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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2006 – April 2007

July 2007

Preface

The 10th Market Surveillance Panel monitoring report covers the period November 1, 2006 – April 30, 2007. This is the first report since Neil Campbell joined the Panel as its Chair in January 2007.

The structure is similar to previous reports and we have included short summaries of sections that are particularly long or detailed. We provide standard data on market operations and performance in Chapter 1 and the Statistical Appendix. Chapter 2 surveys ‘high’ and ‘low’ prices and discusses two other matters worthy of note. Chapter 3 discusses some of the issues raised in previous reports and extensions to our analysis of the potential impact of changing to nodal pricing. Chapter 4 provides a final commentary, lists our recommendations and provides a cross-reference to where they are discussed earlier in the report.

As always, we welcome comments and advice on this monitoring report and, more generally, on how we are doing in the performance of our duties.

Neil Campbell, Chair Don McFetridge Tom Rusnov

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Executive Summary

The IESO-administered market, Ontario's wholesale electricity spot market, once again performed reasonably well according to its design over the six-month period November 2006 to April 2007. Spot market prices generally reflected demand and supply conditions. The Market Surveillance Panel (MSP) found no evidence of gaming, abuse of market power or other inappropriate conduct by market participants or the market operator, the Independent Electricity System Operator (IESO).

Market Prices and Uplift

The average Hourly Ontario Energy Price (HOEP) for the period November 2006 through April 2007 was approximately $7/MWh or 12 percent lower than the same time period a year ago. This appears to correspond with the large change in natural gas prices after the winter of 2005-2006, with an average monthly reduction of 14 percent.

Notwithstanding the fluctuating levels of the HOEP during the period from November 2006 to April 2007, the actual amounts paid per MWh by most Ontario loads are affected by the existence of regulated prices and fixed-price contracts in the market place. While the average HOEP dropped approximately $7/MWh, the load-weighted effective HOEP taking into account adjustments fell only $1.10/MWh compared to the same period a year ago.

Finally, the difference between pre-dispatch prices and the HOEP did not narrow markedly compared to the same period a year ago. While the Panel does not expect pre-dispatch prices to predict the real-time price perfectly, we continue to believe that these persistent price differences are inimical to market efficiency. We identify intertie transaction failures, particularly those outside the control of market participants, and the increasing frequency with which imports set the pre-dispatch price as underlying factors that bear further scrutiny.

Demand and Supply Conditions

Compared to a year earlier, demand in Ontario remained virtually unchanged, falling by 0.15 TWh or 0.19 percent. The Panel continues to observe the long term trend of falling wholesale load consumption. The majority of the reduction in wholesale load is occurring in the Northwest and can be attributed to wood processing facilities.

Exports declined by 1.8 TWh, or 25 percent, compared to the prior period, and were lower in all months compared to the same months a year ago with the exception of February. The Panel attributes this change to a lessening of the arbitrage opportunities between Ontario and New York. The Panel is also observing apparent erosion of the arbitrage opportunities between the New York and MISO markets, which may change long-term trade flows in and out of Ontario.

Cold temperatures in February and March led to a new winter hourly market demand record of 25,961 MW set on February 13, 2007 in HE 19. Peak load growth in Ontario continued to increase relative to median load for the period November 2006 to April 2007. In order to see if this phenomenon was isolated to Ontario, we analysed load patterns in New York and found that peak load growth is also rising there (at a faster rate than in Ontario).

Implications of Nodal Pricing on Revenues and Efficiency

Investment decisions are induced by sufficient revenues for a generator to make an adequate rate of return on its investment. To analyse whether there may be sufficient revenues to prompt investment, consistent with previous MSP reports, we use a standardized model developed by the Federal Energy Regulatory Commission of the United States (FERC) for comparison across markets. This analysis suggests that the average market revenues derived from the HOEP continue to be insufficient to induce the construction of gas-fired generation in Ontario, peak load or otherwise. Any new entry would have to be subsidized by load, through uplift charges.

The Panel has long advocated moving from the current uniform price system to some form of locational pricing as a spur to economic efficiency and market-based investments in generation capacity at relatively low cost to consumers. In this report we tested that proposition through various analyses. Like most projections of future market outcomes we cannot be definitive because of the assumptions and limitations of the model. Nevertheless, the analyses suggest that both allocative (short-run) and dynamic (long-run) potential efficiency benefits are available, with an upper bound of the effective average price increase to consumers to be fairly small, given current conditions.

We examined notional dynamic efficiency by performing the traditional net revenue analysis using the nodal (shadow) prices generated in the IESO's constrained schedule. It appears that the revenue from observed nodal prices would be sufficient to justify new capacity investment in various locations – i.e, a positive impact on dynamic efficiency. We also provided a preliminary estimate of some of the allocative efficiency possible, by assessing the increase efficiency expected if exports to New York paid nodal prices. Finally, after taking into consideration the mechanisms in place to smooth the effective price to consumers if observed nodal prices were paid – the Global Adjustment and the OPG Rebate – we estimated a potential increase to consumers of well under $1/MWh.

Operational Issues & Recommendations

The Panel also makes various suggestions to the IESO for potential improvements to the present market rules and practices based on observed market outcomes over the past six months.

Recommendation 1-1 (pp. 25-28)

Given the persistent large number of intertie failures not under a market participant's control, the Panel urges the IESO to continue to review this issue with New York ISO to better understand why there are such high failure levels and determine whether there are solutions which could reduce such failures to the benefit of both markets.

Recommendation 2-1   (pp. 86-90)

The Panel recommends the IESO review the time lags which it currently employs for replenishing the OR requirements following a contingency. Replenishment as quickly as possible would be consistent with the treatment of other operating reserve or energy obtained through out-of-market control actions and similar to the NYISO practice. This would result in prices which more accurately reflect the loss of supply and encourage market participants to respond as quickly as possible.

Recommendation 2-2   (pp. 97-100)

The Net Interchange Scheduling Limit of 700 MW has been in effect since the market opened. In the light of 5 years' experience with market-based trading, the NISL's potential to limit efficient trade and changes in both the number of generators and their combined ramp capability, the Panel encourages the IESO to review whether the 700 MW limit could be increased.

Recommendation 2-3   (pp. 100-106)

The Panel recommends the IESO should explore improvements to the load predictor tool in order to reduce forecast errors associated with sudden changes in dispatchable load consumption, and the resulting dispatch inefficiencies.

Recommendation 3-1   (pp. 108-113)

The Panel encourages the IESO and OPA to continue to improve coordination between dispatchable load and demand response programs in order to promote the efficient use of dispatchable loads' OR capability.

<u>Recommendation 3-2   (pp. 114-121)</u>

The Panel recommends the IESO review the DACP in order to reduce the costs and improve the effectiveness of the Generator Cost Guarantee. Three-part bidding with 24 hour optimization, similar to the NYISO methodology, may be one such approach. We further recommend as an interim alternative that the IESO consider mechanisms which allow the full magnitude of domestic generator costs to be taken into account in DACP scheduling decisions.

<u>Recommendation 3-3   (pp. 121-123)</u>

In parallel with the recommended review of the DA-GCG, the Panel believes that it would be useful for the IESO to review the interface between the SGOL and DA-GCG as well as mechanisms for considering the full amounts of SGOL cost reimbursements in scheduling decisions.

<u>Recommendation 3-4   (pp. 124-127)</u>

The Panel recommends the IESO review off-peak conditions to determine if the RT-IOG and DA-IOG programs are providing an improvement in reliability commensurate with the payments being made. The IESO should consider discontinuing off-peak IOG payments where these no longer appear to provide corresponding reliability benefits.

<u>Recommendation 3-5   (pp. 127-129)</u>

The Panel recommends the IESO review the treatment of energy exported through Segregated Mode of Operation with a view to including this energy in the determination of RT-IOG offsets for implied wheeling.

<u>Recommendation 3-6 (pp. 129-153)</u>

The Panel recognizes that adopting locational pricing would be a fundamental design change; however, we encourage the IESO to assess the efficiency benefits and costs of such an approach to provide a sound analytic basis for the consideration of future policy decisions.

Chapter 1: Market Outcomes November 2006 – April 2007

1. Highlights of Market Indicators

This chapter provides an overview of the main outcomes of the IESO-administered markets over the period November 1, 2006 to April 30, 2007 with comparisons to the same period a year earlier and in many instances a review of trends since market opening. For ease of reference the November to April period is sometimes referred to as 'winter', e.g., winter 2006 – 2007. There are four substantive sections summarizing the data on prices, demand, supply and trade. Highlights of each of these are summarized in the subsections that follow, starting with section 1.1 Pricing.

1.1 Pricing

The chapter reports on pricing from several different perspectives. The combination of low natural gas prices, strong generator performance, and relatively moderate weather conditions in November, December, and January contributed to lower electricity prices in the period compared to a year ago. The average Hourly Ontario Energy Price (HOEP) was $48.75 compared to $55.88 in the six month period one year earlier.

We also note, in calculating the load-weighted average HOEP, that loads in a position to respond to the spot price were well rewarded: during the period both dispatchable and wholesale loads paid about 5 percent less per MWh than the average for all loads. Another useful extrapolation shows that the smoothing effect of the Global Adjustment and OPG Rebate meant that while the effective price paid by load fell compared to the same period a year earlier, $1.10/MWh, the average HOEP without the adjustment declined about $6.00 more.

Section 2.2 presents statistics on the continued downward trend of Operating Reserve prices for most of the period. We also note that average monthly OR prices have fallen by more than 50 percent in the last 5 years since market opening.

Section 2.3 reports on the type of generation that was the marginal supplier during the period. While coal-fired generation continued to set the market clearing price most often, its share slipped 20 points from 73 percent in winter 2005/2006. A significant portion of this was due to oil/gas generation increasing its share of price setting.

Price fidelity shown by the difference between pre-dispatch prices and HOEP has not improved significantly since the 2005/2006 period. Section 2.4 discusses the underlying factors and identifies, a new one, the frequency of imports setting the pre-dispatch price, as worthy of further scrutiny.

Section 2.5 identifies the factors likely influencing the lower HOEP recorded in this period compared to a year earlier. The most significant is the lower natural gas prices experienced during November 2006 to April 2007.

Hourly uplifts continue to be relatively small, certainly compared to the early days of the market, and are associated with the lower HOEP seen during the period. Total hourly uplift charges declined compared to the previous year (from $215 million to $171 million) with the largest absolute decline being Losses and the largest percentage drop Operating Reserve. This data is summarized in section 2.6.

The map displaying average zonal prices and total Congestion Management Settlement Credit (CMSC) payments in section 2.7 shows the same structural differences between zones as noted in earlier reports. Zonal prices in the Northwest and Northeast continue to be lower than those in the rest of the province. In accordance with the general price decline, all zonal prices except for the Northwest,are nearly 20 percent lower than in winter 2005/2006. CMSC payments were also substantially lower; the largest changes occurring in the Northwest – constrained off supply/constrained on exports fell 80 percent to $3.5 million, while constrained on supply/constrained off exports increased six fold to $2.6 million.

The final perspective on prices is contained in section 2.8 that compares HOEP and Richview nodal prices. Consistent with the data already summarized, there are more observations of each below $20/MWh and fewer above $200/MWh in winter 2006/2007 compared to 2005/2006; however the much greater volatility of Richview is also apparent. There were 246 hours with the Richview price less than $20 compared to 189 observations of HOEP and there were 47 hours where the Richview price exceeded $200 and only one HOEP at this level.

1.2 Demand

Section 3 presents statistics on the decline in aggregate consumption in winter 2006/2007 compared to a year earlier. Total market demand fell 2.27 TWh, most, 1.76 TWh, as a result of a fall in exports over the period as a whole. The section also documents the continuing trend of falling wholesale load consumption while consumption by local distribution companies is stable. The drop in wholesale load consumption was most apparent in the Northwest zone of the province.

The other notable features of demand reported on in the section was the establishment of a new winter peak demand of 25,961 MW on February 13, 2007 and further evidence that peak load continues to grow more rapidly than overall (median) load. This is displayed by normalized load duration curves for the highest 5 percent of hours in Ontario and New York. Also note, New York's peak load is growing even faster than Ontario.

1.3 Supply

Section 4 shows various measures demonstrating that available supply was lower in winter 2006/2007 compared to the previous winter period. The average domestic offer curve shifted to the left likely because of less nuclear plant availability. The supply cushion, a measure of the unused supply that is available for dispatch on an hourly basis, is also generally lower compared to the earlier period. For example, for many of the months the number of hours of negative supply cushion and the number of hours of a supply cushion of less than 10 percent were higher.

With respect to outages, planned outages relative to total capacity appear to be trending slightly upward since market opening, continuing into the current period. Forced outages have been declining since May 2002 but that appears to have levelled off somewhat over the last year.

The section also shows that the monthly average prices of coal and natural gas declined substantially compared winter 2005/2006.

The final dimension of supply considered in section 4 is the results of the net revenue analysis for each of the five years since market opening, May 2002. Net revenues are the revenues that hypothetical generating plants could obtain from the market after covering all associated variable fuel, operating and maintenance costs. Once again, we find that there would be insufficient revenue derived from the market in the current period to exceed the standard thresholds expected to justify new investment in the province.

1.4 Imports and Exports

Ontario continued to be a net exporter for all months except November due mostly to much higher imports on-peak. For the period net exports were 2,264 GWh, a decline of 28 percent relative to the year earlier, mostly due to the reduction in net exports on-peak, even though both exports and imports have been declining.

Using a structural model developed by the IESO, the Panel observed the statistical confirmation of the central role of the price difference between New York and Ontario as a determinant of exports to New York. On average a one percent increase in HOEP or decrease in New York prices lead to a 4 percent decline in exports to New York, other things being equal.

Ontario prices are now the lowest of the five markets in this area, both on-peak and off-peak. Part of the reason for this is that MISO prices have been moving higher, and were even higher than New York on-peak for three of the six months in this period of review. This represents a fundamental shift, which implies greatly reduced opportunities for net imports to Ontario from MISO. While Ontario prices may be lower than elsewhere, comparing the Richview shadow price to other markets gives a different conclusion. That comparison indicates that the actual marginal cost of production for the IESO on average is higher than both NYISO and MISO marginal costs.

2. Pricing

2.1 Ontario Energy Price

The average Hourly Ontario Energy Price (HOEP) between November 2006 and April 2007 was $48.75, which is more than 12 percent below the average HOEP of $55.88 for the same period a year ago. Table 1-1 shows that the monthly average HOEP was lower in the first three months but higher in the following three months. The table also shows the monthly on-peak and off-peak averages, which followed a similar pattern. The lowest monthly average HOEP of $39.25 occurred in December.

Table 1-1: Average HOEP, On-peak and Off-peak, November 2005/2006 – April 2006/2007 ($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2005/2006	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**
November	58.25	49.71	74.11	60.13	44.39	39.75
December	79.77	39.25	101.29	53.06	63.52	29.71
January	55.54	44.48	64.95	53.44	47.79	36.43
February	48.13	59.12	53.98	70.93	42.82	48.39
March	49.01	54.85	57.62	68.31	40.59	42.76
April	43.52	46.05	55.96	57.58	35.23	37.63
Average	55.88	48.75	67.95	60.66	45.89	38.74

When we compare the year over year changes for individual months, we note a marked lowering of HOEP during November 2006 through January 2007. This appears to correspond with the large change in natural gas prices after the winter of 2005-2006, with an average price reduction of 35 percent for these three months (see Table 1-27 titled "Average Monthly Fuel Prices"). However, we observe the HOEP increasing in the period February through April relative to a year ago. This may be explainable in large part by a 10 percent reduction in low-priced baseload nuclear supply, equivalent to about 1,000 MW. The relatively high price in December 2005 at $79.77 alone can account for the year over year difference in the average prices for the six months. If we ignore December, average prices over the other five months are almost the same in both years, just under $50.90.

Figure 1-1 plots the frequency of price outcomes for the HOEP over the periods November 2005 to April 2006 and November 2006 to April 2007. There was a substantial increase in occurrences of the hourly price falling into the $20-40 range compared to the same period a year ago while occurrences of $40-60 prices dropped correspondingly. The frequency of the HOEP greater than $120 also decreased from the previous year with correspondingly more frequent prices in the $70-100 range. Between November 2006 and April 2007, there were only four hours when the HOEP was higher than $150 compared to 96 hours a year earlier, and one hour when the HOEP was higher than $200 compared to six hours a year earlier.[1] At the other end of the price range, there were three hours (all in December) where the HOEP was negative compared to no hours a year earlier. These high and low price occurrences are examined in Chapter 2.

[1] On April 12, 2007, the HOEP was $215.64 in hour 17.

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

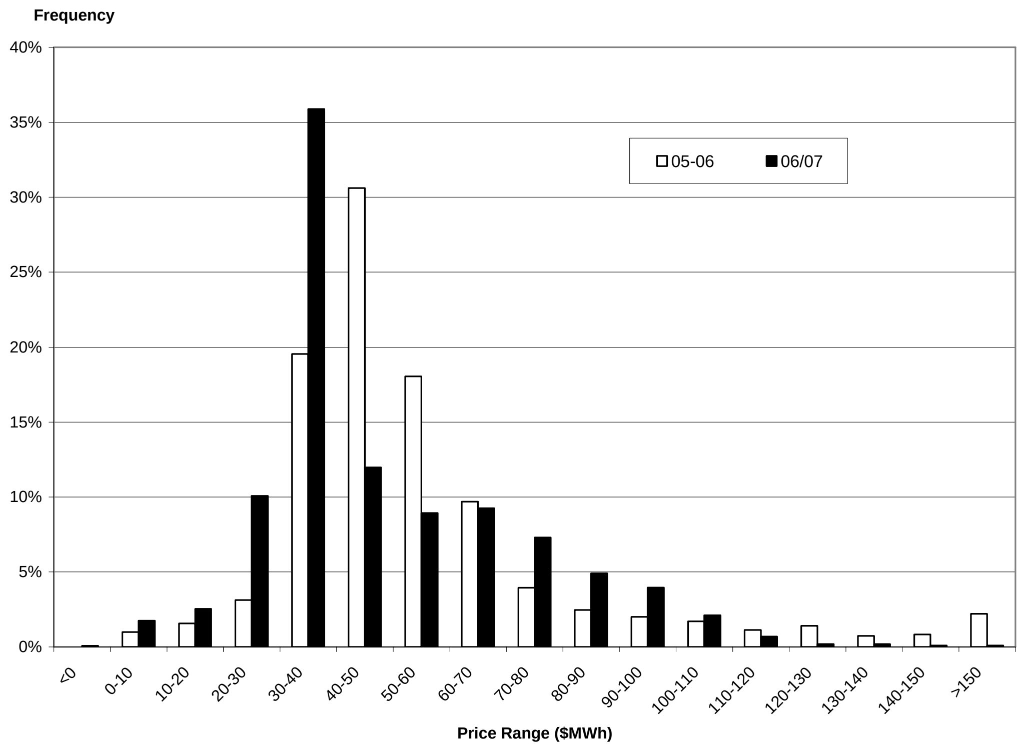
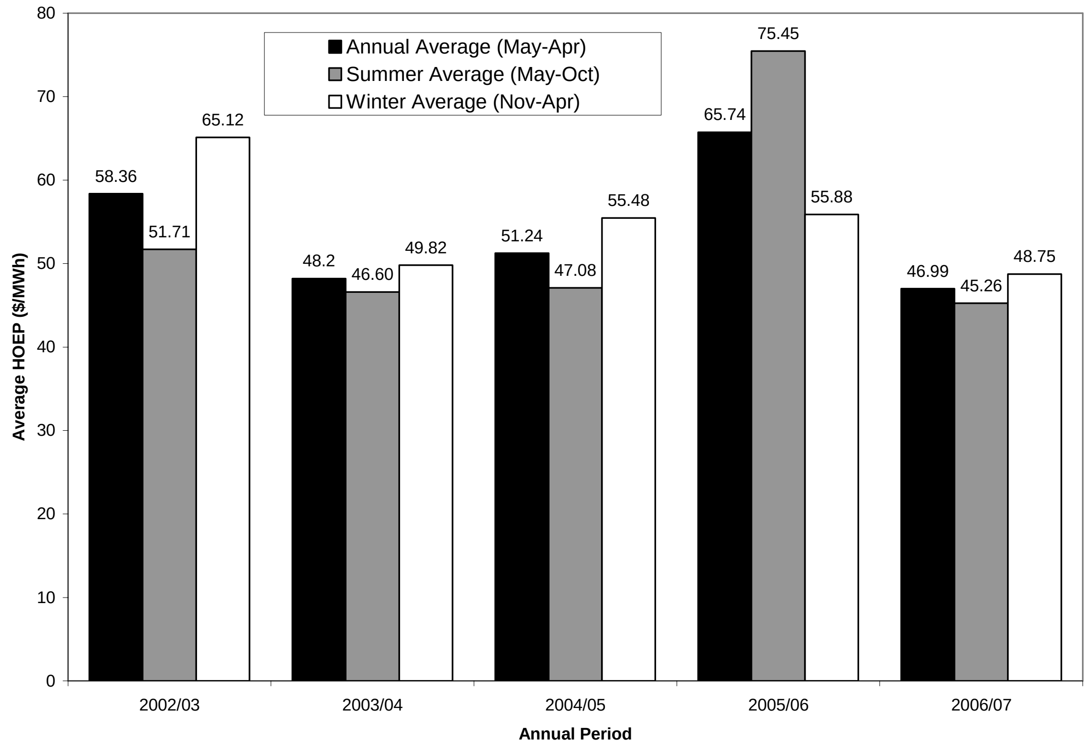


Figure 1-2 exhibits average HOEP since May 2002, comparing annual, winter and summer prices for each year. Over the last year, the HOEP reached its lowest annual average ($46.99), lowest six-month winter average ($48.75), and lowest six-month summer average ($45.26) since market opening.

Figure 1-2: Average HOEP Comparison over Summer, Winter, and All Months, May 2002 – April 2007 ($/MWh)



2.1.1 Load-weighted HOEP

While the HOEP reflects the market outcome for individual intervals, simple averages of HOEP data do not provide an aggregate picture of the overall marketplace because the volume of output varies across intervals. Therefore, we also calculate a load-weighted average HOEP. Load-weighted HOEP is more representative of the amount that loads pay and generators receive for their energy (exclusive of the Global Adjustment and OPG Rebate). Load-weighted HOEP tends to be higher than the unweighted HOEP (by about 4 percent in recent periods) because higher HOEP prices more commonly occur in hours where demand is higher.

Table 1-2 shows the HOEP and the unadjusted load-weighted average price for different customer groups for the November to April period. What is apparent from this data is that if a load can respond to the market price it will be rewarded for its efforts. In

Table 1-2 it can be observed that in 2006/2007 both dispatchable load and other wholesale loads paid about 5 percent less per MWh of consumption than the average for "All Loads", which is a consequence of consuming less at high prices and more at low prices. When the OR revenue that participating dispatchable loads earn is accounted for, dispatchable loads effectively paid $4.17/MWh less than the average in 2006/2007.

Table 1-2: Load-Weighted Average HOEP, November 2005/2006 – April 2006/2007 ($/MWh)

Year	Unweighted HOEP	Load-weighted HOEP[2]			Dispatchable Load OR Revenue
		All Loads	Dispatchable Load	Other Wholesale Loads	
2005/2006	55.88	58.22	54.35	56.16	3.14
2006/2007	48.75	50.89	48.25	48.83	1.53

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

Notwithstanding the fluctuating levels of the HOEP during the period from November 2006 to April 2007, the actual amounts paid per MWh by most Ontario loads are affected by the existence of regulated prices and fixed-price contracts in the market place. The HOEP adjusted for the OPG Rebate and the Global Adjustment results in an effective price to loads. Details of the various programs and fixed contracts that are in place can be found in our previous report, dated December 13, 2006. A simple metric is that about 80 percent of any price excursion is rebated back to the load via the various adjustment mechanisms.[3]

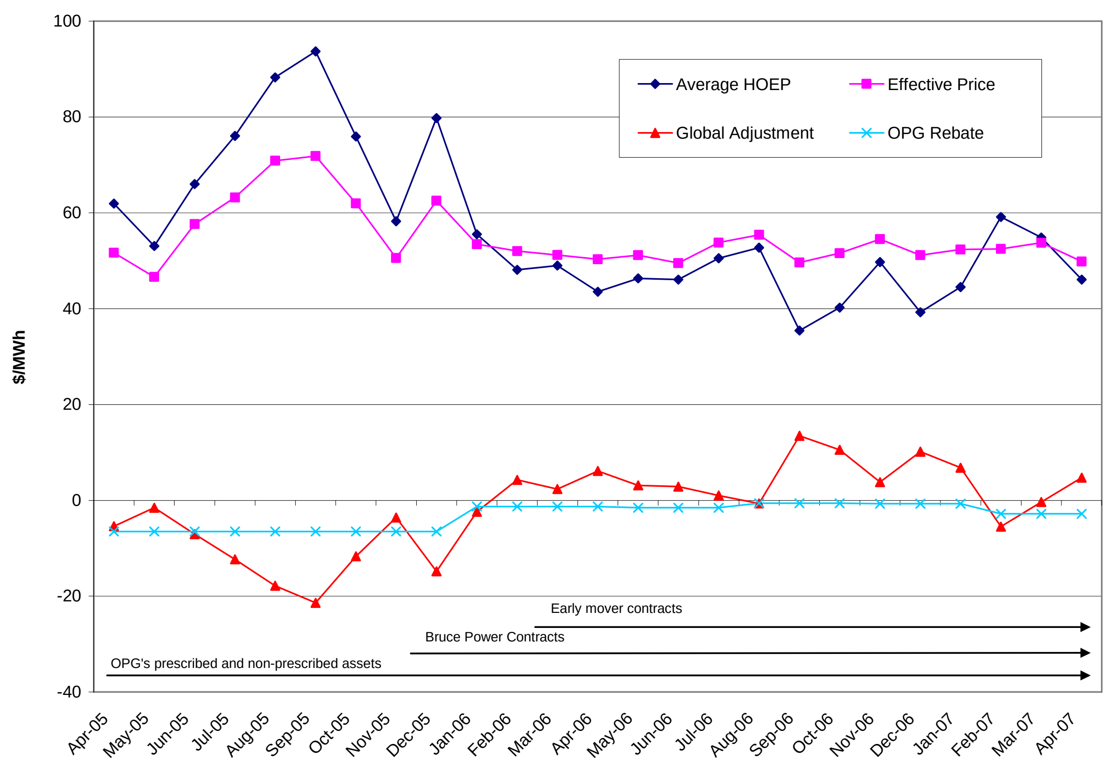
Figure 1-3 depicts the monthly HOEP and adjustments since April 1, 2005, which represents the inception of rate regulation for designated OPG generation. Two other important components in the Global Adjustment include the Ontario Power Authority managed contracts with Bruce Power and the early mover generator contracts. The

[2] Unadjusted – does not include the impact of the Global Adjustment or the OPG Rebate.
[3] See page 144 in our December report.

inception dates of these components to the Global Adjustment are represented by the time series arrows at the bottom of the figure.

For the months November 2006 through January 2007 as well as April, the combined OPG Rebate and Global Adjustment are positive, which results in loads paying an effective price that is higher than HOEP.[4] For the months of February and March which had higher average HOEP, the combined OPG Rebate and Global Adjustment are negative indicating that all loads would ultimately receive a rebate for these two months. Overall throughout the period we continue to see the significant dampening effect of these adjustments to the HOEP.

Figure 1-3: Monthly Average HOEP Adjusted for OPG Rebate and Global Adjustment April 2005 – April 2007 ($/MWh)



[4] Smaller retail loads under the Regulated Price Plan (RPP) would see the adjustments every six months as part of their fixed prices for the next period.

Table 1-3 shows the average year over year effect of HOEP changes and the Global Adjustment/OPG Rebate over the period November to April. We use load-weighted average values to show the impact or potential impact across all Ontario customers. The average HOEP dropped approximately $7.13/MWh while the load-weighted effective HOEP, taking into account adjustments, only fell by $1.10/MWh compared to the same period one year ago.

Table 1-3: Impact of Adjustments on Weighted HOEP, November 2005/2006 – April 2006/2007 ($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate	Load-Weighted effective HOEP
2005/2006	55.88	58.22	4.68	53.54
2006/2007	48.75	50.89	(1.55)	52.44
Difference ($)	(7.13)	(7.33)	(6.17)	(1.10)
% Change	(12.8)	(12.6)	(133.1)	(2.1)

2.2 Operating Reserve Prices

Tables 1-4 and 1-5 provide a comparison of monthly on-peak and off-peak operating reserve (OR) prices for each of the three classes of reserve: 10-minute spinning reserve (10S), 10-minute non-spinning reserve (10N), and 30-minute reserve (30R).

