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
May 2005 – October 2005

PUBLIC

December 2005

Preface

The 7th Market Surveillance Panel monitoring report covers the period May 1 – October 31, 2005. This was a summer in many respects as challenging for the IESO-administered markets as when Ontario's electricity market opened three years ago.

Following the established format of our previous semi-annual reports, we provide standard data on market operations and performance in Chapter 1 and the Statistical Appendix. Chapter 2 surveys 'high' and 'low' prices and identifies other matters worthy of comment. Chapter 3 summarizes important changes to the market, reviews the efficiency of an IESO program and describes an issue at one of Ontario's interties. The final chapter summarizes our perspective on the operation of the market in a general sense and with respect to specific initiatives that, in our view, would improve market efficiency and performance.

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Chapter 1: Market Outcomes May 2005 to October 2005

1. Introduction

This chapter provides an overview of the primary results of the IESO-administered markets over the period May 2005 through October 2005, and compares them with the corresponding period one year earlier. Energy prices averaged $75.45/MWh, the highest six-month weighted monthly average in Ontario since the market opened in May 2002. Wholesale prices reflected a tight supply situation, as well as some particular challenges faced by the Ontario electricity market.

We note the following facts:

- Sustained high temperatures and humidity levels during the past summer, combined with limitations of supply, both from domestic generation and imports, presented a number of challenges for the IESO in managing the reliability of the electricity system.
- The peak hourly Ontario demand of 25,414 megawatts (MW) set in August 2002 was exceeded on seven separate occasions this past summer, resulting in a new Ontario peak demand record of 26,160MW on July 13, 2005.
- Increased demand combined with reduced hydroelectric output due to drought and less coal-fired generation with the shut-down of Lakeview GS increased Ontario's reliance on gas-fired generation both in terms of volume and price setting.
- Ontario again became a net importer of electricity in 2005.
- The natural gas market experienced new highs due to supply issues that affected prices both in Ontario and the surrounding electricity markets.

- As a result of the strain on the system this past summer, the IESO was required to repeatedly activate emergency control actions. These included issuing Public Appeals for customers to reduce their use of electricity on 12 days and implementing sustained five percent voltage reductions on August 3 and August 4 in order to reduce demand and maintain power supplies to Ontario consumers.

- While energy prices were higher, prices of operating reserve were, in general, substantially lower through this period, compared with a year earlier. This was due primarily to the entry into the market of four new dispatchable loads starting in November of 2004 and a severe drought, which shifted hydroelectric resources from the energy to the operating reserve market.

Other highlights of this chapter include:

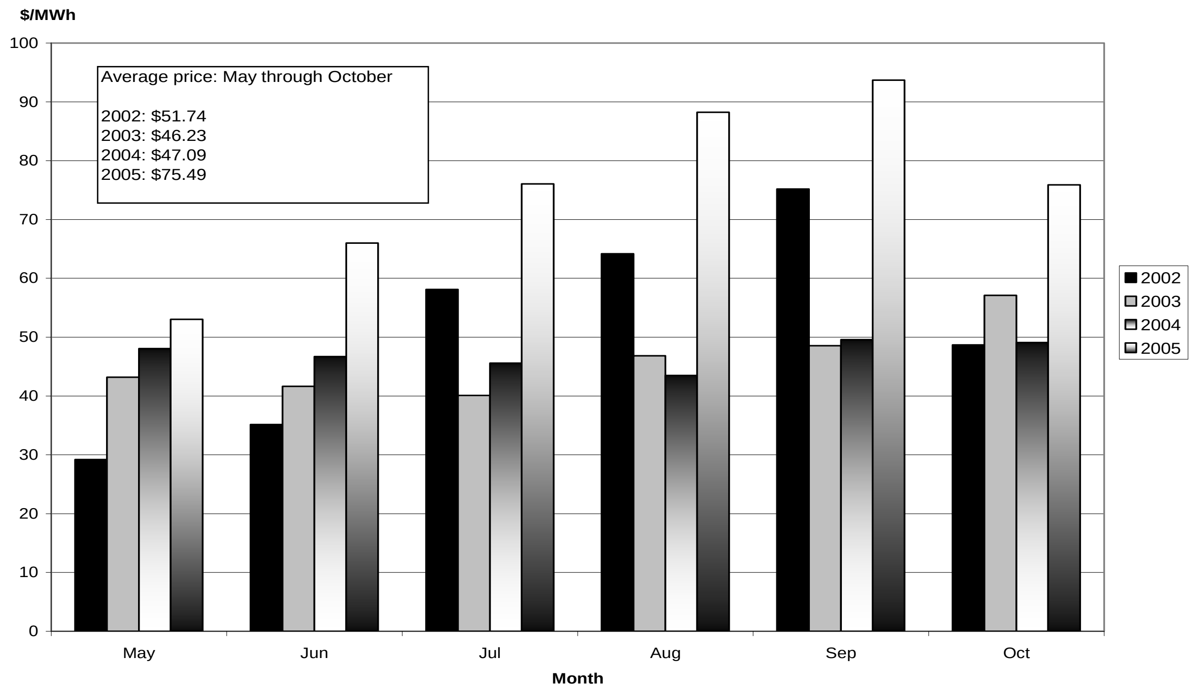
- The discrepancy between pre-dispatch prices and real time prices is reviewed again. While IESO's demand forecast error remains low, at roughly 1%, the discrepancy between pre-dispatch prices and real-time prices has grown as a result of both an increase in failed intertie transactions and greater price-sensitivity to changes in the supply-demand balance due to the shape of the offer curve.

- Net revenue calculations indicate an increase in net revenue for generators in 2005 versus previous summers. We extend the analysis in this chapter to examine an additional year of data and to provide a calculation of the implied Internal Rate of Return for new gas-fired generation.

2. Ontario Energy Price

When we compare the monthly prices to similar periods across the four years that the Ontario electricity market has been open, we view a remarkable similarity in distribution of prices to the summer of 2002: in both periods monthly prices rose through the summer and in July, August and September, both 2002 and 2005 prices were significantly greater than in other years. Figure 1-1 plots the average monthly prices across the four years.

Figure 1 -1 : Summer Monthly Average HOEP, 2002 – 2005 ($/MWh)



As Table 1-1 indicates, the monthly HOEP was substantially higher in all months compared to 2004. The largest change was in September when the average HOEP was $44.13/MWh higher than a year earlier. We observe similar trends for on-peak hours with August exhibiting the highest difference from the previous year at $65.60/MWh and September not far behind. While the HOEP was higher in off-peak hours as well, the differences were not as marked as the on-peak differences. For the period as a whole the average HOEP was $75.45/MWh (about 60 percent) greater than the HOEP of a year earlier.

Table 1 - 1: Average HOEP, On-Peak and Off-Peak, May – October ($/MWh)

	Average HOEP		Average On-peak HOEP		Average Off-peak HOEP	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**
May	48.06	53.05	61.93	63.78	37.60	44.21
Jun	46.69	65.99	60.15	83.57	33.81	49.18
Jul	45.58	76.05	55.55	102.84	37.38	55.84
Aug	43.51	88.24	52.81	118.49	35.84	61.08
Sep	49.57	93.70	59.17	123.65	41.16	67.50
Oct	49.11	75.92	57.48	101.37	42.80	56.71
Average	47.08	75.45	57.84	98.93	38.17	55.72

There has also been a marked change in the frequency distribution of the HOEP over the May - October period compared with the previous year. Figures 1-2 through 1-4 below plot the distribution 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) and more frequent occurrences of prices in excess of $150/MWh. This is true on average and for both on-peak and off-peak prices. The forces leading to this result appear to be higher demand, the shutdown of Lakeview GS and significantly higher natural gas prices. The relative impact of these factors is discussed further in sections 6 and 7 below.

In off-peak hours the dominant frequency of prices has changed little from the previous years. Prices tend still to cluster in the $30-60/MWh range. What has changed is that the frequency of prices below $30/MWh is much reduced from last year while the frequency of prices above $60/MWh has increased substantially. Coal-fired units continued to dominate price setting in off-peak hours through the period under review as shown in section 11. The reduced availability of water led to fewer offers by base-load hydroelectric, typically in the range of $10-30/MWh, and reduced the frequency of prices in that range. Higher temperatures led to greater off-peak demands and a higher frequency of prices being set by higher-cost, gas-fired units.

Figure 1 - 2: Frequency Distribution of HOEP, May - October

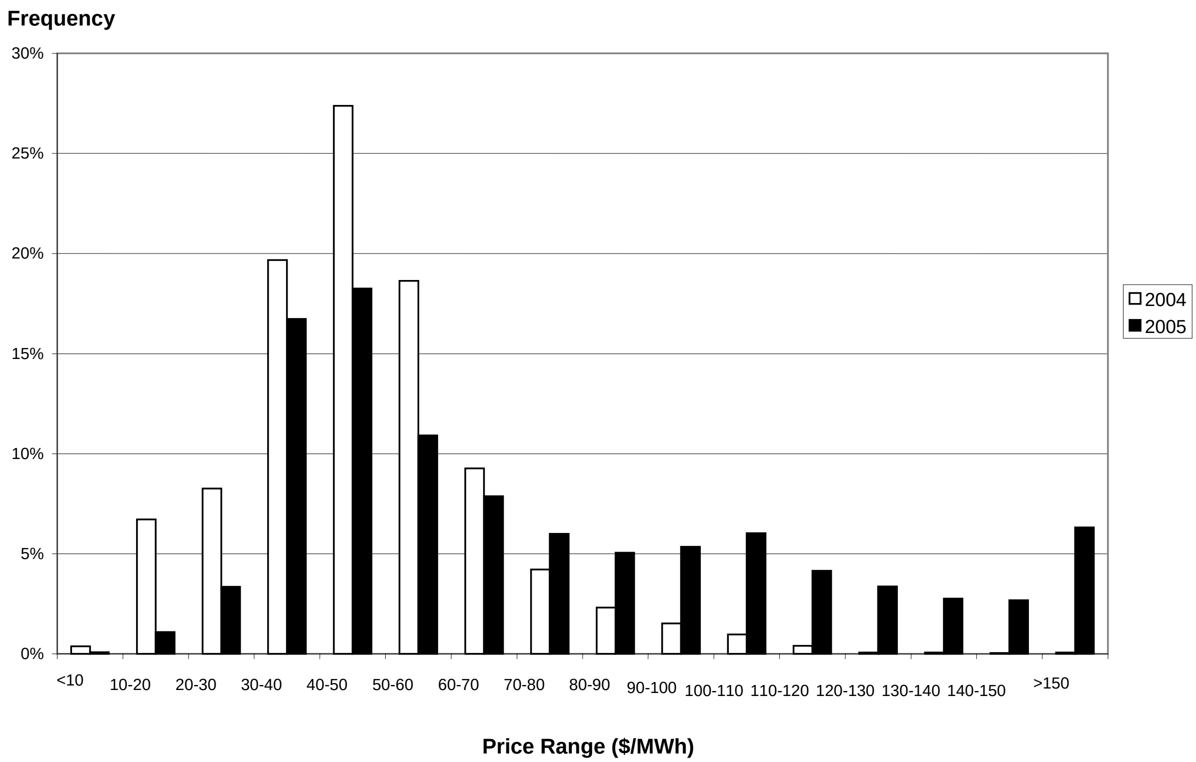


Figure 1 - 3: Frequency Distribution of HOEP, Off-Peak, May - October

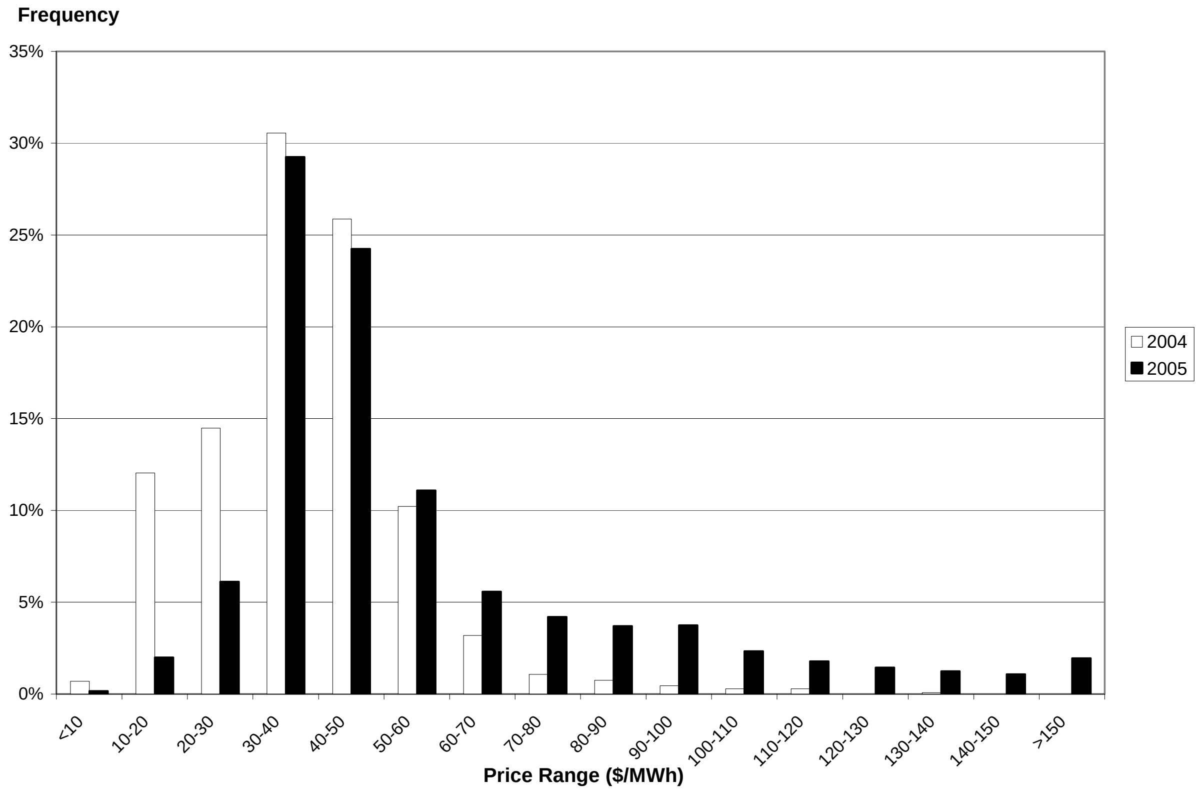


Figure 1-4 shows a significant change in the distribution of HOEP in on-peak periods, with virtually no occurrences of prices below $40/MWh and no clear modal price. We believe the change in the distribution can be attributed to three factors:

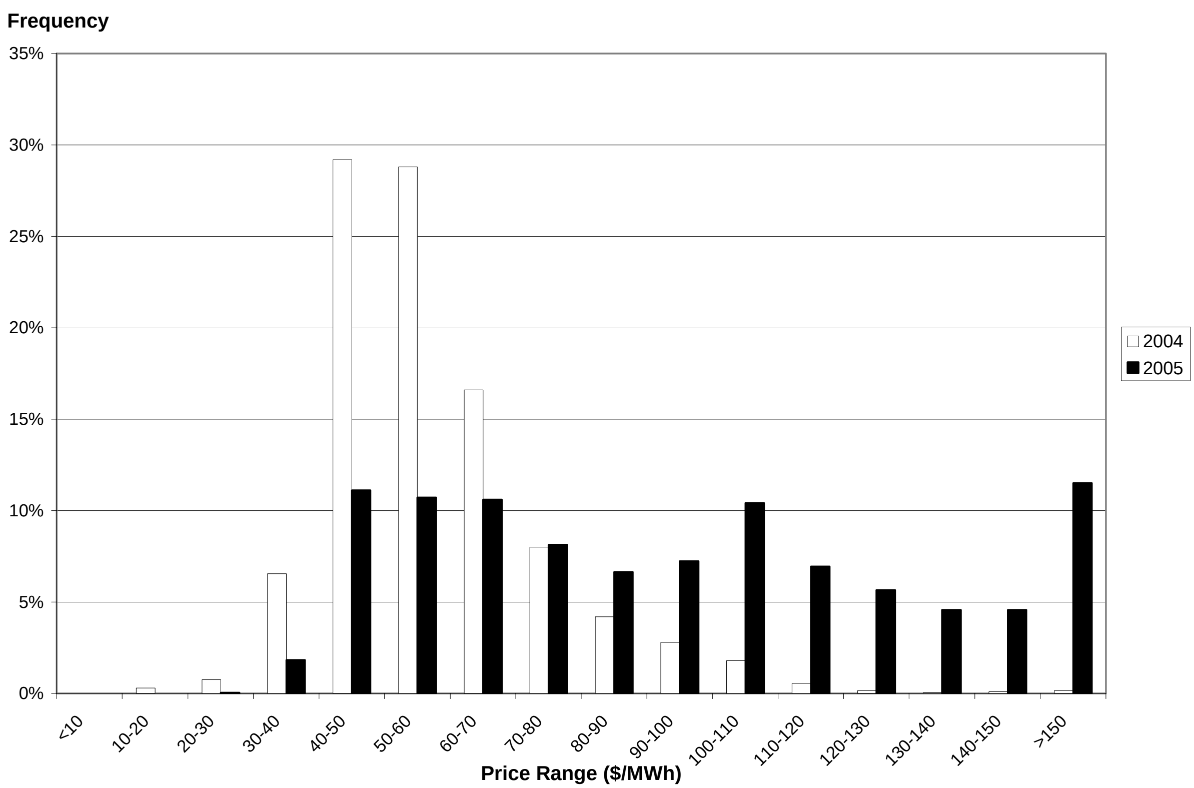
1. Demand was higher and much more volatile this summer as shown in the next section. This resulted in both higher price levels and increased price volatility, with price spikes occurring more frequently than in the past.

2. Supply conditions were tighter due to less water and larger outages on nuclear units, and as a result the demand curve was more likely to cut the supply curve on the steep portion. Thus even a small change in demand or loss of supply would lead to a large change in price.

3. The gas price was higher (particularly in late summer) and caused shifts in the supply curve on the steep portion where the demand usually intersects in on-peak hours. Table 1–8 shows, for example, that the increase in natural gas prices could have led to increased generation costs in the period August-October that ranged from \$30-88/MWh, depending on the efficiency of the plant.

The joint effect of higher and more volatile demand, less inframarginal supply and higher natural gas prices resulted in higher and more volatile market prices for electricity.

Figure 1 - 4: Frequency Distribution of HOEP, On-Peak, May – October



3. Demand

Ontario energy demand over the reference period was, on average, 4.5 percent higher than a year earlier. It was substantially higher in the hot months of June through August, slightly higher in September and October, and slightly lower in May.

The peak Ontario demand of 25,414 megawatts (MW) set in August 2002 was exceeded on seven separate occasions this past summer, resulting in a new Ontario peak demand record of 26,160MW on July 13, 2005.

Prices were higher in all months, even those with lower demands. The lower demand in May could have been weather-related as temperatures in May 2005 averaged about 1.3 degrees (Celsius) cooler than in May 2004. In all other months average temperatures were higher. In fact in the summer of 2005 there were 25 days when the temperature exceeded 30°C, compared to only three days in 2004 with temperatures at that level.[1]

While Ontario demand rose, exports declined in all months except September and October. This decline, related to higher prices, led to lower total market demand and had a moderating impact on the growth of demand (3.4%) over the period.

Table 1 - 2: Monthly Energy Demand (TWh) May – October

	Ontario Demand (NDL)			Exports			Total Market Demand		
	2004	2005	% Change	2004	2005	% Change	2004	2005	% Change
May	11.58	11.32	(2.30)	1.21	0.99	(18.18)	12.80	12.31	(3.75)
Jun	11.84	13.03	9.10	1.12	0.75	(33.04)	12.95	13.78	6.33
Jul	12.56	13.67	8.80	1.11	0.73	(34.23)	13.69	14.40	5.34
Aug	12.49	13.58	8.72	1.28	0.83	(35.16)	13.78	14.41	4.65
Sep	12.03	12.15	1.00	0.49	0.91	85.71	12.52	13.06	4.31
Oct	11.85	11.87	0.17	0.56	0.93	66.07	12.40	12.80	3.14
Average	12.06	12.60	4.52	0.96	0.86	(10.92)	13.02	13.46	3.35

4. Outages

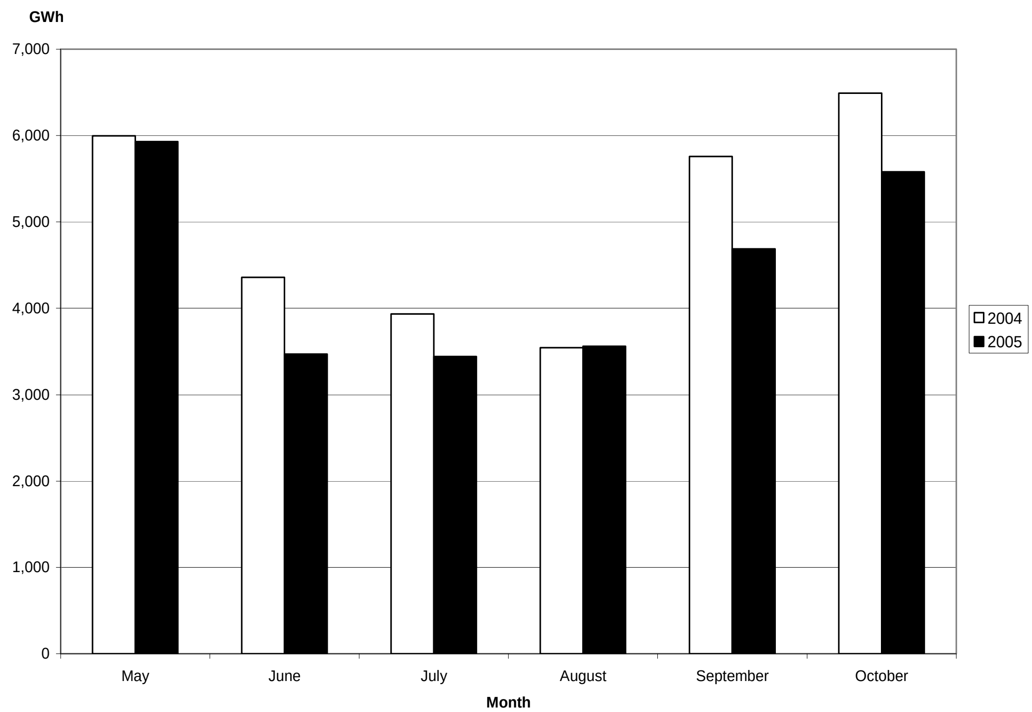
Generators go on outage either for planned maintenance or because of sudden equipment failure forcing them from service. Typically, planned outages are taken in shoulder months of the year

[1] Temperature is measured at Toronto Pearson International Airport.

– spring and fall – when market demand and price tend to be lowest. Generation outages – either planned or forced – can have a significant impact on the market-clearing price.

Figure 1-5 shows the combined planned and forced outages (including derates) over the period May to October in 2004 versus 2005.[2]

Figure 1 - 5: Total Outages both Planned and Forced, May - October



Outages are always an important part of the supply story. Although 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 providing only one hour of energy per day when forced out of service clearly has a lesser market impact than a nuclear generator which is providing energy across all hours.

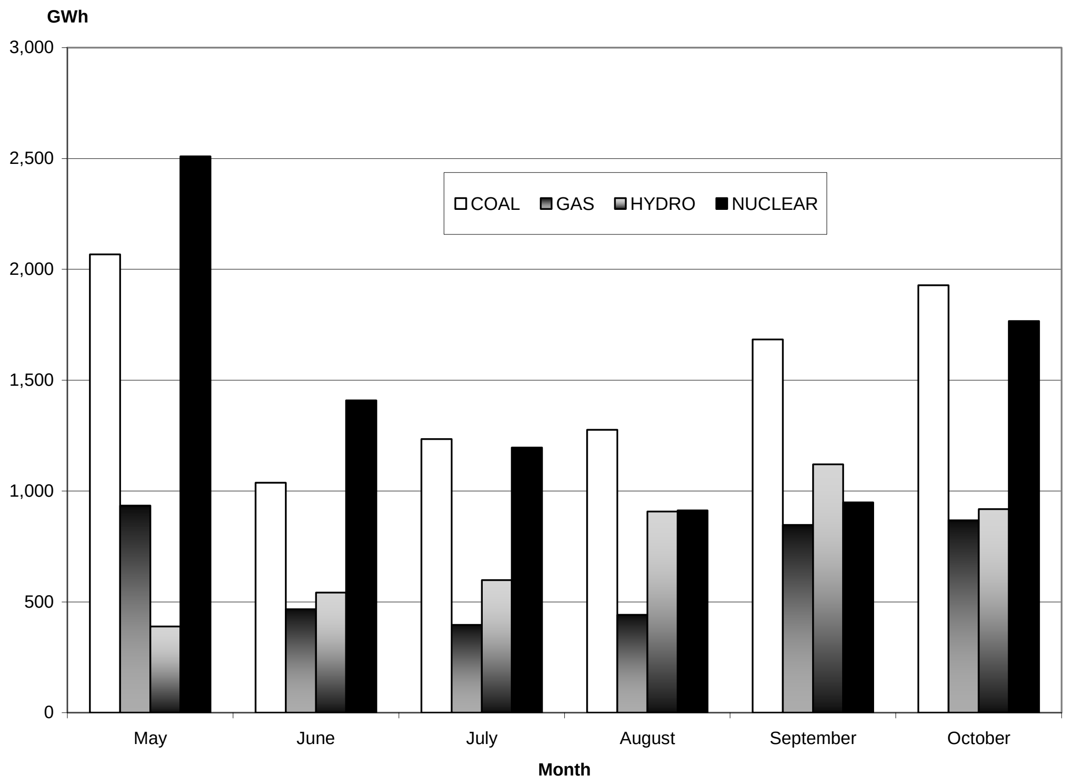
[2] This shows the total potential energy on outage. We have not attempted to estimate the capacity factor of the outages, that is, whether only a portion of the capacity of a generation unit would actually have been available if it had not been on outage because, for example, it had insufficient fuel to run for a 24 hour period.

