm in a more appropriate manner.[27]

5. *Other Issues Arising from Monthly Monitoring Reports*

November 2004

On November 16, 2004 a planned outage to the B560V circuit that carries power from the Bruce nuclear complex led the IESO to implement a generation rejection procedure on two Bruce units. This procedure resulted in an elevated total operating reserve requirement from 1,418 MW to 2,150 MW from hour 11 to hour 24. This high reserve requirement was maintained until hour 10 of November 19, 2004 when the circuit returned to service.

An alternative course of action would have been for the IESO to reduce the output of one of the Bruce units by 100 MW while maintaining operating reserve at 1,418 MW. Reducing output by 100 MW brings the flow out of the Bruce unit down to its limits. In this case, the low-cost generator is constrained down and has to be replaced by a higher cost generator but additional

[27] See our June 2004 report p.63

reserve is not required. The MAU investigated whether this alternative procedure would have a smaller impact on market efficiency while still meeting reliability requirements.
The cost of the action taken by the IESO is the cost of an additional 732 MW of operating reserve. The cost of the alternative procedure is the cost of replacing 100 MW of Bruce output with a higher cost source. The MAU found that, for hour 18 on November 16-18, this alternative would have been $211,440 less costly than the procedure actually followed by the IESO.

Conclusion

The IESO indicated that, when confronted with similar situations in the future, it would always ensure the protection of system reliability while selecting the option with the most efficient outcome. We have encouraged the MAU to develop decision rules to assist the IESO.

APPENDIX TO CHAPTER 2

Table 2 - 13: Market Conditions December 5, 2004, Hour 19

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	19,746	20,428
Average (MW)	n/a	20,235
Energy Price ($)	56	255
Imports (MW)	1,567	1,467
Exports (MW)	1,289	1,189
Self-Scheduler (MW)	891	905
Supply Cushion	18.30%	3.30%

Table 2 - 14: Market Conditions February 17, 2005, Hour 19

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	21,500	21,658
Average (MW)	n/a	21,529
Energy Price ($)	80	340
Imports (MW)	1,451	1,300
Exports (MW)	1,367	1,367
Self-Scheduler (MW)	1,323	1,333
Supply Cushion	11.50%	1.10%

Table 2 - 15: Market Conditions March 5, 2005, Hour 19

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	18,335	18,657
Average (MW)	n/a	18,383
Energy Price ($)	69	394
Imports (MW)	1,189	1,189
Exports (MW)	1,763	1,763
Self-Scheduler (MW)	1,323	1,333
Supply Cushion	15.2%	1.60%

Table 2 - 16: Market Conditions January 1, 2005, Hour 6

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	13,048	13,051
Average (MW)	n/a	13,175
Energy Price ($)	19.38	18.00
Imports (MW)	1,138	1,138
Exports (MW)	1,589	1,570
Hydro (MW)	2,413	2,413
Nuclear (MW)	10,250	10,250

Table 2 - 17: Market Conditions January 1, 2005, Hour 5

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	13,038	13,110
Average (MW)	n/a	12,998
Energy Price ($)	19.00	18.01
Imports (MW)	1,110	1,110
Exports (MW)	1,589	1,570
Hydro (MW)	2,429	2,399
Nuclear (MW)	10,250	10,250

Table 2 - 18: Market Conditions January 2, 2005, Hour 2

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	14,350	14,451
Average (MW)	n/a	14,238
Energy Price ($)	24.07	15.98
Imports (MW)	1,471	1,463
Exports (MW)	1,570	1,420
Hydro (MW)	3,040	2,818
Nuclear (MW)	10,280	10,258

Table 2 - 19: Market Conditions January 2, 2005, Hour 6

	Pre-dispatch	Real-time
Ontario Non-Dispatchable Load		
Peak (MW)	13,992	14,221
Average (MW)	n/a	14,069
Energy Price ($)	24.00	19.50
Imports (MW)	1,443	1,443
Exports (MW)	1,531	1,381
Hydro (MW)	2,834	2,760
Nuclear (MW)	10,280	10,280

Table 2 - 20: Summary of Market Conditions April 7, 2005

	Pre-dispatch	Real-time	Pre-dispatch	Real-time	Pre-dispatch	Real-time
	Hour 9		Hour 10		Hour 11	
Ontario Non-Dispatchable Load						
Peak (MW)	18,021	18,170	18,250	18,110	18,360	18,073
Average (MW)	n/a	17,987	n/a	17,906	n/a	17,889
Energy price ($)	90.00	125.00	132.00	133.00	122.00	39.00
Imports (MW)	1,736	1,736	2,461	2,018	2,842	2,802
Exports (MW)	322	322	347	291	472	25

Table 2 - 21: Real-time Non-Dispatchable Demand Compared to Pre-dispatch Non-dispatchable Demand, April 7, 2005

Hour	Interval	Real-time Demand (MW)	Real-time Demand Minus Pre-dispatch (MW)	MCP ($/MWh)
10	1	18,089	(162)	142.63
10	2	18,111	(140)	138.04
10	3	18,102	(149)	136.80
10	4	17,694	(556)	130.22
10	5	17,696	(555)	130.22
10	6	17,782	(469)	131.83
10	7	17,891	(360)	133.30
10	8	17,944	(307)	133.30
10	9	17,899	(352)	133.30
10	10	17,895	(356)	130.59
10	11	17,792	(459)	126.87
10	12	17,976	(275)	131.46
11	1	17,968	(391)	40.13
11	2	17,931	(428)	39.87
11	3	18,045	(314)	40.64
11	4	17,998	(361)	40.38
11	5	17,749	(610)	38.60
11	6	17,859	(500)	39.36
11	7	17,402	(957)	36.51
11	8	17,714	(645)	38.53
11	9	17,982	(377)	40.24
11	10	18,063	(296)	40.88
11	11	17,879	(480)	39.60
11	12	18,073	(286)	40.88

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

1. *Introduction*

This chapter summarizes the status of separate IESO initiatives to improve the operation of the market (unconstrained) schedule on the one hand, and the constrained schedule on the other. The next section addresses issues that we have recommended in previous reports where action has not yet been taken, or has not yet resulted in changes to the system. We believe that this follow-up function in reporting on previous recommendations and the extent to which they have been addressed is an important issue in accountability for the Panel, and for the market participants to whom those recommendations are addressed. Section 3 provides a preliminary assessment of the success of changes to the operation of the market introduced by the IESO to limit unnecessary volatility in dispatch instructions to Ontario generators. Both matters contribute to improving the dispatch efficiency of the IESO-administered markets, a key focus of our assessment of market performance over the past three years.

This chapter also presents the conclusions of our assessment of the Spare Generation On-Line Program.

2. *Status of Matters Identified in Previous Reports*

2.1 Out-of-Market Control Actions Employed

A recurrent theme of each of our past five reports is that the IESO needs to reform the manner in which it uses out-of-market control actions. These actions include carrying non-market sources of operating reserve and purchasing emergency energy from a neighbouring utility.[28]

[28] See pages 47-51 of our June 2004 report for a full description of the use and impact of these out-of-market control actions.

The issue is that the manual implementation of out-of-market control actions distort market price signals by reducing real-time prices relative to the pre-dispatch levels. In particular, the lower real-time prices do not reflect the tight supply conditions that caused the manual intervention in the first place. The events of April 7, 2005 described in Chapter 2 are another example of this, what has come to be known as 'counter-intuitive' pricing.