Table 1-4: Operating Reserve Prices On-Peak, November 2005/2006 – April 2006/2007 ($/MWh)

	10S		10N		30R	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
November	7.09	3.99	6.21	1.86	5.80	1.86
December	8.95	2.83	7.83	2.32	7.61	2.32
January	3.82	4.72	3.36	3.90	3.34	3.88
February	2.35	6.07	2.30	4.75	2.26	4.61
March	3.29	2.61	2.76	1.78	2.76	1.73
April	12.80	2.99	10.91	2.44	10.48	2.41
Average	6.38	3.87	5.56	2.84	5.38	2.80

Table 1-5: Operating Reserve Prices Off-Peak, November 2005/2006 – April 2006/2007 ($/MWh)

	10S		10N		30R	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
November	3.02	3.48	0.84	0.29	0.84	0.29
December	3.56	2.93	1.55	0.76	1.51	0.76
January	3.06	2.18	0.66	0.47	0.66	0.47
February	2.85	1.43	0.86	0.69	0.86	0.69
March	1.98	1.34	0.84	0.25	0.84	0.25
April	6.25	2.47	4.22	0.65	4.15	0.65
Average	3.45	2.31	1.50	0.52	1.48	0.52

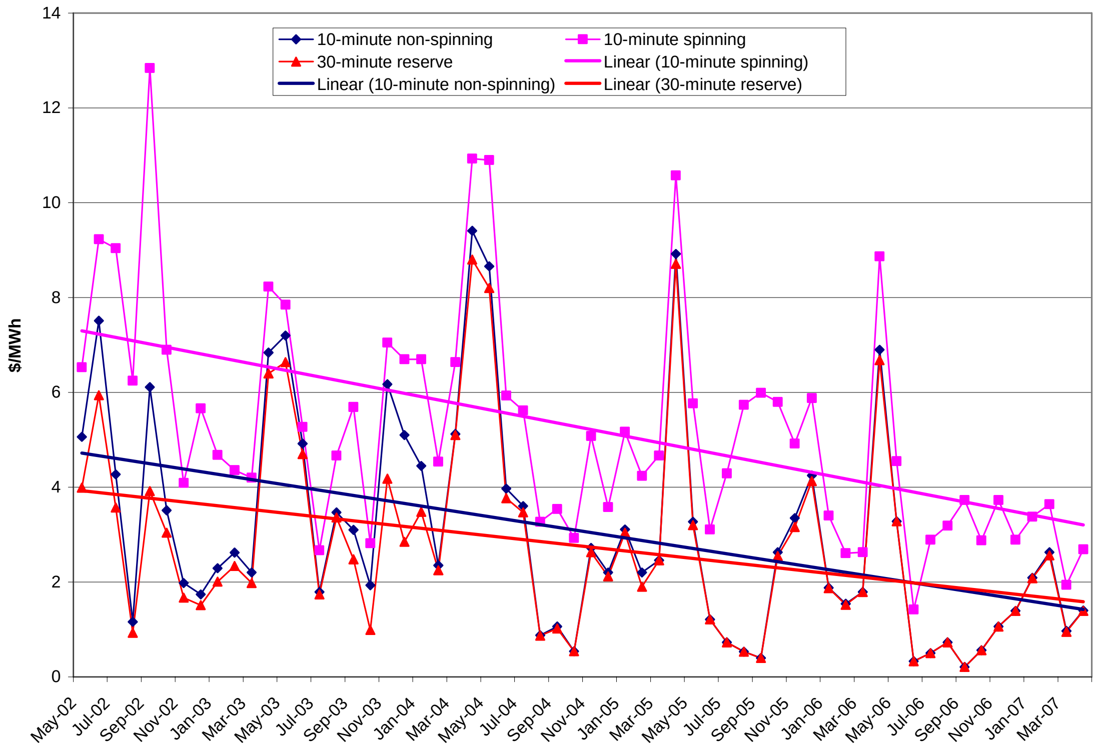
On-peak OR prices were marginally higher in January 2007 and considerably higher in February 2007 compared to 2006, but lower for all other months in the period. The cold weather which emerged later in January and continued through February would appear to have tightened the supply/demand balance and induced higher OR prices. OR prices in April were noticeably lower, since these did not exhibit the typical seasonal increase in OR prices associated with spring freshet. The main reason for a much lower OR price in April 2007 may be that there was much less peaking hydro available for energy. These peaking hydro resources thus were able to offer OR, offsetting the typical freshet increase in the OR price. Less hydro energy from peaking generators is also observed for all months except January. Other factors that led to a lower OR price in the study period include a lower OR requirement due to the implementation of the Northeast Power

Coordinating Council (NPCC) Regional Reserve Sharing (RRS) program in January 2006, which allowed the IESO to reduce its 10-minute reserve requirement by 50 MW, as well as many exporters being able to offer OR at a cheaper price. In fact, as Appendix Table A-48 shows, exporters provided almost 5 percent of OR supply, off-peak, in January to April 2007, compared to essentially nothing a year ago.

During off-peak hours, 10-minute non-spinning reserve and 30-minute reserve prices declined in all months and 10-minute spinning reserve prices declined in all months except November compared to the year earlier period.

Figure 1-4 shows monthly average OR prices since market opening and the continuing downward trend for each class of OR. The downward sloping linear trendlines suggest that average monthly OR prices have fallen by more than 50 percent since May 2002.

Figure 1-4: Monthly Operating Reserve Prices by OR Class since Market Opening May 2002 - April 2007 ($/MWh)



We understand that the IESO is presently stakeholdering approval for dispatchable load to be able to provide 10-minute spinning reserve. Its adoption would likely further reduce the price of this form of reserve and may have a small downward impact on HOEP everything else being held equal.

On April 27, 2007, the NPCC approved a further 50 MW increase in Regional Reserve Sharing (RRS) which allows control areas to reduce their local operating reserve. On May 17, 2007, the IESO reduced its 10-minute (non-spinning) reserve requirement by a total of 100 MW through the RRS program when the energy is available from neighbouring jurisdictions.[5] This again should lead to slightly lower OR prices and possibly lower energy prices everything else being equal. We will monitor this and report on the impact of this change in our next report.

[5] The IESO News Release is available at http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=3455

2.3 Price Setters

Reviewing which type of generation is the marginal supplier can provide insight into the evolution of the market. The frequency with which a given type of generator sets the price can inform us about changes in the supply/demand balance. Lowest marginal cost generation in Ontario tend to be nuclear and baseload hydroelectric facilities. Presently, the next most expensive resources are coal-fired facilities, then gas-fired facilities, and finally hydroelectric peaking generation although this hierarchy is dependent upon highly volatile natural gas prices as well as fluctuations in coal prices.

As can be observed from Table 1-6, coal continues to set the price most frequently. However, the percentage of the intervals when coal generators set the MCP dropped from 73 percent in the 2005/2006 winter season to 53 percent in 2006/2007. A significant portion of this change was due to oil/gas increasing its share of price setting. The increase in price setting by oil/gas generators was a combination of a few factors. First, a significant decline in baseload nuclear supply since January shifted the supply curve to the left, leading the market to rely more on peaking resources, such as oil/gas generators. Second, the OPA's early mover contracts which took effect in February 2006 provide two gas-fired generators with incentives to offer at their marginal cost. Without the contracts, those generators typically offered at their average avoidable cost, which includes start-up cost and O&M costs. As a result, these units under the early mover contracts are now more likely to be online and thus more likely to set the price. Third, the IESO's Day-Ahead Commitment Process (DACP), which was implemented in June 2006, provides a cost guarantee to all eligible fossil generators including all oil/gas-fired generators. The DACP provides an incentive for participating generators to be online and thus more frequently set the price. We will further discuss the DACP in Chapter 3.

Table 1-6: Average Share of Real-time MCP Set by Resource Type, November 2005/2006 – April 2006/2007 (% of Hours)

	2005/2006	2006/2007	Change
Coal	73	53	(20)
Nuclear	0	0	0
Oil / Gas	10	25	15
Hydro	17	22	5

Tables 1-7 to 1-9 provide monthly shares by generator fuel type for all hours, on-peak hours, and off-peak hours compared to the same months one year earlier. The percentage of time that coal generators set the MCP fell in both the on-peak and off-peak hours (except on-peak in December), although the decline was more noticeable during the on-peak hours.

Table 1-7: Monthly Share of Real-time MCP Set by Resource Type, November 2005/2006 – April 2006/2007 (% of Hours)

	Coal		Nuclear		Oil/Gas		Hydro	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	71	52	0	0	12	25	16	23
December	61	62	0	0	23	16	16	22
January	84	60	0	0	6	24	11	16
February	85	41	0	0	4	39	11	20
March	73	49	0	0	9	27	18	24
April	65	56	0	0	8	16	27	28
Average	73	53	0	0	10	25	17	22

Table 1-8: Monthly Share of Real-Time MCP Set by Resource Type On-Peak November 2005/2006 – April 2006/2007 (% of Hours)

	Coal		Nuclear		Oil/Gas		Hydro	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	57	37	0	0	24	41	19	22
December	45	57	0	0	41	30	14	13
January	79	44	0	0	10	41	11	15
February	81	25	0	0	6	59	13	16
March	59	26	0	0	16	44	25	29
April	67	45	0	0	17	25	15	30
Average	65	39	0	0	19	40	16	21

Table 1-9: Monthly Share of Real-Time MCP Set by Resource Type Off-Peak November2005/2006 – April 2006/2007 (% of Hours)

	Coal		Nuclear		Oil/Gas		Hydro	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	84	66	0	0	2	10	14	24
December	72	66	0	0	10	5	18	29
January	88	74	0	0	2	8	10	18
February	89	55	0	0	1	21	9	24
March	86	68	0	0	3	12	11	20
April	63	64	0	0	2	9	35	26
Average	80	66	0	0	3	11	16	24

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

The Panel continues to maintain that inaccurate or unreliable pre-dispatch prices can lead to inefficient production and consumption decisions which in turn can cause real-time scheduling inefficiencies. The difference between pre-dispatch and real-time prices is an important market metric.

The Panel observed in its December 2006 report that both the increasing number of generator contracts being developed by OPA as well as its demand response programs are keyed on the pre-dispatch signal. Efficient operation of the Ontario market is becoming more reliant on correct pre-dispatch price projections.

Table 1-10 describes the differences between the one-hour ahead pre-dispatch price and the HOEP for November through April in the current and prior years. The maximum differences declined in all months. The average difference over the past 6 months is $9.91, which is 11 percent less than $11.12 for the previous period. However in relative terms, the average difference expressed as a percentage of the HOEP increased slightly from 26.8 percent to 27.3 percent. When we review the monthly performance, the pre-dispatch projections improved in November, December, and April relative to the prior year, but deteriorated in the middle three months.

Table 1-10: Measures of Differences Between One-Hour Ahead Pre-Dispatch Prices and HOEP November 2005/2006 – April 2005/2006 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	14.62	8.34	109.26	59.00	(95.91)	(54.45)	24.08	14.52	30.18	24.82
December	17.99	8.77	115.79	91.68	(170.48)	(67.32)	29.64	13.50	31.06	22.68
January	7.76	7.69	98.88	40.71	(54.91)	(82.87)	15.46	12.08	15.99	23.88
February	8.33	14.00	85.36	80.63	(58.70)	(74.28)	12.23	16.26	18.82	32.21
March	10.25	11.06	92.99	87.12	(89.21)	(67.96)	15.45	16.30	24.13	28.46
April	7.74	9.57	107.75	95.48	(621.55)	(119.44)	29.19	17.18	40.88	31.65
Average	11.12	9.91	101.67	75.77	(181.79)	(77.72)	21.01	14.97	26.84	27.28

The three-hour ahead price projections in Table 1-11 also exhibit similar behaviour with the average difference declining over the period to $9.08 versus a previous average error of $10.46. When we look at the average hourly difference as a percentage of HOEP, the six month error has improved slightly from 24.4 percent to 23.8 percent. Interestingly over the past six months, the three-hour ahead pre-dispatch price projections were, on average, more accurate than the one-hour ahead projections and the same pattern exists over the previous two MSP reporting periods. Although the three-hour average is more accurate, the three-hour ahead forecast exhibits a higher standard error, and has had some monthly maximum and minimum errors more extreme than the one-hour ahead forecast, suggesting greater uncertainty with the three-hour ahead forecast.

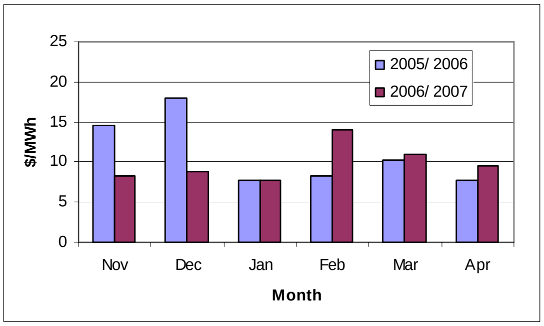
Table 1-11: Measures of Differences Between Three-Hour Ahead Pre-Dispatch Prices and HOEP November 2005/2006 – April 2006/2007 ($/MWh)

	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	15.59	8.85	133.49	62.20	(107.11)	(57.01)	28.53	14.87	31.25	25.36
December	19.94	8.16	128.93	83.82	(139.24)	(73.61)	32.23	14.21	32.25	15.19
January	7.83	6.48	95.15	46.19	(55.84)	(89.72)	16.72	13.18	15.52	20.38
February	7.10	12.93	91.97	73.34	(63.38)	(74.95)	13.21	17.30	16.31	29.42
March	8.58	11.31	98.99	88.29	(76.97)	(67.96)	16.97	16.83	20.14	28.05
April	3.71	6.76	223.01	81.19	(651.03)	(145.64)	31.42	18.26	30.78	24.35
Average	10.46	9.08	128.59	72.51	(182.26)	(84.82)	23.18	15.78	24.38	23.79

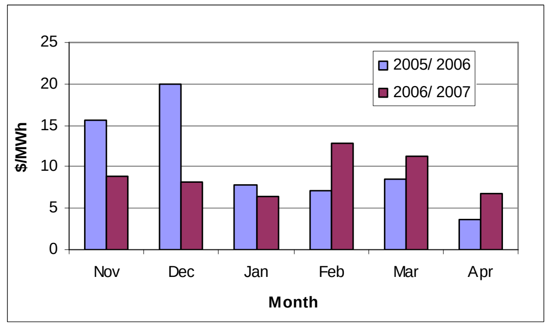
Figure 1-5 shows the trends in monthly average differences for both one-hour ahead and three-hour ahead price projections.

Figure 1-5: Average Pre-dispatch Price Differences
One and Three-Hour Ahead to Real-Time
November 2005/2006 - April 2006/2007
($/MWh)

(One-hour ahead price difference)



(Three-hour ahead price difference)



The main underlying causes of errors in price projections have been identified as:

- Demand forecast error;
- Performance of self-schedulers and intermittent generators;
- Failure of scheduled imports and exports.

A fourth factor has also emerged as a possible contributor to the difference – the frequency that imports set the pre-dispatch price. In the following sub-sections we examine changes in each of these four factors to better understand the underlying cause for the increased errors during the February through April period.

2.4.1 Demand Forecast Error

In past reports the Panel has found demand forecast error to be one of the major components of price projection errors and has welcomed the efforts by the IESO to reduce demand forecast error. For this report we again observe a period over period improvement in the demand forecast error. Comparing peak (5-minute interval) demands, which the IESO uses in creating its pre-dispatch price projections, the forecast has improved slightly. Table 1-12 shows that period average absolute error for the one-hour ahead peak demand forecast has dropped to 0.89 percent this year compared with 0.96

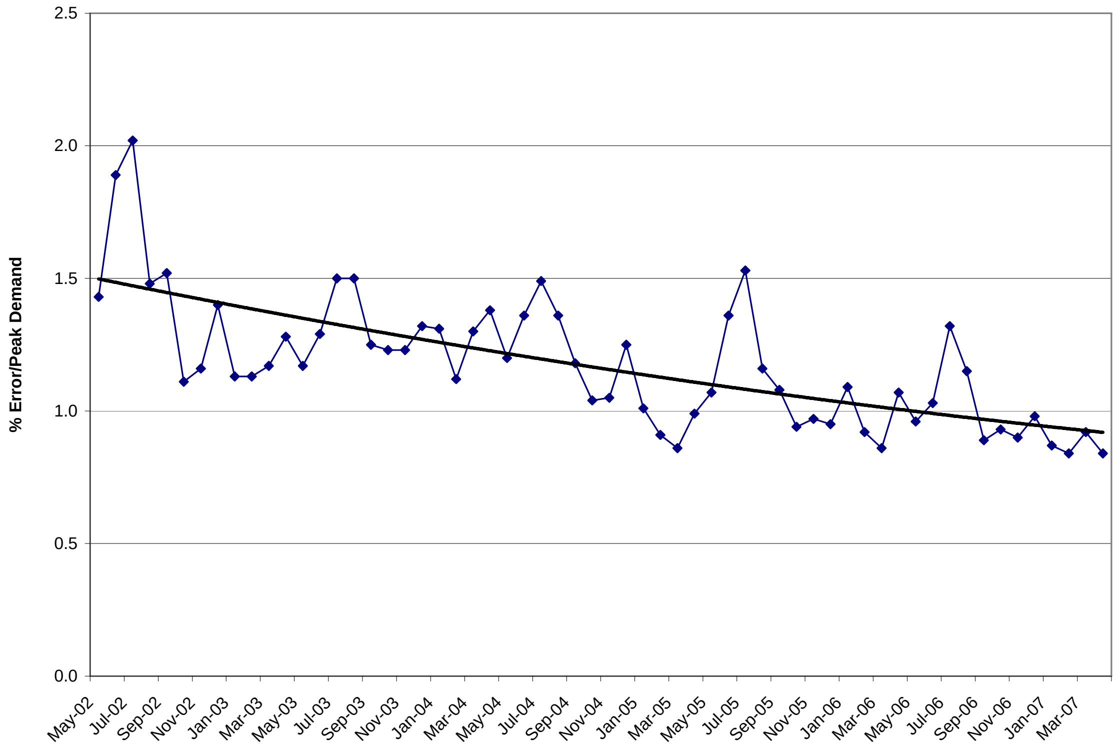
percent in the previous similar period. These forecasts are well within the range of the 2 percent error typical in other northeast ISO's.

Table 1-12: Forecast Error in Demand
November 2005/2006 – April 2006/2007

	Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	Three-Hour Ahead		One-Hour Ahead		Three-Hour Ahead		One-Hour Ahead	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	2.03	1.91	1.84	1.86	1.21	1.05	0.97	0.90
December	1.97	1.99	1.79	1.82	1.22	1.21	0.95	0.98
January	2.09	1.87	1.81	1.72	1.39	1.13	1.09	0.87
February	1.88	1.76	1.68	1.60	1.18	1.07	0.92	0.84
March	1.78	1.70	1.61	1.55	1.06	1.11	0.86	0.92
April	1.87	1.75	1.67	1.59	1.16	1.07	0.94	0.84
Average	1.94	1.83	1.73	1.69	1.20	1.11	0.96	0.89

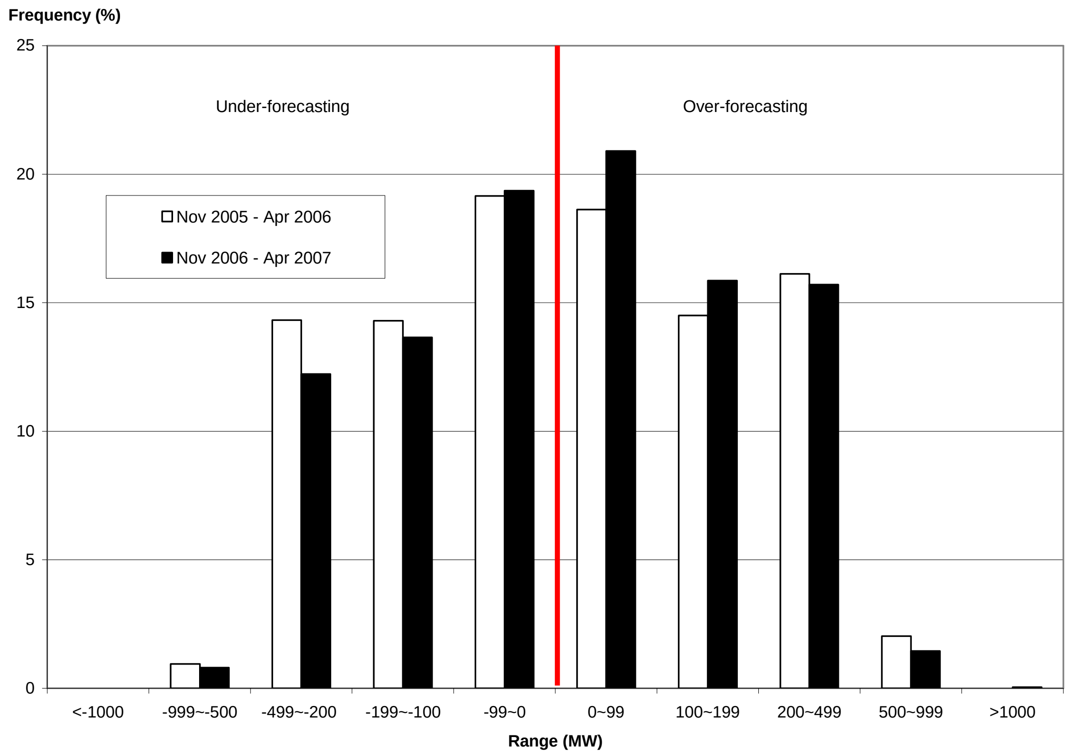
When we look at absolute error since market opening in Figure 1-6, we can observe the marked improvement in the forecast. But what is also apparent is that further increases in demand forecast accuracy are becoming more difficult in that monthly error is flattening at slightly less than 1 percent. Figure 1-6 suggests that there are apparent seasonal effects related to demand forecast error. The Panel observes that demand forecast error generally declines in the November through April period and spikes during the summer months. It appears that this is due to the higher variability in summer load as a result of weather uncertainty and the higher sensitivity of demand to temperature due to the air conditioning load.

Figure 1-6: Absolute Average One-Hour Ahead Forecast Error
May 2002 - April 2007
(%of Peak Demand)



In Figure 1-7 we compare the IESO's demand forecast error for over-forecasting events versus under-forecasting events and note little bias in the demand forecast between over and under-forecasting for both 2005/06 and 2006/07.

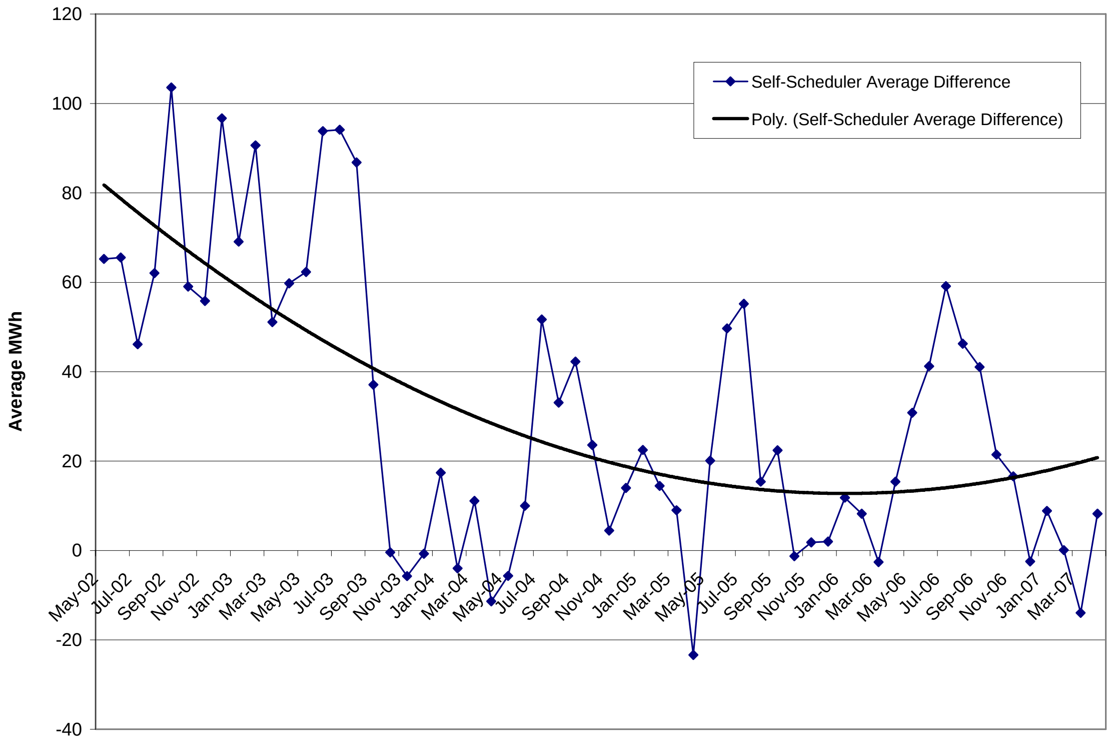
Figure 1-7: Distribution of Ontario Demand Forecast Error (One-Hour Ahead versus Real-time) November 2005/2006 - April 2006/2007



2.4.2 Performance of Self-Scheduling and Intermittent Generation

The error between what self-scheduling and intermittent generators indicate they are going to produce and what they actually produce contributes to discrepancies between pre-dispatch and real-time prices. Based on the path of the polynomial trend line in Figure 1–8, there appears to be a slight upward trend in this error since early 2006. However, relative to the total forecasting differences contributing to errors in price projections, this continues to be small. For example on average the self-scheduling error is presently about 20 MW of over-forecasted production, versus an import failure roughly 5 times larger and an export failure approximately 7 times larger.

Figure 1-8: Average Difference between Self-schedulers' Offered and Delivered Energy May 2002 - April 2007
(MWh)

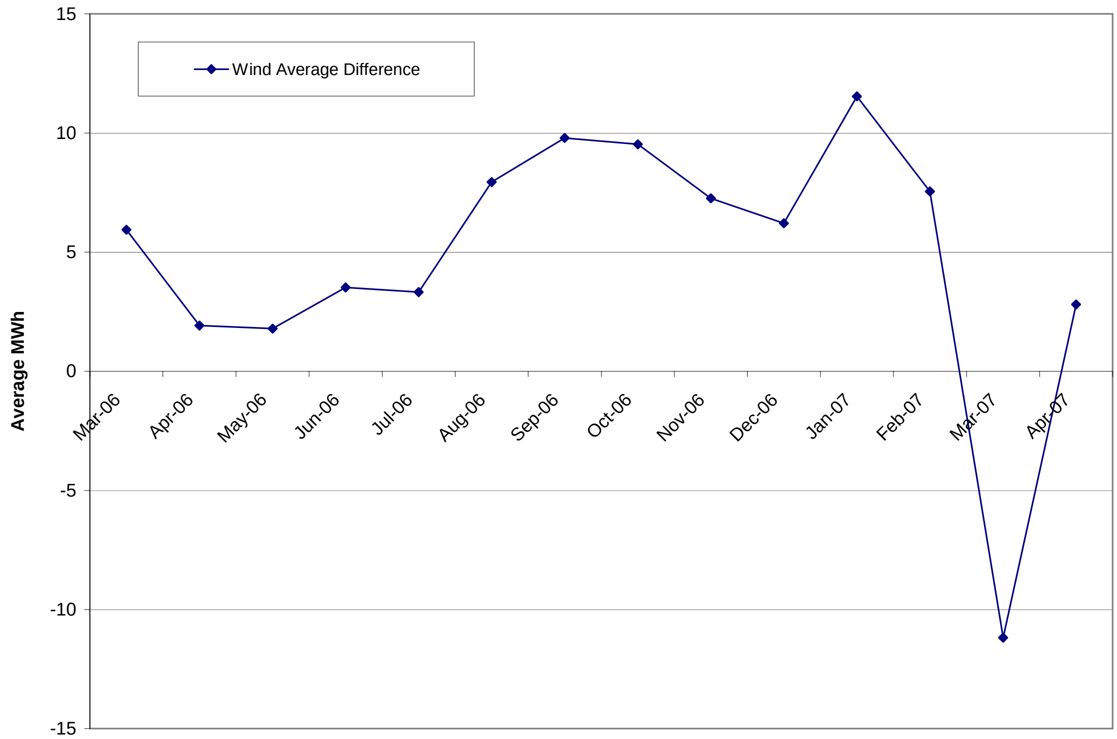


2.4.3 Performance of Wind-Power Generation

From March of 2006 to present, 395 MW of wind power capacity has been installed in Ontario with the highest production to date of 289 MW occurring on December 23, 2006. Figure 1-9 presents the average difference between the amount that wind generators offer and actual production in MWh. The average difference since March 2006 was 4.9 MWh, which represents 1.3 percent of total wind generator capacity.

The MAU has observed that the major reason for the reversal in the self-scheduler error is attributable to the rapid growth in wind generation over the past year. When we review Table A-40 in the Statistical Appendix, the average difference is 5 MW since May 2006, but the maximum and minimum differences are roughly 110 MW.

Figure 1-9: Average Difference between Wind Generators' Offered and Delivered Energy March 2006 - April 2007 (MWh)



2.4.4 Real-Time Failed Intertie Transactions

In previous reports, the Panel has concluded that the major source of error between pre-dispatch and real-time price projections has been import and export failures. Here we explore the relationship between the imposition of an Intertie Failure Charge (IFC) and the incidence of failures. We also note that the reduction of export failures has led to fewer occurrences of a binding Net Interchange Scheduling Limit.

Tables 1-13 and 1-14 report the number of incidents and rates of total import and export failures in 2005/06 and 2006/07. While the import failure rate remained the same across the two periods at just over 3.6 percent we observe a large reduction in the export failure rate from approximately 10.0 percent to 6.8 percent which corresponds to an average hourly reduction of approximately 100 MW.

Table 1-13: Incidents and Average Magnitude of Failed Exports from Ontario November 2005/2006 – April 2006/2007

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)***	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	503	317	850	765.5	224	157	9.17	8.56
December	461	387	1,098	865	221	169	8.95	8.92
January	543	415	1,132	801	216	153	8.92	7.49
February	541	375	1,190	1,220	282	130	12.33	3.91
March	527	404	975	671	260	142	10.02	5.93
April	543	454	1,000	1,028	291	160	10.68	5.88
Average	520	392	1041	892	249	152	10.01	6.78

* The incidents with less than 1 MW are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled exports MWh in the unconstrained sequence in a month

Table 1-14: Incidents and Average Magnitude of Failed Imports to Ontario November 2005/2006 – April 2006/2007

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)***	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	273	242	539	595	112	114	3.15	3.48
December	293	137	667	384	141	102	4.64	3.12
January	212	138	910	553	126	110	3.32	3.33
February	211	230	525	502	107	92	4.85	4.91
March	174	217	405	550	102	112	3.13	3.58
April	84	105	421	250	104	89	3.10	3.27
Average	208	178	578	472	115	103	3.70	3.62

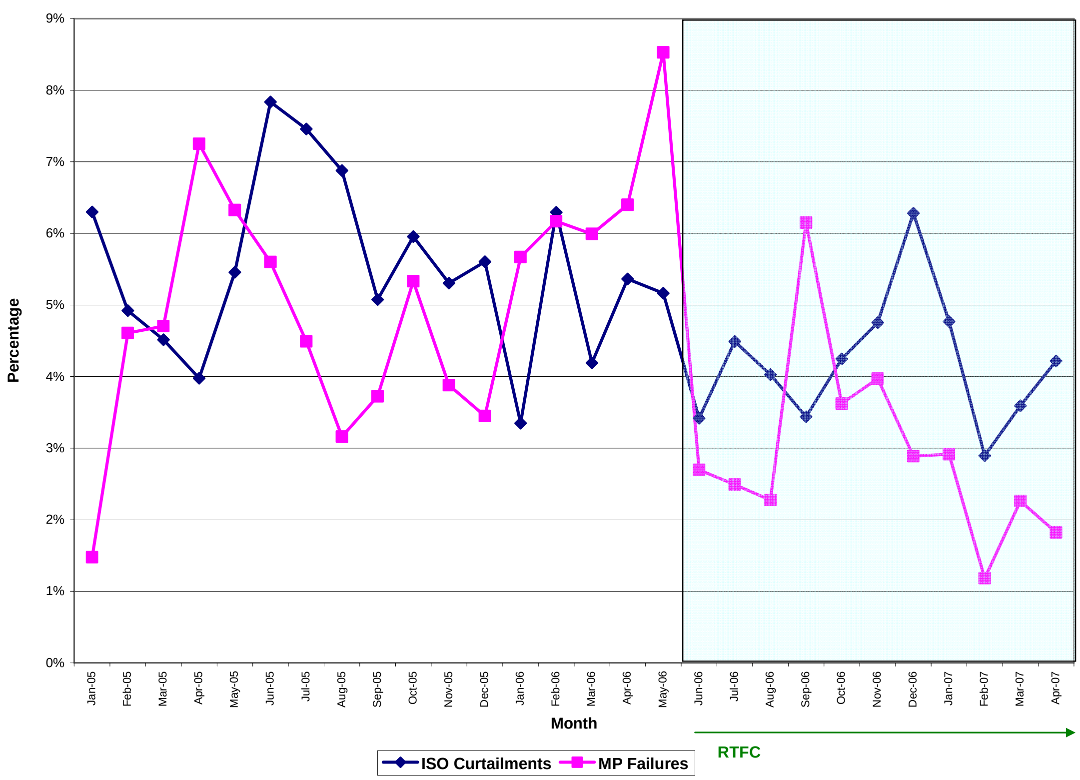
* The incidents with less than 1 MW are excluded
** Based on those hours in which a failure occurs
*** Total failed MWh divided by total scheduled imports MWh in the unconstrained sequence in a month

More detailed data on import and export failures is provided in the Statistical Appendix, Tables A-41 through A-46.