Figure 1–6 breaks down by fuel type the amount of generation on outage during the period May through October 2005. The impact of an outage of an inframarginal generator is to push up the market-clearing price. An outage to an extramarginal generator has no effect on price.

Outages to nuclear units, which are inframarginal, always have a price effect. In the summer of 2005 there were three nuclear units on outage. One of these was a forced outage, with the unit returning to service in mid-July and the other two were a planned outage, of which one returned into service in mid-July and the other was extended as a forced outage with the unit returning to service in mid-August. These outages reduced available supply by roughly 800GWh per month. As part of its ongoing monitoring activities, the MAU investigated the reasons for the forced extension and received an explanation from the market participant that satisfied the Panel that there were operational reasons for the forced extension and that the forced outage was legitimate.

The shift share analysis in section 6 illustrates the price impact of the nuclear outages.

Figure 1 - 6: Outages by Fuel Type, May - October 2005



5. Supply Conditions and the Supply Cushion

The 'supply cushion' is a measure of unused energy that is available for dispatch in a particular hour. It is expressed as a ratio of the difference between energy offered by Ontario generators and energy required (demand and OR) relative to the energy required (demand and OR).[3] Our analysis of historical data shows that when the supply cushion falls below 10 percent one can

[3] 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:

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

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

expect upward pressure on price and probably price spikes. Since the measure incorporates offers from Ontario generators only, it can be negative on occasion. In these tight supply conditions, imports from neighbouring jurisdictions become critical to meet Ontario demand and market prices reflect this scarcity.

Table 1-3 below illustrates the real time supply cushion for the period of May – October for 2005 relative to 2004. The average supply cushion in summer 2005 was lower in May, July and August. In all months except towards the end of the period, the number of hours when the supply cushion was negative and the number of hours when it was less than 10 percent were greater than in the corresponding month of 2004, indicating a greater need to rely upon imports and greater potential for price spikes. Although June and July have, on average, a similar supply cushion in 2005 compared to 2004, the number of hours with a negative supply cushion and supply cushion less than 10% are significantly greater in 2005.

Table 1 - 3: Real-time Domestic Supply Cushion, May-October

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours)		Supply Cushion <10%(# of Hours)	
	2004	2005	2004	2005	2004	2005
May	17.23	14.79	0	5	148	290
Jun	17.28	17.65	7	26	151	255
Jul	18.56	18.14	5	47	126	247
Aug	21.49	17.63	0	48	38	237
Sep	13.24	17.50	22	25	301	219
Oct	13.53	14.62	28	2	333	312

A closer examination of the September numbers is instructive. In that month, the supply-demand balance generally improved. Notwithstanding the improvement in the supply-demand balance and the relatively light increase in demand, the price of energy continued to increase and was substantially higher than in August, or in September of 2004. As discussed in greater detail below, our assessment of the market is that these higher prices were driven essentially by increases in natural gas prices that raised the cost of available energy, rather than by problems of relative supply.

The generally lower supply cushion through the summer period reflects lower hydroelectric availability, which was due to drought, outages on three nuclear units (Bruce G7 and Pickering G4 and G5), lower output from self-schedulers, the removal from the market of Lakeview generation (after April 2005), and higher demand. Table 1-4 below provides a monthly summary of the year-to-year changes of average hourly market schedules by resource type and the average demand. One can see that in all months electricity production by all hydro resources was lower. Nuclear production was lower in early months, especially in May, but higher in September and October as some nuclear units returned from outages. As noted earlier, demand was much greater in June, July and August, with record demands being set on 7 occasions. The removal of Lakeview lowered the supply by 100 - 300MW on average in all months.

Although a new self-scheduler (Great Toronto Airport Authority) added 130MW of capacity into Ontario market in September, the total output of self-scheduling and intermittent generation was less in all months this year, with the lowest production occurring in September.

Indeed, notwithstanding the increase in capacity, the reduction in available supply in September, compared with last year, was close to 151GWh or 203MW on average. We believe that this is a consequence of the design of the original NUG contracts. With the increase in natural gas prices, gas-fired self-scheduling generators are finding it is more profitable to sell their gas contracts than to generate electricity, particularly in off-peak hours.

Table 1 - 4: Average Hourly Market Schedules and Ontario Demand (MW), May - October

	Nuclear		Hydroelectric supply		Self-Scheduling Supply		Lakeview		Ontario Demand (NDL)	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**
May	8,771	7,642	4,954	4,454	880	862	126	0	15,572	15,213
Jun	9,473	8,938	4,319	3,843	962	872	131	0	16,443	18,100
Jul	9,555	9,394	4,436	3,409	997	824	104	0	16,907	18,377
Aug	9,989	9,802	3,875	3,071	892	833	95	0	16,794	18,248
Sep	8,096	9,673	3,953	2,878	887	684	168	0	16,713	16,878
Oct	7,030	8,705	3,794	3,403	955	771	303	0	15,920	15,955

As we pointed out in our previous report[4] and noted above with regard to September, the supply cushion cannot tell the whole story of price determination since it simply measures energy on offer at all price levels (from -$2,000 to $2,000) versus energy (plus operating reserves) required to meet demand. The supply cushion indicates whether the market is likely to clear on the flat part of the supply curve, or on the steep part. It tells nothing about the shape and level of the offer curve. For example, two supply cushions could be exactly same but the offer curve for one could be at a consistently higher price level due to higher fuel cost. This explains why the supply cushion improved in some months but the general electricity price was nevertheless higher.

6. Reasons for the Increase in the HOEP: Shift-Share Analysis

In our previous reports, the Panel has employed the technique of shift share analysis to isolate the respective impact of changes in various exogenous factors on the year-to-year difference in the monthly HOEP. The detailed technique was explained in the Panel's December 2003 report. The shift share analysis asks what the average HOEP for a given month in 2004 would have been if the distribution of 2005 values of specific exogenous factors were substituted for their 2004 distribution. The exogenous factors included in this report are:

- changes in Ontario demand (non-dispatchable load);

- changes in the supply of base-load nuclear generation;
- changes in production of self-scheduler and intermittent generators; and
- and changes in the supply provided by hydroelectric generators.

This report takes a slightly different approach compared to our previous reports. In this report we use interval data instead of hourly average values. By doing so, we significantly increased our sample size and thus made the estimation more statistically robust. Tables A-12 and A-13 in the Statistical Appendix provide data on the changes in hourly average values for each of the exogenous factors identified above for off-peak and on-peak periods, respectively. Tables 1-5 and 1-6 below report the monthly results of the shift-share analysis for off-peak and on-peak periods.

Table 1 - 5: Estimated Impact on '04 Avg Monthly Off-Peak HOEP of Setting the Exogenous Variables at '05 Levels

Factors	May ($/MWh)	Jun ($/MWh)	Jul ($/MWh)	Aug ($/MWh)	Sep ($/MWh)	Oct ($/MWh)
Ontario Demand	(1.90)	8.34	6.19	6.18	0.52	(0.07)
Nuclear Supply	7.82	4.28	0.86	0.81	(6.50)	(5.35)
Self-scheduling Supply	0.61	2.23	1.40	1.08	0.80	(1.93)
Lakeview	0.32	0.12	(.05)	0.62	0.07	0.22
Hydroelectric Supply	9.51	12.68	7.01	5.08	4.38	2.59
Total Effect from Above Factors	16.37	27.65	15.42	13.77	(0.73)	(4.54)
Observed Difference in HOEP	9.96	10.85	15.76	19.29	19.93	7.79
Residual Effect	(6.41)	(16.79)	0.35	5.52	20.67	12.33

[4] See our June 2005 report, page 11.

Table 1 - 6: Estimated Impact on '04 Avg Monthly On-Peak HOEP of Setting the Exogenous Variables at '05 Levels

Factors	May ($/MWh)	Jun ($/MWh)	Jul ($/MWh)	Aug ($/MWh)	Sep ($/MWh)	Oct ($/MWh)
Ontario Demand	(7.17)	19.69	9.84	10.38	1.41	2.00
Nuclear Supply	18.22	3.52	0.21	1.12	(7.56)	(10.36)
Self-scheduling Supply	0.60	0.43	1.57	0.69	0.26	(0.71)
Lakeview	3.31	2.68	0.15	1.10	1.09	2.72
Hydroelectric Supply	5.87	4.77	7.45	6.91	6.22	2.27
Total Effect from Above Factors	20.83	31.09	19.22	20.20	1.42	(4.08)
Observed Difference in HOEP	1.43	25.34	40.97	62.92	61.42	40.39
Residual Effect	(19.40)	(5.75)	21.76	42.71	59.99	44.46

The shift share analysis provides the following insights:

- Ontario demand was lower in May 2005 than in May 2004, which had a downward pressure on market price. The analysis shows that the May price in 2004 would have been $1.90 lower in off-peak and $7.17 lower in on-peak had the demand in 2004 been at 2005 levels. However, Ontario demand was higher in all other months, and thus put upward pressure on market price. For example, the June price would have been $8.34 higher in off-peak and $19.69 higher in on-peak had the 2004 demand been at the 2005 levels.

- The outages of several nuclear stations had the effect of increasing average price in May, June and July, with the largest impact in May. According to the shift share analysis, for example, the off-peak price in May 2004 would have been $7.82 higher and the on-peak price would have been $18.22 higher had the 2004 supply of nuclear been at the 2005 levels. As the nuclear units came back into service, the increased supply put a downward pressure on market price. For instance, the September 2004 price would have been $6.50 lower in off-peak and $7.56 lower in on-peak.

- Self-schedulers and intermittent generation had the effect of increasing average price in all months except October. Although supply was less in October 2005 than in 2004, the different distribution of supply throughout the months, in relation to variations in demands, would have resulted in a lower average price in October 2004, even with the lower average supply of October 2005.

- The removal of Lakeview had an upward impact on on-peak monthly average price in all months except July in which the impact is negligible, with the largest impact in May. That is, had Lakeview been phased-out in 2004 the average price in May 2004 would have been $0.32 higher in off-peak and $3.31 higher in on-peak.[5]

- The lower availability of water in 2005 increased the average price in all months in 2005 compared to 2004. In July where the average price would have been $7.01 higher in off-peak and $7.45 higher in on-peak had the hydroelectric supply in July 2004 been at the 2005 levels. This is consistent with the large drop in water supply in July 2005 compared to 2004.

While the shift share analysis can explain some of the price difference between 2004 and 2005, the relatively large residual implies that factors other than those studied in the shift share analysis are also in play. Those factors may include:

- changes in fuel cost
- outages of non-nuclear units
- changes in exports and imports in response to prices in neighbouring markets and increased import failure
- changes in bidding strategies
- changes in operating procedures of the IESO, related to the treatment of out-of-market control actions and emergency imports.

[5] The negative entry for July in Table 1.5 is not significantly different from zero. There was virtually no Lakeview production in July of 2004.

The impact of fuel cost is discussed in the following section, and the changes in imports and exports are examined in Section 10. The changes in operating procedures are reviewed in Chapter 3.

7. Changes in Fuel Price

In previous monitoring reports we conducted an analysis of the impact of fuel cost, based either on unit-specific heat rates or on an assumed heat rate for all coal-fired and gas-fired units. Given that the frequency with which the real time MCP was set by gas-fired units increased significantly in 2005, and that the heat rates of existing gas-fired generators vary significantly, we combine the above two approaches by assuming a generic heat rate for all coal units, a low heat rate for efficient gas-fired units and a high heat rate for less efficient gas-fired units.

Table 1-7 shows the changes in coal and natural gas prices for May through October in 2004 and 2005. The coal price is a price index calculated by Platts and based on the NYMEX over-the-counter price for the Central Appalachian region. The gas price is the Henry Hub spot price.[6] Although the coal price may not reflect the true cost to a coal-fired generator due to the fact that only small amounts of coal are traded on NYMEX, it does reflect the trend of opportunity cost of fuel inputs to the generator.

Table 1 - 7: Average Monthly Fuel Prices, May-October

	Coal Price (NYMEX $CND/MMBtu)			Natural Gas Price (Henry Hub Spot Price $CND/MMBtu)		
	2004	**2005**	**% increase**	**2004**	**2005**	**% increase**
May	3.01	3.04	1	8.74	8.14	(7)
Jun	2.97	2.80	(6)	8.51	8.89	4
Jul	3.30	2.80	(15)	7.84	9.30	19
Aug	3.34	2.87	(14)	7.10	11.40	61
Sep	3.35	2.77	(17)	6.55	14.51	122
Oct	3.20	2.80	(13)	7.91	15.90	101

[6] Coal and gas price data are obtained directly from the NYMEX web site http://www.nymex.com .

The price of coal decreased in all months except May. For most months the coal price was typically 13 to 17 percent lower. However, the gas price increased sharply since July. The largest increases in gas prices were in September and October, when gas prices were more than double their 2004 values.

The increase in fuel cost would have an impact on production costs of generators that use either coal or natural gas. Table 1-8 below illustrates the component of production cost associated with fuel consumption and the production cost change due to the change in fuel cost. This is based on a generic heat rate for coal-fired generation (9,000 BTU/KWh), an assumed heat rate for an efficient gas-fired unit (7,000 BTU/MWh), and an assumed heat rate for a less efficient gas-fired unit (11,000 BTU/MWh). In this analysis, the transportation cost is not included because the Panel doesn't have accurate transportation cost information. One can see that the decrease in coal price can be translated into $2 to $5/MWh lower production costs for coal-fired units, while an increase in gas price would increase the production cost by $56 to $88 in September and October, for example.

Table 1 - 8: Estimated Production Cost Impact of Fuel Price Changes, May-October

	Estimated Coal-fired Fuel Cost ($/MWh)			Estimated Gas-fired Fuel Cost ($/MWh)					
Heat Rate	**9,000 BTU/KWh**			**7,000 BTU/KWh**			**11,000 BTU/KWh**		
	2004	**2005**	**Change**	**2004**	**2005**	**Change**	**2004**	**2005**	**Change**
May	27.09	27.36	0.27	61.18	56.98	(4.20)	96.14	89.54	(6.60)
Jun	26.73	25.20	(1.53)	59.57	62.23	2.66	93.61	97.79	4.18
Jul	29.70	25.20	(4.50)	54.88	65.10	10.22	86.24	102.30	16.06
Aug	30.06	25.83	(4.23)	49.70	79.80	30.10	78.10	125.40	47.30
Sep	30.15	24.93	(5.22)	45.85	101.57	55.72	72.05	159.61	87.56
Oct	28.80	25.20	(3.60)	55.37	111.30	55.93	87.01	174.90	87.89

As gas-fired units were more likely to set the real time price in 2005 (see Statistical Appendix Table A-20 to A-22), the increase in gas price would have an impact on the monthly average price. As well, peak hydro resources that are energy limited view the opportunity cost of their resource as being the price that gas-fired generators can command in the market. Thus higher natural gas prices influence the offer prices of these units as well. The calculations below therefore assume that the percentage of time when gas units set the price also includes the percentage of time when hydro resources set the price.[7]

Tables 1-9 and 1-10 below present those estimates. The initial table uses the marginal resource share observed in 2004, while Table 1-10 uses 2005 marginal resource shares. The 2004 shares are consistent with the approach in the shift share analysis, however since the shares are so different in 2005 we present this as well.[8] The column 'Impact of Fuel Price – Low' corresponds to the efficient type of gas-fired units (7,000BTU/KWh), and the 'Impact of Fuel Price – High' to the less efficient type (11,000BTU/KWh).

Table 1 – 9: Shift Share Residual Effects and Estimated Fuel Cost Impacts – 2004 Marginal Resources

	On-peak			Off-peak		
	Shift Share Residual ($/MWh)	Impact of Fuel Price -- Low ($/MWh)	Impact of Fuel Price -- High ($/MWh)	Shift Share Residual ($/MWh)	Impact of Fuel Price – Low ($/MWh)	Impact of Fuel Price -- High ($/MWh)
May	(19.40)	(1.61)	(2.62)	(6.41)	(2.01)	(3.23)
Jun	(5.75)	(0.19)	0.30	(16.79)	0.27	0.93
Jul	21.76	0.06	1.87	0.35	2.57	5.37
Aug	42.71	2.64	6.08	5.52	9.50	16.38
Sep	59.99	14.89	25.40	20.67	12.45	21.69
Oct	44.46	19.02	31.17	12.33	5.33	10.12

[7] The estimated fuel price impact is calculated as a weighted average change in production costs with the weighting equal to the percentage of time that fuel is on the margin and setting the MCP. The MCP change for any period is the sum - for coal, gas and hydroelectric generation - of the production cost change multiplied by the percent of time that fuel is at the margin, as shown in section 11, Price Setters. This assumes that the production cost change translates into the same change in MCP, and that there is no change in the resource setting the price. For example, the August on-peak impact – low using 2004 shares is calculated as -4.23 * 80 % + 30.10 * 10% + 30.10 * 10% = $2.64.

[8] Using the 2004 shares we can estimate how much higher 2004 energy prices would have been had only the fuel prices been different, at the 2005 levels. Using the 2005 shares tell us how much lower the 2005 prices might have been had fuel prices been at the 2004 level.

Table 1 - 10: Shift Share Residual Effects and Estimated Fuel Cost Impacts – 2005 Marginal Resources

	On-peak			Off-peak		
	Shift Share Residual ($/MWh)	**Impact of Fuel Price -- Low ($/MWh)**	**Impact of Fuel Price -- High ($/MWh)**	**Shift Share Residual ($/MWh)**	**Impact of Fuel Price – Low ($/MWh)**	**Impact of Fuel Price - - High ($/MWh)**
May	(19.40)	(1.47)	(2.41)	(6.41)	(0.98)	(1.65)
Jun	(5.75)	1.24	2.24	(16.79)	(0.15)	0.35
Jul	21.76	7.57	12.36	0.35	1.24	3.52
Aug	42.71	22.20	35.45	5.52	7.44	13.29
Sep	59.99	42.92	68.08	20.67	15.50	26.33
Oct	44.46	34.50	54.95	12.33	11.88	20.19

The comparison between the residual effect of shift share analysis and estimated impact of fuel cost provides some additional insights into understanding the average price differences in the review period relative to the previous year. The large residual effect in July to October, for example, can be partly explained by the increase in fuel cost, for both on-peak and off-peak. In fact, in September when the largest increase in average price occurred, the residual effect that cannot be explained by those exogenous factors in the shift share analysis is well within the estimated range of cost pass-through: in on-peak the residual effect, $59.99, falls between the estimated impact of fuel cost $42.92 and $68.08 (for 2005 shares), and in off-peak periods the residual of $20.67 again falls between the Low and High estimates.

The residual effect is still far outside of the estimated bounds in some months. As we illustrated in our previous reports, the remaining factors at play may include changes in fuel delivery cost, environmental emission standards for nitric oxide and acid gas emissions, and generators' expectation on output levels. Changes in offer strategy can also play a role and in the next section we report some simple tests that we performed on the offers of gas-fired units to assess whether they appeared to be changing their offer strategies to take advantage of the higher fuel prices.

8. Implied Heat Rate

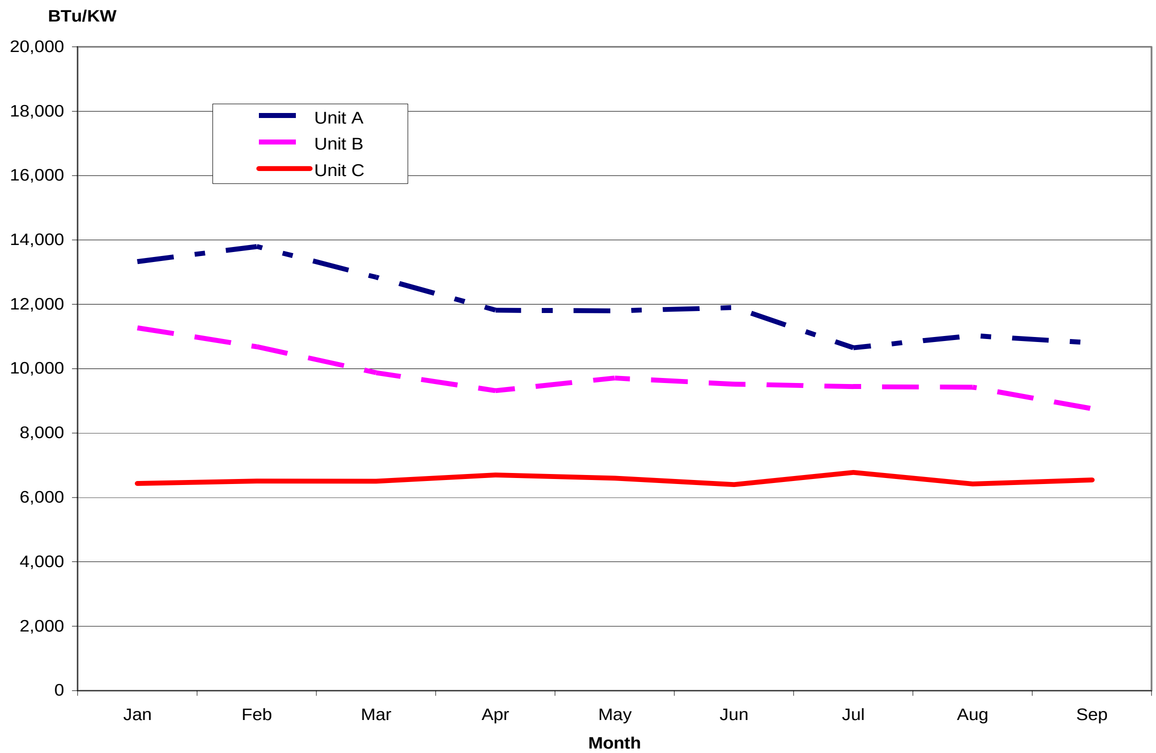
In the previous section, we estimated the implied production cost change based on actual fuel price and assumed heat rates. If a generator is competitive, the increased cost should be reflected in its offer price. All else equal, the market clearing price should increase with fuel cost increases.

Another way to assess the impact of fuel cost is to see how the increase in fuel cost was actually transferred into a generator's offer. This can be done by calculating the implied heat rate based on a unit's offer price and the fuel cost. The implied heat rate is the difference between offer price and O&M cost (assuming $5/MWh) divided by the fuel price. The approach offers additional insights into understanding relative efficiency and the offer change resulting from factors other than fuel cost. For example, an increase in gas prices should transfer into a lesser increase in offer prices by a more efficient generating unit than by a less efficient unit. If a unit is pricing competitively and expecting to produce at a high output level, the implied heat rate should be stable over time, regardless of the market conditions. Note that in some cases, a competitive generator may bid high (thus its implied heat rate is high) because of expected low production level, at which the average avoidable cost is high.[9]

Figure 1-7 below illustrates the monthly average implied heat rate for three gas-fired units since January 2005. One can see that the implied heat rates for all three units are generally stable in the past 10 months, implying that these units were bidding very consistently despite the increase in gas prices. Figure 1-7 also suggests that the high price in summer 2005 was not a result of a change in bidding strategy by gas-fired generators, given that these units were setting the on-peak price quite often.