We believe it is useful to reiterate the observations we made in our report a year ago:

> "… It is unclear to us why the IMO needs to reduce the reserve requirement in the DSO when a shortage of reserve occurs in the constrained sequence in real-time. As far as we can tell, reducing the requirement in the DSO does not improve system adequacy since it does not increase the resources available to the system. We have argued consistently that out-of-market actions blunt the price signals that are necessary to provide consumers and potential suppliers with valuable information about the scarcity value of the resource. The IMO practice of pricing some of the out-of-market actions is a welcome response but the events of January 15 [2004] quite clearly show that energy prices on that day failed to reflect the very serious supply/demand pressure that the energy market was facing.
>
> ….It seems to us that a good part of the difficulty arises because of the joint optimization of the operating reserve and energy markets and the constraints in the DSO that require any manual reduction in operating reserve requirements in the constrained schedule to also be made to the unconstrained schedule. The essence of the difficulty is that out-of-market sources of reserves are acceptable ways of meeting industry-mandated reserve requirements, but when they are implemented manually they have a zero-cost and affect both the constrained schedule (where there is a shortage) and the unconstrained schedule (where there may not be a shortage and they have perverse price effects). Imputing a price to out-of-market control actions appears to us to offer a way to resolve this dilemma because it will allow the DSO to automatically select 'least costly' sources of operating reserve (including appropriately priced out-of-market actions) as required in the constrained schedule without necessarily making the same selection in the unconstrained schedule. The IMO has made significant progress in implementing a pricing regime for out-of-market reserves over the past year and we report on this in Chapter 3. We believe that more can and should be done."[29]

[29] Pages 62-63 of our June 2004 report.

Over a year ago the IESO successfully implemented 400 MW of out-of-market operating reserve into the constrained and unconstrained schedules but it has not completed the planned integration of the remaining out-of-market reserve. [30] The implementation of CAOR, control action sources of operating reserve in the market is discussed pp. 93 – 95 of our June 2004 report. We believe this is an important additional step in improving the operation of the market and we encourage the IESO to take action without delay. In this report, for the first time, we have presented simulation results in Chapter 2, related to two high-priced-hour events, that show clearly what the prices would have been had an additional 400 MW tranche of out-of market operating reserve been priced into the market at levels that are now being discussed by the IESO's Market Pricing Working Group. It is clear from the simulations that the pricing algorithm would have resulted in MCP's and HOEP's that were intuitively more representative of supply and demand conditions in the market at the time, and yet far below the levels that would have arisen had the market been forced to clear with no manual intervention and no price ascribed to out-of-market actions. We strongly believe that pricing the remainder of out-of-market reserve actions will assist not only market efficiency, but the credibility of the auction process and the price signals that result from it. This will contribute to the healthy development of supply and efficient resource use over the longer term.

One observation regarding the use of CAOR is the increased tendency to use voltage reductions as an operating reserve measure, since the introduction of CAOR. This is something that is observed more in the constrained schedule than in the market schedule, and has some potential implications for the quality of supply and reliability. This is an issue for the pricing group to consider, with the possibility of reviewing the prices applied for the existing and any future CAOR tranches.

In addition to pricing these reserves, we also reiterate and encourage the IESO to take action to address the similar distortion when emergency imports are introduced, as they

[30] The implementation of CAOR, control action sources of operating reserve in the market, is discussed at pp. 93-95 of our June 2004 report.

were April 7, 2005, with the effect of deflating the MCP rather than signalling serious supply conditions through higher prices.[31]

2.2 Niagara 25 Hz Sub-system

In earlier monitoring reports and in a report to the IESO Board following our consultation on CMSC,[32] the MSP identified inefficiencies associated with bottling of generation in the 25 Hz sub-system in the Niagara area. The sub-system is comprised of less than 50 MW of load, with substantially more generation and 25 Hz transmission in the area dedicated to serving this load. The sub-system is connected to the rest of Ontario through a frequency changer, which when active, allows some energy to flow into or out of the sub-system. The limited connection between the two has efficiency and reliability implications for the IESO market, requiring at times higher cost generation to be run or lower-cost generation to remain unusable.

In our consultation report we recommended the IESO lead a working group to explore options for resolving this, identifying among other solutions the possible elimination of the 25 Hz requirements. A team was struck to study the issue in the fall of 2003, but no action followed from this. In early 2005 OPG decided to retire one of its Beck 25 Hz units, although problems with the frequency changer have required it to keep operating temporarily. For its part, the IESO is now developing a plan, based on a balance of stakeholder interests, to retire the entire sub-system, with the possibility of converting some of the facilities to 60 Hz.

We are pleased that the IESO is taking the lead on this issue. We continue to believe it is important and will benefit the market in the long term. We look forward to monitoring progress on this issue and hope the 25 Hz sub-system can be retired as soon as is practicable.

[31] The issue of emergency imports was originally raised in our June 2004 at p. 63.
[32] Market Surveillance Panel Report: Constrained Off Payments and Other Issues in the Management of Congestion; July 3, 2003

3. *Impact of Changes in the Constrained Schedule*

In a previous report we concluded that the dispatch of Ontario generation has been efficient in the IESO-administered markets.[33] The efficiency standard we applied was that the market price equalled the incremental cost of the marginal supplier and that all suppliers with an incremental cost less than this were selected for dispatch.

Since then some market participants have expressed concern about the volatility of the five-minute dispatch, the consequent wear-and-tear on generating units and ultimately the adverse impact on system reliability. This arises from the operation of the IESO's dispatch software, the Dispatch Scheduling Optimizer (DSO), which is precise in dispatching generators to minimize overall resource cost and will dispatch generators for small amounts as low as 1 MW. This can result in a number of start/stop sequences and reversals of dispatch messages in a relatively short time frame.

To address this issue the IESO has undertaken a number of measures including the introduction of a multi-interval optimization program to smooth dispatch over several intervals. The following sub-section summarizes efforts by the MAU to assess the success of these measures.

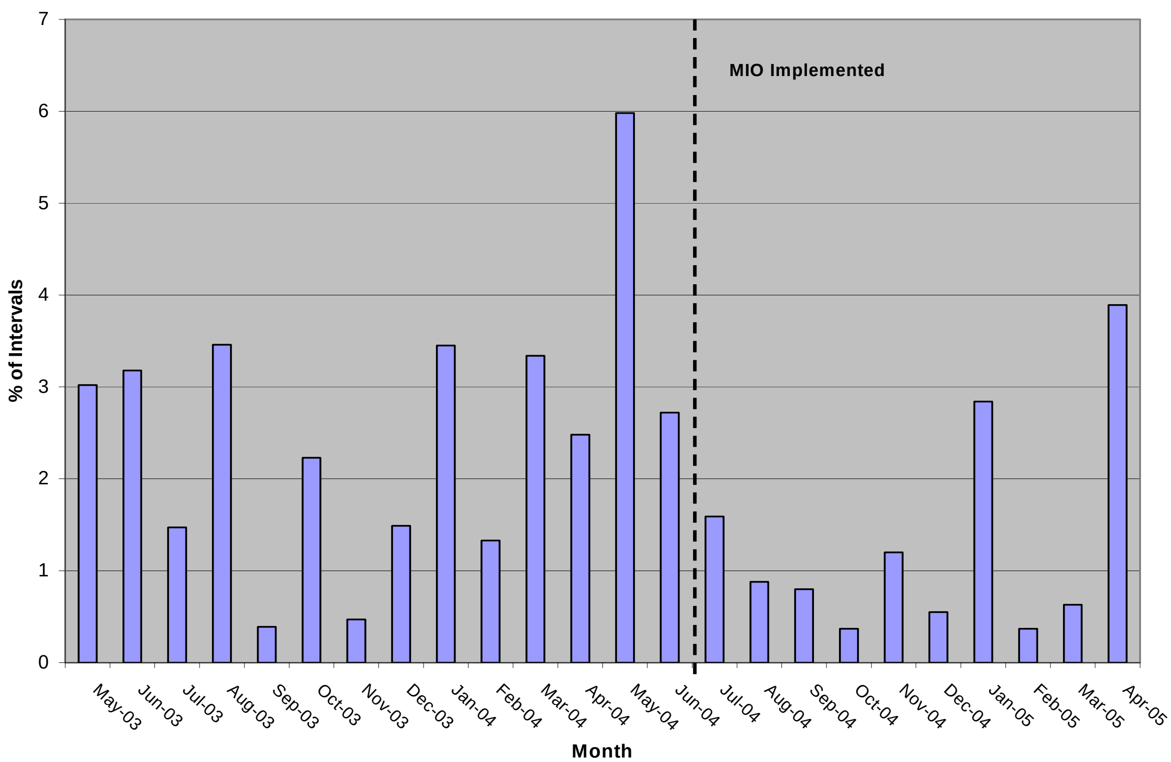
3.1 Assessment of Multi-Interval Optimization