In our previous report we discussed the newly implemented IESO Intertie Failure Charge which was introduced in June 2006. Initial results seem to indicate that the IFC has had an impact on export failures. In addition, to date the IFC had clawed back approximately $2.2 million from participants (approximately $1.2 million since November 2006), the majority of that being as a result of export failures.

Figure 1-10 illustrates the magnitude of monthly export failures which are under the participant's control and those due to external ISO security issues as ratios against total exports since January 2005.[6] It would appear that the intertie transaction failure charge has been influential in reducing failures under a participant's control, while those failures related to the adjacent control areas 'security' issues have remained roughly constant.

Figure 1-10: Ratio of Monthly Total Export Failures by Cause to Total Exports January 2005 - April 2007



[6] Given the introduction of the IFC in June 2006 and market participant entries and departures, data prior to 2005 is not considered.

The Panel remains concerned over the level of intertie failures that are not within the participant's control. For export failures destined for New York, these are due to the New York ISO not accepting transactions although they appear to be economic. Table 1-15 shows that between May 2006 and April 2007, average monthly export failures bound for New York that were failed due to external ISO security totalled 36 GWh, which represents 88 percent of all Ontario exports failed under the external ISO's control.

Table 1-15: Monthly Export Failures by Cause
May 2006 – April 2007
(in GWh and % Failures)

	ISO Controlled	%	Participant Controlled	%
NYISO Failures	36.3	88.3	32.0	96.1
MISO Failures	1.1	2.7	0.7	2.1
Manitoba Failures	0.9	2.2	0.3	0.9
Minnesota Failures	0.5	1.2	0.1	0.3
Quebec Failures	2.3	5.6	0.2	0.6
Total	41.1	100.0	33.3	100.0

Recommendation 1-1

Given the persistent large number of intertie failures not under a market participant's control, the Panel urges the IESO to continue to review this issue with New York ISO to better understand why there are such high failure levels and determine whether there are solutions which could reduce such failures to the benefit of both markets.

Another outcome observed in parallel with the reduction in export transaction failures is fewer occurrences of a binding Net Interchange Scheduling Limit (NISL). NERC defines the net intertie schedule as "the algebraic sum of all interchange schedules with each adjacent balancing authority."[7] That is, the NISL is the allowed maximum change in all transactions as a whole with all external jurisdictions at a given time. NISL represents the limited generation ramping capability within Ontario to respond to hour-to-hour

[7] NERC Glossary of Terms Used in Reliability Standards, November 1, 2004.

changes in net imports. Transaction failures in the preceding hour limit the available net change in the imports or exports allowed when making choices in pre-dispatch.

Intertie trading offers the benefits of:

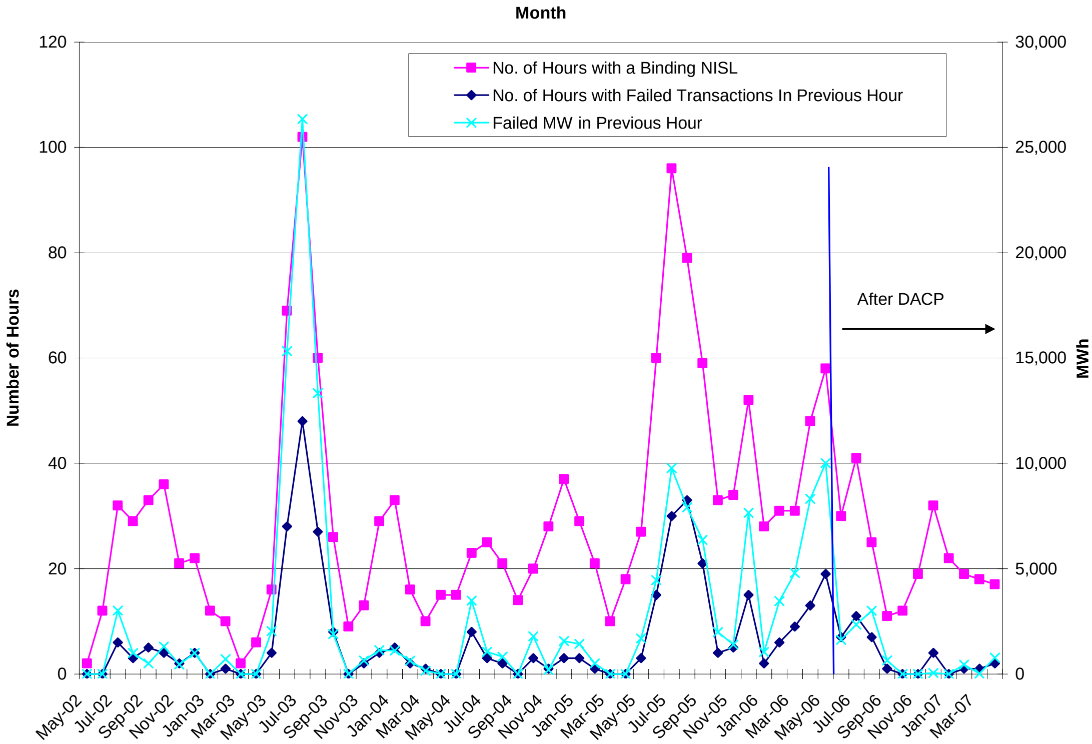
- enhanced global efficiency between markets, achieved by maximizing the capability of the interties to compete away arbitrage opportunities; and
- enhanced reliability, achieved by ensuring the maximum intertie capability can be utilized.

If NISL is not reflective of the actual generation ramping capability within Ontario, a binding NISL could prevent some of these efficiency and reliability benefits from being achieved.

Figure 1-11 lists the monthly total number of hours in which the NISL was binding, the total number of hours with some failed import or export, and the total failed MWh in the previous hour. One can see that the frequency of a binding NISL had been increasing in the first four years of market operation, but has been decreasing since June 2006. The trend for the frequency of import/export failure and total failed MWh in the previous hour is highly correlated to the frequency of a binding NISL, indicating a strong relationship between them.[8] As the Panel illustrated in our December 2006 report as well as in the current report, the Intertie Failure Charge that was imposed on failed transactions since June 2006 has had an effect in reducing intertie transaction failures related to exports within the participant's control. These lower transaction failure rates in turn contributed in part to a lower frequency of a binding NISL (in the hours after the failures) which in turn allowed more of the efficiencies between markets to be obtained.

[8] Since market opening, the correlation coefficient between the frequency of a binding NISL and the frequency of import/export failures in the previous hour is 0.94 and the correlation coefficient between the frequency of a binding NISL and total failed MWh in the previous hour is 0.86. There may be two reasons for the correlation. There may be a greater tendency for failures and binding NISL simply because import/export levels are high. Alternately, a failure in one hour has the potential to induce NISL in the next hour.

Figure 1-11: Total Number of Hours with a Binding NISL and Transaction Failure in the Previous Hour by Month May 2002 – April 2007



2.4.5 <u>Imports Setting Pre-dispatch Price</u>

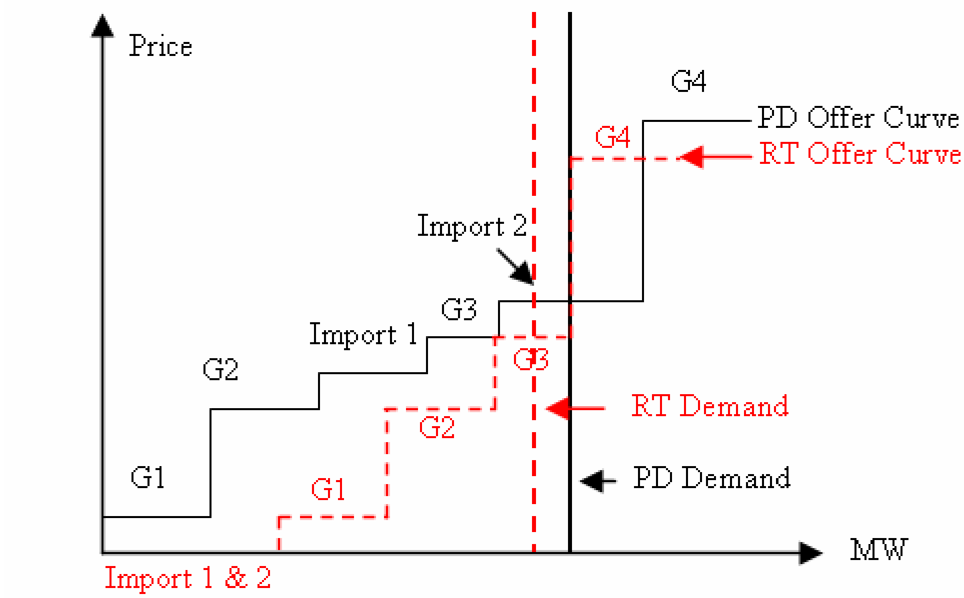
When we review the factors that cause differences between pre-dispatch and real-time prices, it is apparent that the sources of error discussed above were stable or declined, and that should result in a lessening of the difference between pre-dispatch and real-time prices. Counter-intuitively the error grew in the months of February through April 2007 compared to the same months a year earlier. We believe the increasing frequency of imports setting the pre-dispatch price is one of the main factors that lead to the growing error.

In pre-dispatch, imports can set the market clearing price. Imports are scheduled in pre-dispatch then fixed as a constant for the hour in real-time. The scheduled imports are placed at the bottom of the offer stack which has the effect of adding low cost supply and shifting the real-time supply curve to the right. But this process also removes unscheduled import offers that were extramarginal and thereby increases the slope of the supply curve above the pre-dispatch demand. This process which leads to a steeper real-time supply curve was discussed in the Panel's first report (Appendix 1). The effect of a less elastic supply curve is that it makes the real-time price much more sensitive to even small deviations between actual and forecast values of the other variables such as demand, self-scheduling error or failed imports/exports.

If the import is only partially selected in pre-dispatch, a slightly lower (or higher) pre-dispatch demand might have led to the same pre-dispatch price. But because the accepted import offers are relocated to the bottom of the offer stack and all others are removed in real-time, the price is set by a domestic supplier. This essentially guarantees a drop in price if the real-time demand is also slightly lower. If there were many imports around the pre-dispatch marginal price, there could well be a significant price drop even for small real-time changes in demand.

The difference in the offer curves between pre-dispatch and real-time is illustrated in Figure 1-12. The solid lines represent the pre-dispatch demand and offer stack and the dashed lines the real-time demand and offer stack. '*G'* denotes a generator, and '*Import'* an import offer. Because all imports scheduled by the pre-dispatch sequence (*Import 1* and a portion of *Import 2*) are repositioned to the bottom of the supply stack in real-time, the real-time supply curve becomes steeper than the pre-dispatch supply stack. If the real-time demand comes slightly lower than the forecast peak, as often happens, the real-time demand will be set by *G3*, which is inframarginal in pre-dispatch. The real-time price is then lower than the pre-dispatch price. If the real-time demand comes in exactly the same as (or higher than) the pre-dispatch demand, the real-time price would be set by generator *G4* and higher than the pre-dispatch price. However, the pre-dispatch demand is the forecast peak demand for the hour, implying that for most of the hour (i.e., the other 11 intervals) the real-time demand is lower than the pre-dispatch demand. Thus for most of the time in the hour shown in this illustration, the real-time price would be set by *G3* and would be lower than the pre-dispatch price. As a result, the average real-time price, i.e. the HOEP, tends to be lower than the pre-dispatch price.

Figure 1-12: Offer Stacks in Pre-Dispatch and Real-Time



By contrast if a domestic generator sets the pre-dispatch price, there is some range around which small real-time demand reductions may not induce much of a price change. Thus the more domestic supply sets pre-dispatch prices the less of the tendency for real-time prices to drop.

In Table 1-16 we observe a notable increase in the frequency of imports being the marginal supplier in pre-dispatch this year compared with last year. The largest differences occur in the latter half of the six month period, coincident with the period where real-time prices and pre-dispatch to real-time price differences have been increasing. The increases in February to April represent nearly 10 percent of the total hours in those months.

Table 1-16: Frequency of Imports Setting the Pre-Dispatch Price November 2005/2006 – April 2006/2007 (Number and % of Hours)

	2005/2006		2006/2007		Difference	
	Hours	**%**	**Hours**	**%**	**Hours**	**% Change**
November	292	40.6	305	42.4	13	1.8
December	317	42.6	234	31.5	(83)	(11.2)
January	220	29.6	253	34.0	33	4.4
February	204	30.4	280	41.7	76	11.3
March	275	37.0	342	46.0	67	9.0
April	181	25.1	243	33.8	62	8.6
Average	248	34.2	276	38.2	28	4.0

2.5 Analyzing Year over Year Changes in the HOEP

The MAU, under the direction of the Panel, has developed an econometric model to analyse the determinants of changes in the HOEP. In this report, our previous model is updated to include a total of 52 monthly observations over the period January 2003 to April 2007 and we replace the New York energy price with New York load as an explanatory variable.[9] Using the revised model, the MAU performed a decomposition analysis to estimate the impact on HOEP of each of five independent variables.

The econometric model uses a reduced form equation to capture the variables which appear to effect year over year changes in the HOEP, separately for on-peak and off-peak hours. The dependent variable in the model is the monthly average HOEP and the independent variables include Ontario non-dispatchable load, nuclear production, self-scheduler production, the natural gas price, New York load, and fixed effects representing each month of the year to control for common seasonality patterns throughout the year. Increases in Ontario demand, the natural gas price, and the New York load should increase the HOEP. Increases in nuclear generation output and self-scheduling generation output should reduce the HOEP.

[9] See pages 21-25 in the last Market Surveillance Panel Report dated December 13, 2006.

In its last report, the Panel indicated an analytical concern about the strong correlation between the natural gas price and the New York price when used as explanatory variables in the model. In this revised model, the MAU used the New York integrated load to control for demand conditions in the New York market. This allows us to determine the influence of natural gas prices on the HOEP while controlling for demand in New York that may influence the HOEP through the export channel. We expect increases in New York load levels, other things equal, to increase the HOEP. The estimation results for the on-peak and off-peak models are presented in Table 1-17. As expected, the coefficient on New York load is positive and significant for both periods. Overall, the explanatory variables in the model are significant and have the expected signs with the exception of self-scheduler production in the off-peak hours. The goodness of fit of the model, measured by the R-squared, explains much of the variability in the monthly average HOEP.

Table 1-17: Estimation Results of the Updated Econometric Model[10]
January 2003 - April 2007

Variable	On-peak Model		Off-peak Model	
	Coefficient	**P-value**	**Coefficient**	**P-value**
Constant	-27.36	0.00	-20.72	0.00
LOG(Nuclear Output)	-0.72	0.00	-0.65	0.00
LOG(Self Scheduler output)	-0.12	0.20	-0.32	0.06
LOG(Ontario Demand)	1.47	0.00	1.86	0.00
LOG(New York Demand)	2.30	0.00	1.40	0.07
LOG(Natural Gas Price)	0.68	0.00	0.48	0.00
Model Diagnostics				
R-squared	0.93		0.80	
Adjusted R-squared	0.90		0.71	
LM test of Serial Correlation	Absent		Absent	
JB test of normality of residuals	Normal		Normal	
Number of observations	52		52	

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

Using this revised model we performed a decomposition analysis. In this analysis, we changed the value of one explanatory variable at a time in order to estimate the marginal effects of each of these variables on the predicted HOEP. For each month and each variable the current year's value of the variable was used to determine the impact for that variable alone on the previous year's price. The estimates are reported in Table 1-18. For example, if gas prices in November 2005 were as they were in November 2006, all else held constant, the 2005 price would have been $13.23 lower. For the six month periods Table 1-18 suggests that there would have been a large increase in the 2006/07 HOEP's if 2005/06 natural gas price levels were substituted for the actual 2006/07 gas prices. The result is not surprising considering that 2005/06 natural gas prices were much higher than 2006/07 prices. Table 1-18 also reports the actual average HOEP during each month of the previous year as well as the reported calibrated HOEP, which is the price that the model 'predicts' for that month using the actual values of the independent variables which were observed for that month last year. Calibrated values being close to actual values suggest the model is reasonably accurate and has captured most of the factors affecting price.

Table 1-18: Price Effects of Setting 2006/2007 On-Peak and Off-Peak Factors at 2005/2006 Levels ($/MWh)

	Month	Nuclear	Natural Gas Price	NY Load	Self	Ontario Load	Actual HOEP	Calibrated HOEP
All Hours	**November**	4.94	-13.23	-0.67	-2.24	-1.92	58.25	60.96
	December	-0.02	-26.61	-6.30	-4.26	-7.16	79.77	77.39
	January	3.42	-9.62	2.47	-3.70	1.41	55.54	55.76
	February	3.56	2.76	6.16	-2.31	3.41	48.12	51.51
	March	4.52	1.43	2.73	-0.94	0.09	49.01	51.18
	April	1.98	1.75	4.14	-1.35	2.22	43.52	42.27
	Average	**3.07**	**-7.25**	**1.42**	**-2.46**	**-0.32**	**55.70**	**56.51**
Off-peak Hours	**November**	-1.41	-7.59	-2.56	-2.76	-0.56	42.68	45.69
	December	-0.03	-17.16	-6.53	-5.34	-7.64	66.50	63.87
	January	2.21	-5.64	-0.31	-4.41	1.50	46.06	42.97
	February	2.58	1.67	2.59	-2.63	4.31	41.94	42.42
	March	3.11	0.86	1.26	-1.01	0.20	40.69	41.37
	April	1.32	0.97	0.38	-1.26	2.08	28.01	31.54
	Average	**1.30**	**-4.48**	**-0.86**	**-2.90**	**-0.02**	**44.31**	**44.64**
On-peak Hours	**November**	4.85	-16.74	-4.11	-1.13	0.34	69.38	73.15
	December	-0.01	-33.26	-14.61	-2.29	-7.48	89.25	92.21
	January	3.70	-11.47	-0.93	-1.86	1.34	62.30	62.97
	February	3.56	3.16	4.48	-1.21	2.83	52.54	55.56
	March	4.83	1.72	-0.16	-0.52	0.01	54.96	57.78
	April	2.22	2.27	1.48	-0.83	2.44	54.60	51.50
	Average	**3.19**	**-9.05**	**-2.31**	**-1.31**	**-0.09**	**63.84**	**65.53**

2.6 Hourly Uplift and Components

As shown in Table 1-19, total hourly uplift charges were lower than the payments made a year earlier. The largest change occurred in December when uplift decreased significantly from $52 million in December 2005 to $25 million in December 2006. The large decrease in December was primarily due to the mild weather in 2006 resulting in low HOEP levels.

Table 1-19: Monthly Total Hourly Uplift Charge, November 2005/2006 – April 2006/2007 ($ Millions)

	Total Hourly Uplift		IOG*		CMSC		Operating Reserve		Losses	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	40	34	7	8	11	11	4	1	18	14
December	52	25	9	4	13	7	4	1	26	13
January	34	27	3	3	11	7	2	2	18	14
February	25	31	2	4	8	9	1	2	14	16
March	28	31	4	6	8	9	2	1	15	15
April	36	23	1	2	15	7	6	1	13	12
Total	215	171	26	27	66	50	19	8	104	84

* Includes Day-Ahead IOG as of June 2006 and onwards

Total hourly uplift payments across the two periods dropped from $215 million to $171 million mainly as a result of lower losses and CMSC payments. Losses dropped by about $20 million, largely as the result of lower HOEP's. CMSC payments fell to $50 million versus $66 million for the previous period partly due to lower HOEP, lower fuel prices and somewhat less transmission congestion. As well OR payments dropped about $11 million from $19 million to $8 million. The reasons for the lower OR payments are discussed in Section 2-2 of this Chapter.

Table A-17 in the Statistical Appendix shows that most of the CMSC reduction is associated with constrained off payments which dropped by almost 40 percent in the November to April period while constrained on payments were essentially unchanged. CMSC payments are a function of the difference between the nodal prices and the HOEP. Much of the reduced constrained off payment may be explained by the lower HOEP in the recent period.

2.7 Internal Zone Prices and CMSC Payments

Average nodal prices for the 10 internal zones are shown in Table 1-20 for each 6-month period for the last 2 years.[11] This shows that prices in the Northeast and Northwest continue to be much lower than in the rest of the province, due to congestion and losses. All zonal prices in the last 6 months are nearly 20 percent lower than the prices from the period one year earlier, with the exception of the Northwest zone. This implies that most zonal prices have moved downward together with lower Richview nodal prices.

Table 1-20: Internal Zonal Prices May 2005 - April 2007 ($/MWh)

Zone	May05-Oct05	Nov05-Apr06	May06-Oct06	Nov06-Apr07
Bruce	94.93	66.95	49.67	55.37
East	100.09	68.01	51.15	55.49
Essa	96.43	64.51	49.69	52.71
Northeast	82.22	60.78	44.21	47.67
Niagara	96.65	70.65	53.24	55.41
Northwest	33.17	34.43	23.53	36.98
Ottawa	107.22	71.48	53.56	57.01
Southwest	98.49	68.41	52.36	56.04
Toronto	106.18	70.08	53.44	57.22
Western	100.82	69.41	53.59	56.54
Average	91.62	64.47	48.44	51.02

The Northwest zonal price was about 7 percent higher than in the year earlier period. This relatively higher zonal price in the Northwest is a combination of two factors. There was less congestion of flows from the Northwest eastward as the result of less hydroelectric resources and lower imports into the zone. However the reduced production led to a shortage of low priced energy in the western-most areas (near Kenora) and required constraining on generation to satisfy exports. This pushed up nodal prices for many generating facilities and raised the overall zonal price.

Figure 1-13 shows graphically the average zonal price for the last six months.

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

Figure 1-13: Average Internal Zonal Prices
November 2006 – April 2007
($/MWh)

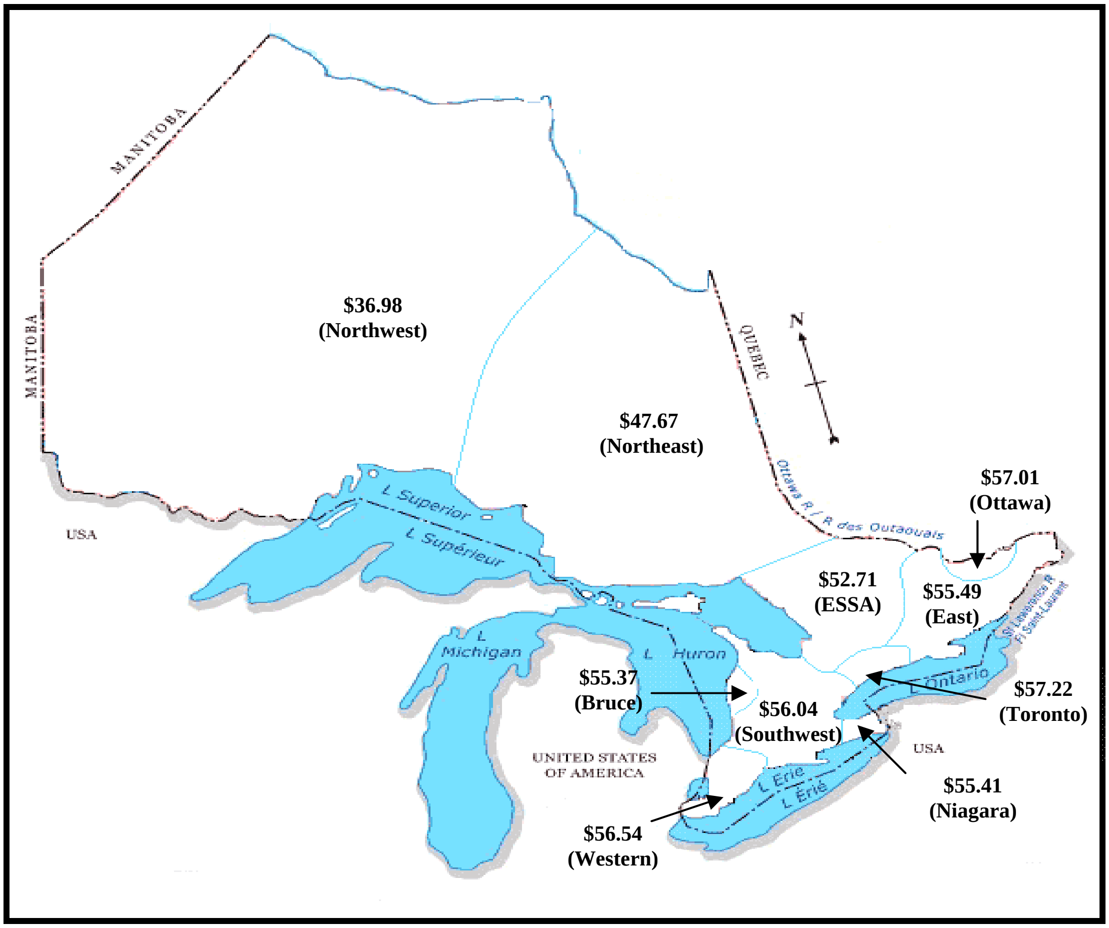
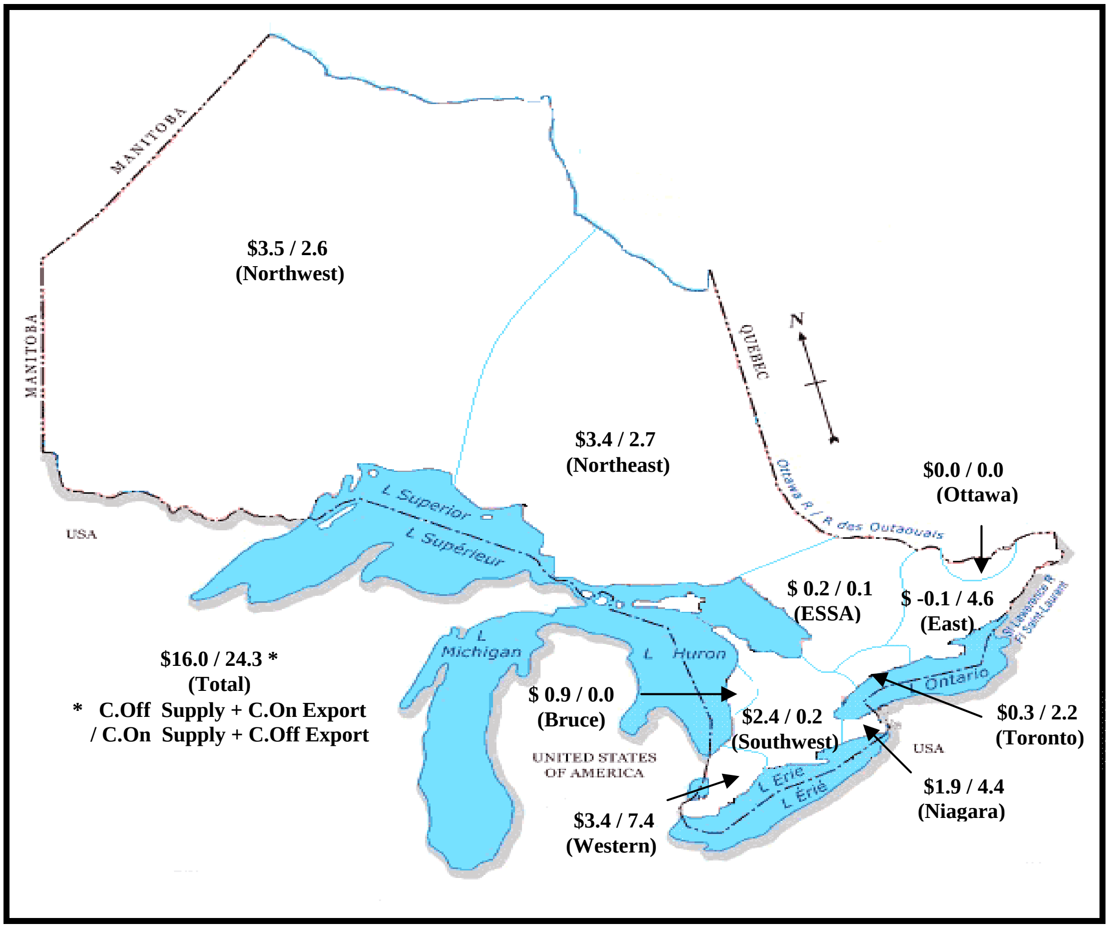


Figure 1-14 shows two sets of CMSC payments for each internal zone for the 6 month period ending April 2007. The first value is the sum of CMSC payments for constrained off generation and imports, plus constrained on exports. The second value is the sum of CMSC payments for constrained on generation and imports, plus constrained off exports. CMSC for imports and exports is attributed only to the zone to which the intertie is connected. The first value is generally indicative of bottling of lower cost supply in an area while the second value corresponds to needing to schedule more costly generation in the constrained schedule in the zone. Dispatchable load CMSC is omitted since it is primarily self-induced, that is, caused by conditions at the load rather than system conditions.

Figure 1-14: Total CMSC Payments by Internal Zone
November 2006 - April 2007
($ Millions)



As noted in the earlier discussion of uplift, CMSC values are substantially lower in total relative to the previous year and this is reflected by lower values in most zones. Compared with the period from November 2005 to April 2006 the total $16 million CMSC for constrained off supply / constrained on exports is down by almost 50 percent from $29 million, while the CMSC for constrained on supply / constrained off exports totalling $24 million is down by about 25 percent from $32 million.

The largest changes in CMSC payments were in the Northwest. CMSC for constrained off supply or constrained on exports has fallen by 80 percent from $17 million in the

November to April period last year to $3.5 million this year. In contrast, CMSC for constrained on supply or constrained off exports have increased by more than a factor of six, from $0.4 million last year to $2.6 million this year. These changes are indicative of much lower water levels in the north and reduced imports being scheduled from Manitoba. Rather than generation being bottled in the Northwest there were many instances when more expensive generation was needed to replace hydroelectric generation reduced because of low water conditions and for exports scheduled to Manitoba and Minnesota.