[9] In deciding whether to start a unit, a generator would look for expected revenues at least as large as the short-run costs it would incur to run the unit. These include fixed costs such as the start-up cost and production costs at the minimum generation level, as well as variable cost associated with production above the minimum level. Before the start-up is initiated, all these are avoidable costs. By estimating expected production over the coming period and the total production costs, the generator can calculate the average avoidable cost per MWh of expected production. At the expected production levels, the market price must be at least this high to recover costs. With expectations of low production levels and running only for a few hours, the fixed costs (start-up and minimum load costs) are distributed over few MWh, driving up the offer price so as to recover the average avoidable cost.

Figure 1 - : Implied Heat Rate, January - October, 2005



9. Wholesale Electricity Prices in Neighbouring Markets

There are now four electricity markets in the United States as "neighbours" to Ontario: New York, PJM, New England and MISO. MISO, the Midwest Independent Transmission System Operator, is a new market that commenced operations on April 1, 2005 and encompasses Michigan, Manitoba, Minnesota and all or part of 13 other U.S. states.

MISO and New York are the two largest trading partners with Ontario. Ontario is usually a net importer over the Michigan intertie and a net exporter to New York. PJM and New England have no direct trade with Ontario, but they are closely linked to the Ontario system because traders are active in these markets and protocols exist among these markets to share operating reserve. While intertie traders cannot fully arbitrage away price differences between two adjacent markets due to transmission constraints, required bid lead-time, imperfect information, or scheduling protocol issues, these prices generally move in the same direction. Figures 1–8 to 1–10 compare monthly average prices, including on-peak and off-peak over the period under review. The Ontario price was usually lower than the prices in New England, New York, and PJM, but always greater than the MISO price, sometimes by a large amount.

The Ontario-MISO price difference warrants further analysis and comment. MISO's new scheduling protocol requires the acquisition of physical transmission service and sufficient ramping capacity shortly before the delivery hour for real-time exports. The impact of these scheduling protocol changes for imports from Michigan to Ontario, as well as other transmission issues between Michigan and Ontario have impaired the ability of traders to arbitrage price differences between MISO and Ontario.

Figure 1 - 8: Average HOEP Relative to Neighbouring Markets, May – October 2005

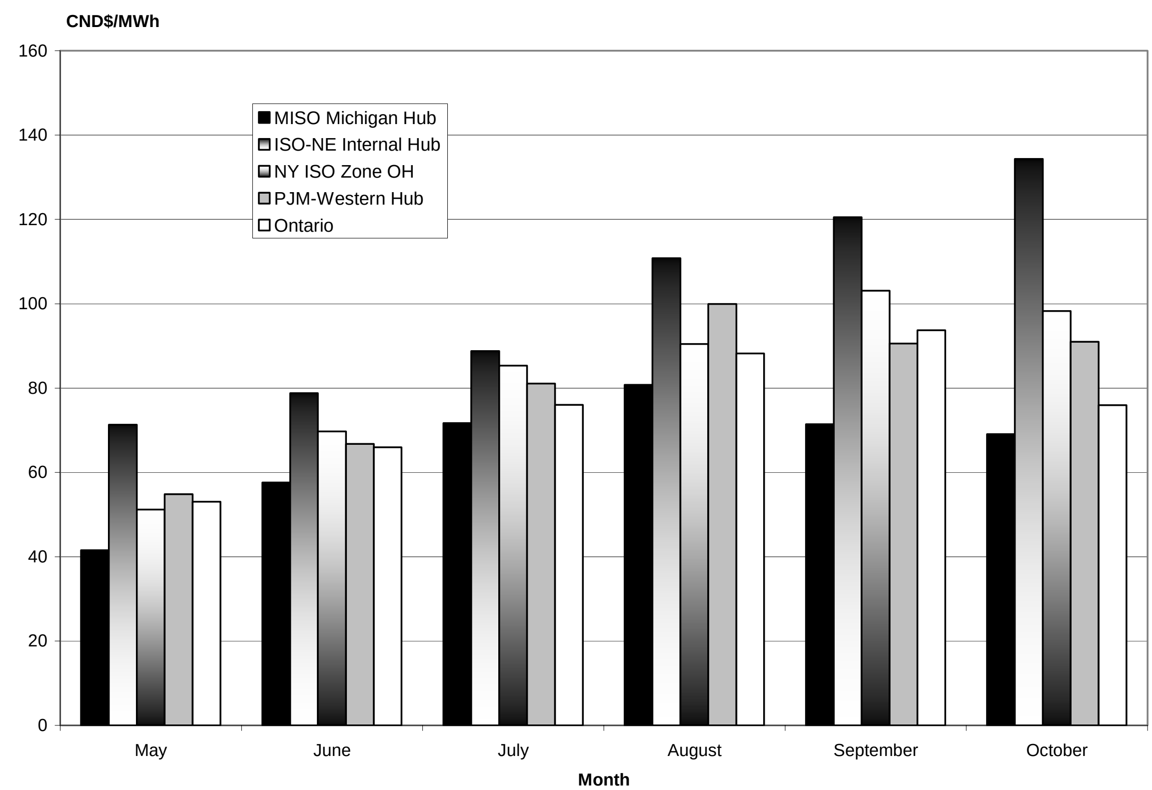


Figure 1 - 9: Avg. HOEP Relative to Neighbouring Markets, On-Peak, May – October 2005

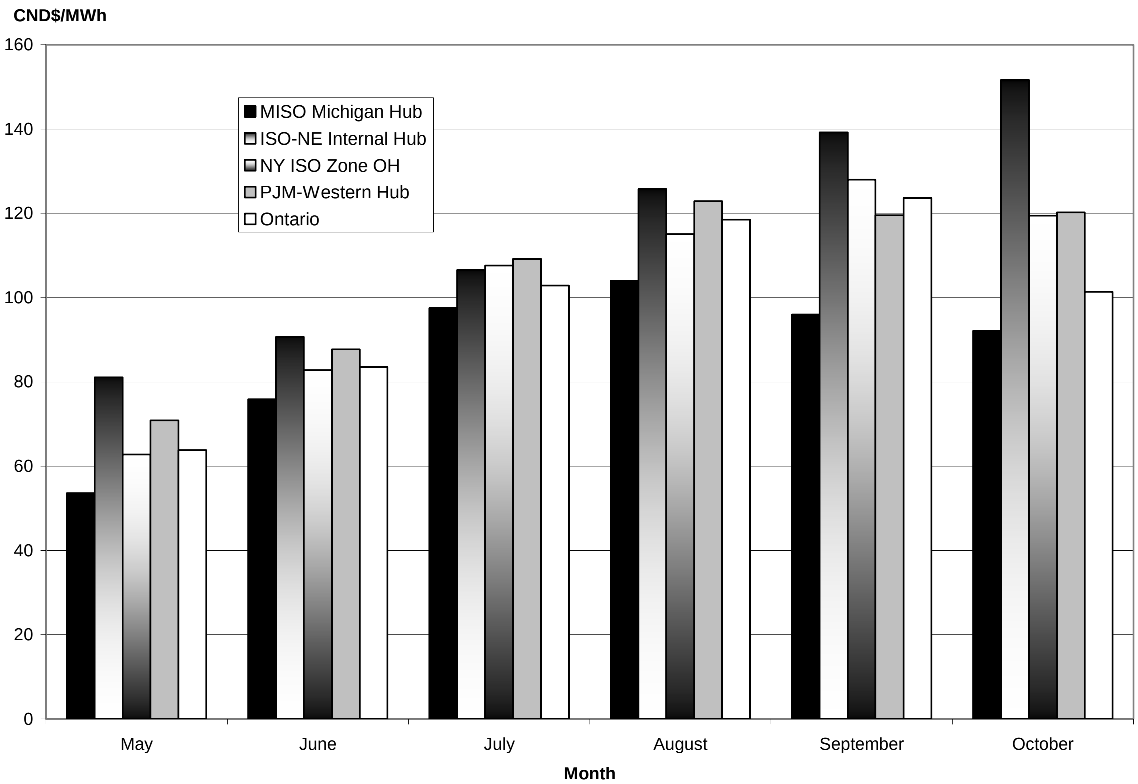
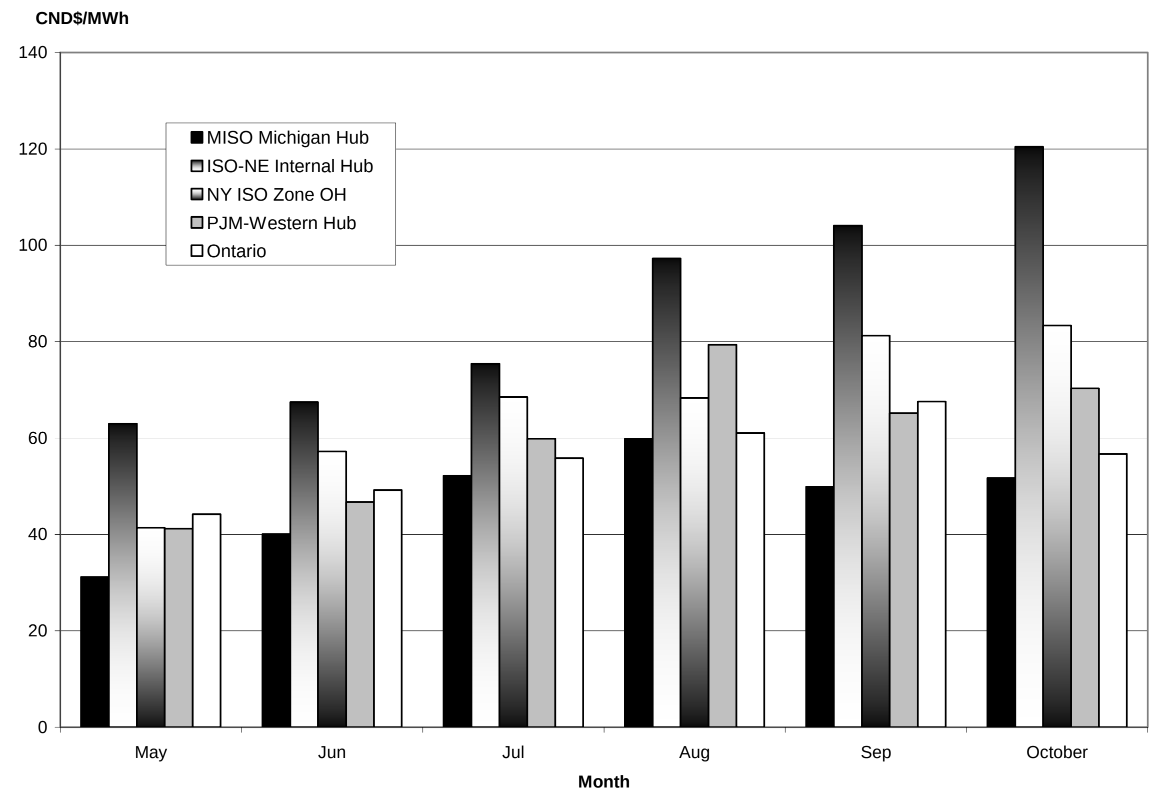


Figure 1 - 10: Avg. HOEP Relative to Neighbouring Markets, Off-Peak, May – October 2005

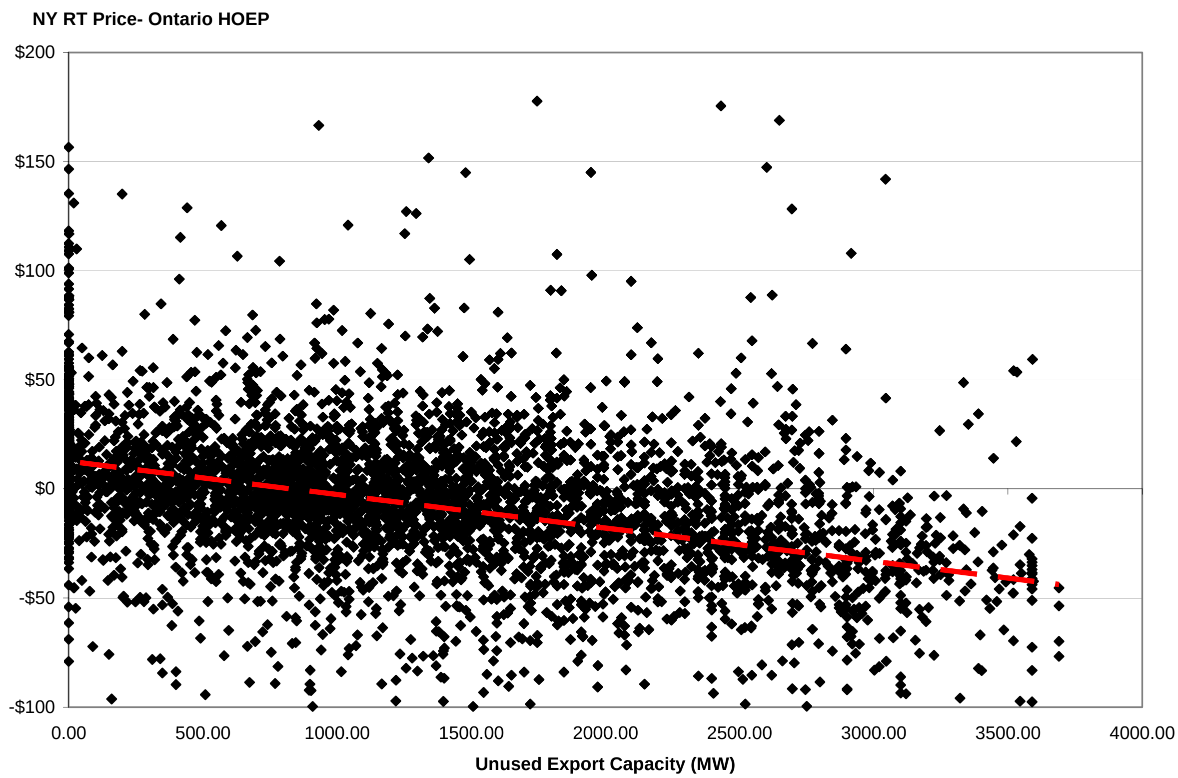


10. Imports and Exports

As discussed above, imports and exports generally respond to price differentials between adjacent markets and contribute to price convergence. Ontario was a net importer in the summer of 2005. Given the very tight supply-demand situation in this summer, net imports played an important role in securing reliability. They also played a role in moderating price since they cannot set the real time price.

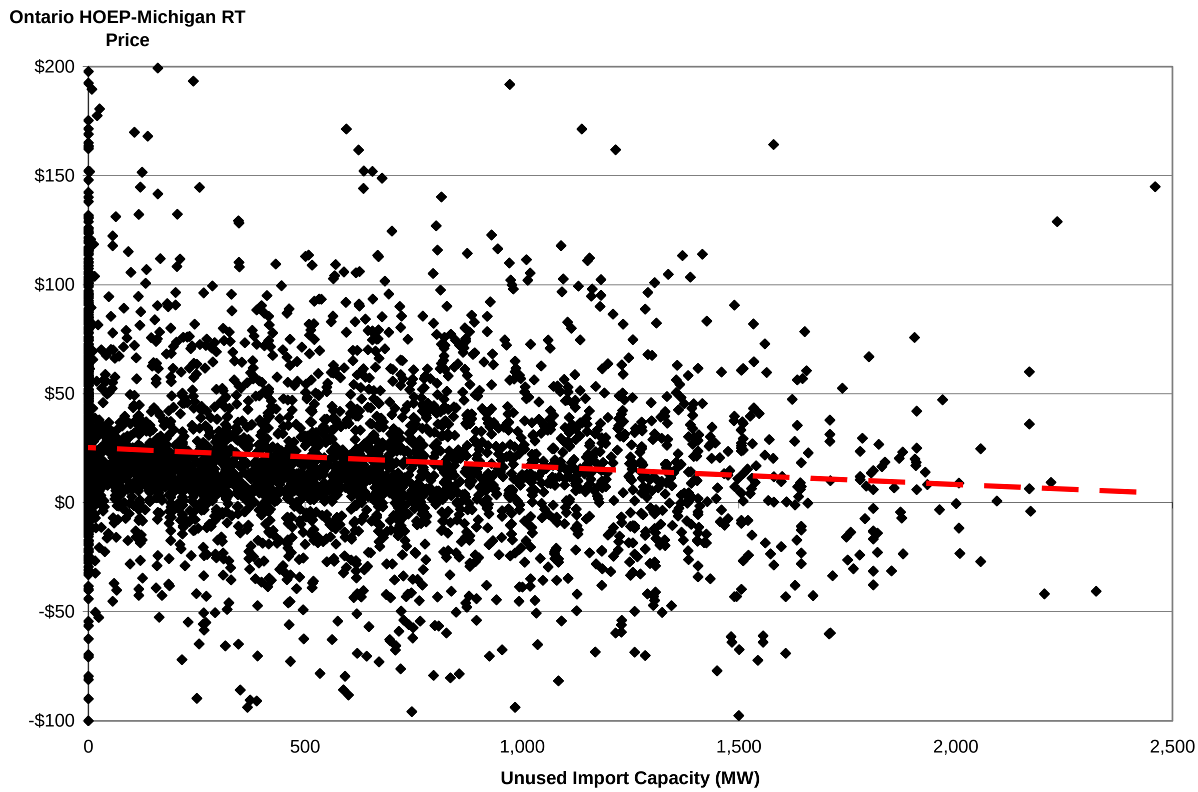
Figure 1-11 below plots the price difference between Ontario HOEP and New York OH zone real time price against unused export capacity on the New York interface (i.e. the maximum export capacity minus scheduled net export in the pre-dispatch sequence) for the period of May to October 2005. The dashed line is the trend line, which slope is statistically and significantly lower than zero. This indicates that as the New York price becomes greater than Ontario price, the unused export capacity shrinks rapidly.

Figure 1 - 11 Net Export vs. Price Difference on New York Interface, May – October 2005



A similar pattern exists on the Michigan interface as shown in Figure 1-12 below: as the Ontario price becomes greater than the Michigan price, the unused import capacity drops rapidly. Both figures show a high frequency of intertie transactions on both interfaces during the review period.

Figure 1 - 12 Net Import vs. Price Difference on Michigan Interface, May – October 2005



On closer inspection of the unused import/export capacity, we found that the Michigan interface was much more likely congested compared to the New York interface, and compared to previous months. This observation led to a further review of the Ontario-Michigan interface through the summer period. The results of this review are reported in Chapter 3.

Ontario was a net exporter in May but reverted to its position as a net importer in later months. As Table 1-11 shows, Ontario was a large net exporter in May – August 2004, but was a large net importer through the summer of 2005.

Table 1 - 11: Net Exports from Ontario On-Peak and Off-Peak (MWh), May – October

	OFF-PEAK		ON-PEAK		Total	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**
May	454,735	62,414	350,336	(539)	805,071	61,875
Jun	236,599	(41,718)	232,714	(259,946)	469,313	(301,664)
Jul	266,695	49,339	276,239	(385,437)	542,934	(336,098)
Aug	256,691	108,893	332,929	(222,398)	589,620	(113,505)
Sep	(253,894)	184,123	(295,300)	(228,831)	(549,194)	(44,708)
Oct	(221,592)	49,850	(175,481)	(116,347)	(397,073)	(66,497)

* positive indicates net exports; negative indicates net imports

There are two observations that warrant further comment. First, in July through September, Ontario was a net exporter during off-peak hours, but a net importer in on-peak hours. This is consistent with the price difference between Ontario and neighbouring markets, especially New York and Michigan. As Figures 1–9 and 1-10 show, the Ontario price was persistently greater than the Michigan price in both on-peak and off-peak periods, and thus Ontario was a net importer from the Michigan zone for most of time (see Appendix Tables 25 and 26). However, Ontario was a large net exporter to New York in the off-peak period given that the New York price was persistently $7-13 higher than Ontario, but a small net exporter or importer on-peak, when the Ontario price tracked the New York price within a range of plus or minus $5/MWh.

Second, the intertie transmission lines were more often limited in 2005 than in 2004 by capacity limits or by the net interchange scheduling limits (NISL). The NISL restricts the net change in imports or exports across an hour to a prescribed limit, which reflects the ability of internal generation to react to a net change in exports or imports. This limit also restricts the extent to which imports or exports can respond to price differences. In Ontario the NISL is normally limited to an hourly import/export change of 700MW.[10] Table 1-12 below lists the percentage of intervals when either import capacity limits or the NISL was binding. One can see that the frequency of import limits being binding on the Michigan tie and the New York tie increased significantly, and especially so on the Michigan tie. This implies that the Ontario price must be higher than the price in either neighbouring market in those intervals. The Michigan tie

[10] The system with a NISL of 700MW cannot increase electricity flow from 1,000MW to above 1,700MW, or decrease from 1,000MW to below 300MW within a one-hour period.

frequently reached its import limits in May and September, which partially explains the large price difference between Ontario and the Michigan hub, particularly in May, June and September (Figure 1-8).

Table 1 - 12: Percentage of Intervals with Intertie Import Limits Binding or NISL Binding

	Michigan Tie (%)		New York Tie (%)	
	2004	2005	2004	2005
May	3	48	0	0
Jun	1	33	0	1
Jul	0	13	0	4
Aug	2	13	0	5
Sep	16	35	2	3
Oct	20	5	0	1

11. Price Setters

The percentage of the time in May – October 2004 and 2005 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 1–13 to 1–15.

Table 1 - 13: Share of Real-time MCP Set by Resource (%), May –October

	Coal		Nuclear		Oil/Gas		Water	
	2004	2005	2004	2005	2004	2005	2004	2005
May	53	67	0	0	11	9	36	24
Jun	62	51	0	0	7	30	31	19
Jul	59	43	0	0	6	37	34	20
Aug	69	46	0	0	6	32	25	22
Sep	69	45	0	0	12	34	18	21
Oct	76	58	0	0	5	15	19	28

Table 1–13 shows that, overall, the percentage of time in which oil/gas generators set the real time price increased substantially in all months with the exception of May, while the percentage of time in which coal and water set the price fell. The large increase in the oil/gas share occurred in June through August, in which the percentage jumped from about 6% to above 30%. As a

result, the market price fell more frequently within the range of $100-$175/MWh, the typical price range for gas-fuelled offers through the period (See also Table A-8 in the Statistical Appendix).

Table 1 - 14: Share of Real-time MCP Set by Resource (%), On-Peak, May - October

	Coal		Nuclear		Oil/Gas		Water	
	2004	2005	2004	2005	2004	2005	2004	2005
May	58	61	0	0	19	18	23	21
Jun	68	34	0	0	13	48	19	18
Jul	69	18	0	0	11	59	20	23
Aug	80	23	0	0	10	51	10	26
Sep	67	21	0	0	23	54	9	25
Oct	62	36	0	0	10	30	28	33

As shown in Table 1–14, this phenomenon was most prominent in on-peak periods, in which oil/gas set the real time price at least 48% of the time in the June through September period.

Table 1 - 15: Share of Real-time MCP Set by Resource (%), Off-Peak, May -October

	Coal		Nuclear		Oil/Gas		Water	
	2004	2005	2004	2005	2004	2005	2004	2005
May	49	72	0	0	5	1	46	27
Jun	57	67	0	0	1	12	42	20
Jul	52	61	0	0	2	21	46	17
Aug	60	66	0	0	2	15	37	18
Sep	71	66	0	0	3	17	26	17
Oct	85	74	0	0	2	3	13	23

During the off-peak hours (Table 1–15), the percentage of time in which water set the price dropped dramatically in May to August, from around 40% in 2004 to 20% in 2005, reflecting the fact that there was less water available for base load as a result of drought.

12. Operating Reserve Prices

Tables 1-12 and 1-13 provide a comparison of average operating reserve prices for each of the three classes of reserve for each period.

Table 1 - 16: Operating Reserve Prices ($/MWh), Off-Peak Periods, May - October

	10N		10S		30R	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**
May	4.43	1.41	8.17	4.83	4.28	1.31
Jun	0.93	0.23	4.15	2.90	0.93	0.23
Jul	1.41	0.20	4.64	3.40	1.37	0.20
Aug	0.35	0.20	3.66	5.14	0.35	0.20
Sep	0.21	0.20	3.66	5.07	0.21	0.20
Oct	0.23	1.00	3.36	4.90	0.23	0.99
Avg.	1.26	0.54	4.61	4.37	1.23	0.52

In both the thirty and ten minute non-spin markets we see a year-over-year reduction in price (except October), while at times prices in the spin market are higher than in the previous summer.