As described in our December 2004 report the IESO implemented a multi-interval optimization (MIO) algorithm in the real-time constrained sequence in June 2004. MIO now minimizes the cost of supplying load over a rolling eleven intervals, instead of the single upcoming five-minute dispatch interval. One of the expectations was that it would reduce the need to employ out-of-market control actions. The logic is that with an improved ability to anticipate supply shortfalls the DSO would be able to dispatch the low ramp rate fossil-fired generators sooner. This would reduce the incidence of insufficient generation in real-time that the IESO often addresses through out-of-market control actions.

[33] See page 110 of our December 2003 report.

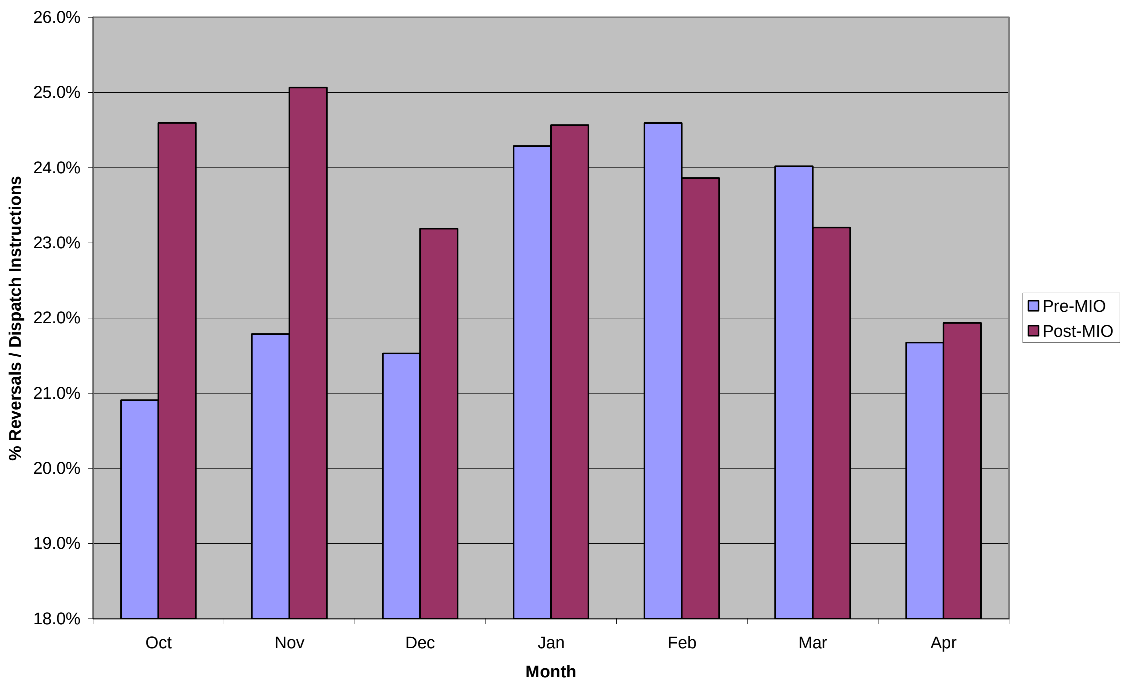
Figure 3 - 1 below plots the monthly percentage of intervals with operating reserve reductions before and after the introduction of MIO.[34] There appears to be a general decline in reductions after the introduction of MIO. For example, the average percentage of intervals with OR reductions during a ten month period (July 2003 – April 2004) before MIO was 2.4 percent compared to 1.3 percent for the same ten months after MIO (July 2004 - April 2005). However, because of the many factors at play it is not possible to conclude that the observed decline in out-of-market control actions is solely attributable to the MIO algorithm.

Figure 3 - 1: Percentage of Intervals with Operating Reserve Reductions, May 2003 – April 2005



Another of the expected results of MIO was a reduction in the number of reversed dispatch instructions for fossil-fired generators. A reversal is defined as a change in the direction of a dispatch message from one interval to the next interval, e.g. an instruction to increase 50 MW in one interval is followed by an instruction to decrease output in the next interval by 20 MW. Figure 3 - 2 compares the percentage of total monthly dispatch instructions to fossil-fired generators that were reversed before and after the introduction of MIO. For example less than 21 percent of dispatch instructions in October 2003 before the introduction of MIO were reversals compared to more than 24 percent in October 2004, after MIO was in play. It is difficult to draw a conclusion from this data because of changing system conditions year-over-year but there appears to be no clear pattern of improvement attributable to the implementation of MIO.

Figure 3 - 2: Reversals as a Percentage of Total Dispatch Instructions to Fossil-Fired Generators
Monthly Comparisons Before and After MIO, October 2003 - April 2005



3.2 Smoothing of the State Estimator

In our last report we noted that the IESO was investigating why there has not been a significant reduction of the numbers of dispatch reversals as a result of MIO implementation. The analysis seemed to indicate that 20 percent of the dispatch reversals could still be attributed to load predictor changes.

[34] The data is derived from Table A - 32 in the Statistical Appendix.

Upon review, load predictor changes in turn could be traced back to fluctuations in the measurement of actual demand between intervals. This actual demand value, known as the ‘initial state’, is used to extrapolate the demand for the succeeding intervals. As demand fluctuates from interval-to-interval the change in magnitude is reflected in full in all future load forecasts. Thus a change in initial state, say 100 MW higher demand, is reflected in the next eleven intervals, as 100 MW higher demand forecast in each interval. MIO in turn uses these next eleven load forecasts in order to determine the correct dispatch of generators. If in the next interval actual demand fluctuates in the opposite direction, for example drops 100 MW, the MIO would begin to reverse the dispatches it had previously sent. These interval-to-interval variations in demand were feeding into the MIO solution and appeared to contribute to excessive cycling of generators.