There was a similarly large relative change in constrained off CMSC in the Bruce zone, dropping from $1.7 million last year to $0.9 million this year, as the result of less congestion of the output at the Bruce plant.

In the three zones in the southern part of Ontario which have major interties, there were moderate CMSC payments to constrain on supply or constrain off exports - amounting to $7 million for the Western zone, $4 million for Niagara and $5 million in the East. The total, $16 million, is down from $23 million for the same months last year. $6 million of the total $16 million is due to imports or exports. Total CMSC for constrained off supply or constrained on exports was about $5 million this period, down about 25 percent from the previous year.

2.8 A Comparison of High and Low HOEP and Richview Nodal Price

Nodal prices are indicative of the marginal cost of supply. Efficient prices lead to efficient consumption and production decisions.

Table 1-21 lists the total number of hours with a HOEP or Richview nodal price less than $20. There are two observations. First, the number of hours with a low HOEP or Richview price was much greater in 2006/2007 than in 2005/2006, especially in November and December. This was largely induced by more baseload hydro supply and a lower off-peak demand in the two months (see Appendix Table A-13). Second, the number of hours with a low Richview price was much greater than the number of hours with a low HOEP in each period.

This finding seems counter-intuitive because the Richview nodal price is typically greater than the HOEP as a result of more constraints applied in the constrained sequence. As the Panel noted in the December 2006 monitoring report, there are many factors that can drive the Richview nodal price below the HOEP, which mainly include constrained on generation, constrained off (net) export and constrained demand under-forecast. Given that the low price hours are typically off-peak hours with little generation constrained on during these hours, the last two factors may dominate the events.

Table 1-21: Number of Hours with a Low HOEP or Richview Nodal Price November 2005/2006 – April 2006/2007 (Number of Hours)

	Number of Hours with HOEP <$20		Number of Hours with Richview Price <$20	
	2005/2006	2006/2007	2005/2006	2006/2007
November	4	25	14	43
December	2	103	7	128
January	3	18	14	24
February	6	0	14	0
March	1	0	9	2
April	94	43	127	49
Total	110	189	185	246

Table 1-22 depicts the total number of hours with a HOEP or Richview nodal price greater than $200. The number of hours with a high HOEP or Richview price was much smaller in 2006/2007 than in 2005/2006, more so in November and December. This is consistent with the observation that the number of hours with a low HOEP or Richview price was higher in 2006/2007, as a result of better supply/demand conditions. As may be expected, the number of hours with a high Richview price was still much greater than the number of hours with a high HOEP in each period.

Table 1-22: Number of Hours with a High HOEP or Richview Nodal Price November 2005/2006 – April 2006/2007 (Number of Hours)

	Number of Hours with HOEP >$200		Number of Hours with Richview Price >$200	
	2005/2006	2006/2007	2005/2006	2006/2007
November	0	0	23	6
December	2	0	41	2
January	0	0	7	10
February	0	0	10	12
March	0	0	10	12
April	4	1	10	5
Total	6	1	101	47

3. Demand

3.1 Aggregate Consumption

During the period November 2006 to April 2007, Ontario energy demand declined by 0.15 TWh or 0.19 percent compared to a year earlier. From Table 1-23 it can be seen that demand fell by more than 6 percent in December 2006 compared to December 2005. This was due mainly to a relatively warm December month compared to the year before. The average temperature in December 2006 was 1.9°C compared to -3.1°C during the same month in 2005 (see Table A-2 of the Statistical Appendix). December 2006 marked the highest average December temperature since market opening by approximately 2°C. By contrast, with the colder weather after mid-January 2007, monthly demand in February 2007 was almost 4 percent higher than in the February of the previous year.

Exports declined by 1.76 TWh, or 25 percent, compared to the prior period, and were lower in all months compared to the same months a year ago with the exception of February. Overall, exports were down primarily as a result of lower price differences between NYISO and IESO in these months reducing the export arbitrage opportunities. In February NYISO prices increased more than the IESO's resulting in a larger price difference and arbitrage opportunity (this is discussed further in Section 5.4.1 below). As a result of the decline in both Ontario demand and exports, total market demand was 1.91 TWh, or 2.3 percent, below the same period last year.

Table 1-23: Monthly Energy Demand (TWh), Market Schedule November 2005/2006 – April 2006/2007 (TWh)

	Ontario Demand*			Exports			Total Market Demand		
	2005/ 2006	2006/ 2007	% Change	2005/ 2006	2006/ 2007	% Change	2005/ 2006	2006/ 2007	% Change
November	12.48	12.22	(2.08)	1.12	0.53	(52.68)	13.6	12.75	(6.25)
December	13.77	12.92	(6.17)	1.04	0.67	(35.58)	14.81	13.58	(8.31)
January	13.62	13.79	1.25	1.20	0.78	(35.00)	14.82	14.57	(1.69)
February	12.57	13.04	3.74	1.09	1.19	9.17	13.66	14.24	4.25
March	13.22	13.21	(0.08)	1.23	0.91	(26.02)	14.45	14.12	(2.28)
April	11.53	11.86	2.86	1.32	1.16	(12.12)	12.85	13.02	1.32
Total	77.19	77.04	(0.19)	7.00	5.24	(25.14)	84.19	82.28	(2.27)
Average	12.87	12.84	(0.23)	1.17	0.87	(25.64)	14.03	13.71	(2.28)

* Non-dispatchable loads plus dispatchable loads

3.2 Wholesale and LDC Consumption

Figure 1-15 compares wholesale load consumption to consumption by Local Distribution Companies (LDC) since market opening in 2002. The long term trend of falling wholesale load consumption was identified by the Panel in previous reports and still continues while LDC consumption is relatively flat.[12]

[12] A 2nd order polynomial trend line was selected to fit the "Loads" data series due to its declining structure

Figure 1-15: Monthly Total Energy Consumption LDC vs. Wholesale Loads May 2002 – April 2007 (GWh)

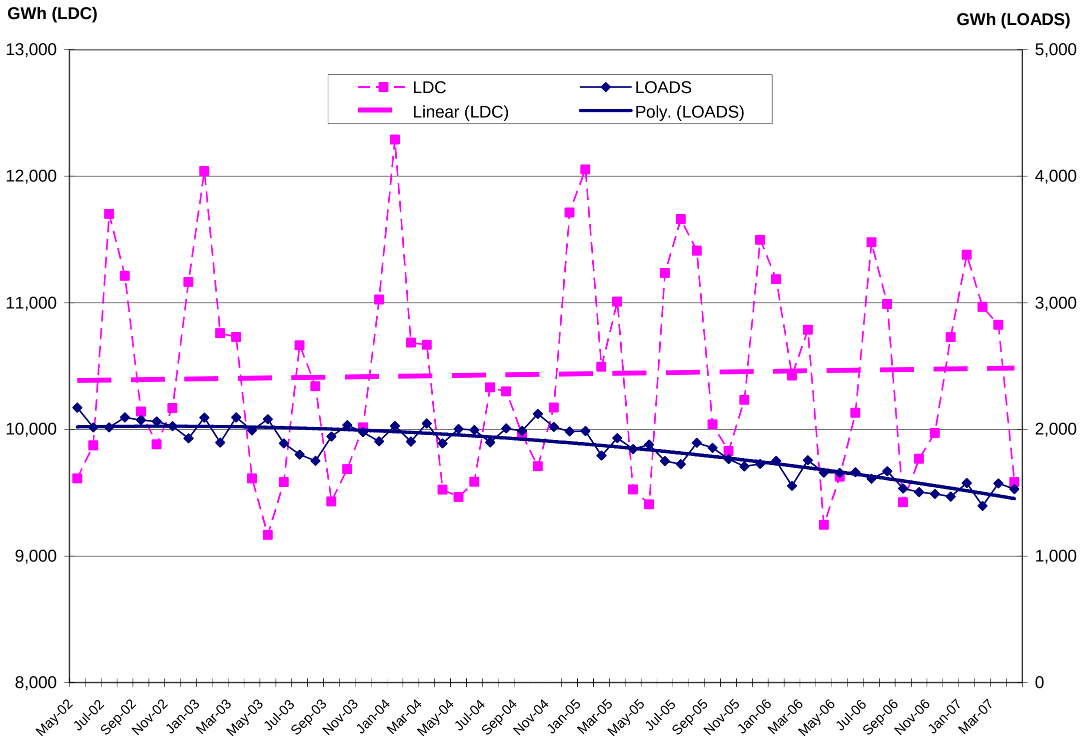
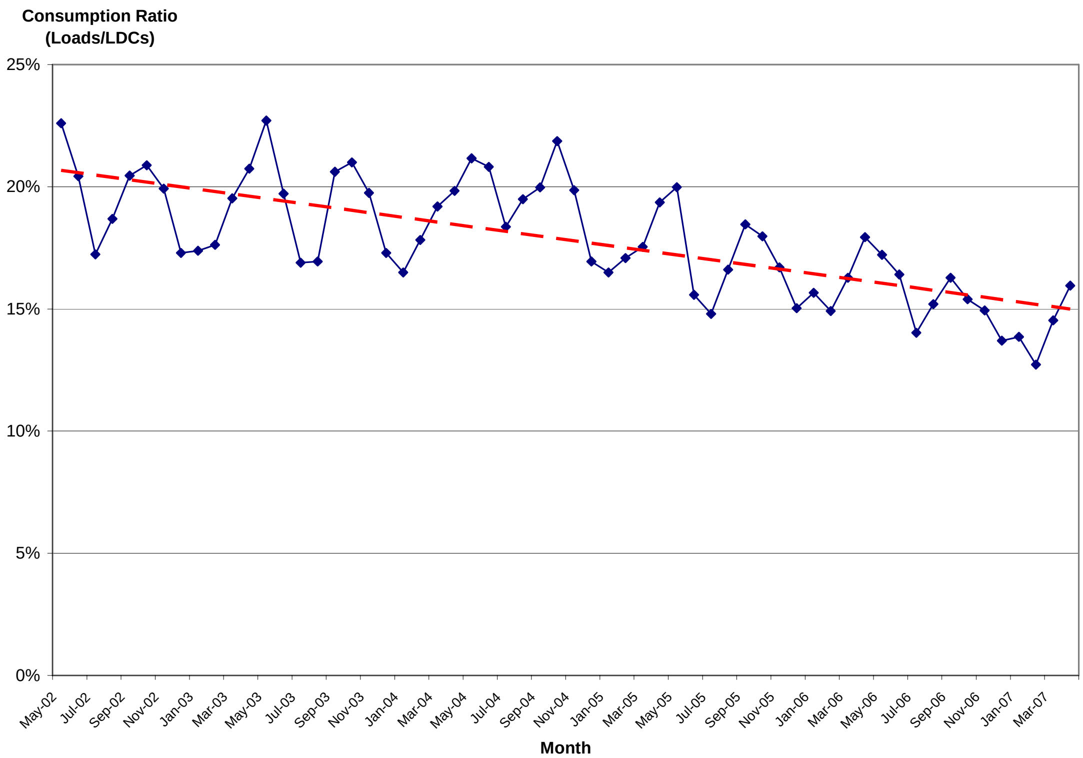


Figure 1-16 shows the ratio of consumption by wholesale loads to consumption by LDC's. Consistent with Figure 1-15, the proportion of consumption by wholesale loads relative to LDC's has been dropping quite noticeably since the last quarter of 2004. The average ratio of wholesale load to LDC consumption was 19.4 percent between May 2002 and April 2003 and dropped to 15.0 percent between May 2006 and April 2007 which represents a decline of approximately 20 percent between the two annual periods. Since LDC consumption has been relatively flat on an annual basis, this reflects declining levels of electricity consumption by wholesale customers.

Figure 1-16: Ratio of Wholesale Load to LDC Consumption
May 2002 – April 2007



We asked the MAU to determine if this reduction in consumption was occurring in certain industry sectors. In the last report, the Panel recognized that reductions in wholesale load were primarily centred in the Northwest zone of Ontario.[13] Figure 1-17 examines trends in wholesale load in the Northwest compared to the rest of Ontario.[14] The Northwest zone continues to experience a dramatic decrease in wholesale load which appears to explain the overall drop in Ontario wholesale load consumption. Wholesale loads in the rest of Ontario have remained relatively constant since market opening. In reviewing specific customer consumption, the majority of the reduction in wholesale load in the Northwest can be attributed to wood processing facilities.

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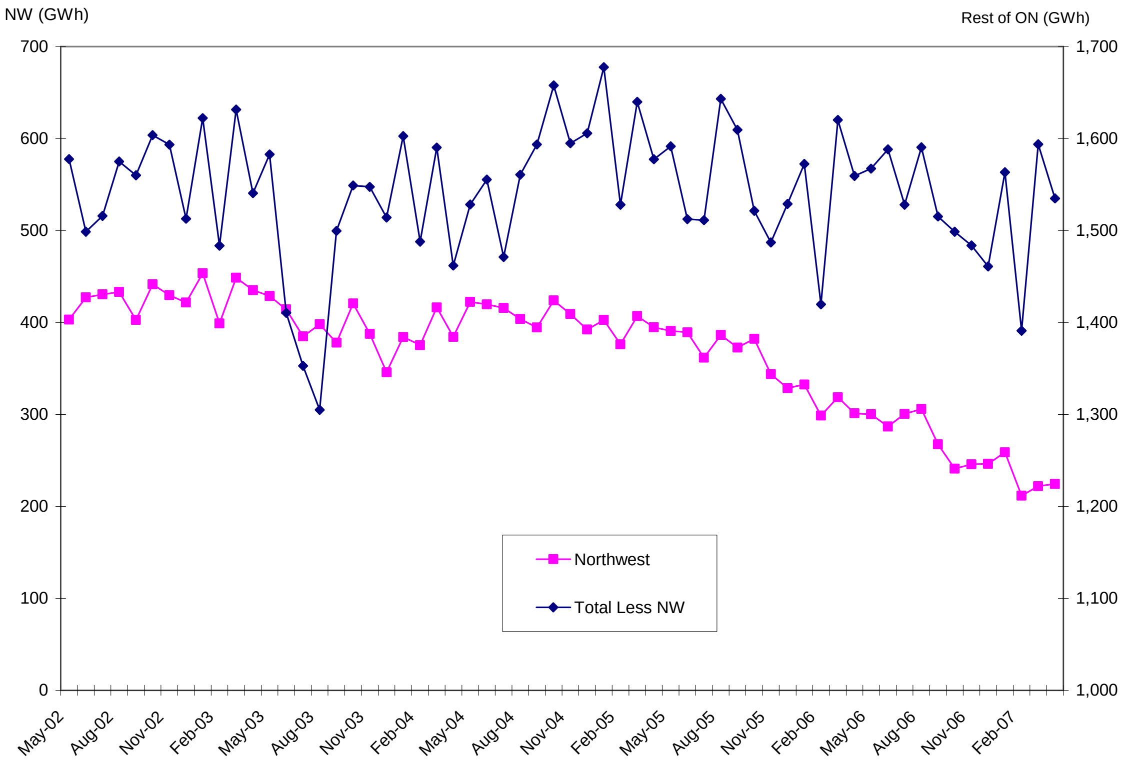
[13] See page 11 in the last Market Surveillance Panel Report dated December 13, 2006
[14] The Bruce zone is not included since there are only a few small loads there.

Figure 1-17: Total Monthly Wholesale Load Northwest and the Rest of Ontario May 2002 – April 2007[15] (GWh)



3.3 New Winter Peak Demand

With the cold temperatures experienced in the latter part of January and February, the historical winter hourly market demand record that was set on January 24, 2005 HE19 was broken three times in winter 2007.[16] The new record winter demand of 25,961 MW was set on February 13, 2007 HE19, with a HOEP $167.71 resulting from fairly tight supply.

For that peak hour, the one hour-ahead peak demand was forecast at 26,093MW, with a projected price $140. This included substantial exports, with net export amounting to 1,273 MW. With the high Ontario domestic and export demand the pre-dispatch total

[15] The low value for total load in August 2003 is due to the Blackout that month.

[16] The historical winter market demand record was set in January 24, 2005 (HE 19). In 2007, the record was broken three times with 25,750 MW on February 5 (HE 19), 25,739 MW on February 13 (HE 20), and the peak hour on February 13 (HE 19).

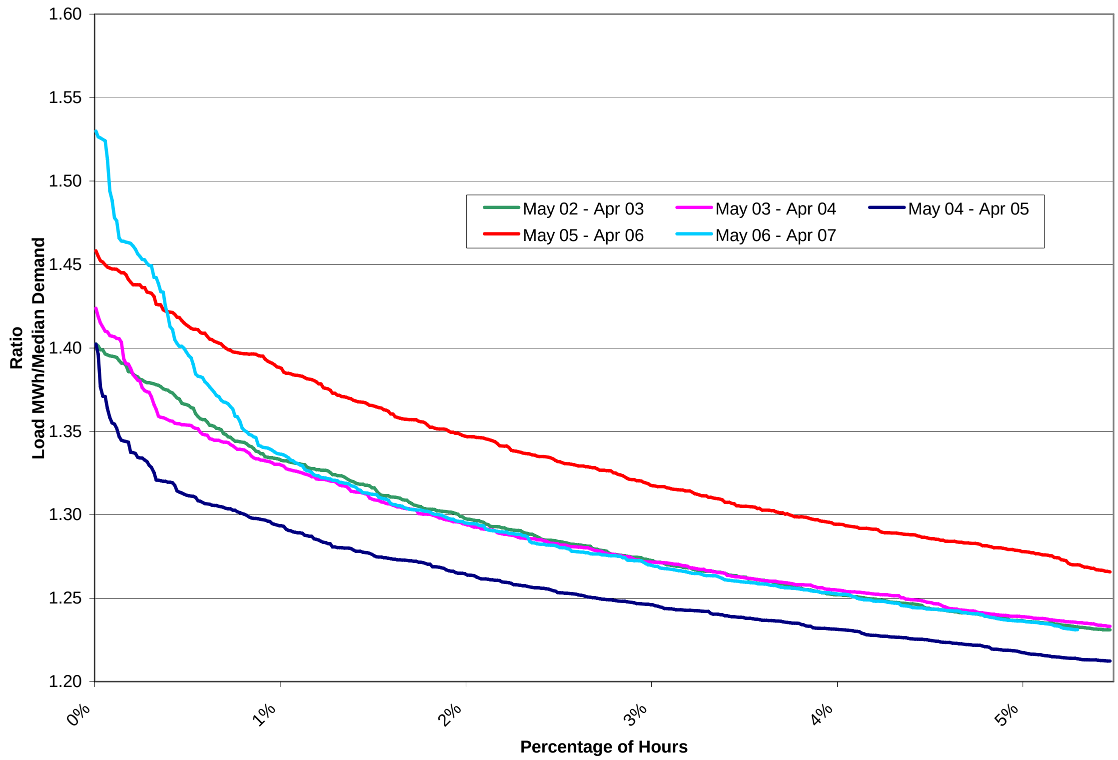
supply cushion was -0.60 percent[17], indicating very tight supply going into the hour and CAOR was used. In real-time the peak interval demand within the hour reached 26,083 MW, essentially the same as forecast. The impact of 50 MW failed import was offset by self-scheduling and intermittent generators producing 57 MW more than they scheduled and all internal generators performed as expected. The price for that interval, $184.82, was set by a peaking hydro resource. The real-time total supply cushion dropped to -1.9 percent. Consistent with the negative supply cushion, 400~500 MW of Control Action Operating Reserve (CAOR) was needed for OR in real-time.

3.4 Changes in Load Patterns in Ontario and New York

The Panel has noted that the peak load has continuously grown relative to the median. In other words, the top one percent of hourly loads is growing faster compared to the median hourly load. Figure 1-18 illustrates the evolution of normalized Ontario load duration curves since market opening. These curves are plotted annually for the top 5 percent of hourly loads. Expressed as a ratio to the median load, the figure shows that hourly Ontario demand peaked at 1.54:1 in 2006/2007 compared to 1.46:1 a year earlier.

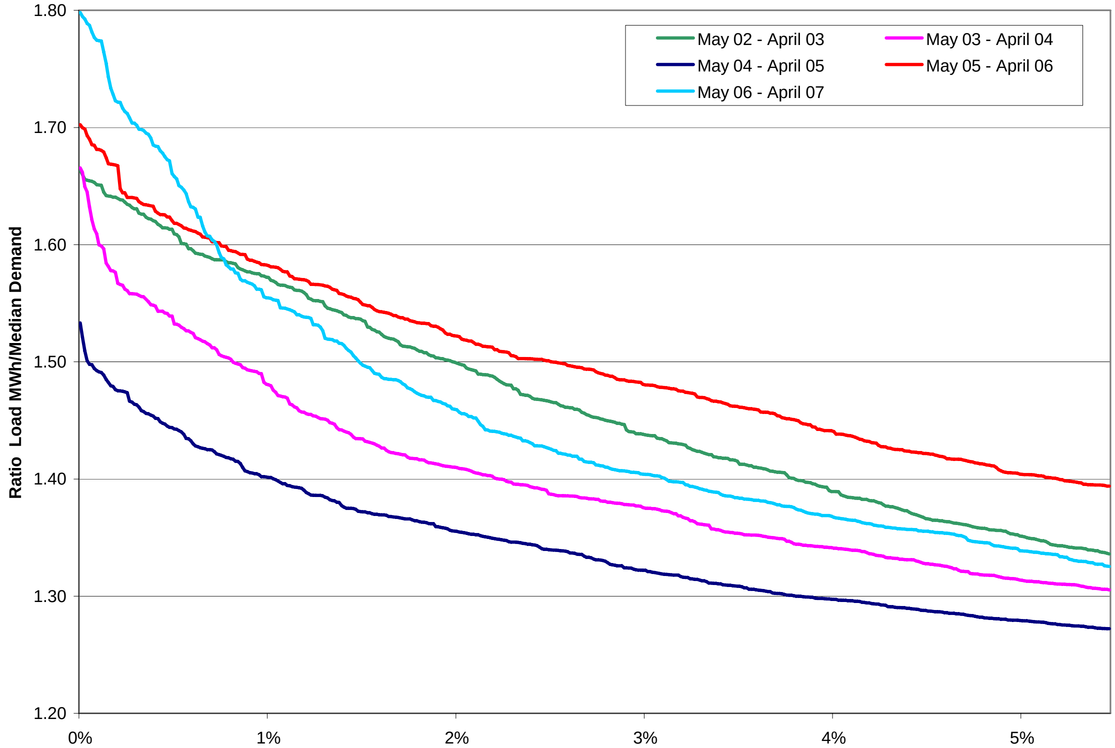
[17] See the Appendix of this chapter for the definition of various supply cushion and the method of calculating them.

Figure 1-18: Normalized Load Duration Curve
May 2002 – April 2007
(Highest 5 Percent of Hours Normalised to Median Load)



Ontario is not the only jurisdiction experiencing peak load growth. In New York, our largest export destination, peak load levels have increased over the last two years and are growing faster than in Ontario. Figure 1-19 presents normalized New York load duration curves for the last five annual periods. New York demand peaked at 1.80:1 as a ratio to median load during 2006/2007 compared to 1:54:1 in Ontario during the same period.

Figure 1-19: New York Normalized Load Duration Curve
May 2002 – April 2007
(Highest 5 Percent of Hours Normalised to Median Load)



4. Supply

4.1 Supply Conditions and the Supply Cushion

The supply cushion is a measure of the unused supply that is available for dispatch in a particular hour. Based on the definition of the supply cushion used in previous Panel reports, we have observed that there tends to be upward pressure on HOEP and a greater potential for price spikes when the real-time total supply cushion falls below 10 percent. Simply put a low supply cushion is indicative of reaching the steep part of the offer curve. A negative domestic supply cushion is a reflection on the reliance of the Ontario market on imports to satisfy demand.

In its previous report, the Panel asked the MAU to refine its calculation of the pre-dispatch total supply cushion to take into account the practical considerations of both the intertie capability as well as the remaining intertie ramping capacity.[18] It became clear in analysing the anomalous events of Chapter 2 in that reporting period that inaccurate assumptions on the pre-dispatch supply cushion were over-estimating the ramping capability ability of the intertie. As a result, we have adopted refinements to the supply cushion calculation. The methodology and assumptions associated with the new supply cushion can be found in the Appendix of this chapter. Table A-20 of the Statistical Appendix contains the re-calculated pre-dispatch and real-time supply cushion since market opening. Real-time supply cushion statistics changed minimally.

When we review both the Pre-dispatch and Real-time Domestic Supply Cushion statistics in Tables 1-24 and 1-25, we note that the six month average supply cushions are similar to the previous year. But, when we review the monthly supply cushion data, the average supply cushion is lower in all months except December and April than for the previous year. For many of the months we also note that the number of hours of negative supply cushion and supply cushion less than 10 percent are both correspondingly higher.[19] The significantly lower nuclear plant availability in most months (except December and April) is likely a primary contributor to these levels. However, based on the relatively low monthly average HOEP levels over the past six months, the supply cushion rarely fell to levels low enough to induce consistently high prices.

Table 1-24: Pre-Dispatch Domestic Supply Cushion
November 2005/2006 – April 2006/2007

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2005/ 2006	2006/ 2007	2005/ 2006	%	2006/ 2007	%	2005/ 2006	%	2006/ 2007	%
November	14.2	13.8	22	3.1	25	3.5	311	43.2	310	43.1
December	13.6	15.5	37	5.0	21	2.8	311	41.8	261	35.1
January	18.0	14.9	2	0.3	1	0.1	170	22.8	294	39.5
February	18.0	17.8	1	0.1	0	0.0	150	22.3	102	15.2
March	16.2	14.7	4	0.5	27	3.6	242	32.5	284	38.2
April	19.2	22.0	0	0.0	0	0.0	154	21.4	68	9.4
Average	16.5	16.5	11	1.5	12	1.7	223	30.7	220	30.1

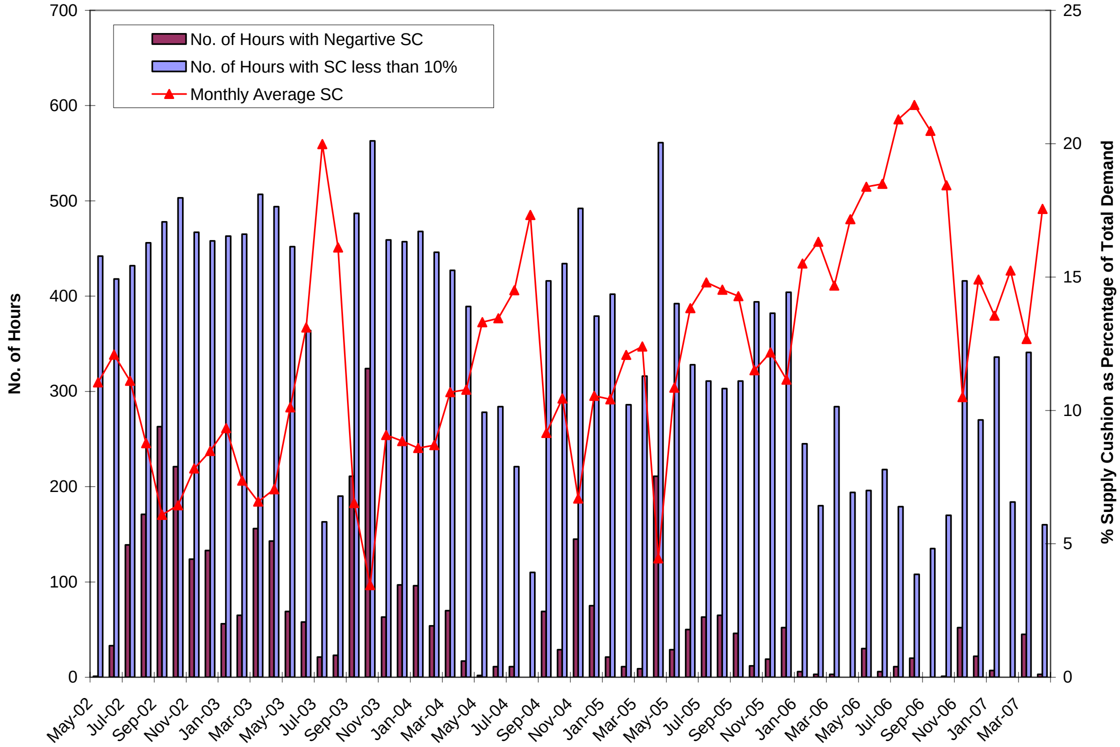
[18] See page 74 in the last Market Surveillance Panel Report dated December 13, 2006
[19] The 10 percent is arbitrarily chosed as an indication of the steepness of domestic supply curve.

Table 1-25: Real-time Domestic Supply Cushion
November 2005/2006 – April 2006/2007

	Average Supply Cushion (%)		Negative Supply Cushion (# of Hours, %)				Supply Cushion Less Than 10% (# of Hours, %)			
	2005/ 2006	2006/ 2007	2005/ 2006	%	2006/ 2007	%	2005/ 2006	%	2006/ 2007	%
November	12.2	10.5	19	2.6	52	7.2	382	53.1	416	57.8
December	11.2	14.9	52	7.0	22	3.0	404	54.3	270	36.3
January	15.5	13.6	6	0.8	7	0.9	245	32.9	336	45.2
February	16.3	15.2	3	0.4	0	0.0	180	26.8	184	27.4
March	14.7	12.7	3	0.4	45	6.0	284	38.2	341	45.8
April	17.2	17.6	0	0.0	3	0.4	194	26.9	160	22.2
Average	14.5	14.1	14	1.9	22	2.9	282	38.7	285	39.1

Figure 1-20 provides comparable monthly data from May 2002. It shows that the supply cushion in the last six months is somewhat typical of the winter periods for the last 3 years and all these are better than the supply cushion for the first 2 years after the market opened.

Figure 1-20: Average Monthly Real-time Domestic Supply Cushion
May 2002 – April 2007



4.2 Supply Curves

Figure 1-21 shows the average domestic offer curve for the November to April period. The offer stack appears to have shifted to the left in 2006/2007 likely due to less nuclear plant availability. However, the lower nuclear availability was offset somewhat by more baseload hydro and self-scheduled energy in certain months, as seen in Table 1-26.