Table 1 - 17: Operating Reserve Prices ($/MWh), On-Peak Periods, May – October

	10N		10S		30R	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**
May	14.27	5.53	14.52	6.92	13.39	5.50
Jun	7.16	2.24	7.80	3.32	6.75	2.22
Jul	6.27	1.44	6.81	5.46	6.03	1.44
Aug	1.52	0.91	2.78	6.41	1.51	0.91
Sep	2.04	0.62	3.40	7.04	1.94	0.62
Oct	0.94	4.80	2.35	7.01	0.94	4.61
Avg.	5.37	2.59	6.28	6.03	5.09	2.55

There are two main factors that influenced the year-to-year reduction in operating reserve prices for both the thirty and ten-minute non-spin markets:

- Dispatchable loads traditionally bring to the market not only additional offers for energy, but also for operating reserve. As mentioned in our previous report, by November 2004 four new dispatchable loads had entered the market providing an additional 145MW of ten-minute 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. The IESO has recently introduced the Hour Ahead Dispatchable Load (HADL) program, (discussed in Chapter 3) to allow a further increase in the IESO's ability to be able to deal with dispatchable loads. We understand that another 230MW of dispatchable load is preparing to enter the market, which will further enhance both efficiency and reliability.

- In the summer of 2005 hydroelectric generators, faced with a drought which limited their capability to produce energy, moved to the operating reserve market.

Neither dispatchable loads nor shutdown hydroelectric generators can provide spinning reserve. As mentioned in previous reports there is a cost to hydroelectric generators to provide spinning reserve, as they must consume energy to allow them to motor.

13. One-Hour Pre-dispatch Price and HOEP

We continue to monitor the difference between pre-dispatch and real-time prices as an important indicator of the performance of the market. Inaccurate or unreliable pre-dispatch prices can lead to inefficient production decisions and can cause real-time scheduling inefficiencies. We have described these concerns and identified the contributing factors to the observed price differences in each of our past reports, most extensively in our March 2003 report.[11]

Table 1-18 below provides monthly data comparing the one-hour ahead pre-dispatch price with the HOEP during this past summer and in the summer of 2004. The average difference in the six months under review has almost doubled ($12.23/MWh vs. $6.12/MWh) and the average difference expressed as a percentage of the HOEP is higher in all but two months compared to 2004.

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 a % of the HOEP**	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**
May	10.05	4.97	72.62	52.37	(62.19)	(175.32)	14.11	16.98	27.58	14.51
Jun	6.73	9.68	53.20	94.12	(108.31)	(238.58)	12.84	18.02	24.09	22.45
Jul	5.21	12.50	41.29	287.05	(71.62)	(417.67)	10.06	37.22	18.32	26.69
Aug	4.99	19.50	33.05	574.86	(36.79)	(267.59)	7.58	58.42	17.61	29.29
Sep	4.01	9.99	31.99	133.67	(93.98)	(474.82)	7.97	36.21	11.57	20.68
Oct	5.72	16.72	51.21	139.98	(45.55)	(372.26)	10.12	35.90	12.69	33.02
Avg	6.12	12.23	47.23	213.68	(69.74)	(324.37)	10.45	33.79	18.64	24.44

The statistics on maximum and minimum values and standard deviations also document the greater volatility in the summer of 2005 compared to 2004. However, while the pre-dispatch price discrepancy persists it is useful to compare 2005 to earlier periods, particularly the equally turbulent summer of 2002. It is also useful to look at the absolute difference since it is a good indicator of the magnitude by which the pre-dispatch price deviates from the HOEP. Table 1-19 shows the average absolute difference between the 1-hour ahead pre-dispatch price and the HOEP.

[11] See pp. 63-90.

Table 1 - 19: Measures of Difference between 1-hour Ahead Pre-dispatch Prices and HOEP

1-Hour Ahead Pre-Dispatch Price Minus HOEP							
Average Absolute Difference as a Proportion of the HOEP (%)							
	Summer 2002	Winter ’02-‘03	Summer 2003	Winter ’03-‘04	Summer 2004	Winter ’04-‘05	Summer 2005
May	16.65		38.45		30.97		19.81
Jun	26.15		45.15		28.83		25.12
Jul	94.14		28.76		22.91		33.22
Aug	53.87		26.42		21.06		35.37
Sep	48.58		23.37		14.31		29.44
Oct	41.53		22.25		15.79		38.99
Average	46.92	49.26	30.90	35.59	22.32	22.99	30.36
Nov		30.98		21.90		27.70	
Dec		48.67		46.70		23.12	
Jan		45.31		46.32		23.50	
Feb		84.62		37.54		17.22	
Mar		55.65		27.79		21.51	
Apr		30.31		33.25		24.88	

Earlier in Figure 1-1 we showed the average HOEP over the summer months since market opening. In each month, May to October, the average HOEP was greatest in 2005. By contrast the measure of the pre-dispatch to real-time price difference in Table 1-19 shows a generally declining price discrepancy. While it is higher in four of the six months in 2005 compared to 2004, the 2002 values are higher in all but one month; an average of 46.92% of HOEP in 2002 compared to 30.36% in 2005. We attribute this improved performance to the market improvements introduced since the early months and especially the improvement in demand forecasts and the pricing of Control Action Operating Reserve (CAOR).

In the rest of this section we briefly report on the status of the contributing factors that we have identified in earlier reports. These include:

- demand forecast error

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

We are satisfied that the last two categories no longer have a significant impact on the remaining pre-dispatch to real-time price discrepancy.

<u>Performance of Self-Scheduling and Intermittent Generation</u>

Table 1-20 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 - 20: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, May-October

	Total MWh Pre-Dispatch		Maximum Difference (MW)		Minimum Difference (MW)		Average Difference (MW)		Fail Rate % (Difference/MW Pre-dispatch)	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**
May	712,553	722,187	146	187	(118)	(61)	(6)	20	(0.42)	2.18
Jun	754,026	724,804	284	243	(91)	(43)	10	50	0.82	4.67
Jul	842,044	701,810	583	244	(283)	(71)	52	55	4.32	6.06
Aug	737,531	667,215	228	201	(53)	(167)	33	15	3.61	1.37
Sep	719,483	543,183	309	259	(104)	(62)	42	22	4.54	3.19
Oct	787,642	629,537	276	171	(97)	(276)	24	(1)	2.41	(0.12)
Average	758,879	664,789	304	189	(124)	(67)	26	27	2.55	2.91

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

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

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 1-21 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, they can still be an important factor during critical events when appropriate price signals are important for supply–demand response.

Table 1 - 21: Intervals with Manual OR Reductions (Market Schedule), May – October (Percentage)

	No reduction		<200		>=200 and <400		>=400 and <800		>=800	
	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005
May	94.49	98.44	1.12	0.48	3.24	0.65	1.15	0.43	0	0
Jun	97.50	98.70	0.38	0.09	1.10	0.47	1.02	0.65	0	0.08
Jul	99.01	98.97	0.04	0.60	0.64	0.12	0.30	0.30	0	0
Aug	99.47	99.81	0.20	0.19	0.32	0	0	0	0	0
Sep	99.75	100	0.05	0	0	0	0.21	0	0	0
Oct	100	98.81	0	0.02	0	0.63	0	0.41	0	0.12
Average	98.37	99.12	0.30	0.23	0.88	0.21	0.45	0.30	0.00	0.03

*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 the market rules

In Chapter 3 we will discuss further changes the IESO has made in the usage of CAOR to eliminate manual out-of-market control actions.

Demand Forecast Error

Table 1-22 shows that the mean absolute percentage forecast difference between pre-dispatch and real-time demand is approximately the same as in the previous year. In the Ontario design, the bid/offer window closes two hours ahead of pre-dispatch. Therefore, 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. At both the 3-hour ahead and 1-hour ahead time points the absolute percentage forecast demand difference is roughly similar to the previous year. One-hour ahead pre-dispatch demand forecast differences are now in the order of 1 percent. This may be as far as the IESO can go in reducing demand forecasts with its present set of forecasting tools. Some further advantage may be possible in the forecasting of average demand in light of the fact that the peak demand error is roughly 0.5% smaller.[12]

Table 1 - 22: Forecast Error in Ontario Demand, May - October

	Mean absolute forecast difference: Pre-dispatch Minus Average Demand Divided by the Average Demand (%)				Mean absolute forecast difference: Pre-dispatch Minus Peak Demand Divided by the Peak Demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2004	2005	2004	2005	2004	2005	2004	2005
May	2.30	2.01	2.07	1.77	1.47	1.44	1.20	1.07
Jun	2.24	2.92	2.05	2.55	1.66	1.93	1.36	1.36
Jul	2.53	3.11	2.24	2.54	1.83	2.25	1.49	1.53
Aug	2.40	2.22	2.12	1.96	1.70	1.64	1.36	1.16
Sep	2.26	1.89	2.07	1.63	1.45	1.39	1.18	1.07
Oct	2.00	1.67	1.90	1.51	1.25	1.22	1.04	0.94
Average	2.29	2.30	2.08	1.99	1.56	1.65	1.27	1.19

A comparison of demand forecasting performance over the period since market opening shows that forecast accuracy has improved. Table 1-23 focuses on the one-hour ahead pre-dispatch statistic and shows a generally progressive decline in this measure of forecast error over time. Each month in 2005 is better than the corresponding month in 2002 and the average error of 1.19% in the summer 2005 compares favourably with 1.56% in summer 2002.

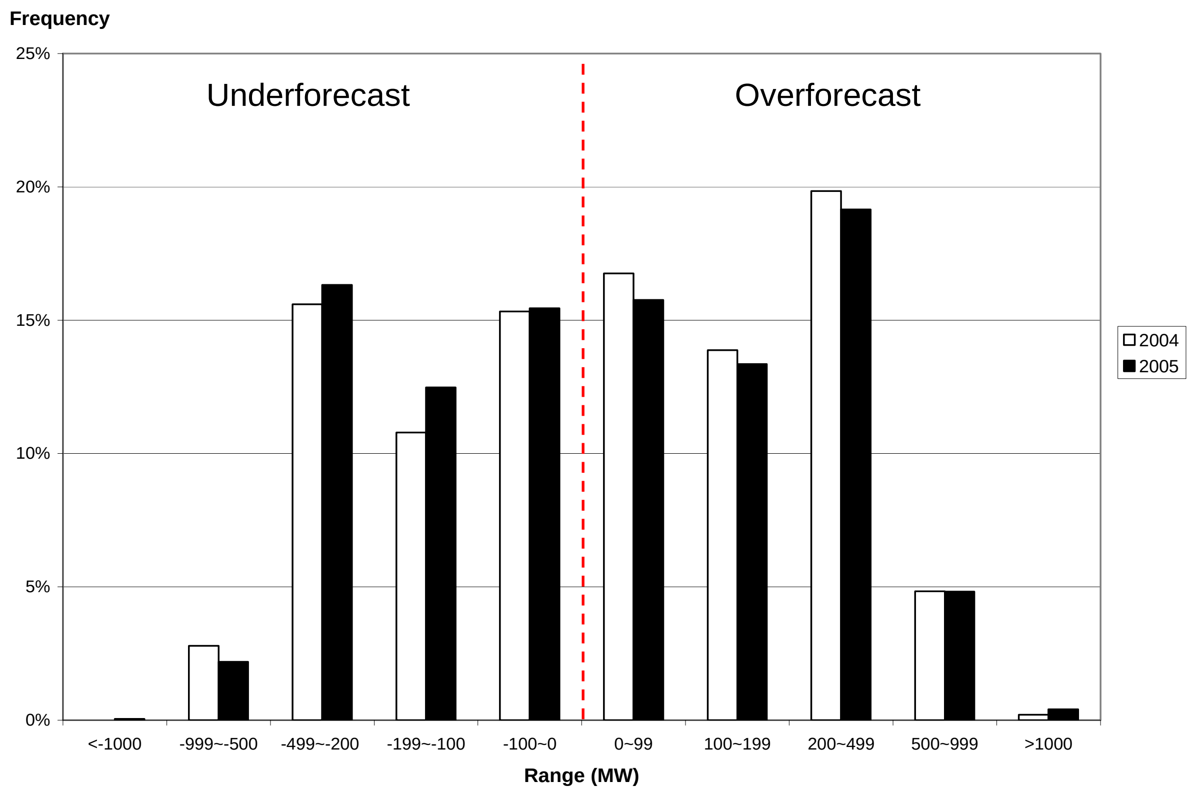
[12] Typically electricity markets in the North-East Power Coordinating Council (NPCC) are setting a standard of Mean Absolute Demand Forecast Difference accuracy of 2%.

Table 1 - 23: Mean Absolute Difference: 1-Hour Ahead Pre-dispatch Minus Peak Demand Divided by Peak Demand

Average Difference as a % of the HOEP							
	Summer 2002	**Winter '02-'03**	**Summer 2003**	**Winter '03-'04**	**Summer 2004**	**Winter '04-'05**	**Summer 2005**
May	1.43		1.14		1.20		1.07
Jun	1.87		1.28		1.37		1.36
Jul	1.99		1.47		1.49		1.53
Aug	1.47		1.49		1.36		1.16
Sep	1.50		1.21		1.18		1.08
Oct	1.09		1.20		1.04		0.94
Average	1.56	1.19	1.30	1.24	1.27	1.01	1.19
Nov		1.14		1.20		1.05	
Dec		1.38		1.28		1.25	
Jan		1.11		1.24		1.01	
Feb		1.09		1.10		0.91	
Mar		1.15		1.27		0.86	
Apr		1.26		1.36		0.98	

In the last report we highlighted the issue of the IESO consistently over-forecasting demand, even on a peak-to-peak basis. When we review the data in Figure 1-13 we see a marked reduction in the tendency to over-forecast demand. In fact it would appear that the frequency of under-forecasting demand is now similar to over-forecasting.

Figure 1 - : Frequency Distribution of Ontario Demand Forecast Error Comparing May – October



Although the frequency of under and over forecasts is more balanced there is still a bias to over-forecast in general. Table 1–24 provides the mean of the forecast differences each month, representing the average bias in the monthly forecasts. In June and July, the forecast bias was positive and increased substantially in 2005. Forecast bias was negative in September and October of both 2004 and 2005, and was larger in 2005. On average through the summer, the three-hour ahead forecast error was positive and slightly greater than last year. The one-hour ahead forecast error was also positive, but slightly less than last year.

Table 1 - 24: Mean Forecast Error in Ontario Demand, May - October

	Mean Forecast Difference: Pre-dispatch minus Peak Demand in the Hour (MW)				Mean Forecast Difference: Pre-dispatch minus Peak Demand Divided by the Peak Demand (%)			
	3-hour		1-hour		3-hour		1-hour	
	2004	2005	2004	200	2004	2005	2004	2005
May	48	13	37	9	0.30	0.08	0.23	0.06
Jun	26	172	26	148	0.15	0.90	0.16	0.78
Jul	81	180	53	120	0.47	0.94	0.30	0.62
Aug	62	47	48	30	0.36	0.25	0.28	0.15
Sep	29	(38)	22	(52)	0.17	(0.21)	0.12	(0.29)
Oct	19	(49)	21	(49)	0.11	(0.30)	0.12	(0.30)
Avg	44	54	35	34	0.26	0.28	0.20	0.17

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.

<u>Real-time Failed Intertie Transactions</u>

While Ontario has become a net importer in the May through October period, we also see a general rise in transaction failures (both export and import) compared to summer 2004. The data in Table 1–25 below show a rise in the average export failure rate.

Table 1 - 25: Incidents and Average Magnitude of Failed Exports from Ontario May – October

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate (%)***	
	2004	2005	2004	2005	2004	2005	2004	2005
May	434	483	958	991	185	267	6.20	11.60
Jun	460	457	1,104	1,128	208	238	7.90	12.70
Jul	460	337	950	1,350	192	275	7.40	11.30
Aug	452	368	1,052	1,478	230	226	7.50	9.20
Sep	373	341	920	1,000	205	242	13.60	8.30
Oct	387	477	964	1,188	232	231	13.90	10.60
Avg	428	411	991	1,189	209	247	9.40	10.60

*Note: the incidents with less than 1MW are excluded
**Note: Average is based on those hours where failure occurred
***Failure rate is the total failed MW divided by the total scheduled MW in the unconstrained sequences in the month.

In the summer of 2005 the total volume of imports was up over the previous year. In 2004 in the May through September period Ontario exported net close to 1.8GWh. In the summer of 2005 Ontario imported net 750GWh. Import failures were more prevalent and larger in 2005 than in 2004.

Table 1 - 26: Incidents and Average Magnitude of Failed Imports into Ontario, May – October

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure Rate *** (%)	
	2004	2005	2004	2005	2004	2005	2004	2005
May	117	355	388	650	77	168	2.20	6.10
Jun	272	348	864	916	120	190	4.80	5.90
Jul	261	349	545	1110	124	192	5.40	6.00
Aug	319	301	667	1025	96	188	4.20	5.70
Sep	293	316	509	885	91	173	2.50	5.40
Oct	293	335	482	810	131	134	3.90	4.30
Average	259	334	576	899	107	174	3.80	5.60

*Note: the incidents with less than 1MW are excluded
** Note: Average is based on those hours where failure occurred
*** Failure rate is the total failed MW divided by the total scheduled MW in the unconstrained sequences in the month.

A further breakdown of import and export failures by on and off-peak is provided in the Statistical Appendix, Tables A-39 through A-44.

Table 1–27 compares failures rates for exports and imports since market opening. The export failure rate is consistently, and substantially higher than the import failure rate. While the export failure rate has declined from the very high levels experienced in summer 2002, there has never been a seasonal average failure rate lower than 6.9% and in the summer of 2005 it rose to 10.6%. The import failure rate also declined in 2003 but has risen since then. This past summer, the import failure rate reached its highest average value, exceeding the failure rate in the summer of 2002.

The IESO is considering the introduction of a Day Ahead Commitment Program, to enhance reliability next summer by reducing the potential for failed import transactions. We comment on this proposed program in Chapter 4.

Table 1 – 27 Export and Import Failure Rates, 2002 – 2005 (Percentage)

	Summer 2002		Winter '02-'03		Summer 2003		Winter '03-'04		Summer 2004		Winter '04-'05		Summer 2005	
	X*	**M***	**X**	**M**	**X**	**M**	**X**	**M**	**X**	**M**	**X**	**M**	**X**	**M**
May	10.70	2.10			11.10	1.80			6.20	2.20			11.60	6.10
Jun	14.50	3.20			15.90	1.70			7.90	4.80			12.70	5.90
Jul	49.00	6.20			12.80	2.00			7.40	5.40			11.30	6.00
Aug	63.10	3.50			14.40	1.70			7.50	4.20			9.20	5.70
Sep	23.00	5.80			13.40	1.80			13.60	2.50			8.30	5.40
Oct	15.50	5.50			13.20	3.50			14.00	3.90			10.60	4.30
Average	29.30	4.40	7.30	2.50	13.50	2.10	6.90	2.20	9.40	3.80	9.70	4.10	10.60	5.60
Nov			6.60	2.20			10.40	2.30			11.40	3.60		
Dec			8.10	3.30			7.50	2.30			10.00	2.90		
Jan			6.10	1.80			5.40	3.40			7.40	3.80		
Feb			6.20	3.00			6.40	1.80			9.70	4.00		
Mar			5.60	2.30			6.00	2.00			8.90	6.10		
Apr			11.00	2.10			5.80	1.60			10.90	4.20		

*'X' stands for exports and 'M' stands for imports

14. Hourly Uplift and Components

The hourly uplift charge consists of payments for Import Offer Guarantee (IOG), Congestion Management Settlement Credit (CMSC), Operating Reserve (OR) and transmission losses on the electrical grid. Typically CMSC payments and line losses make the largest contributions to the uplift charges. Over the period May to October 2005, total hourly uplift charges more than doubled, increasing to $400 million compared to $190 million for the same period in 2004. As shown in Table 1–28, CMSC payment rose from $45M in 2004 to $178M in 2005. Line losses increased from $118M to $156M. IOG payments recorded the largest percentage increase, rising from $8M in 2004 to $55M in 2005. Operating reserve payments dropped from $19M in 2004 to $11M in 2005.

In general CMSC payments are made to dispatchable market participants when the IESO directs them to perform in a manner different from what the market schedule intended them to produce. Facilities are constrained on to bring additional supply to the system and typically they are constrained off to relieve congestion. Therefore under high demand conditions with high levels of congestion one might expect to see large CMSC payments. This is what happened over the period May to October 2005 when Ontario experienced record demand levels and increased grid congestion.

The rise in constrained off payments is partly attributable to constrained-off generation in the Northwest. These generators have relatively fixed offers for their output. Given the overall increase in energy market prices, the spread between the MCP and the offers has widened, leading to larger constrained-off payments. As shown in Table 1–29, over the review period the average monthly constrained-off payment in the Northwest amounted to $5.2M compared to $1.7M in 2004. In August 2005 the amount jumped to $9.2M compared to $2.4M in August 2004.

Constrained off payments to dispatchable loads have increased from a monthly average of $0.9M in the May-October 2004 period to a monthly average of $5.1M in the summer of 2005. The increase in constrained off payments to dispatchable loads is related to two factors. First tight summer supply conditions in the market have frequently necessitated curtailment of these loads for reliability purposes. Second there has been an increase in the number of dispatchable loads participating in the market in 2005 compared to 2004, and a corresponding rise in self-induced CMSC payments.[13] Of note is a large amount of $10M paid to dispatchable loads in August 2005, a month in which loads were constrained off mostly for adequacy reasons. As a result only $1.6M of the $10M was recovered as self-induced CMSC payments.

[13] CMSC can be induced when a load does not fully respond to dispatch instructions over several intervals. This is often caused by a process upset at the plant and can last for several intervals and sometime hours. This is in contrast to the more typical situations where system requirements lead to constraining off a resource. When such self-induced CMSC occurs for a dispatchable load, the Market Rules allow the IESO to reduce or recover the CMSC payments.

In the last report we raised the issue that losses appeared to have changed dramatically from one year to the next. The IESO has reviewed this and concluded losses within the DSO are treated correctly. We note however that in some months uplift associated with losses continues to appear much higher or lower than expected. For example, adjusting for monthly energy price differences, July 2004 exhibited twice the uplift, while September 2005 had about half the uplift of other months.[14] The explanation for this is that what we refer to as "losses" actually includes some other quantities.[15] Normally these other quantities are small but on occasion can be large, leading to the unusual observations in July 2004 and September 2005.

The substantial increase in IOG payments reflects the combination of increased volume of imports and an increased price forecast error between pre-dispatch and real-time in 2005. Six of the ten largest IOG payments occurred in the month of August when Ontario had record demand levels. According to Table 1–30, there were more hours in 2005 where IOG was paid and the price difference in hours with IOG was larger in 2005 than 2004. For example, in July and August 2005 the average price gap between the pre-dispatch and real-time prices was $24 and $35, respectively, compared with differences in 2004 between $8 and $10.

The low level of operating reserve payments reflected increased supply of operating reserves from dispatchable loads in the period May to October 2005.

[14] Using the average HOEP for the month, we calculated an equivalent amount of energy associated with the "losses" uplift payment. Comparing this with the total market schedule energy for the month resulted in a "losses" equivalent between 2.5% and 2.8% in most months. The exceptions are July 2004 and September 2005, which had implied "losses" of 6.3% and 1.2% , respectively.

[15] These are associated with the difference between scheduled and actual net imports, metering error adjustments and the like. Losses and several other amounts are reported by Settlements in a single Settlement code, 150, from which we get the starting point for our uplift calculation. Some large differences can be backed out of the total, such as those related to IOG payments, with the remainder predominantly representing losses.

Table 1 - 28: Total Hourly Uplift Charge, May – October

	Total Hourly Uplift $ Millions		IOG $ Millions		CMSC $ Millions		Operating Reserve $ Millions		Losses $ Millions	
	2004	2005	2004	2005	2004	2005	2004	2005	2004	2005
May	36	32	2	3	9	11	8	3	17	16
June	29	53	1	5	9	21	4	1	15	25
July	47	87	1	12	4	43	4	1	39	31
Aug	26	110	1	20	7	55	1	1	16	33
Sep	28	62	1	7	9	24	1	1	16	30
Oct	24	56	2	8	7	24	1	4	15	21
Total	190	400	8	55	45	178	19	11	118	156

Table 1 - 29: CMSC Constrained-off Payments, May to October, 2004-2005

	Northwest $ Millions		Dispatchable Loads $ Millions		Recovered CMSC/Self Induced $ Millions	
	2004	2005	2004	2005	2004	2005
May	0.40	2.30	0.90	3.50	(0.50)	(3.10)
Jun	1.30	4.80	0.80	2.20	(0.30)	(1.70)
Jul	0.90	8.10	0.30	8.80	(0.50)	(5.80)
Aug	2.40	9.20	0.70	10.10	(0.10)	(1.60)
Sep	3.50	4.20	1.40	3.00	(1.30)	(2.80)
Oct	1.70	2.70	1.60	2.70	(1.00)	(1.80)
Total	10.30	31.40	5.60	30.30	(3.60)	(16.90)
Average	1.70	5.20	0.90	5.10	(0.60)	(2.80)

Table 1 - 30: Pre-dispatch to HOEP Differences in Hours with IOG Payments, May to October, 2004-2005

	2004		2005		
	Number of Hours with IOG	PD-HOEP	Number of Hours with IOG	PD-HOEP	PD-HOEP Diff 2005 vs. 2004
May	434	16.23	549	10.14	(6.09)
Jun	462	11.74	558	14.36	2.62
Jul	421	9.70	523	24.00	14.30
Aug	495	7.70	491	35.37	27.67
Sep	466	6.90	473	24.47	17.57
Oct	489	9.71	553	28.03	18.32
Average	462	10.24	525	22.43	12.19

15. Internal Zone Prices

As the Panel has explained in previous reports, Ontario has two real time sequences: an unconstrained sequence that determines the uniform price which generators receive and a constrained sequence that calculates shadow prices at specific generation unit locations. Constrained on and off payments made to generators and loads are the result of different schedules for the constrained and unconstrained sequences, based on a different view of what is economic in each. Generation offers below the uniform price are economic in the unconstrained schedule. To be economic in the constrained schedule a generator offer must be below the local shadow price. The shadow price is the true cost of supplying energy at that node. Because the nodal prices differ from the uniform price, some resources will be constrained off and others constrained on. These different schedules lead to constraint payments, which are paid to the dispatchable facilities, and collected from loads in the form of uplift.