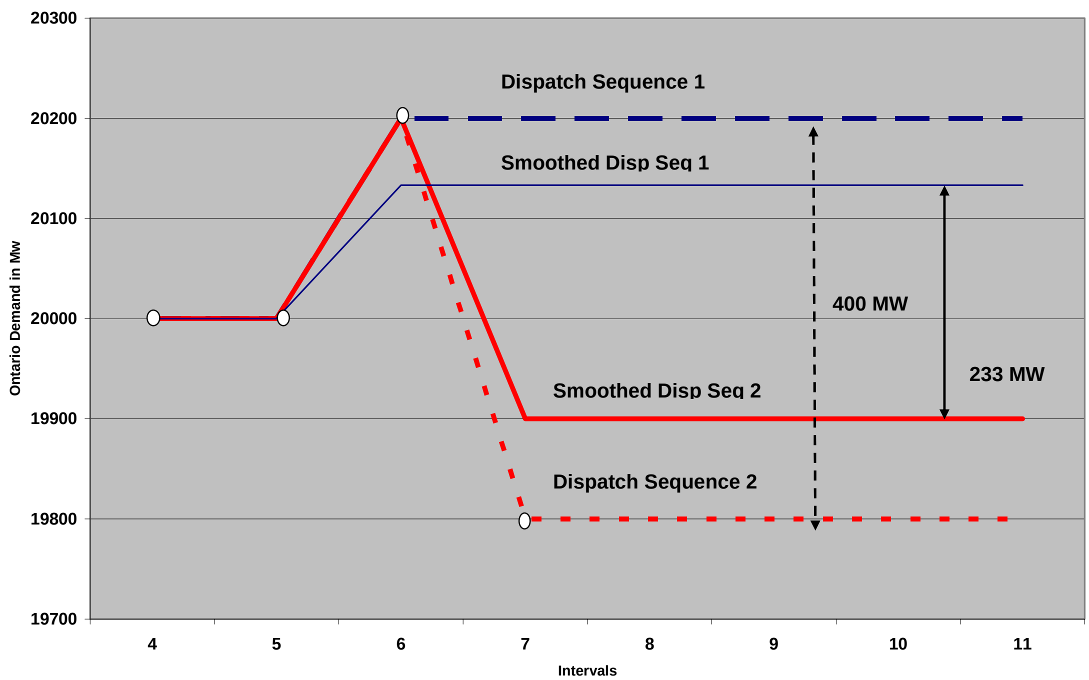
A review of the existing load predictor implementation by the IESO determined that the current algorithm was essentially sound, but that improvements were required in order to smooth the ‘initial state’ used for the projections. Specifically, the improvement was to replace the actual power system demand for the current interval with a state estimator that adjusted for some of the random fluctuations in load. For example, if load were simply bouncing up and down 50 MW each interval, with no real upward or downward trend, the state estimator would remove the random component and reflect the constant load. Where there is a trend the state estimator reflects the actual level of the smoothed trend only, not the additional random component.

With the state estimator now providing the new “initial state”, the load predictor then applies the historical pattern of load changes for the predicted values in subsequent intervals.

Figure 3 - 3 is a representation of how dispatch sequence fluctuations would be dampened using a smoothed set of predicted loads. It shows an original dispatch sequence 1 and a smoothed sequence 1, which differ starting in interval 6. In each sequence, the predicted values in subsequent intervals equal the initial state value, which

is indicative of the historical demand pattern being constant for several intervals. The original sequence uses the actual interval 6 demand (20,200 MW) as the starting point, while the smoothed sequence begins with the smoothed state estimator demand (20,133 MW). Similarly, sequence 2 original and smoothed dispatches are generated from the interval 7 value of actual demand (19,800 MW) and smoothed state estimator demand (19,900 MW).

Figure 3 - 3: Representation of Smoothed Dispatch Instructions



Using the original load predictor values there is a drop of 400 MW based on demand changes from interval 6 to 7. Using the smoothed state values, demand changes by 233 MW based on the demand change between intervals 6 and 7. In the first case there would be a dispatch change for some 400 MW of generation; in the smoothed case only 233 MW would see dispatch reductions.[35]

[35] Note: this example is hypothetical and smoothed to make the essential point. The actual changes can be more complicated because of joint optimization and other factors. The numbers cited in the example are broadly indicative of the degree of dispatch change required.

The smoothed sequence above is based on a close approximation of the methodology used by the state estimator. The state estimator develops a linear trend line around the current interval, using the past three intervals of actual demand and the next three intervals of predicted demand. The predicted demand values are based on the original approach, and use the actual demand as the 'initial state'.

To illustrate the trending, as applied in the previous figure, Table 3 - 1 gives an example of how the smoothing algorithm works. For the case where load is fairly constant, the trend is approximated using an averaging over the three prior intervals and three forward intervals. The smoothed value for the initial state (in interval 6) is the average of the actual demand in intervals 4-6 and forecast demand in intervals 7-9. In this example the smoothed initial state of 20,133 MW avoids introducing a larger change (20,200 MW) relative to the previous interval, and as shown in Figure 3 - 3, leads to a smaller reversal when interval 7 demand is observed to be 19,800 MW.

Table 3 - 1: Hypothetical Example of 'Smoothing' the State Estimator

	Interval 4 (MW)	**Interval 5 (MW)**	**Interval 6 (MW)**	**Interval 7 (MW)**	**Interval 8 (MW)**	**Interval 9 (MW)**
Actual	20,000	20,000	20,200	19,800		
Original Forecast				20,200	20,200	20,200
Smoothed Initial State & Forecast			20,133	20,133	20,133	20,133

The IESO implemented the smoothing algorithm February 2, 2005. It is too early to say whether this change to the state estimator has had a positive impact on the rate of reversal of dispatch instructions. Figure 3 - 2 showed a small decline in February and March 2005 compared to 2004 but a slight increase in April 2005 versus 2004. We have asked the MAU to continue its review to determine the benefits obtained from this change to the algorithm.

3.3 Increased Use of Compliance Deadband

Figure 3 - 4 below, shows that there has been an increase in the total number of fossil dispatch instructions over time, albeit with a seasonal variation. The increase appears to result from the greater number of fossil-fired generators participating in the market in 2004. There also appears to be a proportional reduction in dispatch instructions greater than 10 MW. In other words, dispatch instructions that are greater than 10 MW account for a smaller share of total dispatch instructions over time.

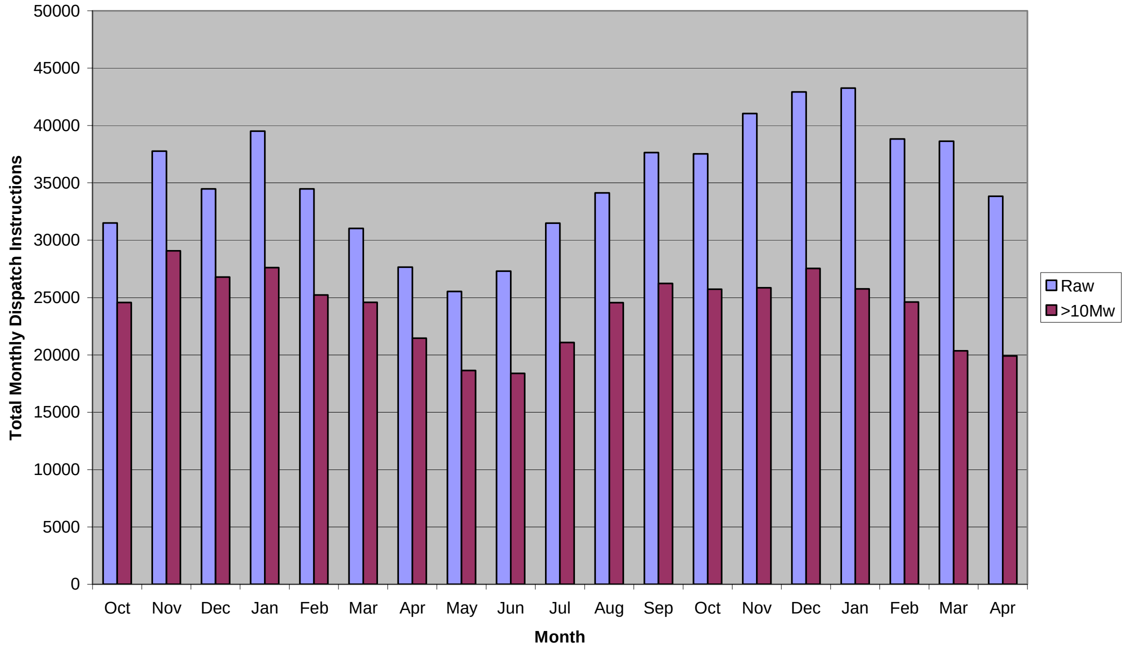
The IESO has recognized there has to be some level at which generators will be non-compliant, since small perturbations in dispatch are difficult for fossil-fired generators to comply with precisely. In July 2003, the IESO issued an Interpretation Bulletin identifying a compliance deadband of 10 MW, within which market participants would not be considered out of compliance with their dispatch instructions.[36]