Figure 1-21: Average Domestic Offer Curve
November 2005/2006 - April 2006/2007

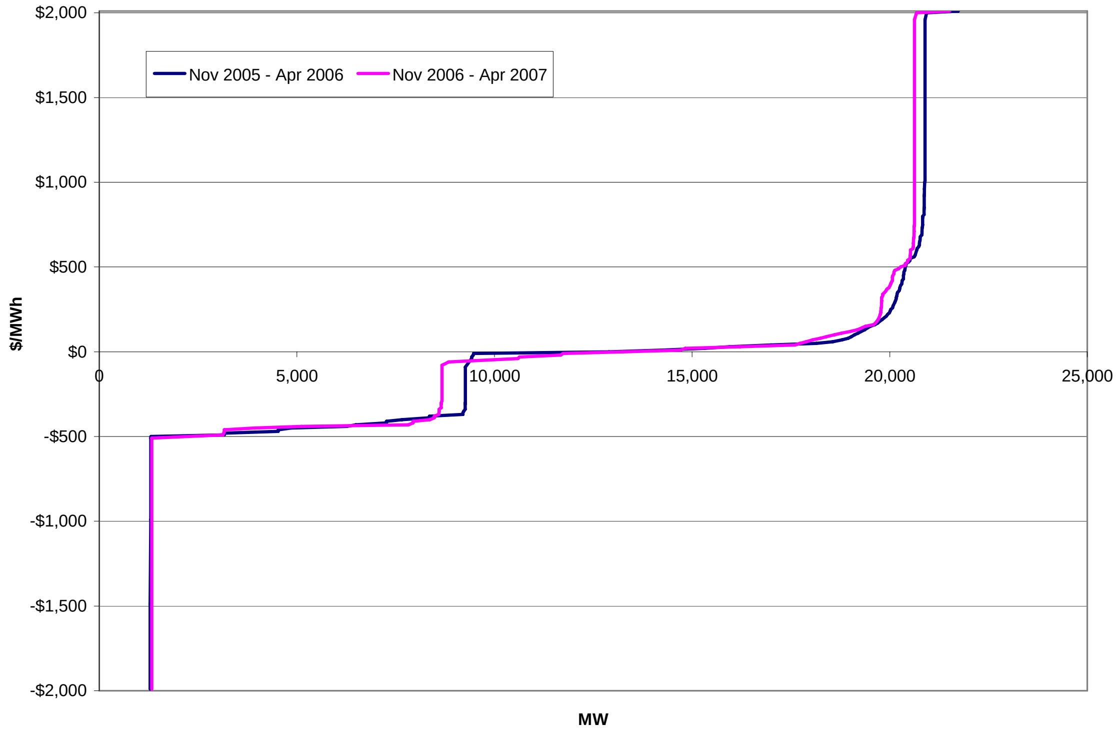


Table 1-26: Average Hourly Market Schedules and Ontario Demand
November 2005/2006 - April 2006/2007
(GW)

	Nuclear		Baseload Hydro		Self-Scheduling Supply		Ontario Demand (NDL)	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	9.2	8.2	2.1	2.1	0.8	1.0	16.8	16.4
December	9.4	9.5	2.1	2.3	0.8	1.0	18.0	16.9
January	10.0	9.2	2.0	2.2	0.8	1.0	17.7	18.0
February	10.6	9.7	2.1	2.2	0.8	1.0	18.1	18.9
March	10.0	9.0	2.2	2.2	0.9	1.0	17.2	17.2
April	9.4	8.9	2.1	2.2	0.7	0.9	15.4	15.9
Average	9.8	9.1	2.1	2.2	0.8	1.0	17.2	17.2

Table 1-26 shows the average hourly market schedule for those resources which are typically inframarginal and the Ontario non-dispatchable demand for each month. The performance of these resources and the Ontario demand will have an impact on the supply cushion, the shape of the supply curve and the resulting market prices. Because they are self-scheduled or offered at very low prices the scheduling of the resources do not normally depend on HOEP. We observe that:

- Nuclear supply decreased in all months except December.
- Baseload hydro was approximately the same year over year although it was higher by about 10 percent in December and January.
- Self-scheduling supply was up in all months due to the significant increase in wind-powered generation. Since March 2006, Ontario has gained 395 MW of wind-powered capacity.
- Ontario demand was lower on average in the first two months of the period. This is likely attributable to the warmer temperatures experienced in November through to the latter part of January.

The reduction in demand as well as increased self-scheduling supply compensated in part for the reduction in nuclear supply, in the first two months of the period. From January onwards, increased Ontario demand plus reduced baseload nuclear put some upward pressure on the HOEP. These factors partly explain price changes observed in Table 1-1. See section 2.5 "Analysing Year over Year Changes in the HOEP", for a more complete discussion of the impact of these supply as well as demand changes on market prices.

4.3 Outages

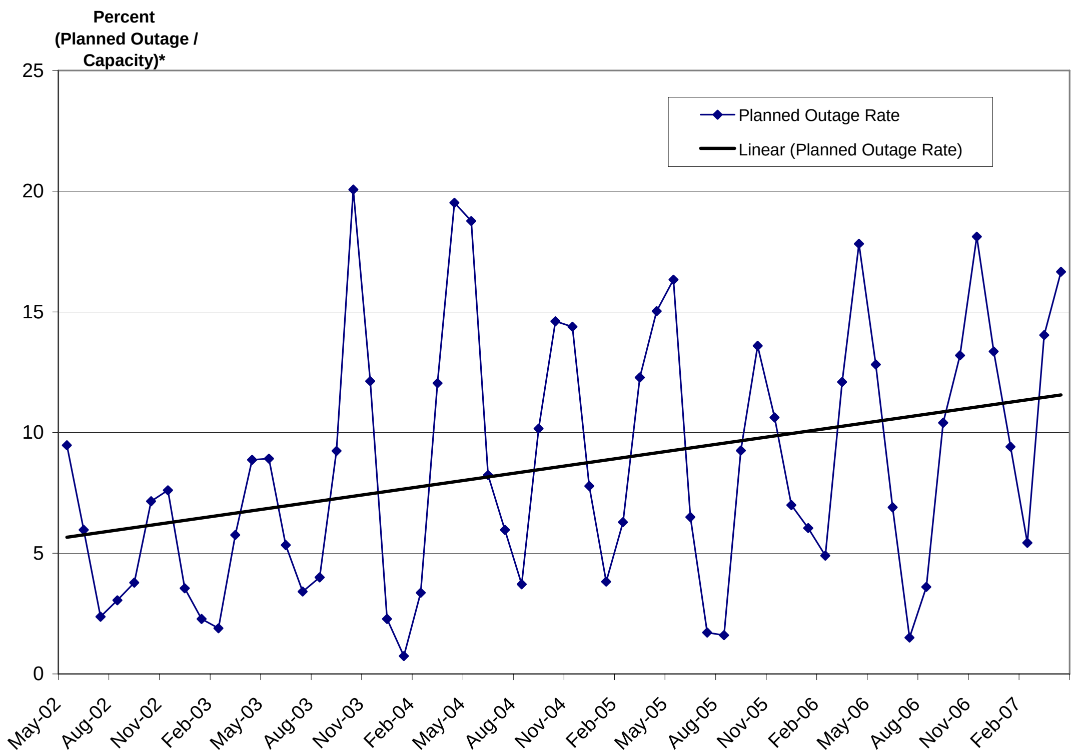
Ontario's supply situation is directly related to the amount of generation that is on outage. Downward pressure on supply may result in an increase in the HOEP. In this section both nuclear and coal outages are reviewed as, removal of these inframarginal resources tends to have a significant effect on price. Hydroelectric outages are not reviewed as they tend to occur in periods of time where they are energy limited and as a result have little impact upon the HOEP.

Outages occur in two forms: forced and planned. Planned outages are taken in order to perform regular maintenance on generators and associated equipment while forced outages are a result of unexpected events that cause a generator to decrease production or shut down completely.

4.3.1 Planned Outages

Figure 1-22 shows the trend in planned outages relative to total capacity in Ontario from May 2002 to April 2007. Planned outages display a tremendous amount of seasonality and are most often taken in the low demand spring and fall months. Relative to total capacity, planned outages appear to be trending slightly upward since May 2002. From May 2002 to April 2003, the average planned outage relative to capacity was 5.2 percent compared to an average of 10.4 percent between May 2006 and April 2007. This may be a result of aging facilities requiring increased maintenance, since the average age of Ontario's coal-fired generators is 32 years, with a typical expected life of 40 years. The average age of the nuclear facilities is now 23 years.

Figure 1-22: Planned Outages Relative to Total Capacity
May 2002 - April 2007
(% of Capacity)

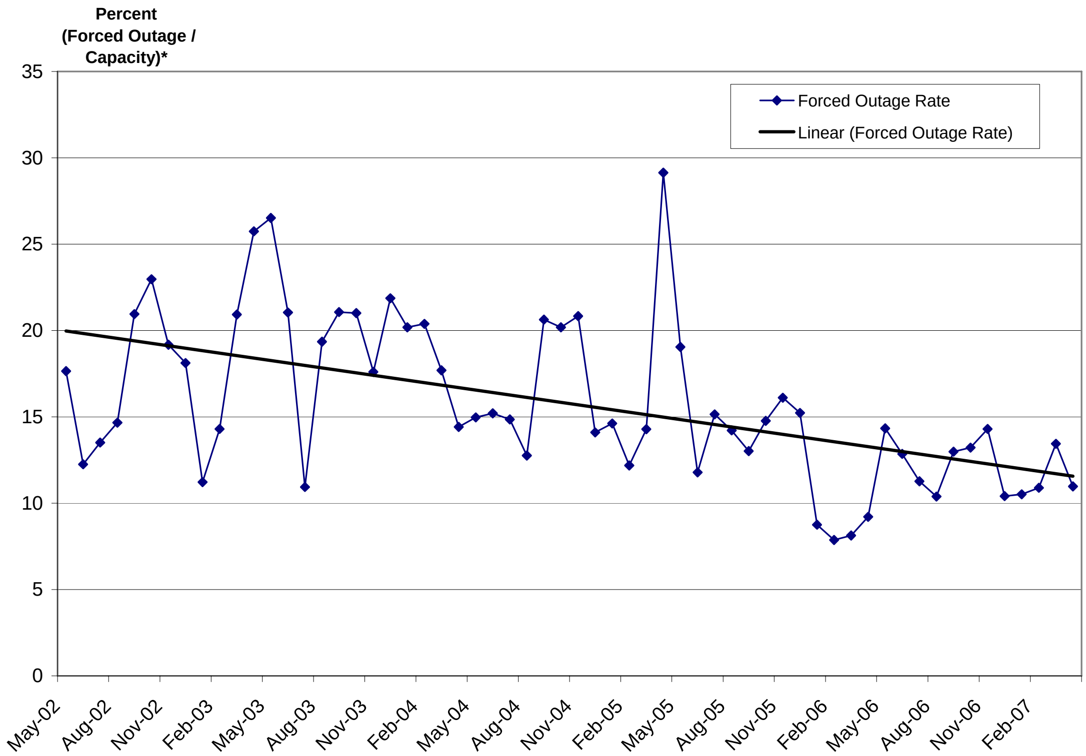


* Nuclear and coal-fired units only

4.3.2 Forced Outages

Figure 1-23 shows that forced outages have been declining since May 2002. However, the trend appears to have levelled off between 10 percent and 15 percent relative to total capacity over the last year.

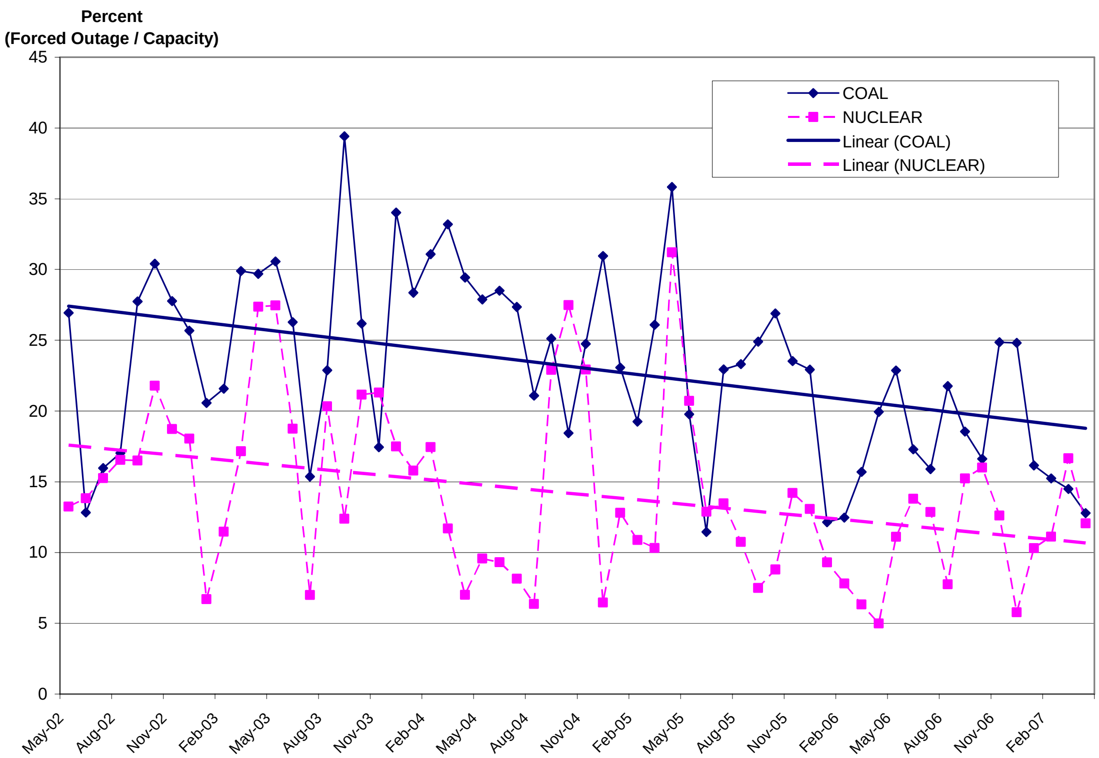
Figure 1-23: Forced Outages Relative to Total Capacity
May 2002 - April 2007



*Nuclear and coal-fired units only

Figure 1-24 shows coal and nuclear forced outages as a percentage of total capacity. There is a continuous decline in the forced outage rates of both coal-fired and nuclear generation, although the linear trendlines demonstrate that coal forced outage rates appear to be declining faster. While the simple long-term trend line also shows a decrease in nuclear forced outages, in the past year there appears to be a bit of an upward trend from the lower forced outage levels experienced in the prior 12 months.

Figure 1-24: Forced Outages Relative to Total Capacity by Fuel Type May 2002 - April 2007 (% of Capacity)



4.4 Changes in Fuel Prices

Table 1-27 shows spot market prices of natural gas and coal for the period November 2006 to April 2007, along with prices one year ago. The average natural gas price is measured by the Henry Hub[20] spot price and then converted to Canadian dollars.[21] For the recent six months, monthly average gas prices ranged from $7.52 to $9.42 per Million BTU. For the 3 months November 2006 to January 2007, this represented a decline of roughly one-third relative to the high prices seen in the same period during 2005/2006. For the next 3 months, February through April 2007, average gas prices were roughly 6.5 percent higher than a year ago.

[20] The Henry Hub is located in Southern Louisiana and is routinely used as the reference price for most of the domestic gas destined for the East

[21] The Bank of Canada nominal noon exchange rate was used to convert commodity prices into Canadian dollars. Between November 2006 and April 2007, the U.S. to Canadian dollar exchange rate reached a high of 1 USD = 1.186 CND on February 5, 2007 and a low of 1 USD = 1.114 CND on April 26, 2007.

The NYMEX over-the-counter price for the Central Appalachian region coal converted to Canadian dollars continues to decrease relative to the same period one year ago.

Table 1-27: Average Monthly Fuel Prices November 2005/2006 – April 2006/2007 ($/MMBtu)

	Coal Price (NYMEX OTC Central Appalachian) ($CDN/MMBtu)			Natural Gas Price (Henry Hub Spot) ($CDN/MMBtu)		
	2005/ 2006	**2006/ 2007**	**% increase**	**2005/ 2006**	**2006/ 2007**	**% increase**
November	2.86	1.92	(32.87)	12.35	8.43	(31.74)
December	2.79	1.99	(28.67)	14.97	7.76	(48.16)
January	2.70	1.93	(28.52)	10.11	7.52	(25.62)
February	2.68	1.98	(26.12)	8.68	9.42	8.53
March	2.61	1.98	(24.14)	7.96	8.31	4.40
April	2.51	1.97	(21.51)	8.10	8.63	6.54
Average	2.69	1.96	(26.97)	10.36	8.35	(14.34)

The on-peak and off-peak HOEP, the price of natural gas, and the price of coal since market opening are plotted in Figures 1-25 and 1-26. These figures show that there continues to be a strong relationship between on-peak and off-peak HOEP and the natural gas price, whereas there is no clear relationship between the coal price and HOEP.

Figure 1-25: Henry Hub Natural Gas Spot Price and HOEP, May 2002 - April 2007 ($/MWh and $/MMBtu)

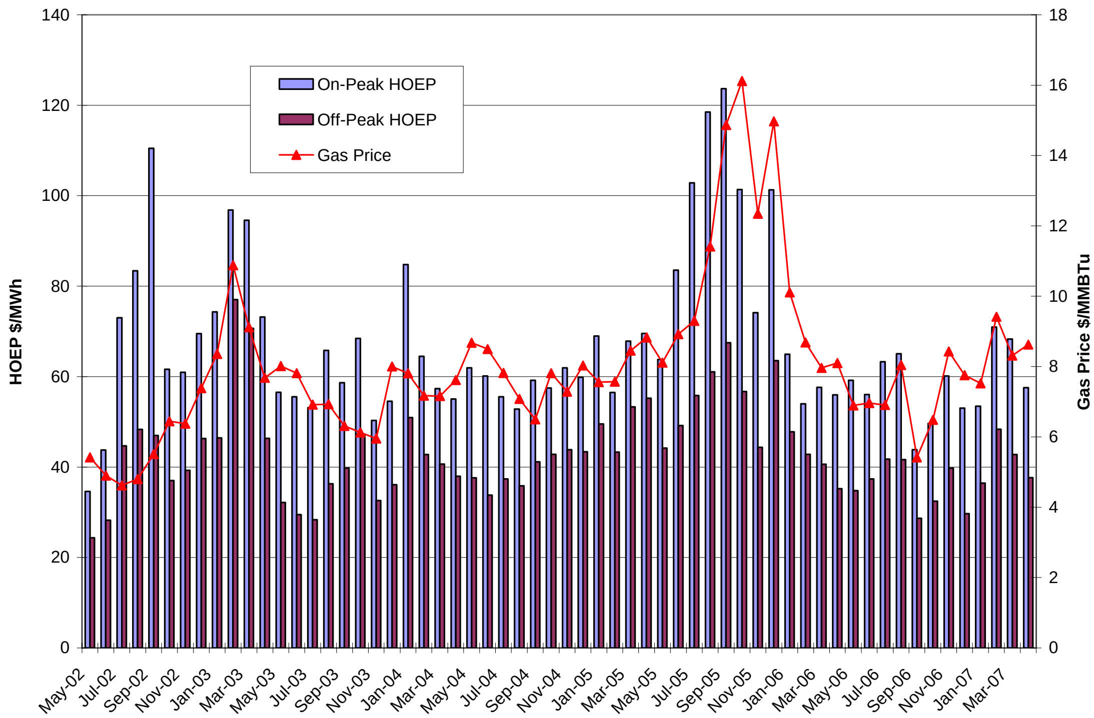
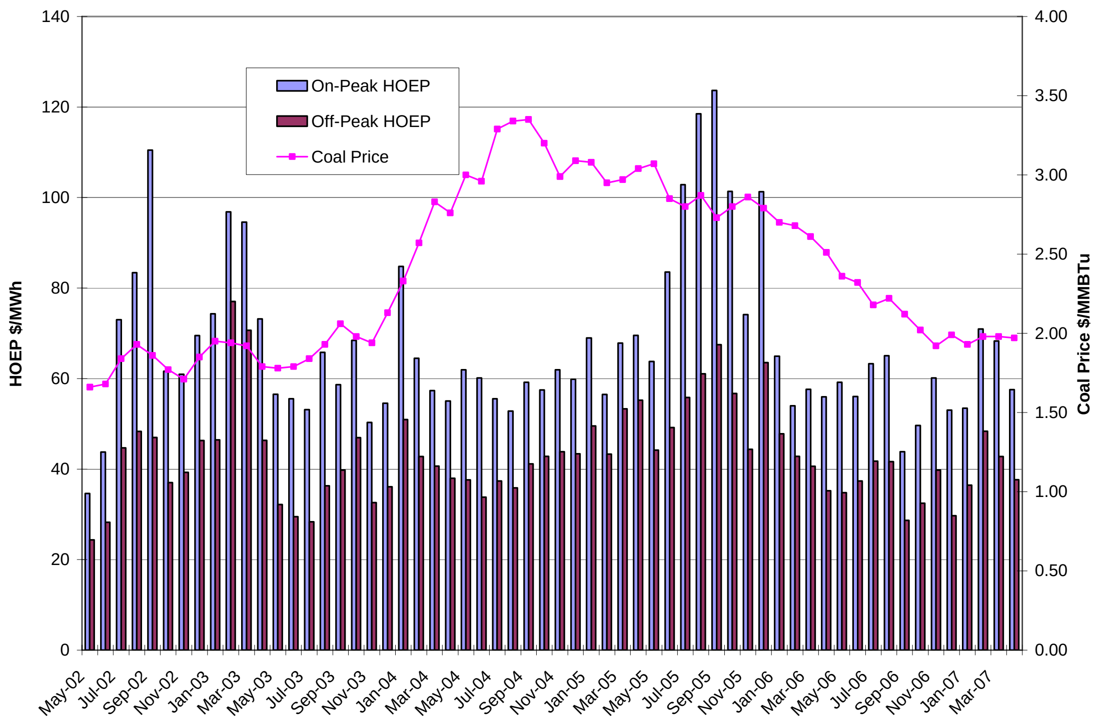


Figure 1-26: NYMEX OTC Central Appalachian Coal Price and HOEP
May 2002 - April 2007
($/MWh and $/MMBtu)



4.5 Net Revenue Analysis

Investment decisions are induced by sufficient revenues for a generator to make an adequate rate of return on its investment. To analyse whether there may be sufficient revenues to prompt investment, consistent with our previous MSP report, we use a standardized model developed by the Federal Energy Regulatory Commission of the United States (FERC) for comparison across markets. The model specifies two types of potential entrants: an efficient combined cycle plant with a heat rate of 7,000 Btu/KWh and an inefficient combustion turbine plant with a heat rate of 10,500 Btu/KWh. The variable operating and maintenance cost associated with each type is $1.10/MWh for the combined cycle and $3.30/MWh for the combustion turbine.[22] For both types, an outage rate of 5 percent is assumed.

[22] FERC assumes US$1/MWh for the more efficient combined cycle unit and US$3 for the less efficient combustion turbine. To translate the numbers to Canadian dollars, we presume an exchange rate of US$1=CDN$1.1.

Unit variable cost is the assumed heat rate times the daily spot price of natural gas at Henry Hub plus the assumed operating and maintenance cost. Note that the use of a spot fuel price tends to overstate the net revenue because transportation and distribution costs are ignored.

Table 1-28: Net Yearly Estimated Net Revenue Analysis for Two Generator Types May 2002 - April 2007 ($/MWh)

Generator Type	7,000 Btu/KWh of Combined-cycle with variable O&M cost of $1.10/MWh	10,500 Btu/KWh of Combustion cycle with variable O&M cost of $3.30/MWh
May 2002 – April 2003	149,255	66,958
May 2003 - April 2004	73,349	17,609
May 2004 – April 2005	47,628	8,584
May 2005 - April 2006	83,252	24,827
May 2006 - April 2007	49,992	9,844
Average	80,695	25,564

Table 1-28 reports net revenue estimates for the past five years. Net revenues appear extremely volatile from one time period to the next. For example, annual net revenue for a hypothetical combined cycle plant was $149,255/MW in the first year and fell over 50 percent in the second period to $73,349/MW. Data for the period May 2006 through April 2007 indicates that net revenues based upon uniform HOEP prices are falling. In 2006/07 a CCGT generator would make only $49,992/MW towards its fixed costs.

The analysis suggests that on average over this five year period, a combined cycle generator would have made a contribution of $80,695/MW per year toward its fixed costs and a combustion turbine unit would make a contribution of $25,564/MW per year. Based on FERC estimates, a combined cycle generator would require approximately requires US$80,000-90,000/MW-year and a combustion turbine unit US$60,000-70,000/MW-year in order to meet debt and equity requirements.[23]

We find that the average market revenues derived from the HOEP continue to be insufficient to induce the construction of gas-fired generation in Ontario. Any new entry would have to be subsidized either by load, through uplift charges. In Chapter 3, we replicate the net revenue analysis using nodal prices in place of the HOEP. Our findings suggest that under recent nodal prices and everything else held constant, there could be sufficient revenue to cover fixed costs for a hypothetical gas-fired generator in certain locations in Ontario.

5. Imports and Exports

5.1 Overview

Imports and exports are essential to the efficient functioning of Ontario's electricity market. Imports are important for economic and reliability reasons. Imports are utilized when the power generated within Ontario is relatively expensive compared to neighbouring regions. Secondly, when domestic supply levels are tight, Ontario has to be a net importer in order to service its load.

Exports fulfil an important role in utilizing idle capacity and contributing to the recovery of Ontario generators' fixed costs. Exports also provide a globally efficient solution to allow arbitrage between markets. One must remember that Ontario's export is someone else's import and vice versa.

Table 1-29 reports net exports from Ontario between November 2006 and April 2007 compared with the same period a year ago, separately for on-peak and off-peak hours.

[23]. For details, see 2004 State of the Markets Report, Docket MO05-4-000

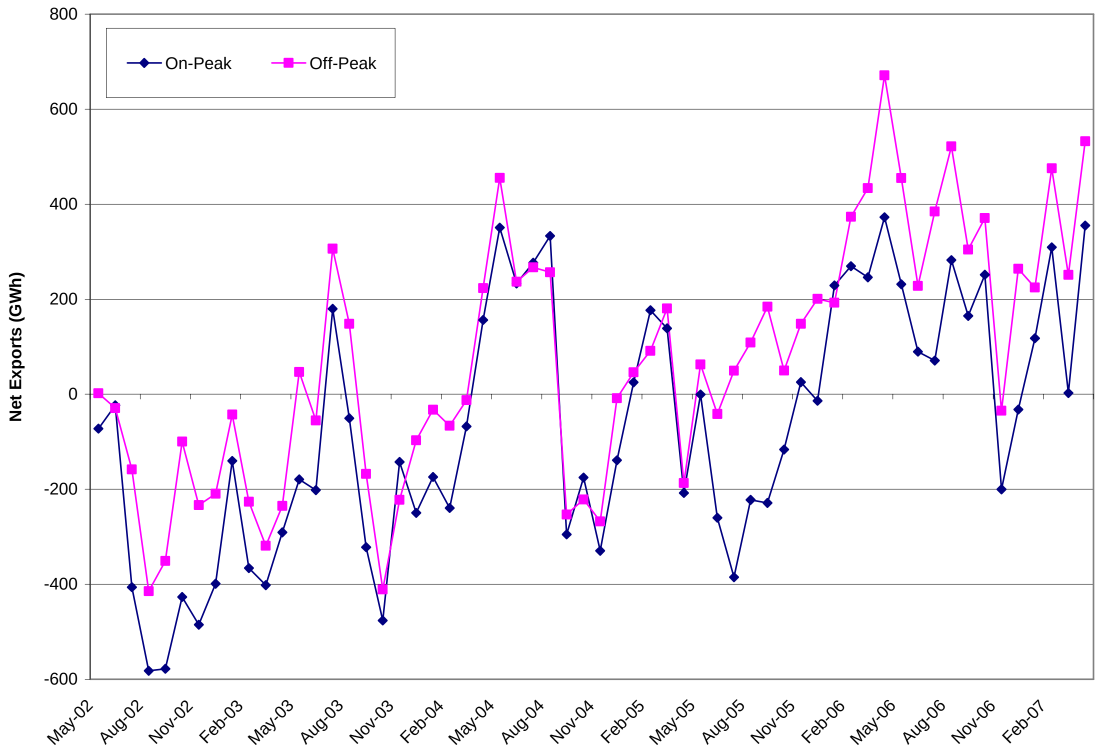
Table 1-29: Net Exports from Ontario On-Peak and Off-Peak, November 2005/2006 – April 2006/2007 (GWh)

	Off-Peak		On-Peak		Total	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
November	148.1	(35.0)	25.5	(200.4)	173.6	(235.4)
December	200.7	263.8	(13.7)	(32.2)	187.0	231.6
January	192.4	224.7	228.8	117.6	421.2	342.3
February	373.3	475.6	269.7	309.1	643.0	784.7
March	433.7	251.0	246.2	2.2	679.8	253.2
April	671.2	532.3	372.7	355.2	1,044.0	887.4
Total	2,019.4	1,712.4	1,129.1	551.5	3,148.5	2,263.9
Average	336.6	285.4	188.2	91.9	524.8	377.3

Ontario was a net exporter for all months of the period except November where net imports totalled 235.4 GWh, a large portion of which was in on-peak hours as illustrated in Table 1-29. Although Ontario was a net exporter in December 2006, the province was a net importer during the on-peak hours of that month (as it was in December 2005). Net exports for the period totalled 2,263.9 GWh compared to 3,148.5 GWh for the same period one year earlier (a 28 percent decline). The bulk of the decline occurred in peak hours (where total net exports fell by 51 percent), but there was also a decline in non-peak hours (where total net export decreased by 15 percent).

When the market initially opened in 2002, Ontario was a net importer of power. However, with increasing supply Ontario has gradually become a net exporter of electricity. Figure 1-27 shows that this is the case for both the on-peak and off-peak hours, although it appears that net exports have plateaued at roughly 300 to 800 GWh per month (total on-peak and off-peak) or an average of about 500 to 1,000 MW per hour.

Figure 1-27: Net Exports, On-Peak and Off-Peak
May 2002 - April 2007
(GWh)



5.2 Congestion

Price differences between Ontario and surrounding markets result in part from import and export congestion. Table 1-30 shows that on average import congestion fell in respect of all neighbouring markets except from Quebec to Ontario where it increased in all months except January 2006 due to transmission outages. Likely import congestion has been less because of the reduced level of imports.

Table 1-30: Import Congestion in the Market Schedule November 2005/2006 - April 2006/2007 (Number of Hours)

	NY to ON		MI to ON		MB to ON		MN to ON		QC to ON		Total	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	0	0	82	26	10	0	213	52	0	52	305	130
December	0	1	114	0	5	0	125	0	11	13	255	14
January	0	0	40	0	3	7	95	0	2	1	140	8
February	0	0	4	0	0	7	121	61	7	16	132	84
March	0	0	35	0	6	19	190	56	0	33	231	108
April	0	0	0	0	0	2	94	0	2	18	96	20
Total	0	1	275	26	24	35	838	169	22	133	1,159	364
Average	0	0	46	4	4	6	140	28	4	22	193	61

Table 1-31 shows that overall export congestion also decreased because of reduced exports, except for February which was a month where higher exports were observed. We also observe that export congestion increased this year on the two smallest interties which are Manitoba and Minnesota due to higher prices in the MISO direction

.