Transmission congestion is a central feature of electricity markets. In the constrained sequence the economic dispatch of the generators ensures the efficient use of the transmission system. Due to transmission congestion and losses this sequence will determine which generators must change their dispatch in order to maximise the utilisation of the available transmission and minimise congestion. This process creates nodal prices. Price differences between nodes indicate congestion. Where there is no transmission congestion nodal prices will differ only because of losses.

This section aggregates the 300 nodal prices for generation in Ontario into ten internal zones that tend to exhibit the same characteristics due to the major transmission interfaces between them. Differences in the ten nodal prices calculated provide an indication of the impact of congestion between the various zones, rather than within any zone.

Small differences between zones can arise because of transmission losses whereas significant differences indicate transmission congestion.[16] The average zonal prices for May–October 2005 are reported in Figure 1-14 below. The zonal prices in central Ontario (i.e. Toronto zone and its neighbouring areas) are very close to each other, around $100, suggesting that transmission congestion was not often an issue among these zones. On the other hand, the zonal price in the Northwest Zone is $33.17, reflecting the frequent congestion of the transmission lines from the Northwest to Central Ontario in the review period, and the constraining off of lower cost generation.

[16] Because of the long distances involved, losses for generation in the Northwest can be substantial, between 10% and 30%, and partly accounts for different prices in that zone.

Figure 1 - 14: Average Internal Zonal Price, May – October 2005

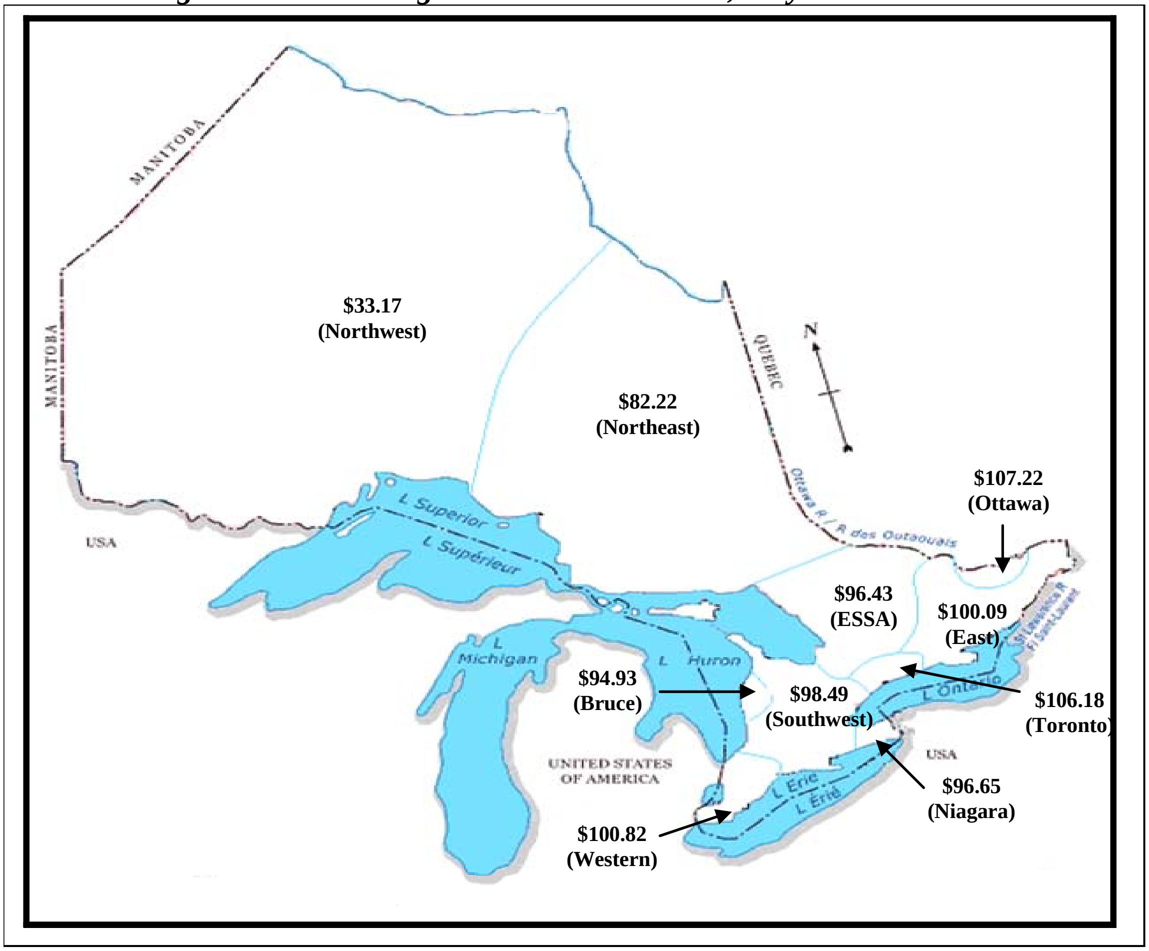
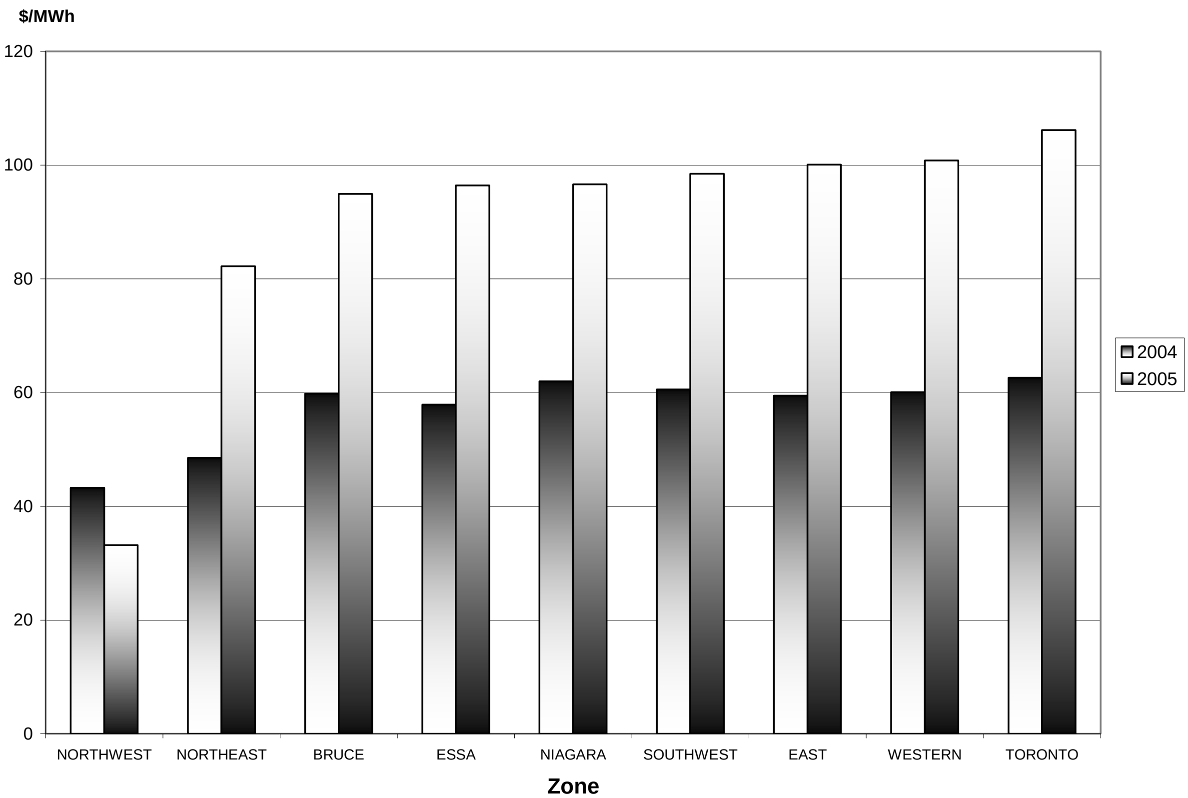


Figure 1-15 below presents the price comparison between 2004 and 2005 by zone. There are two initial observations. First, the zonal price distribution remained similar in the two years: the zonal price in the Northwest Zone was substantially lower than the zonal price in other zones, especially in central Ontario areas. Second, the price difference between the Northwest zone and central Ontario zones increased in 2005: the zonal price in the central area was about $40 greater in 2005 than in 2004, while the zonal price in the Northwest zone was about $10 lower. The lowered Northwest zonal price is indicative of increased congestion in 2005. This is consistent with the increase in CMSC costs in the Northwest from $10.3 million to $31.4 million, shown in Table 1-29.

Figure 1 - 15: Zonal Price, May – October, 2004 and 2005



The differences between nodal prices in the northwest and in the southern portions of the province are also an indication of the CMSC payments in total.[17] The larger difference in the two values in 2005 (approximately a $70/MW/h difference) compared with 2004 (approximately $18/MWh) is again entirely consistent with the much larger total CMSC payments in 2005 ($178M versus $45M).

[17] Consider $33/MWh generation in the Northwest constrained off and replaced by $100 generation in the south. The constrained off generation is paid MCP - $33, while the constrained on generation is paid $100 – MCP. The total of the constrained off and constrained on payments for these marginal generators is ($100 – MCP) + (MCP - $33) = $100 - $33 = $67. This is independent of the specific MCP, and shows that in a theoretical sense that the total CMSC is related to the net cost of replacing the constrained off generation, and approximately equal to the difference in nodal prices.

16. Net Revenue Analysis

The MAU performed a simple analysis to estimate the level of net revenues received by a generator over the review period assuming the realised energy prices in the Ontario market. The analysis adopts the approach used in past panel reports. Essentially a generator is assumed to produce energy whenever the HOEP in any hour exceeds the marginal cost of the generator. The net revenues received over the period are the sum of the hourly energy revenues obtained by the generator. Results for the period May to October, on a year-over-year comparison, are summarised in Figure 1-16 and Table 1-31.

Figure 1 – 16: Net Revenues May 2002 to October 2005

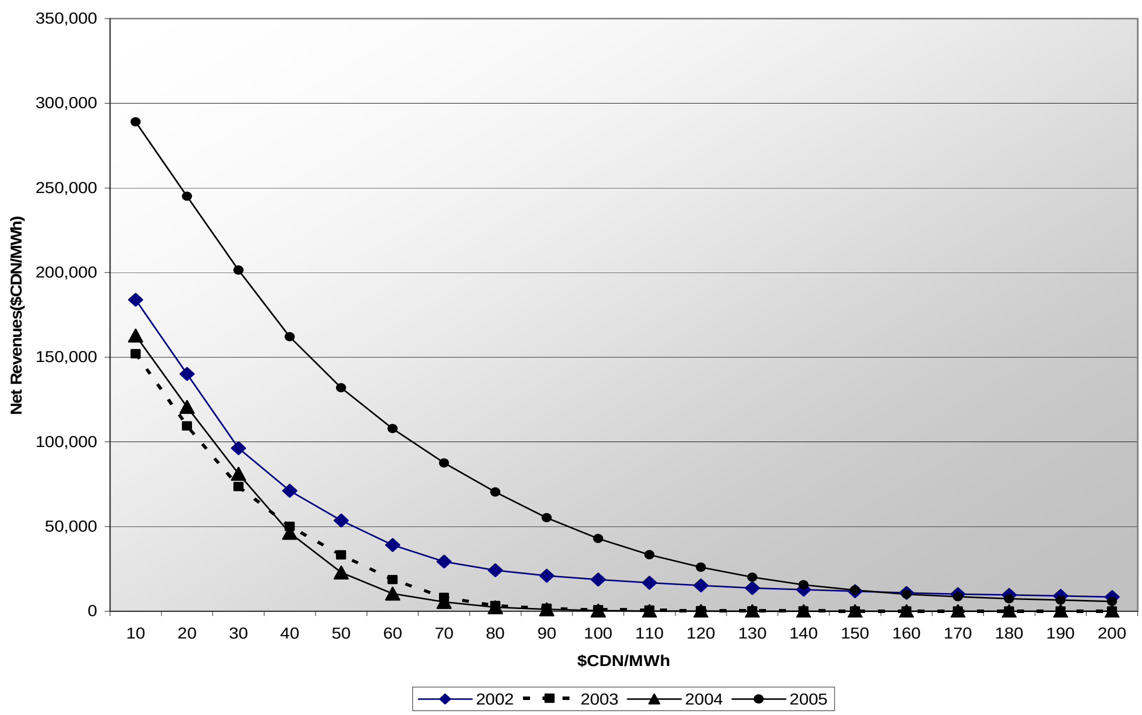


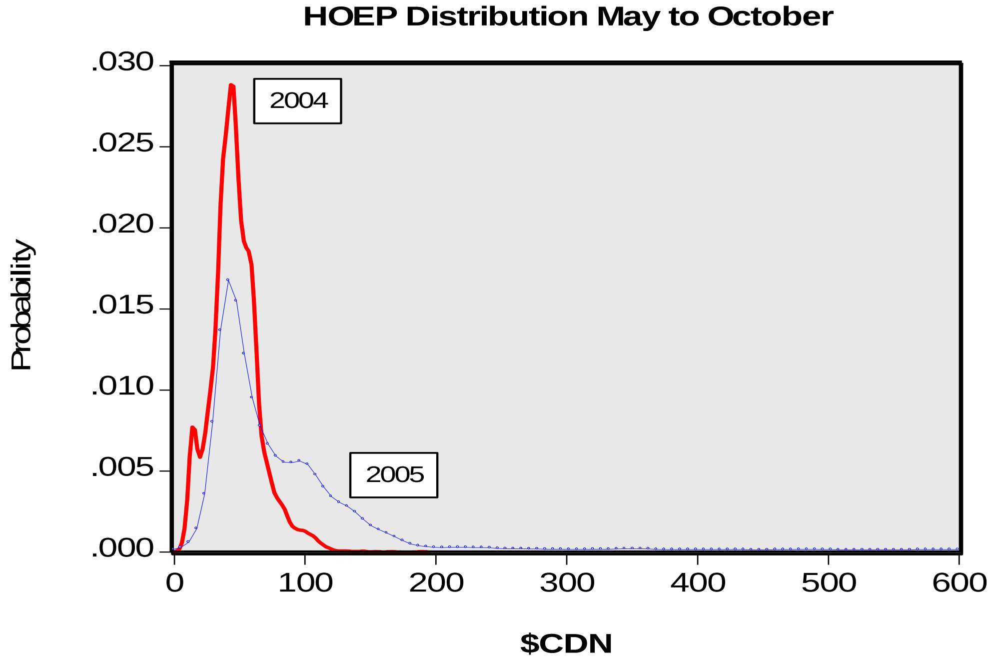
Table 1 - 31: Net Revenues, May to October, 2002-2005

Marginal Cost	2002	2003	2004	2005
10	183,903	152,020	162,864	288,943
20	140,135	109,401	120,718	245,025
30	96,209	73,634	81,167	201,410
40	71,179	50,042	46,326	162,025
50	53,579	33,184	22,872	131,975
60	39,119	18,671	10,389	107,812
70	29,373	8,136	5,452	87,545
80	24,192	3,392	2,363	70,361
90	20,916	1,708	1,067	55,227
100	18,781	844	331	42,963
110	16,881	619	156	33,310
120	15,153	350	104	25,957
130	13,677	276	0	20,126
140	12,705	194	0	15,615
150	11,811	154	0	12,494
160	10,771	140	0	10,054
170	10,121	130	0	8,584
180	9,549	120	0	7,406
190	8,985	110	0	6,532
200	8,313	100	0	5,805

These results indicate that net revenues per megawatt of generation in 2005 were higher than in 2004. For example a $120 marginal cost generatorin 2005 would have made $25,957 in 2005 compared to $104 in 2004.[18] The higher net revenues are mostly attributed to an increased frequency of high energy prices in the market in 2005 compared to 2004. In particular, there were 206 hours where prices fell in the $150 - $200 range in 2005 compared to 3 such hours in 2004. Moreover there were 40 hours in 2005 where prices exceeded $250 compared to no such hours in 2004. This trend is reflected in the hourly price distributions as shown in Figure 1–17 below.

[18] One must be careful in comparing 2004 and 2005 marginal costs because of the rapid natural gas price inflation in 2005. For example a 7000 BTU/KWh generator had an estimated marginal cost of $49 in September 2004 compared to $104 in September 2005.

Figure 1 - 17: HOEP Distributions, May to October, 2004 - 2005



Internal Rate of Return for a New Project

The Internal Rate of Return (IRR) for an investment is the discount rate for which the present value of future cash flows equals the cost of the initial investment. Two items are needed to compute the IRR -- the annual cash inflows and the initial cash outflows. In the following analysis the MAU assumes that the project has a 30-year life with an initial capital outflow of $711/KW. To produce annual cash inflows the MAU first generated price distributions for future years using historical price data and Monte Carlo simulations. Net annual revenues were then calculated using the approach described in the previous section. The results reported in Table 1-32 show that the before-tax IRR ranges from 16% for a $60 generator to 2% for a $100 generator.

Table 1 - 32: Internal Rates of Return for selected marginal costs

Marginal Cost ($)	IRR (%)
60	15.50
80	7.20
90	4.20
100	1.80

These assessments are presented for information only. The Panel has no view on the adequacy of these rates of return, given the wide range of uncertainties, both economic and political, associated with investment decisions in the Ontario market.

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 hours on a daily basis to discern if anomalies are occurring that require further investigation. As well, 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 71 hours during the period May 2005 to October 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 report, a 'low priced hour' is defined as any hour in which the HOEP was less than $20/MWh.[19] There were 52 hours in the period May 2005 to October 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. In its review and analyses of high priced and low priced hours and anomalous events, the MAU did not find any event which suggests that there was any abuse of market power by any market participant.

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

2. Analysis of High Priced Hours

The MAU regularly reviews all hours where the HOEP exceeds $200/MWh or 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 from 2003 to 2005. There were 71 hours in which the HOEP exceeded $200/MWh during the period May 2005 to October 2005. During the same period in the previous year (May 2004 to October 2004), there were no hours in which the HOEP exceeded $200/MWh. There were no hours in which the hourly uplift exceeded the HOEP in May to October 2005.

Table 2 - 33: High Priced Hours, Monthly, October, 2003 – 2005

	2003	2004	2005
May	0	0	3
June	4	0	3
July	0	0	15
August	0	0	25
September	1	0	21
October	1	0	4
Total	6	0	71

As has been the case in previous review periods, all high priced hours during the period May-October 2005 had one or more of the following characteristics:

- Real-time demand was much higher than the pre-dispatch forecasts of demand. This was one of the contributing factors in 37 cases.
- Imports scheduled in pre-dispatch failed in real-time. This was one of the contributing factors in 27 cases.

- One or more generating units that appeared to be available in pre-dispatch became unavailable in real-time as a result of a forced outage or derating. This was one of the contributing factors in 36 cases.

As explained in earlier reports, each of these factors has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion. 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 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. In cases of extreme shortage, the IESO declares an energy emergency alert, in accordance with NERC policies.[20] Under an emergency alert the IESO can initiate various measures to cope with the shortage situation. Of the 71 hours in which the HOEP exceeded $200, there were 36 that involved energy emergencies.

While a tightening of the real time supply cushion relative to pre-dispatch was a contributing factor in all high priced hours during the period May-October 2005, there were also other factors at play. In 38 cases, the pre-dispatch price was $200 or higher implying that the HOEP would also have been over $200 even if there had been no real-time tightening of the supply cushion. Thus, in 38 of 71 cases, unforeseen events in real-time simply exacerbated an already tight supply situation.

[20] NERC Appendix 5C. NERC has established three levels of Energy Emergency Alerts to be used by reliability coordinators in case of emergencies. Level 1 indicates that all available resources are in use. Level 2 indicates that load management procedures are in effect. These may include public appeals to reduce demand, voltage reduction, and interruption of non-firm end use loads, demand side management and utility load conservation measures. Level 3 indicates that firm load interruption is imminent or in progress. Under each alert level, NERC has established defined responsibilities for the IESO. The IESO in turn has also developed its own internal procedures to manage reliability on the grid. These are defined in the IESO market rules and in the IESO internal procedures, Appendix E: Emergency Operating State Control Actions IMP_POL_0002. During shortage conditions the IESO takes actions to avoid the declaration of an Emergency Operating State. These actions range from cancelling outage applications, issuing public appeals, issuing NERC emergency energy alerts, constraining on internal resources, making exports recallable, voltage reductions, constraining on imports, constraining off exports, purchasing emergency energy. If all these measures fail, the IESO will then declare an Emergency Operating State in which it will cut exports, operate to emergency condition limits, implement EDRP (emergency demand response program) and curtail non-dispatchable load. EDRP is a reliability-based program intended to mitigate the adverse impacts of shortages when all commercial mechanisms in the market have been exhausted.

Pre-dispatch prices in excess of $200 are generally characterized by loads in excess of 23,000MW and correspondingly high prices in neighbouring markets. For example, hour-ahead prices in the New York control area ranged from $100 CDN to $270 CDN in the hours where pre-dispatch prices exceeded $200 in the Ontario market.[21] Moreover the IESO was under emergency alerts in 29 of the 38 hours, with most of those alerts occurring in June to August 2005. The high pre-dispatch prices were set mostly by importers.

2.1 Occurrences of High Priced Hours

The 71 hours in which the HOEP exceeded $200 were separated into two groups for purposes of more detailed analysis. The first group contains the 33 hours in which the pre-dispatch price was below $200. The second group contains the 38 hours with a pre-dispatch price at or above $200. Table 2-2 below shows the top ten high priced hours over the review period. These hours span each group.

Table 2 - 34: Top 10 High Priced Hours, May - October 2005

Rank	Date	Hour	HOEP ($)	Pre-dispatch Price ($)	Major Market Factors
1	Sept 21	16	640	165	Forced outage
2	July 20	14	533	116	Demand greater than forecast, forced outages
3	October 23	19	522	150	Forced outage
4	July 20	16	458	130	Demand greater than forecast, forced outage
5	June 24	17	439	200	Labour relation problems at a coal plant
6	August 9	12	419	152	Demand greater than forecast, import failure
7	August 10	12	394	564	Import failure
8	July 18	16	388	270	Record high demand, import failure
9	August 3	12	388	247	Demand greater than forecast, import failure
10	August 9	18	387	450	Demand greater than forecast, forced outages

The next subsections review the situation in more detail in six specific high-price hours. The first three of these are representative of the situation where the pre-dispatch price did not indicate particularly tight supply conditions, but real-time events led to price spikes. The second set of three hours selected for examination is drawn from the 38 instances where the pre-dispatch price

[21] This is the average price at the intertie zone between New York and Ontario referred to as the NY_OH zone.

was also over $200. In two of these cases, even though the situation deteriorated in real-time the HOEP was lower than the pre-dispatch price.

2.2 Hours with Pre-Dispatch Prices below $200 and HOEP above $200

September 21, 2005 - Hour 16

The highest HOEP registered in the period under review, $640/MWh, occurred on September 21 in hour 16.

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

The pre-dispatch forecast of demand was 20,819MW with 810MW of net imports. Based on this level of demand and the offers available in the market, the pre-dispatch price was $165/MWh and the supply cushion was 17%. All available fossil generation was scheduled to its capacity limits leaving only peaking hydroelectric units to supply energy in the event of a real-time shock. These hydroelectric units had offers of 247MW between $166 and $300 with additional offers in the range of $500 to $2,000. In summary, the real-time offer curve was extremely price sensitive to any demand or supply shocks.