The IESO has reinforced to the generators the use of this 10 MW compliance deadband, as a way of reducing the impact of dispatch instruction reversals. Thus to the generator the ‘important’ dispatch instructions are those that change its operating state by more than 10 MW. The IESO determined that the level of non-compliance caused by this ‘lagging’ of generators to react to a precise instruction can be handled by Automatic Generation Control at some additional cost but with no significant impact on reliability.[37]

[36] More precisely a departure from a dispatch instruction is ‘material’ if it is the greater of 10 MW or 2 percent of the generator’s dispatch instruction. See http://www.ieso.ca/imoweb/pubs/interpretBulletins/ib_IMO_MKRI_0001.pdf

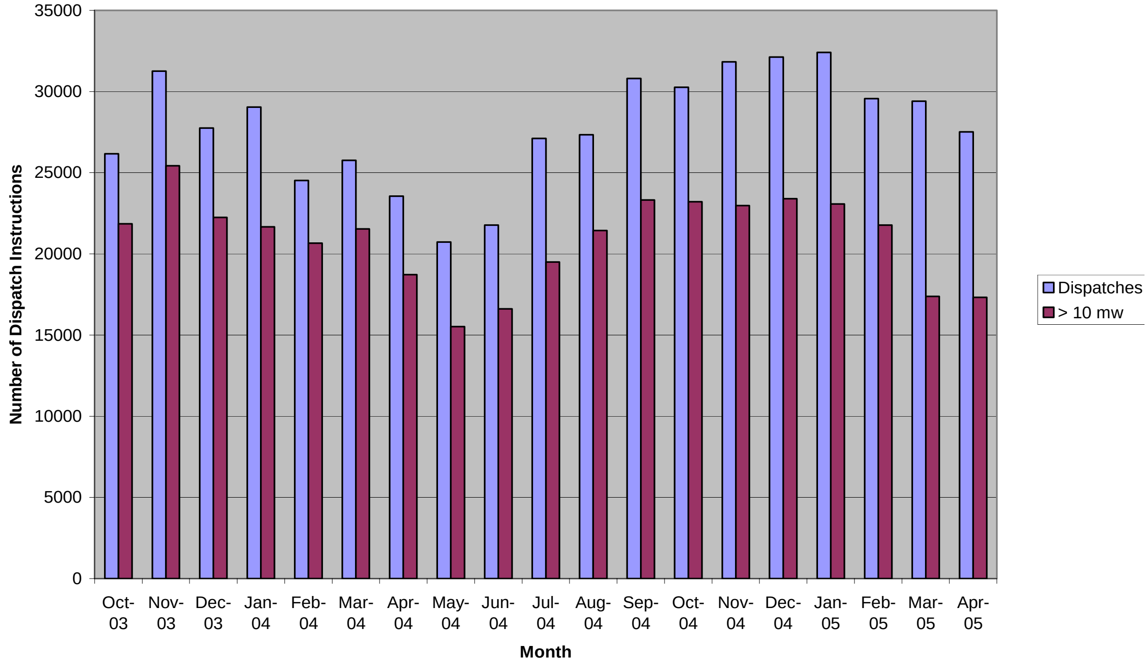
[37] Automatic Generation Control ensures that generation output is automatically adjusted to respond to changes in system frequency and tie-line loading.

Figure 3 - 4: Total Monthly Fossil Dispatch Instructions versus Dispatch Instructions Greater than 10 MW October 2003 - April 2005



During its analysis of dispatch instructions the MAU noted a significant number of the total dispatch instructions related in fact to a small portion of the fossil-fired generation in Ontario. Fossil-fired generating plants in Northwest Ontario account for approximately 6 percent of the total fossil-fired fleet yet make up approximately 25 percent of all dispatch instructions. Figure 3 - 4 has been reproduced as Figure 3 - 5 below to remove the Northwest dispatch instructions. The same basic relationship between total dispatch instructions and the subset of instructions over 10 MW remains, albeit with several thousand fewer dispatch instructions each month. The explanation appears to be that Northwest fossil-fired plants are generally infra-marginal and typically constrained down behind frequently congested East-West transmission lines. Whenever the dispatch algorithm sees an opportunity to increase 'bottled' Northwest fossil output to maximize its transfer to the east, it will re-dispatch the Northwest generators up and at the same time reduce a similar amount of generation in the East (less transmission losses). Thus the large number of constrained dispatches in the West are likely reflected in the East with a similar number.

Figure 3 - 5: Total Monthly Fossil Dispatch Instructions versus Dispatch Instructions Greater than 10 MW Excluding Northwest, October 2003 - April 2005



3.4 Summary

Figures 3-6 and 3-7 show the change in dispatch instructions greater than 10 MW from the period November 2003 to April 2004 versus a similar period in 2004 - 2005. The data are displayed in absolute and relative terms.

Figure 3 - 6: Monthly Total Generator Dispatch Instructions Greater than 10 MW November 2003 - April 2005