Table 1-31: Export Congestion in the Market Schedule November2005/2006 - April 2006/2007 (Number of Hours)

	ON to NY		ON to MI		ON to MB		ON to MN		ON to QC		Total	
	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007	2005/ 2006	2006/ 2007
November	11	0	0	0	0	23	1	2	155	4	167	29
December	32	0	0	0	3	28	0	12	35	0	70	40
January	48	2	0	0	0	0	11	0	33	0	92	2
February	18	68	2	12	0	10	6	32	32	0	58	122
March	96	32	1	0	0	2	1	7	7	0	105	41
April	197	36	28	20	0	0	0	3	2	0	227	59
Total	402	138	31	32	3	63	19	56	264	4	719	293
Average	67	23	5	5	1	11	3	9	44	1	120	49

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

In previous reports the Panel had used a reduced form econometric model to analyse the determinants of the volume of export flows between Ontario and New York, our largest export destination. Over the past 12 months, almost 80 percent of exports were destined for New York. The model allows us to calculate an export elasticity value with respect to both the HOEP and New York Prices. Since our last report, the IESO has developed a structural model to test the hypothesis that exports from Ontario to New York are an increasing function of the difference between the New York price and the Ontario price as well as seasonal and other factors that vary from month to month and over time. This model was presented in the 12-times ramp rate proceeding before the Ontario Energy Board. The model represents an improvement on the reduced-form model that we presented in our last report and we adopt this model in this report. The model is estimated with monthly data for the period January 2003 to April 2007 using the two-stage least squares (TSLS) method. The instruments used in the first stage are Ontario non-dispatchable demand, nuclear output, self-scheduler output, New York load and the price of natural gas. The model is estimated for both on-peak and off-peak periods.

Parameter estimates are reported in Table 1-32. In general, the statistical results confirm the central role of the difference between the New York and Ontario price as a determinant of exports from Ontario to New York. The coefficient estimates for the HOEP and New York prices are both significant and have the expected signs.

Table 1-32: Estimation Results, Export Model
January 2003 - April 2007

Variable	On-Peak & Off-Peak		On-Peak		Off-Peak	
	Coef.	S.E.	Coef.	S.E.	Coef.	S.E.
Constant	3.95	0.928	2.59	1.046	5.08	1.107
Log(HOEP)	-4.06	0.801	-5.99	0.724	-2.14	0.866
Log(New York Price)	4.53	0.796	6.73	0.769	2.41	0.787
January	0.12	0.130	0.29	0.218	0.00	0.106
February	0.09	0.172	0.05	0.304	0.13	0.131
March	0.03	0.139	0.00	0.219	0.05	0.155
April	-0.11	0.127	-0.05	0.247	-0.18	0.149
May	0.23	0.180	0.25	0.308	0.21	0.171
June	0.35	0.166	0.62	0.214	0.10	0.175
July	0.03	0.173	0.24	0.242	-0.13	0.205
August	-0.16	0.298	-0.13	0.353	-0.20	0.316
September	-0.06	0.119	0.08	0.262	-0.22	0.153
October	-0.45	0.270	-0.26	0.300	-0.65	0.314
November	-0.12	0.138	-0.06	0.171	-0.15	0.159
Time Trend	0.01	0.005	0.01	0.006	0.01	0.004
Model Diagnostics						
Correlation between actual and fitted values	0.67		0.67		0.60	
Number of observations	52		52		52	

Since the model is in logarithmic form, the coefficients of the HOEP and the New York price can be interpreted as elasticities. Taking the on-peak and off-peak periods together, the elasticity of exports with respect to the HOEP is minus 4.1. That is, a one percent increase in the HOEP leads to a 4 percent decrease in exports to New York (and vice versa), other things equal. The elasticity of exports with respect to the New York price is 4.53, essentially the same but with the opposite sign. This implies, as one would expect, that a decrease in the New York price has essentially the same effect on Ontario exports as an increase in the HOEP. In other words, export flows are quite responsive to any price spreads between the two markets.

The statistical results for peak and off-peak periods show that exports are much less sensitive to the price spread off-peak than they are on-peak. During the on-peak and off-peak hours, the elasticity of exports with respect to the HOEP is minus 6.0 and minus 2.1 respectively

5.4 Wholesale Electricity Prices in Neighbouring Markets

5.4.1 Price Comparisons

Ontario has four adjacent or nearby electricity markets: New York, PJM, New England and MISO, (encompassing Michigan, Manitoba, Minnesota and all or part of 13 other U.S. states). Ontario has historically been a net importer from MISO and a net exporter to New York. It is also indirectly linked to PJM and New England which will influence surrounding market prices through New England's connection to New York and PJM's connection to both New York and MISO.

Table 1-33 provides the six month average prices for Ontario and its four neighbouring markets. Comparing HOEP with neighbouring market prices, Ontario had the lowest prices of the 5 markets reviewed during the current reporting period while prices were the highest in New England and PJM. Figure 1-28 illustrates prices on a monthly basis and shows Ontario prices are lowest in four months and only slightly higher than MISO prices in the other two months.[24] The same pattern is observed on-peak and off-peak in Figures 1-29 and 1-30 respectively. NYISO has the third lowest prices on average (although on-peak between December and February, the average NYISO prices were lower than MISO prices). As a result of these price relationships, trade flows generally move from MISO to Ontario and from Ontario towards New York and beyond. This is discussed more fully below in section 5.4.1.

[24] Prices in neighbouring markets were converted to Canadian dollars on a daily basis using the Bank of Canada nominal noon exchange rate.

Table 1-33: Average HOEP Relative to Neighbouring Market Prices
November 2006 – April 2007
($CDN/MWh)

	Off-Peak	On-peak	Total
Ontario	38.74	60.66	48.75
MISO	40.56	67.27	52.76
New England	67.92	84.07	75.23
New York	45.27	64.78	54.18
PJM	53.55	72.34	62.13
Average	49.68	69.93	58.92

Figure 1-28: Average HOEP Relative to Neighbouring Market Prices
November 2006 – April 2007

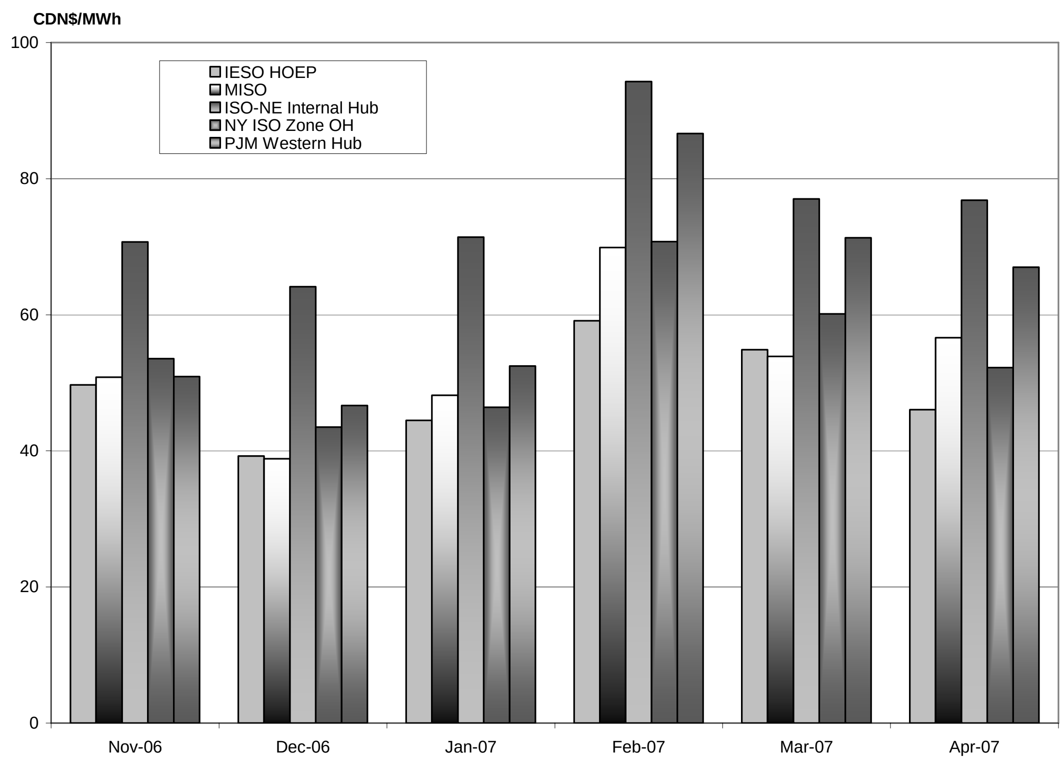


Figure 1-29: Average HOEP Relative to Neighbouring Market Prices, On-Peak, November 2006 – April 2007

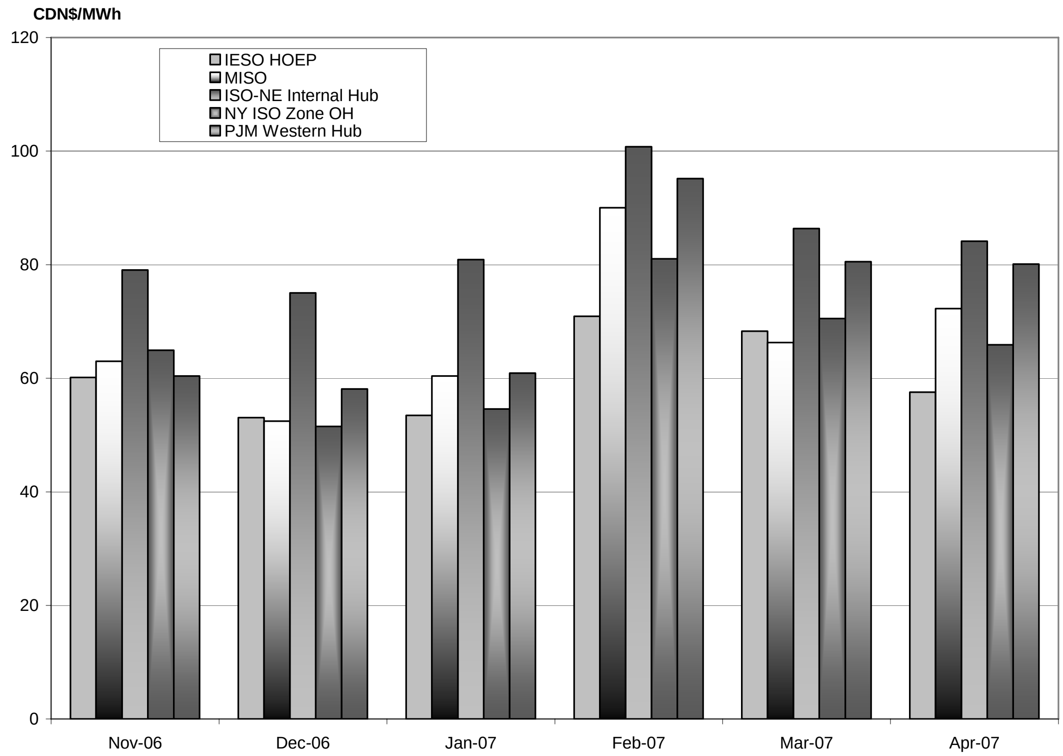
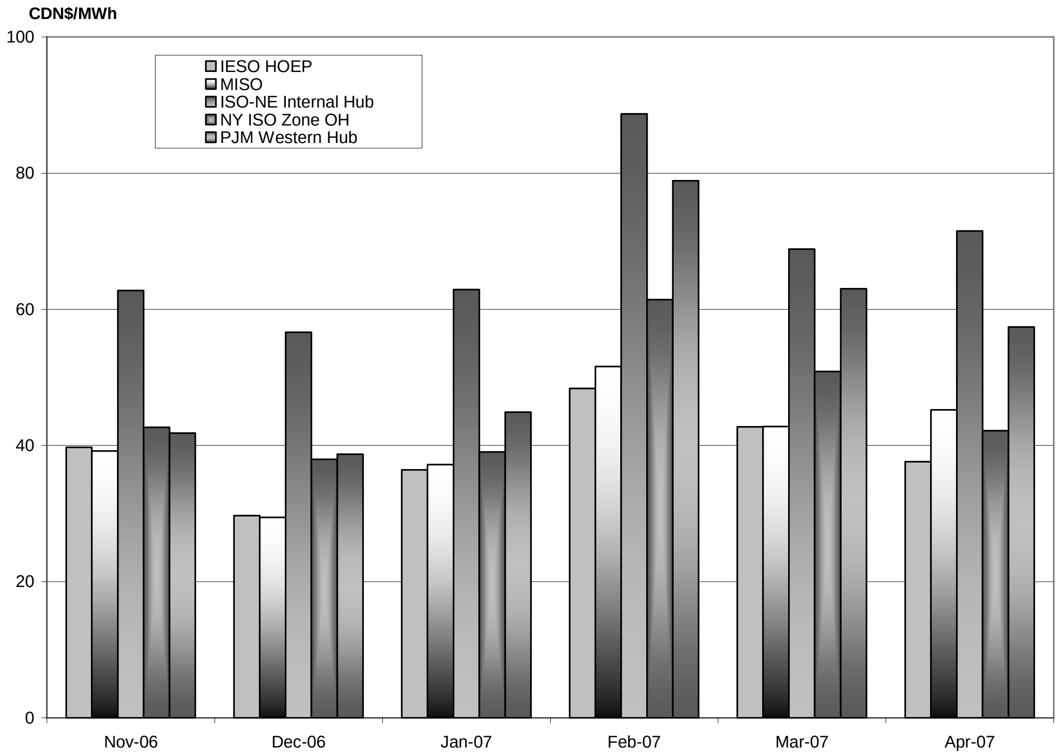
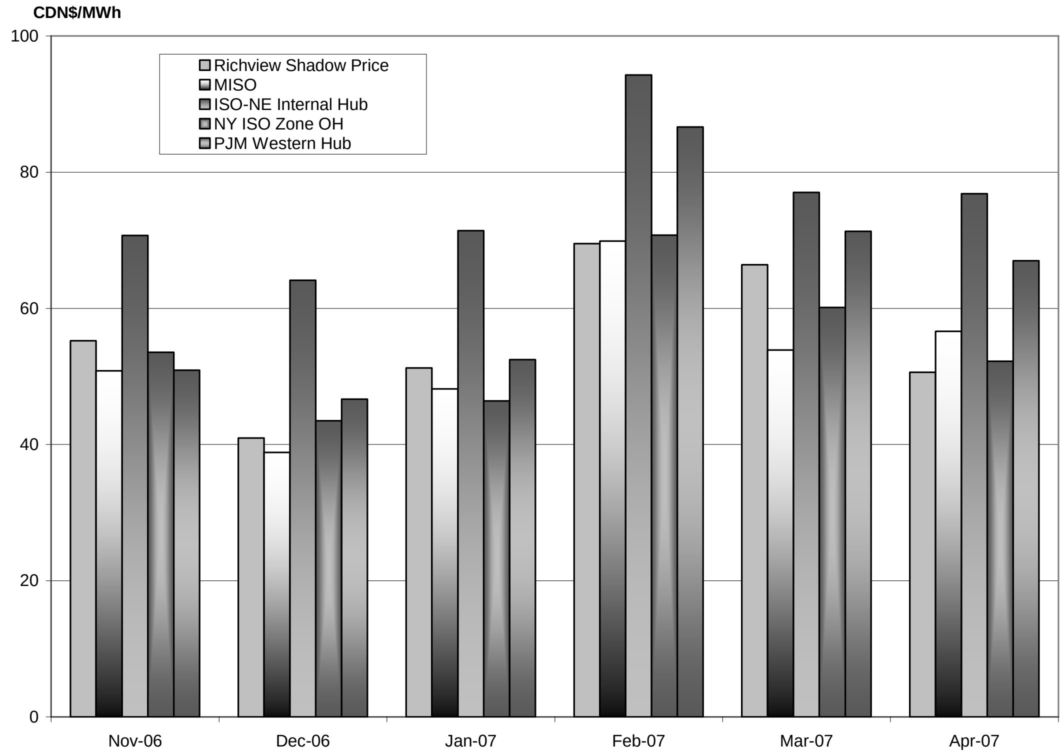


Figure 1-30: Average HOEP Relative to Neighbouring Market Prices, Off-Peak, November 2006 – April 2007



While the HOEP is reflective of the energy price that load pays, shadow prices such as Richview are more reflective of the actual cost of energy production. Figure 1-31 provides a comparison of the Richview nodal price with neighbouring market prices, since the surrounding markets are also nodal. A different picture emerges from this comparison which shows that both New York and Michigan are lower priced on average than Ontario. The prices chosen in both the New York and Michigan markets are those zones closest to Ontario and are representative of their cost of production.

Figure 1-31: Average Richview Shadow Price Relative to Neighbouring Markets November 2006 – April 2007



5.4.2 Market Price Spreads and Trade Flows

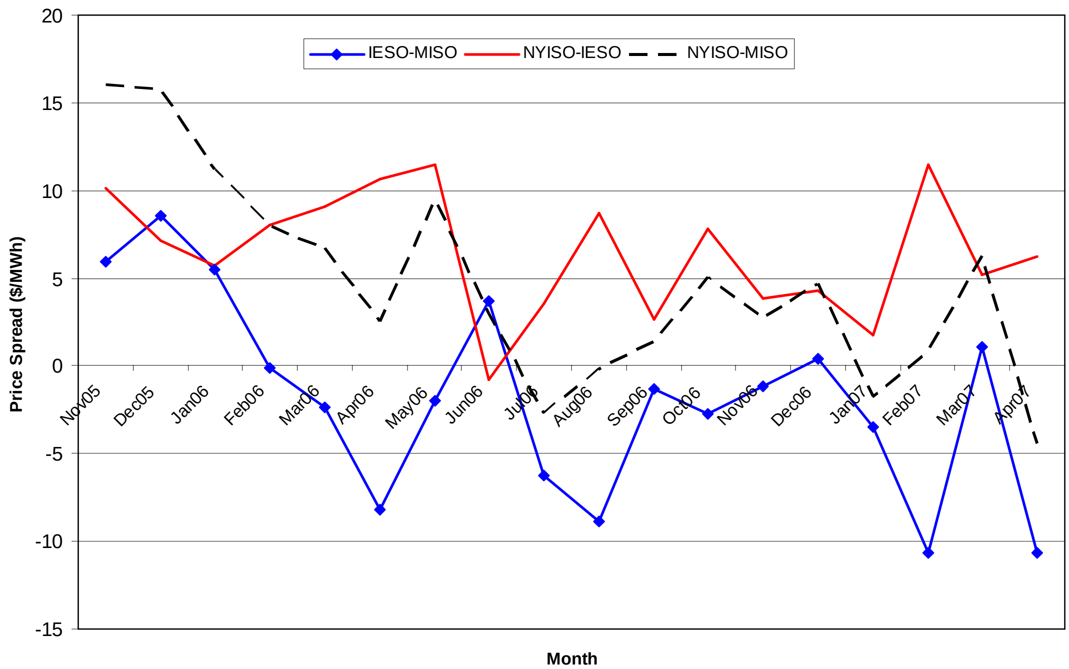
Energy movements between markets are driven by the arbitrage difference or price spread between markets. High prices in one market can be ameliorated by lower cost energy imports arriving from other markets as long as the interties are not congested.

Table 1-29 shows that net exports are down in the current six months compared with last year. A large part of the explanation for this trend is that the spreads between energy prices in Ontario and the major markets in the U.S. have been narrowing.

Figure 1-32 shows monthly average energy price differences between the IESO, NYISO and MISO over the 18 month period to April 2007. The price spread between NYISO and IESO has fluctuated around $5/MWh for most of the period, although there were somewhat higher spreads in the $6 to $12/MWh range in early 2006 and again in early

2007. The price spread between IESO and MISO has been negative almost all of the time since February 2006.

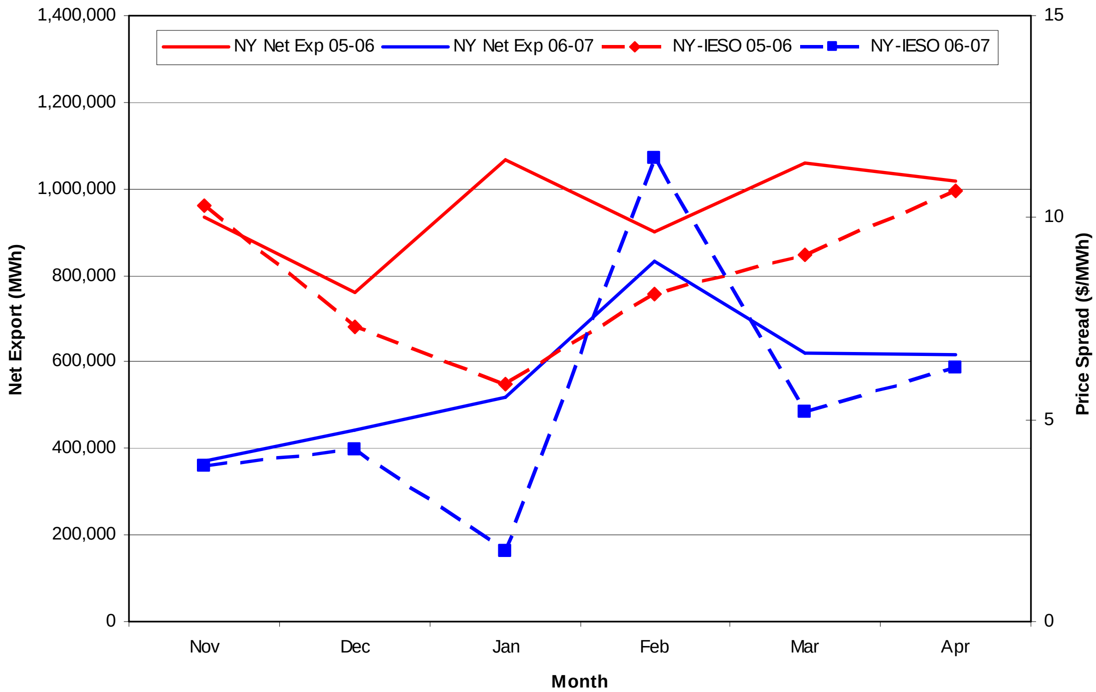
Figure 1-32: Market Price Spreads Between the Ontario, New York and MISO MarketsNovember 2005 - April 2007 ($CDN/MWh)



In Figure 1-33 we observe the November 2005 to April 2006 period saw higher NYISO-IESO price spreads and higher net exports to NYISO relative to the current year. The figure suggests net exports and price spreads are related, although the correlation implied in the figure is not as strong as identified in the econometric analysis in section 5.3, which is based on a larger set of data points and focuses specifically on exports, rather than net exports.[25]

[25] This type of graphical representation is merely illustrative of the relationship. It does not attempt to account for other factors that can influence either exports or price spreads.

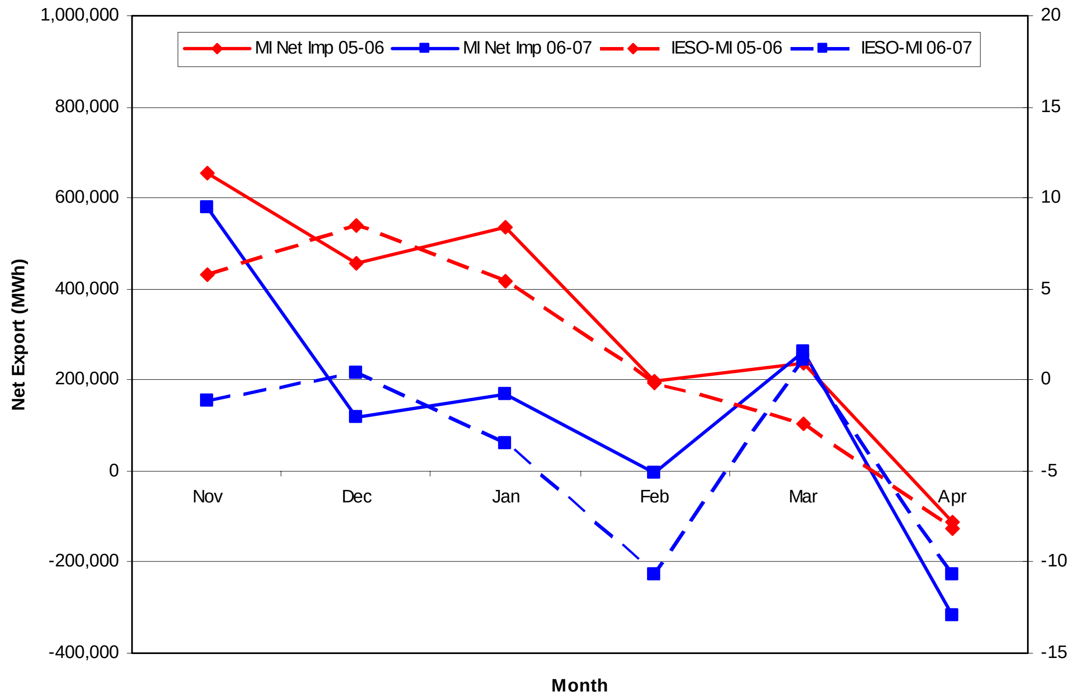
Figure 1-33: NYISO to IESO Price Spreads and Net Exports to NYISO November 2005/2006 - April 2006/2007



Another possible factor in the magnitude of exports to NYISO may be the NYISO-MISO price spreads in Figure 1-32. These are relevant in that they may reflect opportunities for wheeling energy from MISO to NYISO through IESO the simultaneous importing from MISO and exporting to NYISO. At the beginning of the period, spreads were more than $15/MWh (while gas prices were quite high). They then began to fall, dropping to the -$2 to $6/MWh range after May 2006. Until May 2006 the monthly average price differences may have been large enough to justify some wheeling activity. Thus even if NYISO – IESO price differences were small, such as in January 2006, the spreads NYISO to MISO could have contributed to exports to NYISO as part of a wheeling transaction. However given that importers cannot receive an IOG if they are simultaneously exporting, there may be some hesitation by importers to wheel, especially if the spread between NYISO and MISO is uncertain and not that large.

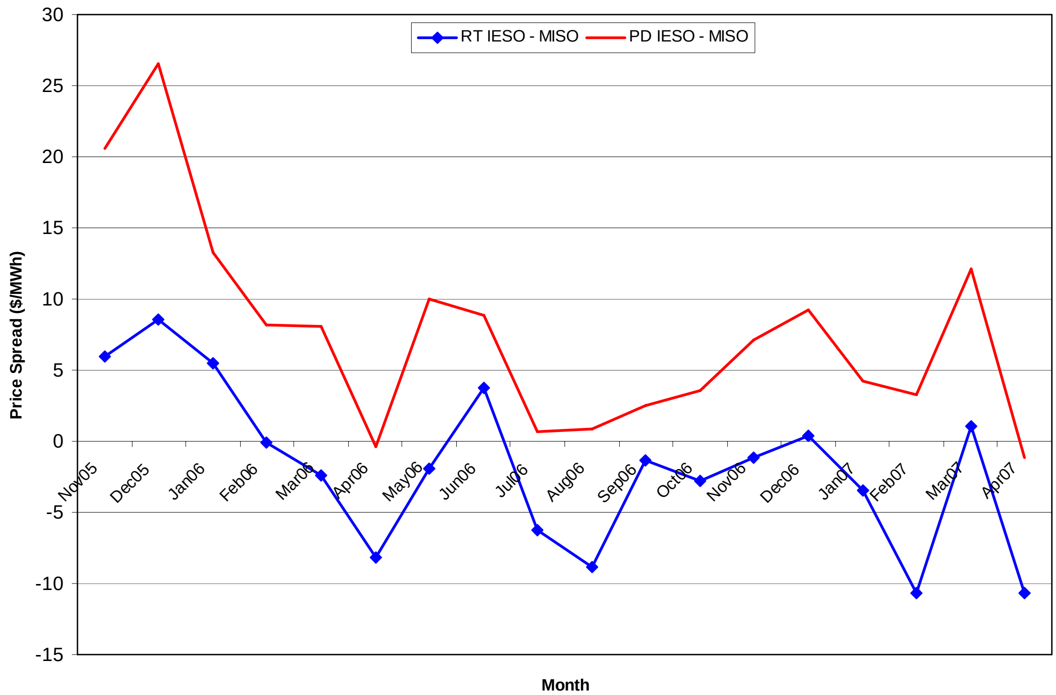
The price spreads between the IESO and MISO in Figure 1-32 suggest a more fundamental shift in market arbitrage opportunities. In the first three months it shows average IESO prices were higher than MISO by more than $5/MWh. Since then however the spread was most often negative, with average MISO prices exceeding the IESO energy price. This suggests greatly reduced opportunities for imports from MISO to IESO, as seen in the actual trend downward in net imports from MISO. This can also be observed in Figure 1-34, which shows net imports from MISO and the IESO-MISO price spread. This figure suggests that the movements of net imports are clearly related to the changes in the price spread between the two markets.

Figure 1-34: IESO to MISO Price Spreads and Net Imports from MISO November 2005/2006 – April 2006/2007



Although the relationship between price spread and net imports is fairly evident from Figure 1-34, it seems curious that imports are occurring when the price spread is low, less than $5, or even negative. This may be explained by the role that IESO pre-dispatch prices and IOG play in import opportunities, given that importers might receive up to the pre-dispatch energy price for a scheduled import. Figure 1-35 shows the spread between the IESO pre-dispatch price and MISO real-time price. It demonstrates that the downward trend is similar for both price spreads, but the pre-dispatch spread is actually larger. So rather than being negative in the last six months, the average monthly price spreads have been in the range between $1 and $12/MWh. These are lower than the previous year's spreads, but still support imports at a diminished level. Figure 1-35 again highlights the importance of having correct pre-dispatch price signals in order to gain efficient production and consumption decisions. While the efficient arbitrage opportunity may have been from Ontario to MISO throughout much of this period, the higher pre-dispatch price signals in Ontario appear to be inducing inefficient imports.

Figure 1-35: IESO to MISO Price Spread – Based on Ontario Real-Time and Pre-Dispatch versus MISO Real-Time November 2005/2006 - April 2006/2007 ($CDN/MWh)



Appendix: A Revised Supply Cushion Methodology

In its first Market Monitoring Report, the Panel introduced a metric - supply cushion (SC) - which is the amount of unused energy that is offered for dispatch in a particular hour. It is expressed as a percentage derived arithmetically as:

$$SC = \frac{EO - (ED + OR)}{ED + OR} \times 100$$

Where:
EO = total amount of available energy offered
ED = total amount of energy demanded (average in an hour)
OR = total operating reserve requirement (average in an hour)

Offers from fossil generators are only considered available if the units are online.