<u>Real Time Market Conditions</u>

In real time, demand came in at 20,599MW, well below the forecast level of demand. Upward pressure on the market price in hour 16 was the result of a forced outage that began in hour 15. At 14:16, the IESO was informed of a forced outage of a fossil unit due to technical problems. The unit was gradually removed from service and it came offline at 15:34. The IESO reduced 30-minute reserve by 100MW to cope with the sudden supply disruption. The real time supply cushion dropped from 17% to 6%. This forced outage resulted in a loss of almost 500MW of inframarginal generation. This caused the offer curve to shift upward to the left into the domain of peaking hydroelectric units with offers ranging from $500/MWh to $900/MWh. As a result, the market cleared on the steep portion of the offer curve and energy prices rose sharply. The MCP ranged from $522 in interval 1 to $779 in interval 11. The HOEP was $640/MWh, the highest observed during the review period. Had the fossil unit that was forced out of production been available in real time, MAU simulations indicate that the HOEP would have been identical to the pre-dispatch price in this hour.

July 20, 2005 - Hour 14

On July 20 in hour 14 the HOEP was $533. This was the second highest HOEP recorded in the review period

Pre-Dispatch Market Conditions

The pre-dispatch forecast of demand in hour 14 was 22,079MW with a pre-dispatch price of $116. All fossil units were scheduled to their capacity limits. A further 446MW were offered by hydroelectric units at prices between $116 and $300 with some additional offers above $300. The pre-dispatch supply cushion was 27%.

Real Time Market Conditions

In real time, demand exceeded the forecast in all but one interval. A fossil unit with a capacity of 155MW tripped off at the beginning of hour 14 and another fossil unit was also forced out resulting in a generation loss of a further 155MW. As a result, the real-time supply cushion fell to just under 7%. To manage the supply disruption, the IESO opened the mandatory submission window and it accepted offers from gas-fired units.[22] In the last 15 minutes of the hour the IESO was short of reserves and it manually reduced the total reserve requirement from 1,418MW to 1,295MW for about 15 minutes. The combination of higher demand and the loss of inframarginal supply caused the market to clear on the steep part of the offer curve where peaking hydroelectric units set prices. The HOEP came in at $533, some $418 above the pre-dispatch forecast of $115.

[22] Market Manual 4, Appendix C, Short Notice Change Criteria, Part C.2.2. The mandatory submission window is the period less than 2 hours (less than 3 hours in the case of hour ahead dispatchable load facilities) before the start of the dispatch hour and at least 10 minutes prior to the start of the dispatch hour. For reliability reasons, the IESO can direct participants to make new (not revised) offers and bids in this period of time.

August 9, 2005 - Hour 12

On Tuesday August 9, in hour 12, the HOEP was $419/MWh, the sixth highest during the review period. Hot weather was the main factor.

Pre-Dispatch Market Conditions

The pre-dispatch forecast of demand was 23,965MW with a pre-dispatch price of $152. There were 359MW of peaking hydroelectric offers between $152 and $400; all other peaking hydroelectric energy was offered above $400. In addition there were 265MW of fossil energy offered at $400. Imports scheduled amounted to 2530MW. The supply cushion was 26%.

Real Time Market Conditions

Failed net imports amounted to 253MW. As a consequence, the market was obliged to turn to a fossil unit with offers at $400 and a peaking hydroelectric unit with offers above $450 in order to meet demand. The fossil unit offered at a price of $400 because it operated under environmental restrictions as an energy-limited resource.[23] The MCP ranged from a low of $400 in interval 1 to a high of $494 in interval 12. In this hour some export transactions on the Michigan intertie were constrained off and they were incorrectly coded by the IESO. This had the effect of overstating both load and the MCP from intervals 6 to 12. As a result the IESO administered prices over these intervals. The net result of the failed imports was to drive the HOEP from $152 in pre-dispatch to $419 in real time.

2.3 Hours with Pre-Dispatch above $200 and HOEP above $200

August 2, 2005 - Hour 13

On this day the IESO declared an EEA 1 (Emergency Energy Alert level 1) at 7:00 am. and a power advisory was issued to the public at 7:09am. At 10:53 the IESO escalated the EEA 1 to

[23] An energy-limited resource will generally have a higher opportunity cost than a resource that is not energy limited, and the offer price of $400 reflects this.

EEA 2. Even with the level 2 alert, the IESO was unable to respect the 30-minute reserve requirement. As a result it declared an Emergency Operating Stateat 11:00.[24] Under this state, the IESO can relax the operating condition limits on transmission lines. This enables the IESO to make bottled energy available at the expense of increased risk to system security. In hour 13 the IESO was under an emergency operating state yet, because of the treatment of emergency energy in the price-determination process, the real time price failed to reflect scarcity conditions in the market.

Pre-Dispatch Market Conditions

Forecast market demand for hour 13 was 24,214MW and the pre-dispatch price was $290. The supply cushion was 25%. Net imports were 2,973MW. All fossil units were committed to full capacity. Further up the offer curve, there was peaking hydroelectric generation offered at above $325 and gas-fired generation offered at prices between $399 and $1,900. This gave rise to a situation in which small increases in load or reductions in inframarginal supply could result in large increases in prices.

Real Time Market Conditions

In hour 13 there were import failures and the IESO was in an Emergency Operating State meaning it did not have sufficient energy to meet demand. As a remedy, the IESO purchased 500MW of emergency energy from New York. The effect of this emergency purchase was to drive the HOEP down to $255, which was $35 lower than the pre-dispatch price. This reduction in the HOEP during an energy emergency (when prices should be signalling scarcity) occurred because emergency energy purchases by the IESO were treated as a reduction in market demand, driving down the market price. In past reports the Panel had recommended that emergency purchases be more accurately reflected in market prices. In this case, MAU simulations indicate that the HOEP would have been $372 (rather than $255) had the 500MW not been treated as a reduction in load.

[24] Market Rules, Chapter 5, Section 2.3 states that the IESO is considered in an Emergency Operating State when observance of security limits under a normal operating state will either require curtailment of non-dispatchable load or restrict transactions on interconnected systems during

In August 2005 the IESO accepted the Panel's recommendations and made changes to the market rules to address the treatment of emergency energy purchases. The new procedure was used on September 12 and we provide more details on this change in Chapter 3.

July 25, 2005 - Hour 15

In this hour the pre-dispatch price was $515. In real time there was an energy emergency yet the HOEP dropped to $228.

Pre-Dispatch Market Conditions

Forecast demand for hour 15 was 24,983MW. At this level of demand, the pre-dispatch price was $515, net imports were 2,192MW and all fossil units were scheduled to their capacity limits. Both the New York and Michigan interties were import congested. There were further offers from peaking hydroelectric units at prices above $530/MWh and the pre-dispatch supply cushion was 20%. The pre-dispatch Richview nodal price was $322.[25] The reason that the pre-dispatch Richview nodal price was less than the pre-dispatch market price is that, apparently in anticipation of transmission restrictions within Ontario, the IESO constrained on 506MW of net imports, which do not show up in the unconstrained (market) schedule. As a consequence, constrained (nodal) prices were lower than the market price in pre-dispatch.

Real Time Market Conditions

Demand came in well below the forecast for hour 15. The lower-than-forecast demand drove the HOEP down to $228 a reduction of $283 from the pre-dispatch price. In the real time constrained schedule, nodal prices ranged from $125 to $248 and averaged $139. In essence, real time constrained prices were not only below pre-dispatch, they were below the HOEP as well. This was because the IESO constrained on imports in real time in addition to those already

an emergency on the IESO grid or on a neighbouring electricity system.

[25] The nodal price at the Richview bus is used as a reference price in the IESO system. This reference price is an indicator of supply and demand conditions in the constrained model of the Ontario grid. More details can be found in our December 2004 report, pages 57-59.

in the market schedule as well as over-forecasting demand.[26] The IESO constrained on imports because of concerns about insufficient internal resources related to reduced generation at the a base-load station and reduced hydroelectric energy in the current hour. The generation was reduced at the base-load station to alleviate internal transmission limits and hydroelectric units were constrained down to preserve their energy for future hours where demand was expected to increase.

June 24, 2005 - Hour 17

On June 24, the HOEP reached $438 in hour 17. On this day the temperature soared to 34 degrees Celsius and was equivalent to 41º C when Humidex conditions are factored in. In its System Adequacy Assessment (SAA) the IESO indicated energy and capacity shortfalls in hour 11 to hour 18. Pre-dispatch prices ranged from $30 to $200. On that hot summer day, labour problems led to the gradual shutdown of all six Nanticoke generating units.[27] The IESO declared an EEA 1 just before midday, escalated it to EEA 2 at 16:00. A provincial power warning was issued and consumers were asked to reduce electricity use until 21:00. The largest price impact, related to the forced shutdown of the remaining two Nanticoke units, occurred in hour 17. The HOEP came in $238 higher than forecast in pre-dispatch.

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

By early afternoon, four of the six Nanticoke units had been removed from service. This represented a generation loss of 1,590MW. In hour 16, a gas-fired generator was forced out due

[26] IESO Procedure 2.4-7 "Interchange Operations"-Appendix B. Under normal conditions, the IESO uses the outcome of the hour ahead pre-dispatch (PD) constrained sequence to set intertie transactions for the next hour. For a variety of reasons, it is impossible to always use the pre-dispatch results. The IESO may occasionally change intertie schedule quantities for reasons such as: a) internal adequacy (i.e the ability to meet reserve/load requirements; b) internal security (i.e. the ability to meet security limits); c) external adequacy or security curtailments (TLR's and contingencies); d) coordinated scheduling protocols (i.e. New York–IESO protocol); e) failure of market participant to successfully navigate adjacent markets and; f) operating reserve activation. Interchange schedule quantity changes are made by the IESO and they require manual codification. Four reason codes can be applied: TLRi, TLRe, OTH and ORA. In general TLRi is applied when there is a shortfall in the present or next hour because of internal security limit or when the IESO needs to shift energy limited resources for future hour adequacy. The OTH code is used when there is a shortfall in the present or next hour because of a lack of internal resources. The IESO can use the TLRi code and constrain on imports when: a) internal security problems occur after the hour ahead pre-dispatch timeframe and there are insufficient real time internal resources to solve the problem or conditions change in real time and there are insufficient internal resources to solve the problem; b) a net intertie scheduling limit is violated in real time as a result of a failed transaction on that tie; and c) hydraulic facilities are constrained off for future hour adequacy.

to mechanical problems, resulting in an additional 232MW generation loss. Forecast demand for hour 17 was 23,458MW. At this level of demand, the pre-dispatch price for hour 17 was $200/MWh. Imports scheduled amounted to 2,588MW and net imports were 1,533MW. There was an additional 1,432MW of imports offered at prices between $200 and $350, an additional 675MW of hydroelectric generation offered at prices between $200 and $2,000MW and an additional 41MW of gas-fired generation offered at prices between $250 and $1,000. This resulted in a pre-dispatch supply cushion of 16.8% for hour 17.

Real Time Market Conditions

At the start of hour 17, Nanticoke G3 and G4 were forced out. The resulting generation loss was 770MW. Although real-time demand came in lower than forecast in all intervals, the real-time supply cushion was 1.3%. As a result of this significant loss of inframarginal supply, the MCP jumped to $1,000 in intervals 1 and 2 and to $999 in intervals 3 and 5 (See Table 2-3.). There was considerable uncertainty about reliability, and a concern that the remaining two Nanticoke units might also be forced out. As a result, beginning in interval 4, the IESO cut exports by 700MW for the balance of the hour.[28] The emergency reduction in exports led to price stabilizing in the range of $155/MWh.

[27] On this day there was picketing activity by Hydro One workers at the Nanticoke plant which is owned by Ontario Power Generation (OPG). This picketing activity prevented OPG employees (who were not on strike) from safely operating the Nanticoke units.

[28] The IESO cut exports for internal security reasons in accordance with Appendix E Market Manual 7.4. Due to a coding error in interval 5, the export reductions were not reflected in the market schedule and the price spiked from $150/MWh to $999/MWh. The coding was corrected in interval 6.

Table 2 - 35: Prices and Demand, Hour 17, June 24, 2005

Interval	Actual MCP	PD MCP	Actual - PD	Real time minus Pre-dispatch demand
1	1000	200	800	(153)
2	1000	200	800	(173)
3	999	200	799	(227)
4	155	200	(45)	(201)
5	999	200	799	(250)
6	155	200	(45)	(168)
7	155	200	(45)	(175)
8	155	200	(45)	(207)
9	155	200	(45)	(152)
10	155	200	(45)	(172)
11	155	200	(45)	(159)
12	180	200	(20)	(57)

The Panel notes that the procedure used by the IESO to curtail the export transactions led to price signals that were counterintuitive, in light of the very real supply issues that the market and the IESO were facing that day. This is similar to the issues we have identified in the past with regard to the introduction of emergency imports and which have now been addressed by the IESO. We see no reason why a similar arrangement should not be in place to ensure that reliability-based actions to suppress exports do not lead to counterintuitive price results. We have therefore asked the MAU to initiate discussion with the IESO as to the appropriateness of the operating procedures related to the emergency curtailment of export transactions.

3. Analysis of Low Priced Hours

A ‘low priced hour’ is any hour in which the HOEP was less than $20/MWh. As Table 2-4 indicates, there were 52 hours during the period May to October 2005 for which the HOEP was less than $20. During the same months in 2004, there were 314 low priced hours and that large number was attributed to the increase in base-load generation in Ontario over that period.

Table 2 - 36: Hours with HOEP <$20, May-October, 2003-2005

	2003	2004	2005
May	8	70	11
June	40	84	25
July	20	70	4
Aug	1	75	3
Sep	10	15	0
Oct	0	0	9
Total	79	314	52

As has been stated in previous reports, hours in which the HOEP is less than $20 have at least one of the following characteristics:

- Ontario demand is less than 15,000MW. 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 months of April, May and June but it can occur at other times.

While these are the main 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.

3.1 Occurrences of Low Priced Hours May, 2005 – October, 2005

A review of these low priced hours indicates that they were mainly a result of over-forecasts of demand and failed exports. Over-forecasts of demand were a contributing factor in 46 of the 52 low priced hours, exports failures were a contributing factor in 50 hours. In all cases demand was below 15,000MW. This is illustrated in Table 2-5 below. When demand is this low base-load generation may be sufficient to meet it. The case of October 8, hour 5 is illustrative and we discuss it below.

Table 2 -37: Summary Data On Hours With HOEP Less Than $20/MWh

	May	Jun	Jul	Aug	Sep	Oct
Total Hours	11	25	4	3	0	9
Average Demand (MW)	11,926	12,372	12,038	13,193	n/a	12,440
Average Failed Exports (MW)	427	375	690	1373	n/a	523
Average Failed Imports (MW)	4	39	83	582	n/a	72

October 8, 2005 - Hour 5

On this day in this hour, demand was forecast in pre-dispatch at 12,429MW. The pre-dispatch price was projected at $27 and a total of 1,727MW of exports were scheduled. Net exports amounted to 412MW. In real time, average demand came in at 12,228MW with peak demand at 12,398MW. Net exports were 202MW, 210MW below pre-dispatch. The result was a HOEP of $16/MWh. The MCPs in hour 5 were set by a base-load hydroelectric generator.

4. Other Anomalous Events

The MAU also monitors for any other events that appear to be anomalous, even though they may not meet the 'bright-line' price tests. The following are a summary of the key anomalous events identified by the MAU during the period May through October 2005.

4.1 Unavailability of Reserve Offers from Hydroelectric Units

On May 11, 2005, it was observed that the HOEP in hours 9 and 10 reached $149 and $142 respectively. Typically the HOEP in these hours in the month of May is in the range of $50-$60. Subsequent investigation revealed that this was due in part to the unavailability of reserve offers from some hydroelectric units. Typically hydroelectric units have both energy and reserve offers in the market and they tend to be a relatively cheap source of reserve. On this particular day these units only had energy offers in the market and this resulted in the scheduling of more expensive energy and reserve offers.

The unavailability of reserve offers from hydroelectric units is a new event and it merited further inquiry. This inquiry revealed that on May 11 a combination of reduced storage capability and environmental limitations at the generation facilities involved meant that they were incapable of providing operating reserve for a full hour as is required by IESO rules and were thus ineligible to offer reserve into the market. Following discussions with the MAU, the market participant involved has made changes to its processes to offer "partial energy and partial operating reserve" when faced with similar conditions in the future. For example, if a 60MW hydroelectric facility has sufficient water to operate for 30 minutes, its energy and OR offers would now be for 30MW.

4.2 Anomalous Rise in Constrained-Off Payments

During the period under review the MAU observed a significant increase in constrained off Congestion Settlement Management Credits (CMSC) payments to some participants trading through the interties into congested zones within Ontario. Upon further review the MAU noted that participants could structure their bids and offers into known congested zones so as to receive a stream of CMSC payments with little likelihood of ever delivering energy into the Ontario market. Traders offering energy into a congested zone within Ontario at a price between the pre-dispatch and the nodal price in the zone at the intertie would be selected in the market schedule but constrained off because their offer is above the constrained (nodal) price. Similarly, participants working on an export transaction could bid at a price high enough to be accepted in the market schedule but constrained off because of congestion in the zone.

We are on record with concerns that we have identified with constrained off CMSC payments.[29] This appears to be another example of a distortion introduced with this construct. We note that a

[29] See the discussion paper and report at http://www.oeb.gov.on.ca/html/en/industryrelations/msp_cmsc.htm Our most recent commentary on constrained off payments is at pp. 90-92 of our December 2004 monitoring report.

system of location based marginal pricing in Ontario would avoid these problems and provide the proper signals to market participants and load. However, we are not seeking to re-open the debate at this time. We asked the MAU to bring this matter to the attention of the IESO's market rules group to consider amendments that would in some manner restrict CMSC payments in the circumstances outlined above. The IESO has initiated a process to address the issue.[30]

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

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

1. Introduction

This chapter summarizes changes in the market since the last report. Section 2 reports the status of issues raised in previous monitoring reports. Section 3 provides an assessment of other changes in the market. In this report, we focus in Section 3 on transmission issues raised with the installation of new equipment in March 2005, as well as providing an assessment of the operation of the Hour Ahead Dispatchable Load Program, introduced by the IESO in July of 2003.

2. Status of Matters Identified in Previous Reports

2.1 The Treatment of Emergency Imports and Voltage Reduction

In our past six reports, the Panel has consistently argued that the IESO should reform the manner in which it uses out-of-market control actions.[31] In our most recent report we focused on the events of April 7th 2005 to illustrate how these actions distort market price signals by reducing real time prices relative to the pre-dispatch levels.[32] In particular we noted the counterintuitive prices that result from the way in which voltage reduction and emergency imports are introduced in the market. Under the previous procedure, emergency imports were always included in the market schedule and at the same time demand was reduced in both the constrained and unconstrained schedules.

The Panel is pleased to report that the IESO has taken measures to address these issues. On August 11th, 2005 the IESO implemented a new procedure for the treatment of emergency imports and voltage reduction.

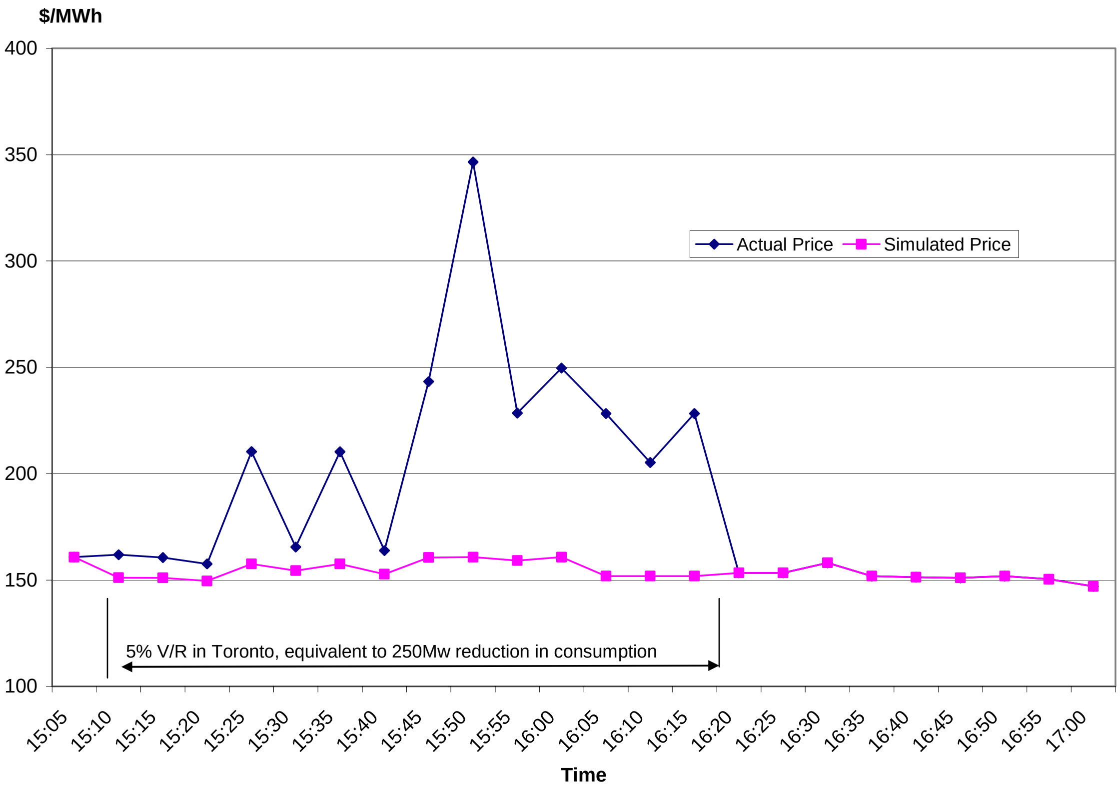
[31] See pages 47-51 of our June 2004 report for a full description of the use and impact of these out-of-market control actions.
[32] June 2005 report pages 60-66

Under the new procedure, emergency imports are excluded from the market schedule and, in periods where the voltage has been reduced, IESO increases demand in the market schedule by an estimated amount equivalent to the voltage reduction. The outcome of these two approaches is that demand is effectively added back into the schedules to calculate a Market Clearing Price assuming these actions had not occurred.

The experience on September 12, hours 16 and 17, provides an indication of the difference that the new procedure has made and will continue to make in the market. On September 12, the IESO reduced voltage from interval 2 of hour 16 to interval 3 of hour 17 because of overloading concerns at a transformer in the Toronto area. The IESO implemented the new procedure and added 250MW to demand in the unconstrained schedule over the relevant intervals. This additional demand allowed the average price in hour 16 to settle at $205 compared to a simulated price of $156 had the demand not been added to the market schedule. Figure 3-1 below shows the actual and simulated price paths. It is apparent that in this case the new procedure resulted in prices that more accurately reflected the true scarcity conditions in the market.

The Panel is encouraged by the progress made by the IESO in dealing with the issue of counter intuitive price signals in times of scarcity. The Panel notes that this manner of dealing with the emergency imports and the voltage reduction requires manual intervention by the IESO. In particular, the control room operator has to estimate the demand cut induced by the voltage reduction and then the operator has to insert this demand level back in the market schedule. There is evidently room for human error, which may bias the market price in either a positive or a negative manner. To this end the Panel has asked the MAU to monitor events where this new procedure is used and to report any noticeable bias in the demand estimation.

Figure 3 - 18: Simulated and Actual Price Paths, September 12, Hours 16, 17



2.2 Out-of-Market Control Actions

In previous reports the Panel recommended that the IESO reform the manner in which it uses out-of-market control actions. We have argued consistently that manual actions to reduce operating reserve requirements in times of stress should not be assumed to be 'free' and that Control Action Operating Reserve (CAOR) should be appropriately priced and selected as a market choice by the DSO. Such actions would improve the fidelity and integrity of price signals.

More than eighteen months ago, the IESO successfully priced 400MW of out-of-market operating reserve into the constrained and unconstrained schedules.[33] Our last report recommended that the IESO proceed expeditiously to price the remaining CAOR.

[33] The implementation of CAOR, control action source of operating reserve in the market, is discussed at pp. 93-96 of our June 2004 report.

We are pleased to report that the IESO has accepted this recommendation, and that on September 23 the IESO Board approved a change that brings an additional 400MW of CAOR into the real-time market. The price for the first 200MW is $75/MWh and the other 200MW is priced at $100/MWh. As well, IESO procedures will no longer permit manual reductions in the operating reserve requirement if a shortage were to occur in the future; rather, the shortage price will be exposed. The IESO implemented these changes to CAOR on November 23. This will contribute to the healthy development of supply and efficient resource use over the longer term.