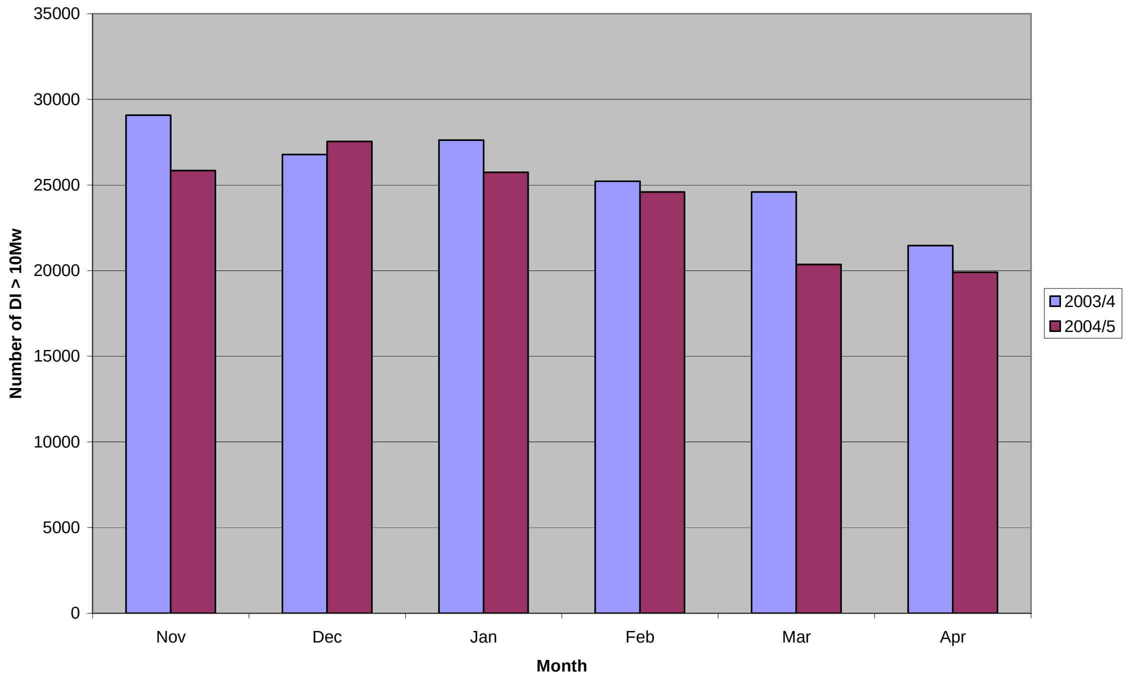
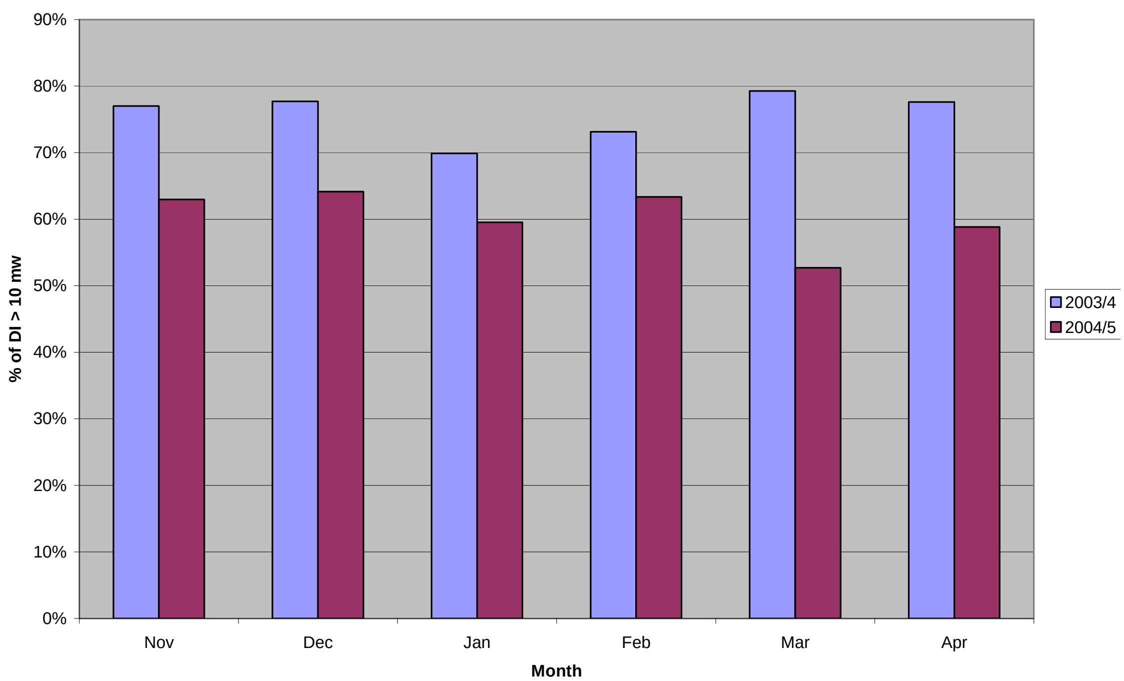


Figure 3 - 7: % of Dispatch Instructions Greater than 10 MW against Total Dispatch Instructions



In both cases we seem to see a downward trend in the dispatch instructions that generators must follow. Generally there appears to be a reduction of roughly 1,800 dispatch instructions over the two corresponding periods. While the IESO has not yet found the 'silver bullet' to solve the dispatch issue it appears that the combination of a compliance deadband and on-going changes in the marketplace have reduced the impact of the issue. While it is not possible to assess the impact on the decline of each of the changes in market operation discussed above, it is likely that in combination they are having a positive impact on dispatch efficiency.

4. *Spare Generation On-Line Program*

As indicated in Chapter 2, the bidding behaviour of one participant led us to request that the MAU examine the Spare Generation On-Line (SGOL) program, to assess whether it was meeting its objectives and its impact on market efficiency.

The IESO instituted the SGOL program in August 2003 to respond to observation that during lower demand periods of the day some Ontario generation capacity was available but not on-line and able to provide electricity should demand increase or other sources of supply fail. These units, typically fossil-fired, require long and costly start-up processes and need to run for a minimum period of time, once started. Based on market participants' assessment of expected market prices during the day, they frequently decided not to offer these units into the market because the market revenue was not expected to cover their costs. In response the IESO introduced the SGOL program that allowed eligible generators to register and receive compensation for their start-up and minimum run-time costs where these costs were not covered by market revenue.[38] In other markets, such as the New York ISO, generators are compensated under a Bid Production Cost Guarantee program if they lose money by generating in the market.

[38] A simple explanation of SGOL program is provided in the IESO's Quick Take at http://www.ieso.ca/imoweb/pubs/training/QT9_SGOL.pdf

Fundamentally the SGOL program was introduced to increase the reliability of the IESO-controlled grid by increasing the amount of spare generation on-line, particularly in shoulder periods. The IESO also stated that the program would reduce price volatility and lead to fewer instances of counter-intuitive pricing. The logic was that – without SGOL - if demand surged or less supply than anticipated was available, the gap would have to be satisfied by more expensive Ontario-based generation or imports. These alternative sources of supply were likely to be more expensive than the high fixed cost (start-up and speed no-load costs), high incremental cost fossil-fired units that had chosen not to be on-line. The counter-intuitive pricing would be avoided if the availability of 'spare generation' meant that the IESO did not feel compelled to take out-of-market control actions to maintain reliability, with the inevitable impact of depressing real-time prices.

The Panel asked the MAU to review the SGOL program to determine its impact on market participant behaviour, market efficiency and whether there was a rationale, apart from system reliability, to modify or extend the program. The MAU reported that total payments under the program from inception in August 2003 until the end of April 2005 were approximately $33.3 million. It reviewed the distribution of payments for three months (February – April 2005) to give an indication of the operation of the program. Over that period there were 506 generator starts eligible for SGOL payments. Of those there were 454 applications for payment and 347 recovered some form of payment. In terms of the actual payment over this three-month period, total payments amounted to $8.4 million to twenty-nine generating units with over 80 percent received by six generating units.

As expected, a sample of hours when the SGOL program was initiated showed the HOEP was lower than it would have been in the absence of the program.

The Panel's conclusion on the basis of the MAU's review is that the program is meeting the objectives set for it by the IESO. It does, however, detract from overall market efficiency. It represents a subsidy from base-load generators to load and high start-up cost generators. And, it can result in higher-cost generation being dispatched in preference to lower-cost generation. In our view, the market would operate more efficiently if spot market price signals were not constrained by operational decisions such as the use of out-of-market control actions and the twelve times ramp rate, and if the spot market were supplemented by an effective day-ahead market. The SGOL program seems to us to be a response to a second-best market environment. In this context, however, it is well designed since it only pays out when market returns are not adequate and will therefore phase itself out should price signals become more credible and markets continue to evolve.