There are two versions of the supply cushion. The total supply cushion (TSC) includes scheduled imports, while the Domestic Supply Cushion (DSC) only considers in province supply sources.

The supply cushion also differentiates between pre-dispatch (PD) and real-time (RT). The pre-dispatch supply cushion uses all information immediately after the pre-dispatch run, while the real-time supply cushion uses information which is current at the beginning of the dispatch hour. The differences between the pre-dispatch and real-time supply cushion are the result of demand forecast error, generation outages and intertie failures that have occurred after the pre-dispatch run.

Thus we have four supply cushions: PD-TSC (pre-dispatch total supply cushion), PD-DSC (pre-dispatch domestic supply cushion), RT-TSC (real-time total supply cushion), and RT-DSC (real-time domestic supply cushion).

In the December 2006 report, the Panel identified a few shortcomings with the old methodology, especially with the PD-TSC, and asked the MAU for a further modification. The table below summarizes the differences between the old and the modified approach.

Table 1A-1: Comparison of the Old and New Supply Cushion Methodologies

	Old Approach	New Approach
Import offers	Offers counted in the PD-TSC and actual imports included in the RT-TSC	Scheduled MW in the PD-TSC and actual MW in the RT-TSC.
Ramp capability	Not considered	Considered with 60 minute horizon for pre-dispatch and 5 minute for real-time
Energy demand	Non-dispatchable demand plus both dispatchable demand and exports that bid at $2,000	Non-dispatchable demand plus dispatchable demand that bid at $2,000 (exports excluded)
Non price responsive generators, such as nuclear , self-scheduling, and intermittent generators	Offers in all SC	Offers in the PD SC, but actual supply in the RT SC
Definition of an online fossil generator	Online in the delivery hour	Online at the time PD run for the PD-TSC and PD-DSC, or online in interval 12 in previous hour for the RT-TSC and RT-DSC[26]

In summary, the new approach has a few important improvements. First, the new PD-TSC which measures the supply condition right after the pre-dispatch run takes into account all intertie capability and the NISL because the pre-dispatch sequence has already incorporated all relevant constraints. In contrast, the old approach (which measured the supply condition right before the pre-dispatch run) used import offers that may be unavailable due to either intertie limitation or NISL. Second, the new approach recognizes generation ramp capability and uses a redefined online status. Third, the new approach does not count potential export curtailment and voltage reduction (i.e. CAOR) as a resource.[27] Fourth, the new approach uses the actual supply from non-dispatchable generators (including nuclear units) rather than their projected output in the real-time

[26] If a unit is offline at the PD run, its scheduled MW in the pre-dispatch run will be counted into both PD supply cushions which takes into account the contribution of the unit to the market as it starts up in the coming hour. Otherwise, its available supply for the PD SC is the ramp capability up to maximum capacity. If a unit comes online during the delivery hour, it is not counted into the RT supply cushion. This provides a more conservative measurement. Furthermore, its average contribution to the hour may be relatively small given that the supply cushion is hourly based.
[27] The CAOR resource was removed from supply in our December 2006 report.

supply cushion, which provides a truer picture of real-time supply condition. Table A-20 of the Statistical Appendix contains the re-calculated pre-dispatch and real-time supply cushion since market opening.

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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 anomalous events. Anomalous behaviours are actions by market participants (or the IESO) leading to market outcomes that fall outside of predicted patterns or norms.

The MAU monitors high and low priced hours and 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. The Panel believes the explanation of these types of events provides transparency on why certain outcomes occur in the market and leads to learning by all market participants.

On a daily basis the MAU reviews the previous day, not only to discern anomalous events but also to review:

- changes in bid strategies;
- the impact of forced outages;
- import/export arbitrage opportunities;
- the appropriateness of uplift payments;
- and the implementation of IESO procedures.

In addition to identifying anomalous events, such reviews may lead to identification of incorrect market incentives that lead to inefficiencies.

The MAU also 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 in which the hourly uplift exceeded the HOEP. In addition, the MAU reviews all low priced hours and reports its findings to the Panel. For the purpose of this review, a low priced hour is defined as any hour in which the HOEP was less than $20/MWh.[28]

With respect to high priced hours, there was only 1 hour during the review period November 2006 through April 2007 in which the HOEP was greater than $200/MWh. Section 2.1 of this chapter reviews the factors covering this relatively high HOEP. There were three hours during the review period in which the hourly uplift exceeded the HOEP. In all three cases, the HOEP was negative so even a small positive uplift in an hour leads to uplift exceeding the HOEP.

Regarding low priced hours, there were 189 hours in the period November 2006 - April 2007 in which the HOEP was less than $20/MWh. Section 2.2 of this chapter reviews the factors typically driving the prices down in these hours.

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

2. Anomalous HOEP

2.1 Analysis of High Priced Hours

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

Table 2-1 depicts the total number of hours with a HOEP greater than $200/MWh and the total number of hours with an uplift greater than the HOEP. The number of hours with a

[28] $200/MWh is typically an upper bound for the cost of a fossil generation unit. $20/MWh is a lower bound for the cost of a fossil unit.

high HOEP was smaller in 2006/2007 than in 2005/2006, since only one such event occurred, in HE 17 of April 12, 2007 (which is examined in detail below). There were three hours in 2006/2007 in which the uplift was greater than the HOEP, compared to none in 2005/2006. All three high uplift hours occurred in December 2006 with a negative HOEP. We will discuss the three incidents in section 2.2 of this chapter.

Table 2-1: Number of Hours with a High HOEP
November 2005/2006 - April 2006/2007

	Number of Hours with HOEP >$200		Number of Hours with Uplift > HOEP	
	2005/2006	2006/2007	2005/2006	2006/2007
November	0	0	0	0
December	2	0	0	3
January	0	0	0	0
February	0	0	0	0
March	0	0	0	0
April	4	1	0	0
Total	6	1	0	3

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

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

Each of these factors has the effect of tightening the real-time total and domestic supply cushion relative to the pre-dispatch total and domestic supply cushion. Spikes of the HOEP above $200/MWh are most likely to occur when one or more of the factors listed above cause the real-time total supply cushion (RT-TSC) to fall below 10 percent.

2.1.1 April 12, 2007 HE 17

In this hour the HOEP was $215.64/MWh. Table 2-2 lists for each interval the real-time Market Clearing Price (MCP), the Richview nodal price, and the unconstrained and constrained Ontario demand. The MCP started to increase rapidly from interval 8 although the unconstrained Ontario demand was relatively constant across intervals. Of interest is that the Richview nodal price for intervals 8 to 12 was much smaller than the MCP except in interval 10.

Table 2-2: Summary Real-time Information for HE 17, April 12, 2007

Hour	Interval	MCP $/MWh	Richview Nodal Price $/MWh	Ontario Demand (Unconstrained) MW	Ontario Demand (Constrained) MW
17	1	97.33	134.47	19,251	19,254
17	2	97.33	125.20	19,246	19,251
17	3	126.04	132.09	19,264	19,289
17	4	124.15	133.90	19,227	19,308
17	5	117.40	151.61	19,203	19,268
17	6	125.48	132.00	19,256	19,180
17	7	153.68	132.00	19,269	19,179
17	8	230.12	148.13	19,260	19,273
17	9	363.02	195.21	19,215	19,281
17	10	396.65	499.25	19,267	19,254
17	11	396.65	139.87	19,265	19,347
17	12	359.82	167.06	19,213	19,369
Average		215.64	174.23	19,245	19,343

Pre-dispatch market conditions

The one-hour ahead pre-dispatch market demand was forecast at 19,021 MW with a price of $96.20/MWh. About 1,000 MW were offered between $96/MWh and $380/MWh, almost exclusively from hydroelectric units. The Ontario market was a net exporter in the amount of 1,308 MW. The pre-dispatch total supply cushion was 7.9 percent.

Real-time market conditions

In real-time, demand averaged 19,245 MW with a peak of 19,269 MW, which is about 200 MW higher than projected in pre-dispatch. About 30 minutes after the pre-dispatch run, the IESO (at 15:36) was asked to derate several units at a large station because of ice problems. The MAU was satisfied that this was for legitimate reasons.

To mitigate the future impact on system reliability, the IESO subsequently derated the units at the station for HE 17 as well in pre-dispatch. As a result of the deratings, the real-time total supply cushion dropped to 0.4 percent and the real-time demands were exceeding supply.[29] The supply-demand imbalance reached -400 MW at 16:43, and the IESO subsequently activated 500 MW of OR for the rest of the hour.

Assessment

Table 2-3 summarizes several actions taken by the IESO in HE 17 and HE 18. The deratings reduced supply between 123 MW and 669 MW across several intervals in HE 17 and 669 MW in all intervals in HE 18. Although the OR requirement was reduced by 500 MW in the last four intervals in HE 17 in the unconstrained sequence,[30] it was not sufficient to offset the impact of the derating on the energy market, given that demand was also running high by about 200 MW. The MCP jumped above $300/MWh from interval 9 onwards. In HE 18, the demand started to fall and net exports were fewer, and as a result the MCP dropped below $150/MWh.

[29] This real-time demand-supply balance in Ontario is measured by Area Control Error (ACE), which must regularly be reduced to zero according to NERC / NPCC standards.

[30] Because the constrained sequence runs two intervals ahead of the unconstrained sequence for a given interval, when an OR requirement reduction is implemented, the reduction will show up immediately in the following unconstrained run but two intervals later in the constrained run. However, when across hours, the reduction in OR requirement may affect one sequence but not the other because the DSO also matches the OR reduction with the delivery hour. In the current case, the OR requirement for HE 18 was originally set at 1,368 MW. When the constrained sequence ran for interval 1 of HE 18, it picked the original OR requirement of 1,368 MW. But at the time when it ran this constrained sequence, the unconstrained sequence run replicated interval 11 of HE 17, in which the OR requirement was still 1,228. Although the OR was activated for only two intervals (the last two intervals in the constrained sequence), the OR requirement for the unconstrained sequence was not restored to the pre-contingency level because the IESO's practice is to change the OR requirement only once for both sequences.

Table 2-3: Outage and Reduction in the OR Requirement in HE 17 & HE 18 April 12, 2007 (MW)

		Unconstrained			Constrained	
Hour	**Interval**	**Output Loss**	**OR Requirement**	**OR Reduction**	**Output Loss**	**OR Requirement[31]**
17	**1**	0	1,728	0	0	1,728
17	**2**	0	1,728	0	0	1,728
17	**3**	127	1,728	0	0	1,728
17	**4**	127	1,728	0	0	1,728
17	**5**	127	1,728	0	123	1,728
17	**6**	127	1,728	0	123	1,728
17	**7**	298	1,728	0	123	1,728
17	**8**	480	1,728	0	123	1,728
17	**9**	662	1,228	500	305	1,728
17	**10**	662	1,228	500	487	1,728
17	**11**	662	1,228	500	669	1,228
17	**12**	662	1,228	500	669	1,228
18	**1**	662	1,368	0	669	1,368
18	**2**	662	1,368	0	669	1,368
18	**3**	662	1,368	0	669	1,368
18	**4**	662	1,368	0	669	1,368
18	**5**	662	1,368	0	669	1,368
18	**6**	662	1,728	0	669	1,368
18	**7**	662	1,728	0	669	1,368
18	**8**	662	1,728	0	669	1,728
18	**9**	662	1,728	0	669	1,728
18	**10**	662	1,728	0	669	1,728
18	**11**	662	1,728	0	669	1,728
18	**12**	662	1,728	0	669	1,728

In the constrained world, the IESO manually constrained on several hydro generators and subsequently activated OR. A manually constrained on generator is modelled in the DSO (Dispatch Scheduling Optimizer) as non-dispatchable. This is equivalent to fixing the supply from these resources at the bottom of the supply stack although these resources may be offering at a high price. In this hour, more than half of the manually constrained-on MW (about 330 MW) was offered above $400/MWh. This manual reallocation of the

[31] The operating reserve requirement in HE 17 was higher than the normally required 1,368 MW. The increase was due to a prior outage of a transformer at another generating station. In case of a loss of another transformer, which might lead to a shutdown of additional units, the IESO had increased the OR requirement to reflect the contingency for HE 7 to HE 19. In the first few intervals in HE 18, the OR requirement was lowered to the normal level of 1,368 MW because the transformer was originally expected to be back in service at the beginning of the hour; however, this was reversed when it became apparent that the unit's return was delayed until late in HE 19.

offer stack drove down the Richview price well below the MCP in the latter part of the hour.

The IESO's current practice in the event of a contingency is to initially reduce the requirement for OR by the amount of the supply loss involved on the assumption that if a further contingency were to occur, it could be covered from out-of-market sources such as energy procured from other ISO's. According to IESO's procedure under such circumstance the IESO will sequentially restore the OR requirement using blocks of up to 250 MW to its pre-contingency level, where practical, within 90 minutes. In HE 17, the IESO restored the OR requirement in two intervals, i.e., within 10 minutes.

While the NERC and NPCC allow a reduction in Operating Reserve after a contingency and the IESO followed acceptable technical procedures, the MSP questions whether it is appropriate, in general, to reduce the OR requirement following the occurrence of a contingency. Load pays for OR as a reliability insurance premium in order to insure that it can continue to consume after a contingency has occurred. If, as seems reasonable to believe, the probability of a second contingency occurring is the same as the probability of the first contingency, the demand for OR and the willingness of load to pay for it should be at least as great as it was prior to the first contingency. Given the supply loss and an unchanged OR requirement, both the OR price and the energy price should increase to reflect the increased scarcity in the market. It is our understanding that surrounding markets such as New England and the NYISO's policy is to not lower the OR requirement after a contingency.

To see how the reduction in the OR requirement impacted the real-time price, the MAU ran a real-time simulation by adding back the reduced OR requirement to the pre-event level. Table 2-4 shows the comparison of the actual prices and simulated prices. The HOEP would have been $6.61/MWh higher had the IESO not reduced the OR requirement during the contingency, and the OR price would have been $6.52/MWh to $6.76/MWh higher. In this case the market would have turned to CAOR (recallable exports or voltage cuts) to maintain the required level of reserves.

Table 2-4: Price Comparison With and Without the Reduction in the OR Requirement in HE 17 April 12, 2007 ($/MWh)

Hour	Interval	Actual				Simulated			
		MCP	10N	10S	30R	MCP	10N	10S	30R
17	1	97.33	0.34	11.93	0.34	97.33	0.34	11.93	0.34
17	2	97.33	0.34	11.93	0.34	97.33	0.34	11.93	0.34
17	3	126.04	2.00	15.48	2.00	126.04	2.00	15.48	2.00
17	4	124.15	0.67	14.15	0.67	124.15	0.67	14.15	0.67
17	5	117.40	0.67	12.26	0.67	117.40	0.67	12.26	0.67
17	6	125.48	2.00	15.48	2.00	125.48	2.00	15.48	2.00
17	7	153.68	18.10	33.68	18.10	153.68	18.10	33.68	18.10
17	8	230.12	30.00	45.88	30.00	230.12	30.00	45.88	30.00
17	9	363.02	2.00	19.41	2.00	391.02	30.00	46.38	30.00
17	10	396.65	18.10	35.51	18.10	407.62	30.00	46.48	30.00
17	11	396.65	18.10	35.51	18.10	407.62	30.00	46.48	30.00
17	12	359.82	0.67	16.55	0.67	389.16	30.00	45.88	30.00
Average		215.64	7.75	22.31	7.75	222.25	14.51	28.83	14.51
Simulated - Actual		N/A	N/A	N/A	N/A	6.61	6.76	6.52	6.76

The Panel has long been of the view that reducing reserve requirements during times of scarcity has a perverse effect on the prices of both energy and OR. It has previously recommended that reserves obtained through out-of-market control actions be priced to reflect their scarcity value and this recommendation has been adopted by the IESO.[32] Not lowering the reserve requirement or returning the reserve requirement as quickly as possible would allow price to better reflect scarcity conditions at that instant.

Recommendation 2-1

The Panel recommends the IESO review the time lags which it currently employs for replenishing the OR requirements following a contingency. Replenishment as quickly as possible would be consistent with the treatment of other operating reserve or energy obtained through out-of-market control actions and similar to the NYISO practice. This would result in prices which more accurately reflect

[32] This issue was identified in our first MSP report (May-August 2002). The first tranche of the recommendation was implemented by the IESO on August 6, 2003; with subsequent tranches implemented on Octdober 15, 2003 and September 23, 2005.

the loss of supply and encourage market participants to respond as quickly as possible.

2.2 Analysis of Low Priced Hours

Table 2-5 lists the total number of hours with a low HOEP. The number of hours with a low HOEP was much greater in 2006/2007 than in 2005/2006, especially in November and December. This is consistent with the observation that the number of hours with a high HOEP was smaller in 2006/2007, as a result of better supply/demand conditions. The higher number of low priced hours and the lower number of high priced hours reflects the shift in price distribution as illustrated in Figure 1-1 of Chapter 1. This was largely induced by more baseload hydro supply and lower off-peak demand in these two months (see Table A-13 in the Statistical Appendix).

Table 2-5: Number of Hours with a Low HOEP
November 2005/2006 - April 2006/2007

	Number of Hours with HOEP <$20	
	2005/2006	**2006/2007**
November	4	25
December	2	103
January	3	18
February	6	0
March	1	0
April	94	43
Total	110	189

In previous reports we have identified a few primary factors that lead to a low price, including:

- A low market demand. This typically occurs in the overnight hours, on holidays or during the spring/fall seasons.

- Abundant baseload supply from run of river hydro facilities. This occurs most frequently during the spring-time months of April and May but it can occur at other times.

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

Table 2-6 provides key information on all low HOEP hours by month. Apparently in this period demand was on average significantly over-forecast and there were a large number of export failures in these hours. The low HOEP was typically not projected by the pre-dispatch run.

Table 2-6: Summary Information on Low HOEP Hours
November 2006 - April 2007

Month*	Number of Hours	Pre-dispatch Market Demand (MW)	Real-time Market Demand (MW)	Demand Over-forecast (MW)	Export Failure (MW)	Pre-dispatch Price ($/MWh)	HOEP ($/MWh)
Nov-06	25	15,183	14,818	365	76	25.60	13.07
Dec-06	103	15,772	15,323	449	166	24.16	10.84
Jan-07	18	15,823	15,336	487	258	24.96	10.84
Apr-07	43	14,952	14,498	454	228	20.21	12.58

* Note: there were no low price hours in February and March.

All three hours with a negative HOEP occurred in morning off-peak hours: December 19, 2006 HE 4 and December 26, 2006 HE 2 and HE 3.

2.2.1 December 19, 2006 HE 4

The HOEP in this hour was -$0.18/MWh

Pre-dispatch market conditions

The pre-dispatch peak demand was forecast at 15,094 MW with a projected price at $23.83/MWh. Baseload hydro generators offered 237 MW at prices between $-0.18/MWh and $23.83/MWh. The pre-dispatch total supply cushion was 29.0 percent.

Real-time Market Conditions

The real-time demand came in at 14,806 MW, with a peak at 14,859 MW which is 235 MW less than forecast hour ahead. In the hour, there were no generation outages and no intertie transaction failures. Self-scheduling and intermittent generators as a whole produced only 21 MW less than they projected, which slightly offset the impact of demand under-forecast. The real-time total supply cushion increased to 29.9 percent, and the HOEP dropped to -$0.18.

Assessment

The negative real-time price was the result of low demand associated with a large amount of baseload supply. The low price was further depressed by the over-forecast of demand. In the hour, the over-forecast led to the purchase of 181 MW of imports, which were offered at $23.83 and set the pre-dispatch price. These imports were guaranteed an IOG payment of about $5,000, but had the effect of suppressing the real-time price.

The real-time price was set by a run of river baseload hydro unit which receives a fixed price $33/MWh for its output. Offering a negative price minimizes the potential to spill water at the plant but setting a negative energy price does not affect the revenue to the unit. In fact, the Global Adjustment for the hour was estimated at $4.67, and the OPG rebate $2.83. The net result is that consumers paid or will pay $1.66, although the wholesale price was -$0.18.

Exporters, however, are the only buyers that are tied to the negative price. They were actually paid $0.18 for every MW exported, rather than paying $1.66 like other buyers.

The majority of the energy was provided by baseload, self-scheduling and intermittent generators. Apparently some self-scheduling and intermittent generators were induced online by their fixed price NUG contracts which caused production efficiency loss as there were also a few fossil generators online, but they were producing at their respective minimum level to avoid a restart-up during the load pick-up period in later hours. Although exports are typically most price responsive and benefited the most from the negative price, they could not change their offer in the hour due to the two-hour offer window and therefore, could not fully take advantage of the low prices.

2.2.2 December 26, 2006 HE 2

The HOEP in that hour was -$1.65/MWh

Pre-dispatch Market Conditions

The pre-dispatch demand was forecast at 13,109 MW with a projected price of $20.78. Baseload hydro and coal generators offered 760 MW at prices between -$1.65 and $20.78. The pre-dispatch total supply cushion was 20.2 percent.

Real-time Market Conditions

The real-time market demand came in at 12,711 MW, with a peak at 12,858 MW which is 251 MW less than forecast hour ahead. In the hour, there were no generation outages, but failed exports amounted to 425 MW due to New York ISO security requirements. Self-scheduling and intermittent generators as a whole produced as offered. The real-time total supply cushion increased 24.6 percent, and the HOEP dropped to -$1.65.

Assessment

The negative price was a result of a low demand level coupled with demand over-forecast and export failure. Demand over-forecast led to over-purchase of imports by 186 MW, which were paid more than $4,000 of IOG payment but depressed the real-time price.

The negative price was set by a run of river baseload hydro unit which receives a fixed price $33/MWh for its output. The unit offered a negative price to minimize the potential spill but was actually paid its fixed rate. Exporters were paid $1.65/MW for exporting electricity out of Ontario, while domestic consumers ultimately will pay $0.18/MWh because of the Global Adjustment ($4.67/MWh) and OPG rebate ($2.83/MWh).

In this hour, besides baseload and self-scheduling and intermittent generators, there were only five fossil units online who were producing at their minimum level to avoid restart in load pick-up period. There was no major production efficiency loss aside from the inefficiency due to self-scheduling generators.

For this hour, the three-hour ahead pre-dispatch price was projected at $3.80/MWh. With such a low price, exporters started to bid in or adjust their offers so as to be scheduled in real-time. In fact, even with a two-hour ahead price at $19.60/MWh, selected net exports were 500 MW more than the three-hour ahead pre-dispatched sequence had scheduled. Given that the Richview nodal price which approximates the opportunity cost of energy in Southern Ontario, was below -$3/MWh and external prices were above $15/MWh, all exports were efficient.

2.2.3 December 26, 2006 HE 3

The HOEP in that hour was -$1.66/MWh.

Pre-dispatch Market Conditions

The pre-dispatch demand was forecast at 12,365 MW with a projected price of $3.10/MWh. Baseload hydro generators offered 200 MW at prices between -$1.66/MWh and $3.10/MWh. The pre-dispatch total supply cushion was 24.9 percent.

Real-time Market Conditions

The real-time average demand came in at 12,414 MW, with a peak 12,475 MW which is 110 MW greater than forecast hour ahead. In the hour, there were no generation outages, but failed exports amounted to 360 MW due to New York security issues. Self scheduling and intermittent generators as a whole produced almost exactly the amounts offered. The real-time total supply cushion increased to 26.5 percent because failed exports more than offset the increase in demand, and the HOEP dropped to -$1.66/MWh.

Assessment

The negative HOEP was a result of the large export failure in HE 2 causing the Net Interchange Scheduling Limit (NISL) to be binding for HE 3 and implying imports/exports were scheduled out-of-merit. For HE 3, 186 MW of imports that were offered above the pre-dispatch price were scheduled (but would not have been under normal conditions). These imports were guaranteed $2,200 of IOG payments, and further suppressed the real-time price.

Again the negative price was set by the same baseload hydro resource as in HE 2. Exporters were paid to export, but because of the Global Adjustment ($4.67) and OPG Rebate ($2.83) internal consumers paid or will pay $0.17/MWh.

In this hour, besides baseload and self-scheduling and intermittent generators, there were only four fossil units online which were producing at their minimum level to avoid restart in the load pick-up period.

For this hour, the three-hour ahead pre-dispatch price was projected at $3.50/MWh. With such a low price, exporters started to bid in or adjust their offers so as to be scheduled in real-time. Even with a two-hour ahead price at $15/MWh, selected net exports were 900 MW more than the three hour ahead pre-dispatched sequence had scheduled. Given that the Richview nodal price was about -$6/MWh and external prices were above $7/MWh, all exports were efficient.

3. Other Anomalous Events

There were two other events worth noting – the impact of the Net Interchange Scheduling Limit (NISL) on exports and imports, and an anomaly in the constrained sequence algorithm associated with dispatchable loads deviating from dispatch and consuming less than anticipated.

3.1 April 25, 2007 HE23 - A Case of a Binding Net Interchange Scheduling Limit

The Panel feels that an explanation of the events of April 25th, HE 23 would be helpful for participants in understanding the impact of a binding NISL on the DSO's import and export choices.

The NISL restricts the hour-to-hour net change in total intertie schedules across all interfaces into or out of the Ontario market. This constraint is intended to reflect the internal maximum generation ramp capability, up or down, to meet the change in intertie transactions. The business practice is that intertie transactions are ramped-in over ten minutes between one hour and the next. The difference in the intertie schedule between hours must be accommodated by internal generation ramping quickly enough to accommodate the change in net exports. Prior to the opening of the market, the agreed upon constraint was a net change of 700 MW which could be physically accommodated by internal generators.

Pre-dispatch Market Conditions

In HE 22, the pre-dispatch price was $64.15/MWh and the IESO imported 587 MW and exported 2,931 MW, implying a net export of 2,344 MW. The NISL for HE 23 was

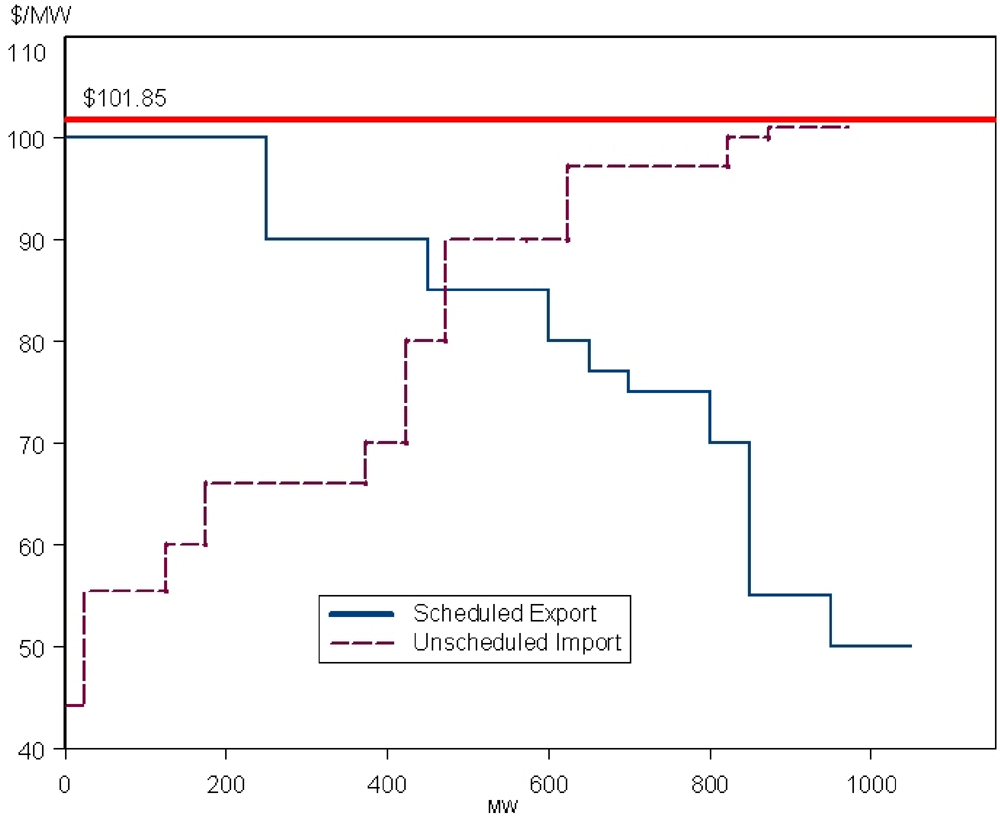
700 MW. That is, the net export could not be higher than 3,044 MW or lower than 1,644 MW.

For HE 23, about 900 MW of exports to Michigan and New York that had bid at a high price and been scheduled for HE 22 were not bid again in the market while all others were bid at the same price as for HE 22. The disappearance of the 900 MW of high priced exports by itself was enough to cause the NISL to bind since it allows only a 700 MW reduction in export. But there was another factor which also contributed to NISL being a limitation to efficient trade.

The pre-dispatch price for HE 23 was higher than HE 22 at $101.85/MWh, mostly as the result of a nuclear unit which shut down after HE 22. Except for the NISL restriction, the higher price should have discouraged exports and encouraged imports. In HE 23, 2,031 MW of exports were scheduled, of which 1,021 MW were scheduled out-of-merit. At the same time, 387 MW of imports were scheduled, but there were a further 973 MW offered below $101.85/MWh which were not selected. Had exports and imports been scheduled according to the $101.85/MWh pre-dispatch price, the net exports would have been (2,031 – 1,021) – (387 + 973) = 1,010 – 1,360 = -350 MW. This would have been almost 2,000 MW below the NISL allowed limit of 1,644 MW, which explains why almost 2,000 MW of exports and imports were scheduled in what appears as out of merit.

Figure 2-1 illustrates all exports that were scheduled with bids below the pre-dispatch price of $101.85/MWh and all imports that were offered at a lower price but not selected. Because the NISL was binding, an additional MW of import scheduled must be fully offset by an additional MW of export. The next highest priced export that was not scheduled in the hour was bid at $41/MWh, while the next cheapest import that was not selected was offered at $44.15/MWh. The DSO thus finds it optimal for not scheduling additional import/export; otherwise the market will lose $3.15 (=$44.15-$41.00) if an additional MW is scheduled.

Figure 2-1: Out-of-Merit Dispatch of Export and Import April 25, 2007 HE 23



Assessment

If a real-time price of $101.85/MWh was realized as projected by the pre-dispatch sequence, all those exporters with lower bid prices would have been worse off because the price that they would have to pay would have been higher than what they were willing to pay. Those importers not scheduled because of NISL were worse off not being scheduled, whatever the real-time price, since IOG would have provided them payments at least equal to their offer.