To assess the likely impact of this change in CAOR the MAU ran a simulation for 2004 based on various CAOR scenarios, and found that the CAOR change would have led to an average increase in the energy price of $0.24/MWh, and an average increase in operating reserve prices in the range of $0.29-$0.36/MWh. (see Table 3-1). During the 236 hours when there was a reduction in operating reserve due to a shortfall, the price impacts are larger. Table 3-2 shows an average increase in the energy price of $9.28/MWh, and an average increase in operating reserve prices in the range of $10.77-$13.48 per MWh. In 2004 the pricing of the 800MW CAOR would have led in nearly all instances to no reduction in operating reserve that had a price-suppressing effect. Thus, eliminating manual out-of-market control actions and pricing CAOR results in relatively small average annual increase in prices, but provides much better price signals during shortfall situations.

Table 3 - 38: Impact of Additional CAOR – All Hours

	Price ($/MWh)	MW	Average Energy Price ($/MWh)	Average OR Price ($/MWh)		
				10 min. Spin	10 min. Non Spin	30 min. Reserve
Initial CAOR	30	400	49.91	5.77	3.73	3.50
Additional CAOR	75	200	50.15	6.06	4.02	3.86
	100	200				
Price Impact			0.24	0.29	0.29	0.36

Table 3 - 39: Impact of Additional CAOR – Hours with OR Reduction

	Price ($/MWh)	MW	Average Energy Price ($/MWh)	Average OR Price ($/MWh)		
				10 min. Spin	10 min. Non Spin	30 min. Reserve
Initial CAOR	30	400	85.38	22.10	20.14	16.99
Additional CAOR	75	200	94.66	32.87	31.43	30.47
	100	200				
Price Impact			9.28	10.77	11.29	13.48

2.3 IESO Measures to Reduce Dispatch Volatility

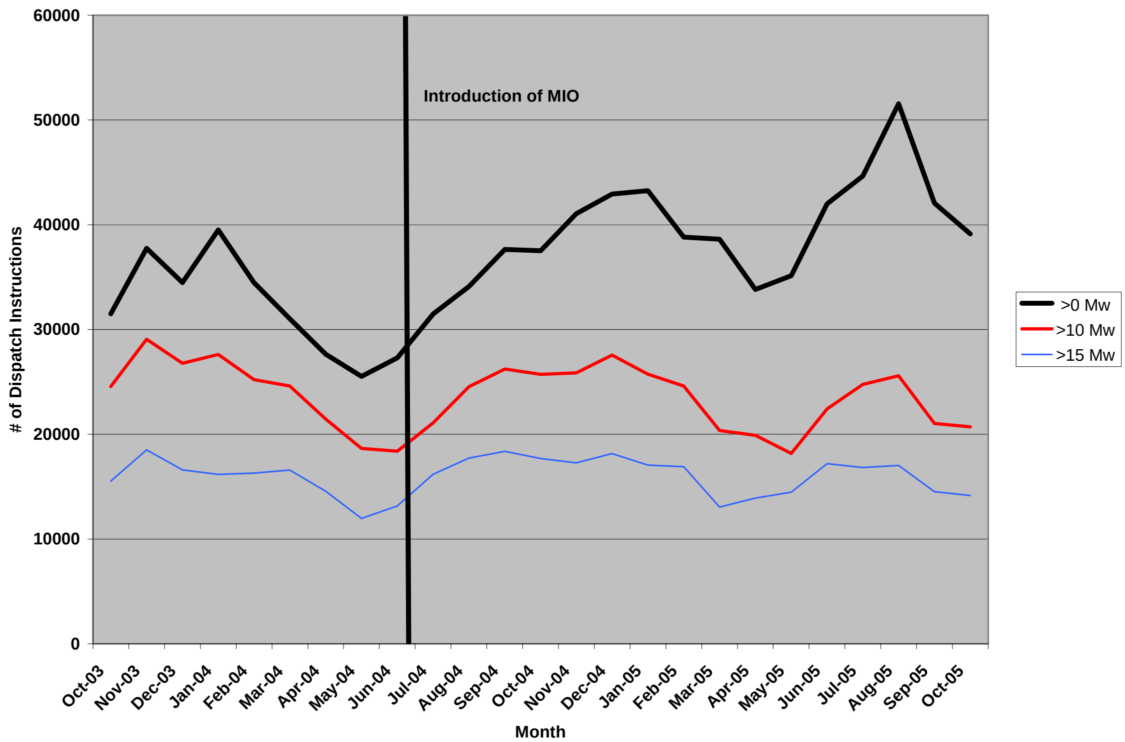
In previous reports we concluded that the dispatch of Ontario generation has been generally efficient in the IESO-administered markets. In coming to this judgment we have adopted as a standard of dispatch efficiency that all suppliers with incremental cost less than the incremental cost of the resource that set the market price were selected for dispatch. We also noted that this definition of dispatch efficiency was not a dynamic measure and, in particular, does not reflect the impact of frequent changes in dispatch instructions on the continuing efficiency of generators. We recognized that this was an issue and in our previous reports outlined some of the measures that the IESO, in consultation with market participants, was taking to deal with it.[34] This chapter updates our assessment of the situation.

A simple metric to review the effect of measures in place is the number of monthly dispatch instructions issued to all fossil fired generators in the Province. Figure 3-2 shows that the total number of dispatch instructions to fossil fired generators is increasing over time, while the number of dispatch instructions of greater than 10MW appears not to be changing. The MAU believes that the increase in number of dispatch instructions may be attributable to the Multi-Interval Optimisation (MIO) introduced in June 2004. Although it was believed at the time that the MIO would reduce the frequency of dispatch instructions by providing a longer ‘look ahead’ it appears not to have done so. Indeed, by anticipating reserve shortages over many intervals it

[34] See p. 80 - 85 of our December 2004 report, and pp. 79-89 of our June 2005 report.

has resulted in dispatching slower-moving fossil plants earlier, but with the consequence that other plants have been dispatched down and total dispatch instructions have increased.

Figure 3 -19: Monthly Dispatch Instructions to Fossil-Fired Generators, October 2003 – October 2005



One of the measures introduced previously by the IESO was a non-compliance dead-band of 10MW. If a generator receives an energy dispatch message to alter its production by less than 10MW, there is no necessity to comply. The IESO believes that this lagging by generators can be handled by Automatic Generation Control at some additional cost but with no impact on reliability. At the same time, in not complying with the dispatch instruction the participant is implicitly agreeing to forego any associated CMSC payment. In reviewing Figure 3-2, on average there are substantially fewer dispatch messages that generators must comply with when the 10MW deadband is taken into account. Indeed, the number of dispatch instructions that could be ignored averaged 13,000 per month over the entire period from October 2003 to October 2005, and 20,000 per month over the May-October period reviewed in this report.

The IESO continues to seek measures that can further ameliorate dispatch volatility and, in particular, is considering the following:

- further increasing the compliance deadband from 10MW to 15MW. Figure 3-2 shows that this might reduce the average number of monthly dispatch instructions that require compliance by a further 7,000. Discussions with market participants to assess the feasibility of this measure began on November 14, 2005.

- facilitating the ability of hydroelectric generators with more than one facility and injection point to respond to dispatch instructions with greater flexibility in how they actually deploy their units, and

- developing a pilot project for watershed aggregation to allow generators on a cascade river to aggregate dispatch instructions and redistribute them across the river system to maximize the efficiency of the river system.

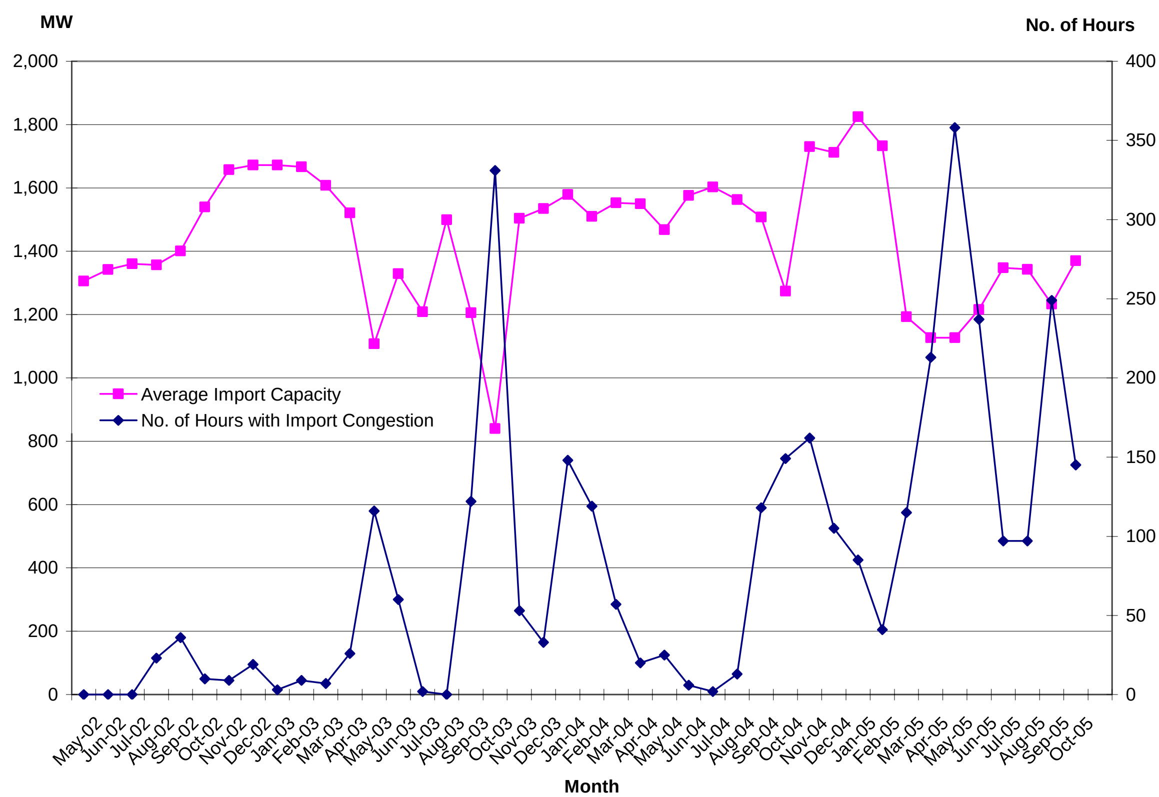
It appears that a combination of compliance dead-bands and on-going changes in the marketplace are helping to reduce the impact of the issue and will have a positive impact on dynamic dispatch efficiency. We will continue to monitor these initiatives and report on them.

3. New Matters to Report

3.1 Intertie Issues with MISO Reduced Michigan Intertie Limits

Michigan is the primary source of imports to Ontario, accounting for 60% to 70% of all imports in recent years. It is a source of competitively priced imports and contributes to the overall efficient use of resources in the electricity marketplace. Although total imports from Michigan have actually increased in the last six months compared with 2004 (see Table A-26 in the Statistical Appendix), there is a recent upward trend in the number of hours in which import congestion occurred. This suggests that intertie capacity limits have, over the past summer, more frequently prevented additional available supply from being utilized in Ontario when it would have been economic to do so. The MAU drew to our attention that the average import capability of the intertie was reduced in March 2005 (see Figure 3-3 below). This reduction coincided with, and resulted from the placing in-service of two Phase Angle Regulators (PARs) between Ontario and Michigan at the Lambton Generating Station.[35]

Figure 3 - 20: Total Number of Hours with Import Congestion and Average Import Capacity on Michigan Interface



The IESO has advised the Panel that the import and export limits on the Michigan interface were reduced due to a change in PARs ratings supplied by Hydro One. In an effort to minimize the limiting impact of the PARs, Hydro One approached the manufacturer to seek more flexible ratings (i.e. 24 hour rather than continuous). However the manufacturer declined to provide such

[35] PARs, commonly referred to as Phase Shifters, are specialized transformers which are designed to allow operators to control the amount of power flowing on an interface within certain limits. In this case, the PARs are designed to allow control of up 500MW in either direction and are intended to control the inadvertent parallel flow of power through Ontario between Michigan and New York. This is the so-called Lake Erie Circulation. These PARs units are jointly owned by Hydro One and Michigan's International Transmission Company.

ratings. Effectively the Michigan interconnection was de-rated by approximately 400MW due to the PARs, thus limiting import and export capability and, in periods where significant arbitrage opportunities existed, increasing congestion at the interconnection.

Hydro One advised that it was known from the beginning that the PARs would be the limiting elements on this interconnection, but their phase angle regulating capability (about ±500MW) was expected to more than offset the reduction. That is, by controlling inadvertent parallel power flows that may at times impede import capability, greater scheduled transactions would be enabled across the New York/Michigan interfaces. These inadvertent flows are commonly referred to as “Lake Erie Circulation” (LEC). Unfortunately, Hydro One and the International Transmission Company in Michigan have been unable to execute an operating agreement governing the operation of the PARs under normal conditions and these cannot actually be used to limit the circulation and expand import capabilities. We understand from the IESO that an agreement has been reached such that the PARs can be operated to prevent 5% voltage reductions in Ontario or Michigan, to prevent load shedding, and for testing. At all other times the PARs simply reduces import/export capability over the Michigan intertie, which can increase congestion.

The Panel has attempted to understand why the installation of transmission equipment whose original purpose was to increase interface limits has in reality reduced these interface limits. At its simplest it appears that:

1. The PARs rating currently being used is a limit based on continuous operation. For shorter periods of time, typically 24 hours or 15 minutes, equipment can be operated at higher ratings. However, MISO is unable to accept a 15-minute rating, while the manufacturer has not provided a 24 hour rating for the PARs.[36] This leads to the lower continuous rating being applied, limiting the transfer capability.

[36] The NERC requirement following a contingency is that a system is “re-prepared” within 30 minutes, which means operating reserves and transmission flows etc. are returned to normal within 30 minutes. Some systems may be able to rebalance more quickly, but are not required to do so.

2. The joint procedure between IESO and MISO for directing operation of the PARs cannot be updated to permit broader use of the facilities until the issues between the transmission co-owners of these facilities are resolved. However, successful negotiation of an enduring operating agreement is contingent upon development of viable plans to restore a major interconnection between Michigan and Ontario, a circuit named B3N, that has affected transmission operation in Michigan.[37]

3. ITC would like the B3N circuit returned to service. The circuit was damaged in the Spring of 2003, and has been out of service since then, with Hydro One needing to negotiate a new easement before the line can be repaired.[38] If an easement cannot be negotiated, Hydro One would have to consider alternative routing for the interconnection. A specific return date has not been projected.

A modified procedure to allow operation of the PARs under normal conditions and the application of a higher PARs rating (either 24 hour,15-minute or some rating between these) could result in removal of some of the causes for the reduced intertie capability. Given the availability of lower cost resources in MISO, there would be efficiency gains for the market if these matters could be resolved and the import capability increased.

3.2 Hour-Ahead Dispatchable Load (HADL) Program

The Hour-Ahead Dispatchable Load (HADL) Program was launched in July 2003, in an effort to increase market transparency and efficiency by addressing the following two issues:

- lack of load capability to respond to the real time price over a short time horizon, and/or
- uncertainty of the fidelity of the real time price signal.

[37] With this circuit unavailable, import capability to Ontario has actually increased somewhat and export capability decreased. This is due to the fact that when it was in operation power flowed out of Ontario at this point and back into Ontario on the circuits further south. The apparent large reduction in the import capability observed in Figure 3-3, is partly due to the higher initial capability associated with B3N out-of-service.

[38] The PAR for B3N is on the Michigan side of the interconnection. It failed independently one month before the circuit failed. Once Hydro One has provided assurance to ITC that it has negotiated an easement to repair the line, it is understood that ITC will begin to replace or repair the associated PAR.

The first issue is associated with market participants themselves due to a lack of appropriate equipment to cut consumption in high price hours or the cost of disrupting production processes being too great to compensate for the savings in energy cost that they would realize. The second problem comes from the market and has been discussed in all of our previous reports. The essential problem for load that would like to be dispatchable but can only react to the hour-ahead price, is that there are many factors that may make the real-time price lower. This creates the risk that they will modify or shut down production processes when, given that a lower price does materialize, it would not have been in their interest to do so.

Loads in the Program are protected against this latter risk. If the HOEP for the dispatch hour turns out to be less than the offer price of a scheduled hour-ahead dispatchable load, the IESO pays the participant the difference between the offer price and HOEP for the load scheduled. This Hour Ahead Dispatchable Load Offer Guarantee (HADLOG) compensates the load for reducing consumption when real time prices turn out to be such that it would have wanted to consume.

Currently there are four facilities registered under the Program for a total of 240MW. There was a total of 110 hours from July 2003 to October 2005 where hour-ahead dispatchable load was scheduled. The maximum single hourly reduction was 37MW. The IESO paid a total $38,661 for 49 hours in which the real time price turned out to be lower than the HADL offer price.

At the Panel’s request, the MAU undertook an assessment of the benefits of the HADL Program. The technique used by the MAU is outlined in the Appendix to this chapter. The analysis is based on two assumptions: first, the HADL offer is assumed to reflect the true willingness-to-pay of the loads; second, the loads are assumed not to have the capability of responding to the real time price unless scheduled by the system operator in pre-dispatch.

The MAU’s analysis estimates the net gains or losses to the market as a whole as a result of HADL reductions. There is a net gain to the market when a HADL offer is accepted and the real-time price (HOEP) turns out to be higher than the HADL offer price. There is a net gain to the market in this case because the value of the consumption foregone by a HADL participant (as reflected in an accepted HADL offer price) is less than the cost that would have been incurred in order to supply this consumption. This cost per MWh of this incremental supply is at least as great as the HOEP.

There may be a net loss to the market when load is reduced and the HOEP turns out to be lower than the HADL offer price. There is always a loss to the market when the HADL consumption involved would have been supplied either by increasing Ontario generation or reducing exports. There may be a loss to the market if the foregone HADL consumption would have been supplied by imports but this would occur only if the hour-ahead pre-dispatch price is set by an importer and it is lower than the HADL accepted offer price (and, by implication, also lower than the three hour-ahead pre-dispatch price). The intuition behind any net loss to the market when the HADL offer price exceeds the HOEP is that the value of foregone consumption by HADL participants exceeds the cost of the increased generation, increased imports or foregone exports that would have been required to supply it. That is, an opportunity for mutually beneficial exchange between HADL participants and suppliers of energy is foregone. The overall benefit to the market as a whole resulting from the HADL program is the difference between the net gain that is realized when HADL participants are correctly dispatched down in real time and the net loss that is realized when HADL participants are incorrectly dispatched down.

Of the 110 hours in which hour-ahead dispatchable load was scheduled, there were 49 hours in which the IESO paid the HADLOG. The HOEP for these 49 hours was less than the HADL offer price. HADL participants reduced their consumption by a total of 1,110MWh in these 49 hours. Had they known what the HOEP would be, they would not have done so. The benefit foregone by HADL participants as a result of being incorrectly dispatched down is the difference between the HADL offer price and the HOEP on the 1,110MWh. As is shown in Table 3-3 this amounted to $38,661 between July 2003 and October 2005. The net loss to the market as a whole (also known as the efficiency loss) from dispatching down loads who would have been willing to pay more than the cost of supply is the difference between the HADL offer price and the cost that would have been incurred either to generate or import the foregone output or to bid it away from exports. This amounted to $11,863.

Table 3 - 40: Statistics of HADL Program

	With HADLOG	Without HADLOG	Total
Number of Hours	49	61	110
Total MWh Curtailed	1,110	1,380	2,490
HADL Offer Guarantee	$38,661	N/A	$38,661
Net Gain to the Market	($11,863)	$25,436	$13,573
Net Gain per MWh	($10.69)	$18.43	$5.45

In the case of the 61 hours in which dispatchable load was scheduled hour-ahead but no HADLOG was paid, load was reduced by a total of 1,380MWh between July 2003 and October 2005. In this case, the HOEP was above the HADL offer price implying that value placed by HADL participants on their foregone consumption was less than it would have cost to supply them. The resulting benefit to the market from the HADL-induced load reduction was $25,436.

Taking the 49 hours in which dispatchable load was incorrectly dispatched down together with the 61 hours in which it was correctly dispatched down, the net gain to the market was $13,573. Obviously the HADL program had a minimal impact on market efficiency.[39] There are two reasons for this. First, participation in the program was limited. Second, the three hour-ahead price on which the dispatch decision for HADL is based frequently overstates the HOEP so that decisions by HADL to forego consumption turn out to be unwarranted in real time. In 49 of the 110 hours in which HADL was scheduled, the three hour-ahead price was higher than the HOEP and the difference was large enough to result in a net loss to the market. When the three hour-ahead pre-dispatch price is a good approximation of real time price, the market generally benefits

[39] When load is reduced the market price tends to drop as well, everything else equal. We estimated the effect of reduced HADL consumption was an average reduction of $0.66/MWh in HOEP over the 110 hours. However, this does not represent an efficiency improvement for the market, rather a wealth transfer between market participants. It is also interesting to note that when there were net gains this amounted to over $18/MWh compared with a smaller loss, almost $11/MWh, when the gains were negative.

from the program. Almost half the efficiency benefits from the program were offset by the losses in those hours where the pre-dispatch price was a poor estimate of HOEP.

In conclusion, efficiency gains from the HADL Program are highly dependent on the accuracy of the three hour-ahead pre-dispatch price. The higher is the three hour-ahead price relative to the HOEP, the more likely it is that HADL offers above the HOEP will be accepted, with the consequence that dispatchable loads willing to pay the HOEP will have been incorrectly dispatched down. A reduction in the tendency for the three hour-ahead pre-dispatch price to exceed the HOEP would increase the extent to which the market benefits from the HADL program.

Chapter 3 Appendix: Estimating the Efficiency Gain from the HADL Program

The efficiency calculation is based on the unconstrained dispatch.

The Hour Ahead Dispatchable Load (HADL) program reduces consumption. This foregone consumption has a value to the HADL as reflected by the HADL offer price. The cost of supplying this foregone demand is also avoided. In the simplest case, this avoided cost is given by the offers of the Ontario generators who would have supplied the HADL megawatts.

In the more general case, foregone consumption is associated with a combination of reduced Ontario generation, reduced imports and additional exports. In other words, if the HADL load had continued to consume, it would have resulted in some combination of additional Ontario generation, additional imports and reduced exports.

In the simplest case, with no imports or exports, the HADL can only affect Ontario generation. In this case the HADL program has two possible outcomes. First, when the HOEP turns out to be lower than the accepted HADL offer price, there will be an Hour Ahead Dispatchable Load Offer Guarantee payment (HADLOG) to the HADL. In this case, the HADL is compensated for a consumption reduction that turns out to be incorrect in the light of the real time price. Second, when the HOEP turns out to be greater than the accepted HADL offer price, there is no payment to the HADL. In this case, the decision of the HADL to reduce consumption turns out to be correct in the light of the real time price and no compensation is needed.

The first case is illustrated in Figure A1. With the HADL program in place, the demand for electricity is *Demand1* and the HOEP is P_{rt}. Without the HADL program, real time demand would have been *Demand2*, and the HOEP would have been $P_{rt}^{'}$. The value of the megawatts foregone by the HADL is given by the accepted HADL offer price, P_{off}. The cost of producing them is given by the *RT Supply* curve and it is less than or equal to $P_{rt}^{'}$. It is apparent from Figure

A1 that the value of the consumption foregone by the HADL exceeds the cost that would have been incurred to supply it. The difference is given by the shaded area in Figure A1. This is the net loss to the market resulting from the HADL program.

While there is a loss to the market as a whole, the HADL does not suffer any loss since it is compensated for its consumption reduction. This compensation is the HADLOG and it is equal to (P_{off} - P_{rt}) * (*Demand2 – Demand1*) . The HADLOG is shown in Figure A1 as the rectangle between P_{off} and P_{rt} and between *Demand1* and *Demand2*. The HADLOG is a transfer from load to the HADL and is included in the uplift. The HADLOG is greater than the loss to the market (also known as the efficiency loss) which is given by the shadowed area in Figure A1.