Chapter 4: State of Competition within and the Efficiency of the IESO-Administered Markets

1. *Introduction*

We are satisfied that the IESO-administered markets continued to function well over the six-month period spanning the winter and early spring 2005. While prices were on average more than 11 percent higher than the comparable period in 2003-2004 we attribute this largely to higher fuel costs and a significant level of generator outages, particularly in April 2005. We found no evidence of inappropriate behaviour by market participants. Under our direction the Market Assessment Unit maintains close contact with market participants and from time-to-time requested additional information so that we could be satisfied that observed anomalous behaviour did not constitute gaming or an abuse of market power. No formal investigations were launched during the period under review. Once again an important focus of our work, as set out in the earlier chapters of this report, has been to highlight activities of the IESO as market operator that, in our view, impact market efficiency.

The period November 2004 to April 2005 coincided with a series of announcements by the Government of Ontario specifying some of the key details of its broad policy initiatives in the sector. Some market commentators have questioned the role and robustness of the spot market in light of these changes. No doubt the new environment has eclipsed some aspects originally encompassed in the market's role, for example as a driver of investment. However, as described in the next section, we believe the market continues to play a valuable role by ensuring the lowest cost resources satisfy load at any given moment. And the spot market price continues to be a key benchmark for the electricity sector. We also discuss in the next section our role in monitoring the market going forward.

2. *The Changing Nature of the IESO-Administered Markets*

The Government of Ontario has announced an array of initiatives that will shape the electricity sector in Ontario for some time into the future. These include three Requests for Proposal (RFPs) for new clean generation, demand-side projects and new renewable energy supply. Together with the expansion of the Beck Tunnel project, the refurbishment of Ontario Power Generation's Pickering A Unit 1 and the potential restart of Bruce Power's A Units 1 and 2, the government estimates that 5,000 MW of capacity will be brought on line. In February 2005 the government established prices effective April 1, 2005 capping allowable revenue for OPG's generation assets. Also effective April 1st, the Ontario Energy Board released its Regulated Price Plan that sets the user price for a large segment of the province's consumers. Finally, at the end of April, OPG's coal-fired Lakeview Generating Station on the outskirts of Toronto was closed according to schedule. At the time of drafting this report the government had not released details on its plan to replace OPG's four remaining coal-fired stations.

These are sweeping changes for Ontario's electricity sector and we offer our thoughts on the impact they are likely to have on competition and efficiency in the IESO-administered markets.

2.1 New Supply

The new generation facilities that result from the government's Requests for Proposal are expected to make hourly offers into wholesale market as do existing dispatchable generators.[39] The owners of these facilities will receive revenues based on their actual production in the market and the prices computed in the market – just as would any other dispatchable generator. However, under the RFP contracts the generators are provided with a guaranteed price to ensure that they can recoup their costs. If the net revenue deemed to have been received by the generators from the market is less than or exceeds the agreed-upon price, generators will either receive whatever support payments are needed to achieve the guaranteed price, or will be required to pay back 95 percent of excess revenue. In this regard, the contract represents a form of risk sharing agreement where the two parties share the risk of uncertain future wholesale spot electricity prices. The contracts protect the supplier from future prices that would be too low to cover expected entry costs (capital and financing costs for the development and construction facility) and future fixed operating cost (including fixed avoidable costs such generation start-up costs and speed no-load costs). The contract provides the buyer with some protection against the potential that it over-compensates the supplier for its initial investment in the event that the wholesale prices are sufficiently high to cover the cost of this investment.

In our view the RFP contracts for new generation should not distort the suppliers' day-to-day production decisions. These decisions should be consistent with what the facility owners would have done absent the contracts and therefore do not have an adverse impact on the efficiency of the market. The contract details for the demand side projects differ but our conclusion is the same. Overall, we believe that short-term dispatch efficiency should not be affected by the RFP contracts and the market price should continue to reflect the lowest cost of production associated with the mix of assets available to the market at the time.

2.2 Ontario Power Generation and the Competitive Fringe

As is well known OPG is the dominant generator in the province with a market share of about 70 percent. The decontrol plan at the opening of the market is no longer in effect but the government's plans to remove OPG's coal operations are estimated to reduce its market share by 20 percent. The regulations promulgated in February 2005 have the effect of replacing the rebate mechanism and revenue cap on most of OPG's generation that evolved from the initial Market Power Mitigation Rebate at the start of the market.[40]

[39] More details on the Requests for Proposals are found at http://www.ontarioelectricityrfp.ca/

[40] See the description of the MPMA rebate in our first report at pp. 30-32 and the IESO's 'Quick Take' on Market Rebates (http://www.ieso.ca/imoweb/pubs/training/QT8_MPMR.pdf) for a concise description of its evolution into the Business Protection Plan Rebate.

The first regulation fixes the price of OPG's base-load generation facilities at $33/MWh for hydro and $49.50/MWh for nuclear from April 1, 2005 until March 31, 2008, or until the OEB issues its first order. The government estimates the weighted average price paid to these generators to be about $45/MWh. For hydroelectric output greater than 1,900 MWh in any hour, OPG is paid the market price. The market share of these base-load facilities, referred to as the 'prescribed assets' is approximately 38 percent.

The second regulation introduces a new pricing plan for 85 percent of the rest of OPG's generation, known as 'non-prescribed assets', over the period April 1, 2005 to April 30, 2006. A revenue cap of $47/MWh is imposed on the output from these non-prescribed assets (but not including the Lennox Generating Station) over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts[41] and forward contracts in effect as of January 1, 2005. At the end of the 13-month period OPG's adjusted revenues from 85 percent of these assets above this set price will be rebated. The market share of the non-prescribed assets is roughly 27 percent.

The regulation provides a direction to OPG on its participation in the market and highlights a role for the Market Surveillance Panel. Paragraph 27 reads:

> "With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board."

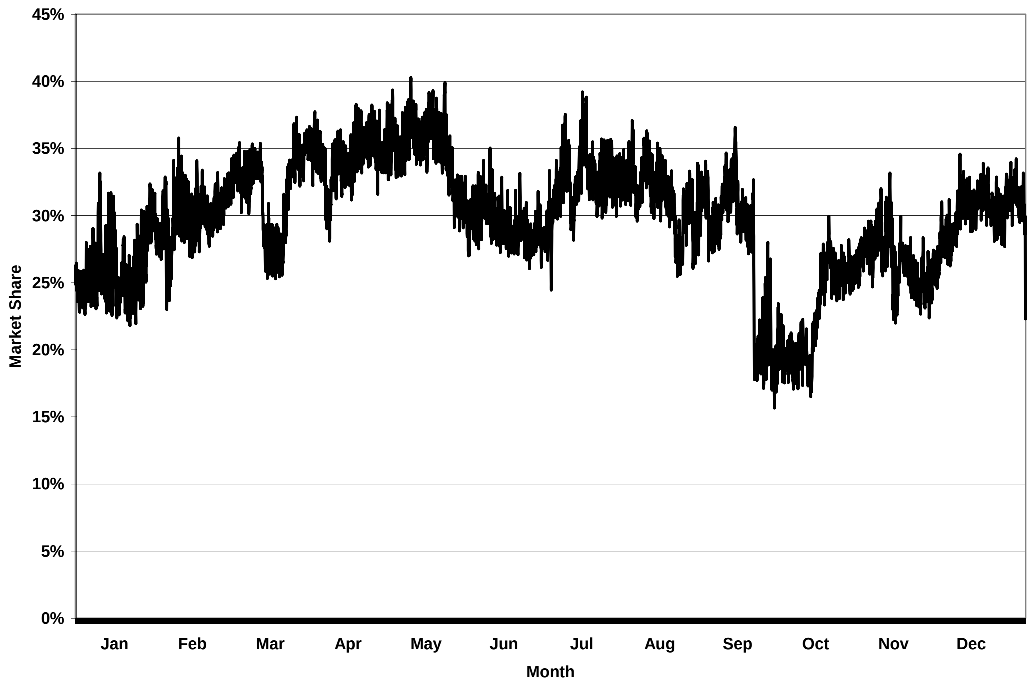
This is a change from the arrangements that were in effect for the three years of market operations from May 1, 2002 where the Panel was directed to have 'due regard' to the licence conditions of OPG. These conditions allowed OPG to engage in unilateral action to maintain hourly market prices at an average annual level of $38/MWh and if this was exceeded, the sole remedy was payment of the Market Power Mitigation Rebate.

[41] Some industrial customers prior to market opening had contracts with Ontario Hydro which allowed for more flexible supply and corresponding rates. To ease the transition of these customers into the market, they were provided 4 year Transitional Rate Option contracts in which an increasing portion of the price paid would be based on the spot market price. These contracts expire in April 2006.

Our expectation is that OPG will continue to participate in the market as it has done in the past by offering energy and operating reserve at the individual generating facility's marginal cost. Because of the new rate regulation OPG has a clear incentive to run its base-load facilities grouped in the prescribed asset pool and to offer competitive prices to ensure that these resources are selected by the IESO's Dispatch Scheduling Optimizer (DSO). Similarly 85 percent of the non-prescribed assets are subject to a revenue cap that acts as a disincentive to exercise market power. The possible exercise of market power exists for the remaining 15 percent and the hydroelectric output of base-load units greater than 1,900 MWh in any hour. However, as discussed in our previous reports, we have always interpreted the Panel's monitoring responsibility to include monitoring the actions of OPG and we will continue to do so. We believe, as we have stated in previous reports, that we have a responsibility to monitor for the exercise of market power and we view Paragraph 27 of the regulations as totally consistent with this position. We also believe that as the market continues to develop, with OPG as a dominant producer and with the lack of any long-term framework that provides for either divestiture or market power mitigation, it is incumbent upon us to set out the framework we intend to use to monitor for the exercise of market power. We have been working for many months to develop a robust, and analytically sound, framework and we look forward to presenting this framework to market participants for discussion later this year.

Some commentators have alluded to a relatively thin share of the market whose revenue is not already predetermined, either because of the OPG regulations or the RFP contract arrangements in the future. In fact a significant portion of supply is not affected by these arrangements. This is demonstrated in Figure 4 - 1 that shows the actual hourly production in 2004 by all generation operating in the spot market and not subject to the February 2005 regulations. The figure shows that depending upon the time of year and time of day, the share of generation to the Ontario market that is remunerated on the basis of the spot market price varies between 25 and 35 percent.[42]

Figure 4 - 1: 2004 Ontario Domestic Competitive Market as a % of Ontario Market Demand on an Hourly Basis



2.3 Prices Paid by Consumers

Approximately 54 percent of consumers (17 percent industrial and 37 percent commercial) are subject to wholesale prices while the remaining 46 percent (low-volume and designated consumers) may be covered by the Regulated Price Plan (RPP). These low-volume and designated consumers have the option of accepting the RPP, simply by purchasing through their local distribution company. Alternately, they can choose to purchase through a retailer and pay according to the contract arrangements agreed with their retailer. There will be little impact on wholesale market prices as a result of the RPP arrangements except to the extent that the on-peak, off-peak incentives succeed in shifting load.

[42] The dip in market share in September-October 2004 was caused by a large unit outage.

Those consumers not eligible for the RPP will pay the spot price, with an adjustment that reflects OPG's regulated prices, NUG contracts and RFP payments. This 'Global Adjustment' establishes a mechanism for refunding/recovering the cost of implementing the changes and of operating under the new structure.[43] This mechanism replaces the Business Protection Plan Rebate that ended March 31, 2005. The Global Adjustment is calculated monthly and may involve a positive or negative adjustment, depending on the average market price. Those consumers not eligible for the RPP will also receive a one-time payment based on the fixed price paid to OPG non-prescribed assets to April 2006.[44]

The new pricing arrangement for loads paying wholesale prices should not distort the incentive for loads to manage their energy consumption efficiently to the extent that they can and it is profitable to do so. We have heard that with the majority of OPG's assets having revenue limits and the present NUG's having fixed contracts, a majority of the generation in the province is under an 'involuntary bilateral' and loads no longer believe that the spot market price is important to their business. However, we view the present arrangements as not significantly dissimilar to the previous MPMA in terms of behavioural drivers to loads. Our understanding is that the new rebate mechanism is taken over a longer period rather than by the hour. While the rebate itself is a significant portion of money, in any particular hour it does little to distort market price signals and should not change behaviour. If it made sense for a dispatchable load to avoid consumption previously as the price of energy was above their costs, it still makes sense. As an example if the rebate is $5/MWh, if it made sense for a load to avoid a $200/MWh then likely it makes sense for that load to avoid a $195/MWh net price after the rebate. With the fixed price for OPG resources, there continues to be large pay-offs for loads responding to price.

[43] See the IESO's Quick Take for a summary of the new settlement arrangements.
http://www.ieso.ca/imoweb/pubs/training/QT18_Bill100.pdf

[44] The Global Adjustment and payment for OPG's non-prescribed assets apply to RPP eligible consumers also, but only through variances calculated in the current year and as applied to RPP rates in subsequent years.

2.4 Summary

All generators and dispatchable loads continue to bid and offer through the real-time market in order to be dispatched. Generators and loads continue to have the motivation to offer incrementally in order to minimize their costs. In other words, we do not expect the new arrangements to adversely impact efficiency in dispatch. We defined this in an earlier report as being satisfied when the market price equalled the incremental cost of the marginal supplier and all suppliers with an incremental cost less than this are selected for dispatch.[45] This in itself is an important benefit that should continue to be a key goal in Ontario. We see our job as maintaining a spotlight of these efficiency issues and pointing to ways to continually improve the operation of the IESO-administered markets to this end.

The other dimensions of market performance, consumption efficiency and investment efficiency have been largely subsumed by the government's policy initiatives, rather than developed over time through market mechanisms. The OPG price setting regulations, Regulated Price Plan and smart meter initiative are directed at allowing consumers to adjust to the real cost of energy over a longer transition period. Similarly, the direct contracting for new sources of Ontario-based generation has supplanted the market as the vehicle to attract new investment, at least for a transitional period. Both policy approaches have been implemented in such a way that they are not harmful to the efficient operation of the market and with the prospect that they can be removed as the market continues to evolve.

In many ways what we see in Ontario at the three-year point of the market is what exists in other electricity markets – mechanisms to protect consumers from volatile prices, as well as bilateral arrangements underpinning a significant share of market trading. But there are also substantial differences. Ontario has a very different structure of generation from other electricity markets, with a much greater reliance on base-load generation and a dominant market participant. As well, the evolution of forward markets that can

[45] See our December 2003 report at page 110.

complement the spot market has not progressed as far in Ontario as elsewhere. These differences in structure and in market evolution have required and resulted in different approaches from those taken in other markets. But 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 in dispatch. In the interim, market monitoring continues to be important to ensure spot market efficiency.

Within this framework, the Panel will continue to monitor the behaviour of market participants to prevent any instances of abusive behaviour or gaming. We will also continue to monitor the operations of the IESO and will recommend changes in structure, market rules or operational procedures where we think such changes can enhance the efficiency of the IESO-administered markets.