The net benefit to the market can be expressed algebraically as follows:

Net Benefit = Avoided Cost of Generation – Foregone Value of HADL consumption; or in terms of offer or bid lamination

$$NB = \sum P_i^{gen} * MW_i^{gen} - P_{off} * MW \qquad (1)$$

Where

NB --- net benefit to the market

P_i^{gen} --- generation offer price at lamination *i*, which is less than $P_{rt}^{'}$

MW_i^{gen} --- generation offer quantity at lamination *i*, conditional on $\sum MW_i^{gen} = MW$

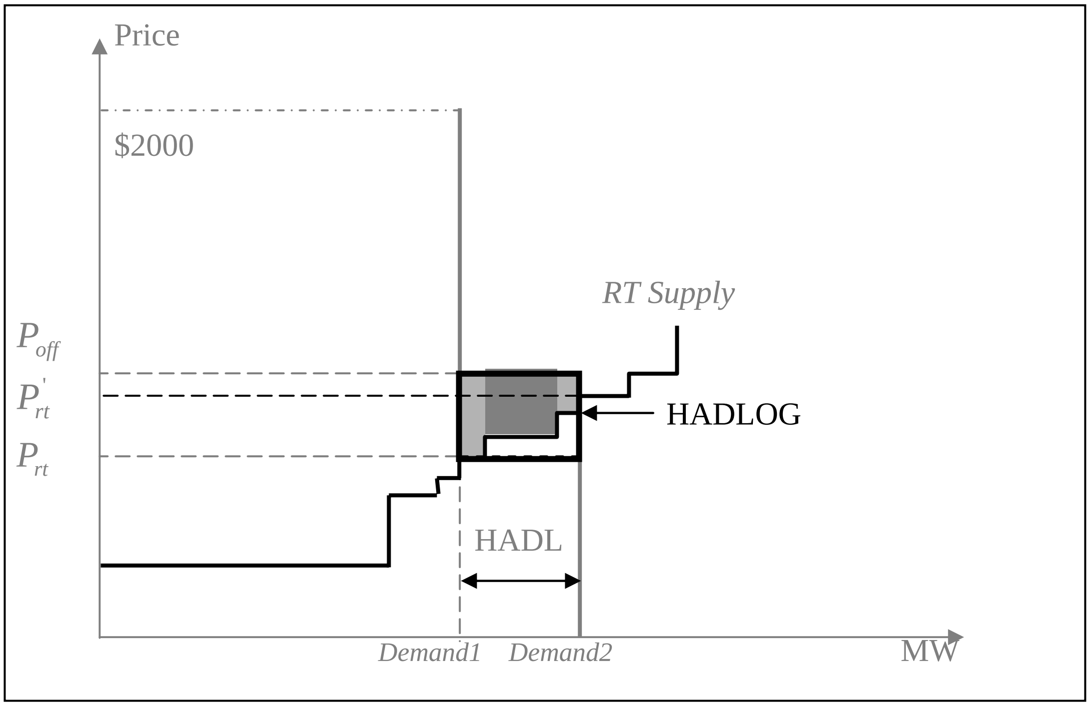
P_{off} --- HADL offer price

MW --- HADL offered quantity

Note that the accepted HADL offer can have multiple laminations. For demonstration simplicity, however, we assume the HADL offer has only one lamination.

Net Benefit is negative when P_{rt} is less than P_{off} .

Figure A1: Case with Payment for HADL



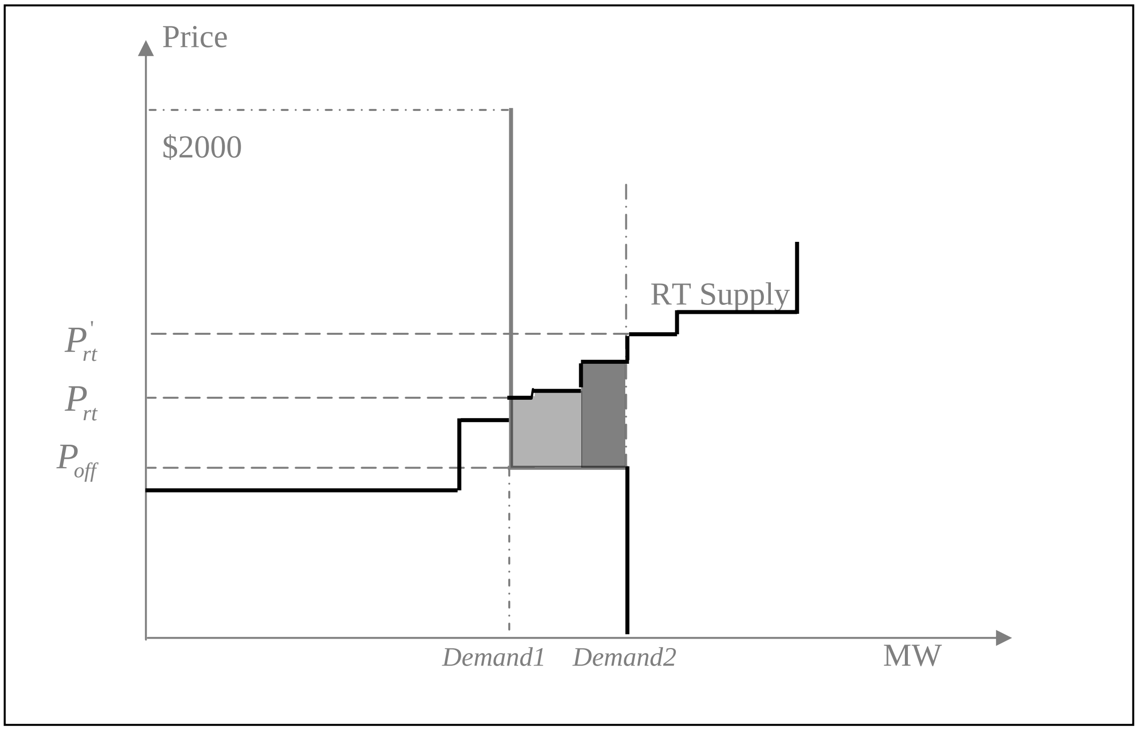
The second case, in which there is no compensation to the HADL for its consumption reduction, is illustrated in Figure A2. With the HADL offer accepted, the real time demand is *Demand1*, and the HOEP is P_{rt}. If the HADL program did not exist, demand would have been *Demand2* and the HOEP would have been $P_{rt}^{'}$. In this case, the value of the HADL megawatts, P_{off}, is less than what it would have cost to produce this energy (given by the *RT Supply* curve) so that the program results in a net gain to the market given by the shaded area in Figure A2.

The net benefit to the market in this case can be expressed algebraically as follows:

$$NB = \sum P_i^{gen} * MW_i^{gen} - P_{off} * MW \qquad (2)$$

which is the same as in the first case. In this case, however, P_{rt} is greater than P_{off} so that the net benefit is positive.

Figure A2: Case without Payment to HADL



The HADL program may also affect the amount of imports and exports in the pre-dispatch sequence and this would affect the amount of Ontario generation needed in real time. For example, in the absence of the HADL program, pre-dispatch demand would have been higher, and the IESO might have dispatched more imports to meet this higher demand. In this case, the HADL program has the effect of reducing imports as well as, or instead of, Ontario generation. To take a simple example, assume the HADL offers 30MW at $200 and the three hour-ahead price is $250. In this case, the HADL offer is accepted and is dispatched down by 30MW in the one hour-ahead pre-dispatch sequence, implying the total demand is 30MW lower than without the HADL Program. Assume further that the 30MW decrease in demand reduces imports by 30MW rather than reducing Ontario generation. Now there are two possibilities. First, if the avoided imports would have been available to the market in hour-ahead pre-dispatch at a price that is greater than the accepted HADL offer price of $200, there is a net gain to the Ontario market from the HADL program.[40] Second, if the avoided imports would have been available to the market in the hour-ahead pre-dispatch at a price that is less than the accepted HADL offer price of $200, there is a loss to the Ontario market resulting from the HADL program. To take the numerical illustration a step further, if the hour-ahead pre-dispatch price is $250 and it is set by an importer, the net gain to the Ontario market from the HADL program is the difference between the avoided cost of the imports involved (30MW times $250) and the foregone value to the HADL (30MW times $200), which is a net gain of $1,500.

Alternatively, if the hour-ahead pre-dispatch price is $150 and it is set by an importer, the net gain to the Ontario market is the difference between the avoided cost of the imports involved (30MW times $150) and the foregone value to the HADL (30MW times $200), which is a net loss of $1,500. This net loss scenario could only occur if the hour-ahead pre-dispatch price is lower than the three hour-ahead pre-dispatch price. If the HADL offer would also have crowded out imports hour-ahead, this is necessarily a gain to the Ontario market. This net loss scenario requires a further qualification to take into account that imports are paid the greater of their offer price or the HOEP. The net loss to the market in this example is reduced to the extent that the HOEP comes in above the hour-ahead pre-dispatch price of $150. Of course, if the HOEP comes in above $200 (the accepted HADL offer price), there is a gain to the Ontario market. In sum, the case in which the HADL crowds out imports, the net gain or loss to the market depends on the difference between the HADL offer price and either the HOEP or the offer price of the marginal importer, whichever is greater.

Reduced consumption by HADL may also be replaced in part by additional exports. These exports pay the HOEP. Whether the replacement of consumption by HADL with exports constitutes a net benefit to the Ontario market depends on whether the HADL values the MW involved more highly than do the export customers. If the accepted HADL offer price exceeds the HOEP, there is a net loss to the Ontario market. If the accepted HADL offer price is less than

[40] Given Ontario market design, an importer is paid the HOEP or its offer price, whichever is greater. Thus the price here shall be the HOEP or import offer price, whichever is greater. For simplicity of demonstration in the following analysis, we assume the HOEP is always lower than the import offer price.

the HOEP, there is a net gain. To take a simple example, assume that a reduction in HADL is replaced entirely by additional exports so that there is no change in Ontario generation and no change in imports. In this case, the net benefit to the Ontario market is the difference between the value of the additional exports as reflected by what exporters pay, the HOEP, and the value of the consumption foregone by the HADL.

The common thread running through all the cases examined is that when the HOEP is greater than the accepted HADL offer price, the HADL program increases the efficiency of the Ontario market. That is, it benefits the Ontario market as a whole.

If the HOEP is less than the accepted HADL offer price, the effect of the HADL program on the efficiency of the Ontario market depends on the extent to which it results in reduced Ontario generation, increased exports or reduced imports. Insofar as it reduces Ontario generation or increases exports, the HADL program reduces the efficiency of the Ontario market. With respect to imports avoided, the HADL program cannot result in losses to the Ontario market if the hour-ahead pre-dispatch price is at least as high as the three hour-ahead price. If the hour-ahead price is set by imports and it is lower than the three hour-ahead price, the possibility exists that the value of avoided imports could be less than the value of foregone HADL consumption so that a reduction in imports also results in a loss to the Ontario market

In summary, the final net benefit consists of the lost value of the HADL offset by any of three corresponding components: avoided Ontario generation cost, avoided cost of imports, and the additional value of increased exports. Algebraically, with HADL MW decomposed into three parts - affected generation MW^{gen}, affected import MW^{imp}, and affected export MW^{exp}, - the calculation can be expressed as follows:

Net Benefit = {avoided cost of generation (MW^{gen}) - lost value to HADL (MW^{gen})}
+ {avoided cost of import (MW^{imp}) – lost value to HADL (MW^{imp})}
+ {revenue from export (MW^{exp}) – lost value to HADL (MW^{exp})}

where HADL $MW = MW^{gen} + MW^{imp} + MW^{exp}$

This can be reduced to the following, as a result of summing all values to HADL:

$$NB = \sum P_i^{gen} * MW_i^{gen} - P_{off} * MW + \sum Max(P_j^{imp}, HOEP) * MW_j^{imp} + HOEP * MW^{\exp} \qquad (3)$$

Where

NB --- net benefit to the market

P_i^{gen} --- generation offer price at lamination i, which is less than $P_{rt}^{'}$

MW_i^{gen} --- generation offer quantity at price P_i^{gen}, and $\sum MW_i^{gen} = MW^{gen}$

P_{off} --- HADL offer price

MW --- HADL offered quantity

P_j^{imp} --- import offer price at lamination j

MW_j^{imp} --- import offer quantity at price P_j^{imp}, and $\sum MW_i^{imp} = MW^{imp}$

HOEP --- the Hourly Ontario Energy Price

$MW^{\exp}$ --- export offer quantity

and $\sum MW_i^{gen} + \sum MW_j^{imp} + MW^{\exp} = MW$

Chapter 4: The State of the IESO-Administered Markets

1. Introduction

The IESO-administered markets functioned reasonably well over the six-month period from May through October 2005. Prices were substantially higher than in the summer of 2004. There were two key factors at play. First, there was a much tighter balance between demand and supply. High temperatures led both to record levels of demand through the summer period, and reduced levels of hydroelectric supply. The effects of high temperatures on the demand-supply balance were exacerbated by nuclear outages that put additional upward pressure on price. Second, and apart from the tight demand-supply balance, the rapid and substantial increases in the price of natural gas led to cost pressures that were reflected in energy prices. On average, the hourly spot price last summer was 60% higher than in the summer of 2004.

Although the summer was challenging from a reliability perspective, the IESO managed to maintain supplies with virtually no interruption, due in large part to net imports to Ontario – including emergency imports of energy that were required for 17 hours on different occasions through the summer period.

Our overall assessment of the IESO-administered market through this period was that dispatch continued to be efficient. The effectiveness of price discovery worsened somewhat as the average absolute difference between the pre-dispatch and real-time price increased. This increase appears to be due primarily to a higher incidence of failed intertie transactions rather than IESO forecast error or out-of-market control actions, both of which decreased through the period.

An important function of the spot market is to provide transparency about the real resource cost of electricity in Ontario. We believe that the market is performing this important function reasonably well, although there remains room for improvement.

In previous reports we discussed how the manual use of out-of-market control actions in real-time has played a key role in the discrepancy between the pre-dispatch prices and the HOEP. We have also expressed concern that the way in which emergency imports were introduced into the price-determination process had the perverse effect of reducing the energy price in times of emergency. This summer the IESO acted to resolve both of these long-standing concerns. The measures taken, described in more detail in Chapter 3, will improve the fidelity and integrity of price signals in the Ontario electricity market. While these measures are welcome, we believe that further steps can and should be taken to improve the effectiveness of the IESO-administered markets. In particular, we continue to advocate the introduction of locational marginal pricing (which would allow the elimination of the CMSC regime) the development of an efficient day-ahead market, and the elimination of the 12-times ramp provision.

Under our direction, the Market Assessment Unit continues its close contact with market participants and from time-to-time has requested additional information from them, so that we could be satisfied that observed anomalous behaviour did not constitute gaming or an abuse of market power. In the period under review we did not find any behaviour that appeared to be abusive or potentially abusive, and no formal investigations were launched. We did become concerned about an increase in constrained-off payments in certain circumstances that appeared to us to be consistent with gaming behaviour. We asked the MAU to bring this matter to the attention of the IESO's market rules group to consider amendments that would restrict CMSC payments in these circumstances. The IESO has initiated stakeholder consultations on this issue and it has had at least one review by the Technical Panel. We will follow this issue closely and will provide an update in our next monitoring report.

The balance of this Chapter reports on three issues of concern to us:

- the continuing relevance of the spot market in the light of government contracts for electricity,
- proposals by the IESO to introduce a Day Ahead Commitment Process to enhance reliability next summer, and

- potential inefficiencies resulting from the operation of the Ontario/Michigan intertie.

2. New Supply and the Competitive Fringe

In our last report we described the regulated price and contract arrangements for OPG's prescribed and non-prescribed assets, as well as the supply additions planned under the RFP processes earlier this year. Since that time the Government and OPA have announced a large number of additional supply procurement programs as well as new contractual arrangements for existing generation in the market. In particular, the Government announced an agreement with Bruce Power on October 17 that will guarantee Bruce Power a price of $45/MWh for production from the Bruce B units and $63/MWh for production from Bruce A. The Bruce A guarantee covers the currently operating Bruce A units 3 and 4 and will support the refurbishing of units 1 and 2 and their return to service in 2009.

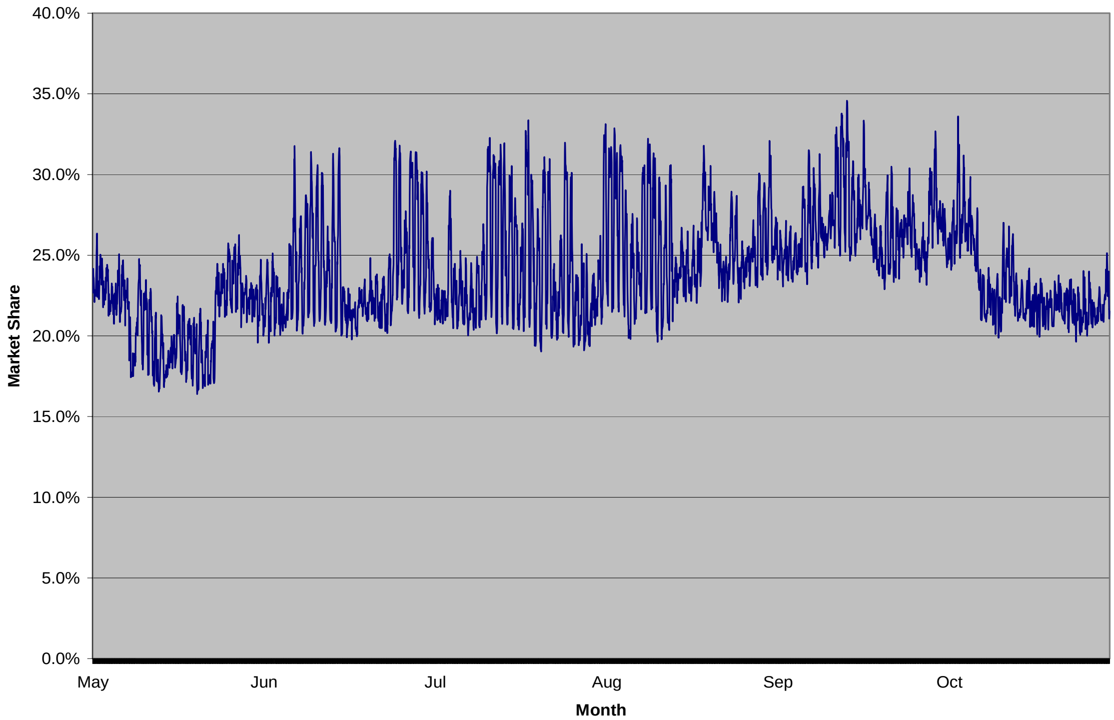
These initiatives to secure supply have significant implications for the role that the competitive spot market continues to play in Ontario.

First, procurement for the near future will continue to take place through such contracting processes and agreements. With government-backed support available, it is unlikely that any generator would choose to build new supply without contractual guarantees. Indeed, the Government has now directed OPA to negotiate contracts with generators that recently came to Ontario with no government support. These so-called 'early movers' include Brighton Beach (580MW), the TransAlta Sarnia cogeneration plant (575MW) and an additional 160MW of smaller facilities.

The second implication relates to the nature of the contractual arrangements being negotiated, and this is tied critically to the existence and utility of the competitive spot market. Most of the contractual arrangement for existing base-load supply has taken the form of a fixed price related to cost. But most of the contractual arrangements for incremental supply are taking the form of a net revenue guarantee, based upon generator performance relative to the spot-market price with risk sharing on both sides. To the extent that the spot market continues to operate in a healthy environment, with price outcomes that do reflect the true resource cost of energy, contractual arrangements based upon net revenue guarantees will be more efficient and will, over time, more effectively avoid taxpayer subsidization of new generation capacity. We urge the Government and the OPA to design contractual arrangements for new supply and, indeed, for the so-called 'early movers', in a way that makes use of market information and is sensitive to such information. Our focus continues to be on ensuring that the price information produced by the spot market does, in fact, provide a measure of real resource cost that is not affected by manipulation.

Despite the proliferation of contractual arrangements, the spot market continues to provide the relevant return to a substantial portion of Ontario generation. Similar to the data presented in our last report, Figure 4-1 below shows, for the period May to October 2005, the portion of Ontario domestic production that would have been paid the market price, assuming the contracts announced this year. This includes generation without contracts and those portions of OPG's prescribed and non-prescribed assets that are paid at the market price (i.e. baseload hydroelectric above 1,900MW, Lennox and 15% of other fossil-fired and hydroelectric production).

Figure 4 - 21: Ontario Domestic Competitive Market as a Percent of Ontario Production May-October 2005



The implied hourly competitive share in this period ranged from a high of 35% of Ontario generation, to a low of 16%, with an average of 24% over all hours. Equivalently, the absolute amount of Ontario generation that was remunerated at the spot price ranged between 7,660MW and 2,100MW and averaged 4,230MW over the period. The maximum shares in this period are lower by about 5% relative to those reported previously, reflecting the new Bruce Power arrangements, while the minimum shares are about the same. If the contracts that are struck with the so-called 'early movers' are fixed-price contracts, rather than net-revenue contracts, then an additional 1,000MW would move out of this competitive group, dropping the average share to about 22%.[41]

[41] By way of comparison, a majority of the load are tied to the market clearing price. Approximately 48% of consumption by Ontario loads is covered by the Regulated Price Plan (RPP) which currently sets prices between 5.0¢ and 5.8¢/kWh, primarily for smaller retail customers whose consumption is less than 250,000 kWh annually. Other Ontario load pay the market price, although there are monthly and annual rebates paid to these, corresponding to the various contracts and regulated prices for generation.

3. The Proposed Day-Ahead Commitment Process

In the summer of 2005 the IESO market operated in an emergency state for more than 178 hours. Import failures were a major factor in the reliability challenges faced. As a result of the experience of this past summer, the IESO is considering the introduction of a Day Ahead Commitment Process (DACP) to enhance reliability in the summer of 2006. Essentially, this process would involve two new features: a Day-Ahead Import Offer Guarantee (DAIOG), which would compensate imports selected day-ahead on the basis of the higher of the real-time HOEP or their day-ahead offer, and a Day-Ahead Cost Guarantee (DACG) for domestic generators that would ensure that any domestic generator selected day-ahead would be fully compensated for its start-up and speed-no-load costs.

Our appreciation of this initiative is that the key rationale that is driving it is the belief that if imports can be contracted on a day-ahead basis, with financial penalties for failure to deliver, there will be a much higher probability that seams issues can be resolved and the rate of import failure will fall substantially. It is less clear to us that the absence of a day-ahead cost guarantee for domestic generation has been a problem in the summer of 2005, but such a measure may be deemed desirable to provide a somewhat level playing field as between domestic generators and imports in the day-ahead commitment process.

The DACP envisaged by the IESO is clearly a second-best solution. It is not a substitute for a comprehensive day-ahead market with a two-settlement system. The IESO recognizes this but cannot complete the design and implementation of a day-ahead market for operation in the summer of 2006.

With the DACP design, there are risks that the IESO will over-commit imports day-ahead and thus convert what would be higher clearing prices into greater uplift, which distorts pricing signals. There are also greater opportunities to game this process. Should the IESO decide to proceed with the DACP, there would be an enhanced requirement for the MSP to monitor both IESO and market participant behaviour and the design of the Program should include transparency around both forecasts and operational decisions so that such monitoring can effectively take place. We have asked the MAU to work with the IESO in the design of the DACP to ensure that this occurs.

We are also concerned that the implementation of the DACP may detract attention from the more important task of continuing the evolution toward a comprehensive day-ahead market in Ontario. There may a temptation on the part of some market participants to view the DACP as a comfortable resting place. We believe that this should not be allowed to happen. We therefore urge the IESO, to ensure that there is a sunset on the DACP and that work proceeds on a DAM design so that the IESO Board is in a position to make a judgment about implementing a comprehensive DAM by the time the sunset clause is up for reconsideration. As well, during the period when the DACP is in operation, we urge the IESO to limit its use to those periods where it perceives that reliability will be a serious concern. We recognize that there are risks in trying to turn the DACP on and off, but we do not believe that it is intended or desirable that the DACP create a risk-free environment. The DACP should be viewed as a risk-management tool, with explicit recognition that there is a balance to be achieved between reducing the risk to reliability and minimizing the inefficiency implications for the operation of the market.

4. The Operation of the Ontario/Michigan Intertie

In Chapter 3 we explained how the installation of the Phase Shifters (PARs) at the Michigan-Ontario interface has actually led to a reduction in import and export capability, with the effect of limiting import of an efficient source of energy. Some of the underlying causes include the lower ratings of the PARs and the lack of a joint procedure directing the operation of the Phase Shifters under normal conditions, which appears to be contingent on restoring the B3N circuit at the interconnection.

Accordingly the Panel recommends the following:

- That the IESO should confirm with Hydro One whether the PARs can be temporarily bypassed and restored quickly enough to help during emergency conditions.

- That Hydro One continue to take the necessary steps to restore B3N to service, or implement alternatives. This should enable MISO and IESO to arrive at a mutually acceptable operating agreement for the interties, including operation of the PARs under normal conditions.

- That the IESO work with MISO and the transmitters regarding the use of emergency ratings for the PARS acceptable to all parties. To this end, Hydro One should continue negotiations with the manufacturer to develop acceptable short-time and long-time emergency ratings for the PARs, consistent with NERC standards.