NISL is effectively a physical constraint on relating to collective generation capacity within the province that must be accommodated in the market place. At times such as HE 23, the DSO may make choices that are not in line with participants' costs and bids/offers. Given its potential to affect market outcomes, and having regard to the improved supply conditions documented in Chapter 1, it would be timely to review whether 700 MW is the appropriate magnitude for the NISL.

<u>Recommendation 2-2</u>

The Net Interchange Scheduling Limit of 700 MW has been in effect since the market opened. In the light of 5 years' experience with market-based trading, the NISL's potential to limit efficient trade and changes in both the number of generators and their combined ramp capability, the Panel encourages the IESO to review whether the 700 MW limit could be increased.

3.2 An Anomaly in the Load Predictor Affecting the Constrained Sequence Algorithm

The Ontario market runs two dispatch-scheduling sequences every five minutes in real-time - an unconstrained and a constrained sequence. In this section we explain how dispatchable loads consuming less than anticipated can lead to higher prices in the constrained sequence and inefficient outcomes. In the example drawn from February 2, 2007 there was an estimated $80,000 efficiency loss for the hour examined.

Because the constrained sequence is run to create ten-minute-ahead dispatches for each generator and dispatchable load, the IESO load predictor tool forecasts demand ten minutes ahead. This means that the nodal prices consistent with these dispatches are also based on a ten-minute ahead demand forecast.[33] While it is accepted that forecasted demand is always somewhat inaccurate, the Panel emphasized the benefits from reducing such inaccuracies to the extent possible. If a forecast error is induced by tool imperfection or market design flaws, the resultant dispatch is more likely to be inefficient. That is, high cost generators may be unnecessarily dispatched on and consumers with high values may be unnecessarily constrained off.

In the example outlined below, a decrease in the consumption of a dispatchable load caused an increase in the forecasted non-dispatchable load. This result seemed non-

[33] In addition to these different modeling assumptions between the two sequences, nodal prices also can differ from the MCP for a variety of other reasons identified in earlier reports.

intuitive in that consumption by a dispatchable load should not have an immediate or direct effect on consumption by other loads. With further investigation it was determined that this is an unintended consequence of the approach used to develop the forecast.

The Dispatch Scheduling Optimizer (DSO) calculates the forecasted non-dispatchable load and then solves the constrained sequence based on this non-dispatchable load. The problem arises because the forecast non-dispatchable load is derived from forecast total Ontario demand minus the actual dispatchable load, but the forecast of total Ontario demand is not immediately sensitive to the fluctuations of the dispatchable load. Because the DSO uses a smoothing approach (linear regression) to forecast total demand, a persistent change for dispatchable consumption will only gradually be seen after a few intervals although the forecast error due to the consumption discrepancy will eventually be removed.

HE 19 of February 2, 2007

In its daily review of market outcomes the MAU noticed an instance where a spike in the Richview nodal price occurred that did not seem to fully reflect supply/demand conditions. With help from IESO staff, the MAU identified an issue with the algorithm that is used to forecast demand for the constrained sequence.

In HE 19 on February 2, 2007 the Richview nodal price spiked up to more than $2,000/MWh. Table 2-7 provides summary information for the two hours HE 18 and HE 19. The Richview nodal price jumped above $1,000/MWh in the first three intervals of HE 19 from values below $100/MWh in HE 18. Market clearing prices which are calculated based upon actual demand stayed around $80/MWh. The highest Richview nodal price occurred in interval 4 of HE 19, about $1,949/MWh higher than the market price. What particularly drew the MAU's attention was the Richview nodal price suddenly jumping to $1,217.40/MWh in interval 1 of HE 19 from $219.80/MWh in interval 12 of HE 18, while the market price was lower than the previous interval (by $0.78/MWh).

Table 2-7: Summary Data for HE 18 and HE 19, February 2, 2007

		Constrained				Unconstrained			
Delivery Hour	**Interval**	**Richview Nodal Price ($/MWh)**	**Ontario Demand (MW)**	**Import (MW)**	**Export (MW)**	**MCP ($/MWh)**	**Ontario Demand (MW)**	**Import (MW)**	**Export (MW)**
18	**8**	36.76	21,163	1,074	1,119	35.28	21,343	905	1,069
18	**9**	44.62	21,242	1,074	1,119	35.89	21,448	905	1,069
18	**10**	81.75	21,400	1,074	1,119	64.16	21,549	905	1,069
18	**11**	85.95	21,550	1,074	1,119	64.16	21,693	905	1,069
18	**12**	219.80	21,908	1,074	1,119	78.05	21,742	905	1,069
19	**1**	1,217.40	21,768	855	1,529	77.23	21,616	855	1,429
19	**2**	1,299.90	21,823	855	1,529	83.67	21,739	855	1,429
19	**3**	1,299.90	21,794	855	1,529	77.54	21,659	855	1,429
19	**4**	2,026.94	21,783	855	1,529	77.23	21,617	855	1,429
19	**5**	2,000.00	21,729	855	1,529	77.23	21,612	855	1,429
19	**6**	1,255.01	21,788	855	1,529	77.54	21,637	855	1,429
19	**7**	287.76	21,857	855	1,529	64.16	21,480	855	1,429
19	**8**	99.21	21,712	855	1,529	77.22	21,556	855	1,429

At first it was assumed that a change in net export of 629 MW was the cause of the price spike. But, in examining the various constrained sequences prior to interval 1, the spike in the Richview shadow price was not forecast even though the constrained sequences reflected the large change in net exports. Table 2-8 illustrates the relevant information at each constrained run for interval 1 of HE 19.[34] Note the Ontario demand in Table 2-8 is slightly different from that in Table 2-7 because the demand here is the initial forecast used by the DSO while the demand in Table 2-7 is the final dispatch. The factors leading to the difference include adjustment to dispatchable loads and small generation deviation. The DSO uses a look-ahead approach and the first time included the dispatch for the interval was at 17:10. The look-ahead approach never had a Richview price greater than $200/MWh up to the last run (17:55). At the last constrained run, the tool forecast a 77 MW higher total demand (from 21,606 MW to 21,683 MW).

Also noted was the consumption change by dispatchable loads, which decreased by 113.6 MW (from 485.7MW down to 372.1MW) from 17:50 to 17:55. Based upon the

[34] The DSO constrained runs look-ahead up to 12 intervals. The reported data reflects different views of the look-ahead for HE 19 interval 1.

algorithm which determines demand (as described above) this led to an additional 113.6 MW increase in forecast non-dispatchable load. Together with the increase of 77 MW in total forecast demand for the last constrained sequence, the non-dispatchable load was consequently forecast to increase 190.6 MW. Given that at the dispatch time most ramping capability was exhausted due to a large increase in net exports (from a net export of 45 MW in HE 18 to 675 MW in HE 19),[35] the sudden increase of another 190.6 MW in demand drove the Richview price up to $1,217.40/MWh.

Table 2-8: Summary of Constrained Sequence Runs for Interval 1 of HE 19 February 2, 2007

Constrained Sequence Execution Time for Interval 1 of HE 19	Ontario Demand (MW)	Difference From the Previous Run	Richview Nodal Price ($)	Dispatchable Load Actual MW at the Execution Time (MW)
17:10	21,168	N/A	58.20	509.4
17:15	21,282	114	60.50	421.2
17:20	21,301	19	59.89	417.2
17:25	21,309	8	60.61	479.3
17:30	21,331	22	85.95	485.1
17:35	21,365	34	85.95	491.4
17:40	21,404	39	109.12	415.3
17:45	21,502	98	193.13	480.1
17:50	21,606	104	193.13	485.7
17:55	21,683	77	1,217.40	372.1

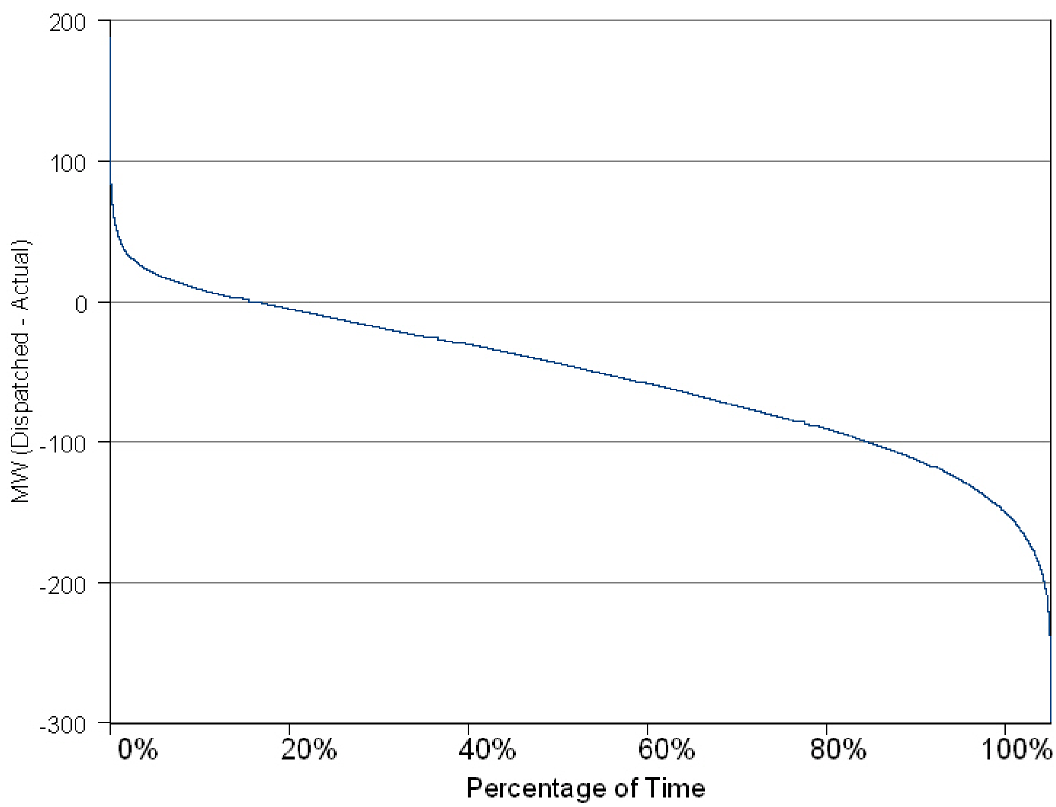
The Richview nodal price continued to stay at a high level in the following intervals as the non-dispatchable load was still high and the consumption of dispatchable load continued to be below expectation. The consumption deviation of dispatchable loads, in turn, continued to contribute to a higher forecast of non-dispatchable load and thus a high Richview nodal price.

[35] In the real-time dispatch, all import and export are ramped within two intervals: the last interval of the previous hour and the first interval of the current hour. This is also another significant difference between the pre-dispatch and real-time sequence: the pre-dispatch sequence assumes the change in import and export is ramped in an hour.

In this example the high shadow price led to constraining off dispatchable loads that were willing to consume power at a very high price. The IESO staff simulated that the Richview nodal price for HE 19 of February 2, 2007 would have been below $200/MWh had the double counting of non-dispatchable load not occurred. If the bid price of the constrained-off dispatchable loads reflects their true value of consumption, the lost efficiency (i.e. the difference between lost value to consumers and the cost of supplying those constrained-off energy) amounted up to $80,000 in the hour.

In other cases, the dispatchable loads may consume more than dispatched, leading to under forecast of non-dispatchable load and a lower nodal price. Figure 2-2 presents the duration curve of dispatchable load deviation (actual consumption minus dispatched quantity) for 2006. It can be seen that in about 17 percent of the time (intervals), the dispatchable loads as a whole consumed less than dispatched, and about 83 percent of the time more than dispatched, indicating that the formulation used by the DSO most often would lead to a lower shadow price, all else held constant.

Figure 2-2: Duration Curve of Dispatchable Load Consumption Deviation January to December 2006 (Dispatch – Actual Consumption)



The Panel's Comments

The example highlighted above illustrates how the Richview shadow price can be distorted by the design of the load predictor algorithm. The method for estimating non-dispatchable load causes an error in the forecast of total load. This in turn causes an incorrect dispatch. A distorted dispatch not only affects the transfer payments among market participants, but also, as illustrated in this example, can have a significant impact on market efficiency.

The Panel encourages the IESO to undertake further analysis of this issue. There may be no need to forecast the demand of dispatchable loads in real-time because they have already submitted bids into the market on an hourly basis which reflect their expected demand. The DSO has fully incorporated those bids into its dispatch algorithm. By using the forecast non-dispatchable load only, the constrained sequence could eliminate the distortion arising from the dispatchable load deviations and produce a more efficient dispatch as well as more representative nodal prices. We understand that the IESO is also working on a process to incorporate outages to dispatchable loads into its market tools. Such an upgrade to its outage tools would also enhance efficient dispatch.

> ***<u>Recommendation 2-3</u>***
> ***The Panel recommends the IESO should explore improvements to the load predictor tool to reduce forecast errors associated with sudden changes in dispatchable load consumption, and the resulting dispatch inefficiencies.***

Chapter 3: New Matters to Report in the Electricity Marketplace

1. Introduction

This chapter summarizes changes to the market and new analyses in the past six months. Section 2 reports on the updated status and analysis of issues raised in previous reports, namely, multiple ramp rates, efficiency gains from dispatchable loads, and the Day-Ahead Commitment Process (DACP) and its effect on certain reliability programs including the Day-Ahead Generator Cost Guarantee (DA-GCG), the Spare Generation On-Line (SGOL), and real-time IOG programs. Section 3 presents a new issue regarding segregated mode of operation.

In section 4 we examine the implications of nodal pricing on generator revenue in order to estimate if these could be sufficient to induce new generation investment. We look at the implied change using observed nodal prices to revenues for existing generators with contracts and regulated rates. Finally, we consider what the potential export-related efficiency benefits would be from nodal pricing.

2. Status of Matters Identified in Previous Reports

2.1 Multiple Ramp Rates in the Unconstrained Schedule

In previous Monitoring Reports we have described how the unconstrained sequence derives schedules and the corresponding energy prices assuming generation can ramp at 12 times its actual capability as specified in the offer data. This inherently leads to prices which are inconsistent with actual capability and dispatches thereby introducing an element of inefficiency into the market price.[36] The Panel has previously recommended using the actual (one times) ramp rate in the market schedule.

[36] For a detailed discussion, see the Panel's June 2004 Monitoring Report, pp. 63-66 and other references such as the December 2006 Monitoring Report, p.106.

In January 2007 the IESO approved a market rule change to be implemented on February 10, 2007 which specified that the ramp rate multiplier should be changed from 12 to 3. The Panel regards this as a positive directional change, although a 3 times ramp rate would still contain some of the inefficiencies noted above. The Association of Major Power Consumers of Ontario (AMPCO) applied to the OEB to review the market rule change, and the OEB stayed the implementation of the market rule change pending completion of its review, The OEB, after holding hearings into this question, rendered a Decision and Order on April 10, 2007 (corrected on April 12, 2007), concluding that the efficiency benefits that are anticipated to arise as a result of the rule change are consistent with the purposes of the *Ontario Energy Board Act, 1998*, and that the expected impact of the rule change on consumer bills is relatively modest.[37] AMPCO launched an appeal from the Board's Decision and Order to the Divisional Court of Ontario on April 27, 2007. This matter remains before the Court.

2.2 Efficiency Gains from Dispatchable Load Supplying Operating Reserve

There were only two dispatchable loads when the market started in May 2002. Since then a significant amount of additional load has chosen to become dispatchable. Typically, these loads are large industrial or commercial users who have a direct link to the IESO-administrated grid and can follow the IESO's dispatch instructions. Currently there are nine registered participants, with a total registered capacity of 709 MW, which account for less than three per cent of the annual energy consumption in Ontario.

In our December 2006 report,[38] the Panel pointed out the potential efficiency gains from the dispatchable load program. First, by bidding directly into the market, these participants can be dispatched based on the nodal price that reflects the incremental cost of supply at their location, thus promoting transparent dispatch efficiency. Second, these loads also offer operating reserves into the market at a lower cost than generating resources, often freeing the latter resources to produce energy. Hence, the combined

[37] OEB Decision and Order in proceeding EB-2007-0040. The OEB referenced the Panel's prior reports at pages 20, 21 and 22 of its decision.
[38] Refer to the Panel's December 2006 Monitoring Report, p. 130.

energy and OR demand in Ontario is met at a lower overall production cost. In 2006, 2.2 TWh of OR was scheduled from these resources.

In this report, the Panel quantifies the production cost savings arising from the ability of these loads to supply OR as noted above, which distinguishes them from other price responsive loads.[39] In this regard, the Panel suggests that any demand response programs that are operated by either the IESO or the OPA should encourage dispatchable loads that are capable of providing OR to do so.

During off-peak periods when demand is low and there are a lot of resources available for energy and OR, energy prices are generally lower. Since there is little opportunity for dispatchable loads to respond with energy reductions, any efficiency gained is only in the OR market. The efficiency gain is thus the cost saved by providing an amount of OR by dispatchable loads instead of from generation resources.

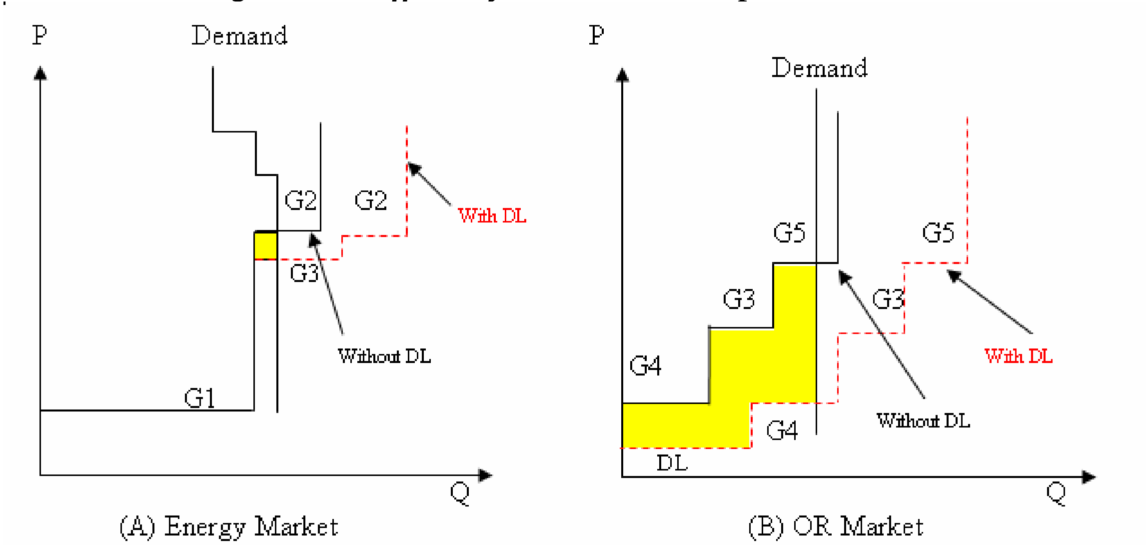
When demand is higher, measuring the efficiency gain is more complicated under conditions of joint optimization of the OR and energy markets. Efficiency gains in both energy and OR are more common during on-peak hours.

Figure 3-1 illustrates such an example. *G* represents a generator. DL represents dispatchable loads as a whole, that typically offer OR at a very low price. The dashed lines are offers (and schedules if they are on the left hand side of the demand curve) of generators and dispatchable loads in the energy market (in Panel A) and in the OR market (in Panel B) with dispatchable loads offering OR. The solid lines are offers (and schedules) without the OR offers by dispatchable loads. Generators G4 and G5 are not shown in the energy market for illustrative simplicity because they offer energy at a very high price. These generators are typically peaking hydro units who have a high opportunity cost to supply energy but a low opportunity cost to supply OR.

[39] The combined energy and OR market has seen other efficiency gains as well, for example on the supply side, we have seen steadily improved availability of nuclear and coal-fired generation since market opening.

Without dispatchable loads supplying OR, G2 is the marginal generator in the energy market, and G3, G4 and G5 supply OR. Although G3 has a lower offer price than G2 in the energy market, the DSO determines it would be cheaper to dispatch G3 for OR rather than energy. With dispatchable loads supplying OR, however, the OR supply curve is shifted to the right and G3 is freed up from the OR market. Consequently, G3 is now cheaper to supply energy than G2. In this case, the same amount of energy and OR demand is now met with a cheaper production cost; the cost saving is equal to the yellow (shaded) areas between the two supply curves in both markets. The yellow (shaded) areas are the efficiency gains due to the dispatchable loads that are able to supply OR. The majority of time, when the price is not high enough to back-down dispatchable loads (i.e. the demand curve is vertical at lower price levels since dispatchable loads bid much higher prices before they are willing to be dispatched down), the efficiency gain is equivalent to production cost saving.

Figure 3-1: Efficiency Gains Due to Dispatchable Loads



To approximate the total efficiency gains, the MAU ran a simulation based on the unconstrained algorithm for the year of 2006 by assuming no OR offers by dispatchable loads.[40] Because the unconstrained algorithm uses 12 times ramp rate and ignores most

[40] Due to the complexity of the constrained algorithm, it is impossible to run such simulation on a reasonably large scale to derive a meaningful conclusion.

physical constraints, it tends to understate the efficiency gains, particularly in cases when transmission lines are congested.[41] On the other hand, the simulation may slightly overstate the efficiency gains because it ignores any supply or demand behavioural changes which would reduce the impact of having less dispatchable load OR available. These two factors work in opposite directions and would tend to offset one another somewhat, suggesting the resulting estimate based on the unconstrained schedule is fairly reasonable.

Table 3-1 lists the estimated on-peak and off-peak efficiency gain in 2006 by month. In total, the provision of OR by dispatchable load brought about $7 million of cost savings to the market, of which most are for the on-peak period.

An important observation is that in freshet months such as in April and May when hydro resources are supplying energy and thus are unavailable to supply much OR, the efficiency gains due to the dispatchable program tend to be much higher than in other months. In these months the dispatchable load OR tends to offset more fossil OR. The efficiency gain in the second half of the year was significantly lower for two apparent reasons. First, as discussed more fully below, some dispatchable load migrated to the OPA's demand response program, preventing their participation in the OR market from August on. Second, lower inflows reduced available water to hydroelectric generators and thus their energy capability in the latter part of the year freeing up more of these hydroelectric resources to provide OR.

[41] See section 2.1 in this chapter for an update on the pending market rule change to fix the ramp rate multiplier at 3 times as opposed to the current application of the 12 times multiplier.

Table 3-1: Estimated Total Cost Savings Due to Dispatchable Load Being Able to Offer OR January to December 2006 ($ Thousands)

	Off-Peak	On-Peak	Total
January	107	555	662
February	113	414	527
March	135	600	735
April	795	1,359	2,154
May	353	1,127	1,480
June	53	108	161
July	68	66	134
August	19	138	157
September	25	31	56
October	21	149	170
November	52	345	397
December	116	305	421
Total	1,857	5,197	7,054

In our previous report we noted that one dispatchable load ceased offering OR in mid-September 2006 after it had migrated from the dispatchable load program to the OPA's Demand Response program. In past, the load had offered 40 to 80 MW into the OR market, depending on its consumption at the time, but no longer did so once it began participating in the Demand Response program. The MAU ran a simulation for the period of September 2006 to April 2007, assuming the load had offered OR following its historical pattern. The simulation result is shown in Table 3-2. In total, the estimated efficiency loss to the market due to the loss of this dispatchable load amounted to $82,000 during this 8-month period. Once again, most efficiency loss was in the freshet months, when the supply of OR was costly.

Table 3-2: Estimated Efficiency Loss Due to a Loss of One Dispatchable Load, September 2006 – April 2007 ($ Thousands)

	Efficiency Loss
Sep-06	1
Oct-06	5
Nov-06	5
Dec-06	6
Jan-07	17
Feb-07	18
Mar-07	11
Apr-07	18
Total	82

Although the efficiency loss due to the migration of this single dispatchable load was relatively small during this period, it could have implications on other existing dispatchable loads and other loads that may become dispatchable in the future. For example, we understand that another load that was planning to become dispatchable in 2006 did not do so because it was accepted into the OPA Demand Response program.

We have been advised that there are discussions under way between the IESO and the OPA towards a better coordination of the demand response and dispatchable load OR programs. This might allow dispatchable loads to offer OR when they are not reducing load under the Demand Response program. Similar to our recommendation in our last Panel report we encourage such coordination as a means to improve market efficiency.

<u>Recommendation 3-1</u>

The Panel encourages the IESO and OPA to continue to improve coordination between dispatchable load and demand response programs in order to promote the efficient use of dispatchable loads' OR capability.

2.3 Day-Ahead Commitment Process

There are two dimensions of reliability as defined by NERC – security and adequacy. Security is 'the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements." Adequacy is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

Programs aimed at improving reliability typically provide suppliers with certain financial benefits or guarantees to limit their financial risks if their resources are committed pursuant to the program. As one might expect, the provision of such benefits or guarantees can change the supplier offer behaviour and may also affect dispatch efficiency.

The Panel believes that a reliability program should only pay market participants up to the value that it adds to system reliability. A program is efficient if the incremental cost for the services provided by the program is equal to the incremental benefits to system reliability.[42] As long as the benefit from improved reliability outweighs the efficiency loss, the program provides an overall improvement to the operation of the market.

Following a sustained period of extremely challenging operation in summer 2005, the IESO introduced the Day-Ahead Commitment Process (DACP) on June 1, 2006 to enhance reliability.[43] The intent of the program was to ensure that sufficient resources have been committed day-ahead to meet Ontario's forecast demand. The DACP schedules both imports and domestic generation day-ahead in the constrained pre-dispatch schedule, and offers a guarantee to keep the importer or generator whole provided they are committed via the DACP and actually deliver the energy. The

[42] For more information on the use of cost-benefit analysis generally and in the context of other aspects of the IESO's work, see the report commissioned by the IESO titled "*Overview of Cost-Benefit Analysis and its Applications in Public Policy Decisions*", by M. Trebilcock, A. Yatchew, and A. Baziliauskas, CRA International, June 2007 available at: http://www.ieso.ca/imoweb/pubs/consult/mep2/MP_WG-20070607-Overview-of-Cost-Benefit-Analysis.pdf.
[43] For a more detailed description, refer to the Panel's December 2006 Monitoring Report, p. 120.

guarantees provided to both importers and domestic generators are effectively a reliability premium similar to the real-time import offer guarantee.

While our last report provided some information on the DACP program, its use in that reporting period was limited and we asked the MAU to continue to review the effects of the program in the IESO-administered markets. This section provides a further assessment of the market impacts of the DACP.

Table 3-3 indicates that, since its implementation, the DACP has paid generators $20.3 million for Day-Ahead Generator Cost Guarantees (DA-GCG) and importers $9.3 million for Day-Ahead Intertie Offer Guarantees (DA-IOG). The payments in the first five-month period (June 2006 - October 2006) after its inception were much lower than the payments in the subsequent six months (November 2006 – April 2007), suggesting that as market participants became more familiar with the program, total payments may be increasing. On average, the cost of the two types of DACP payments for reliability during November 2006 – April 2007 was $0.24/MWh, a $0.10/MWh increase compared to June – October 2006. In the same 11 month period payments for real-time IOG were $27.5 million (see Appendix A-51), or about three times as much as for DA-IOG. This indicates that imports are attracted more to real-time prices than the day-ahead prices.

Table 3-3: DA-IOG, RT-IOG, and DA-GCG Payment
June 2006 – April 2007
($ Millions)

	DA-IOG	DA-GCG	Total	Average $/MWh
Jun 06 - Oct 06[44]	1.9	7.7	9.6	0.14
Nov 06 - Apr 07	7.3	12.7	20.0	0.24
Total	9.3	20.3	29.6	0.20

Prior to the introduction of the DACP, the IESO had concerns about generators not being on-line when needed. The IESO was also concerned that other ISOs (e.g. NYISO)

[44] Note, the DACP commenced June 1 2006, so the initial period covers only 5 months.

assigned lower transmission priority to imports to Ontario when these were only scheduled an hour ahead.[45] The DACP addresses both issues:

1. Large fossil generators typically take many hours of preparation to be able to operate. The DACP provides generators a better signal about when they should start-up as well as a cost guarantee (DA-GCG) if their revenues from the real-time market are insufficient to cover their total costs to run the unit. There are currently four participants registered in the program, with 27 fossil units and a total capacity of 2,071 MW (573 MW of gas and 1,498 MW of coal) that are eligible for the DA-GCG.

2. The DACP provides day-ahead imports with a day-ahead guarantee (DA-IOG) for energy delivered – in the event that the real-time price drops below the importer's day-ahead offer price. Being scheduled day-ahead allows importers maximum flexibility to schedule themselves in neighbouring markets and to purchase transmission service that is more firm than hour ahead service. Importers receiving the DA-IOG are subject to a financial charge if they do not deliver the chosen MW as scheduled.

The IESO did not establish specific quantitative measures (such as a potential reduction of unsupplied energy) for the reliability improvements sought or expected from DACP, but did identify goals such as the ability to schedule imports day-ahead, the lowering of import failures and the scheduling of sufficient internal generation day-ahead to meet demand requirements. Given that DACP forecasts hourly OR requirements and peak hourly Ontario demands, the total day-ahead scheduled supply is sufficient to satisfy forecast domestic requirements in all intervals of the next day.

[45] For supporting material, see the IESO's "Day-Ahead Commitment Process Design" webpage at: http://www.ieso.ca/imoweb/consult/consult_isr.asp

2.3.1 Day-Ahead Generator Cost Guarantee

The cost guarantee allows a generator to recover its production costs to its minimum loading point (MLP), its start and speed-no-load costs plus its variable operating and maintenance costs (O&M) for its minimum run-time.[46] While most of the guarantee components are similar to that of the real-time Spare Generation On-Line program (SGOL) (discussed in an earlier Panel report,[47] as well as in the next section 2.3.2 of this report), variable O&M is not included in the SGOL. Thus, if a generator believes it will commit its facility in real-time and has a risk it may not fully recover its costs from the market, the variable O&M component of the DA-GCG provides an incentive to be committed day-ahead.

Actual generator costs are submitted by the participant two days after the fact and do not have to be reflective of the participant's offers in DACP. In turn the IESO determines revenue that the generator received and compares it to its submitted costs. Any deficiency is paid out to the generator and is recovered as a monthly uplift payment from load.

During the current reporting period, the MAU observed that, as a result of the present self-commitment structure where the cost guarantee is independent of a generator's energy offer in the wholesale market, a generator has little or no risk being online and thus has incentives to underbid its marginal cost in order to be scheduled in the DACP. To be eligible to obtain the DA-GCG, the IESO's manuals are explicit that a generator must be scheduled to its minimum in all hours of its minimum run-time. Unless the unit perceives that it will be inframarginal in all hours, it would have an incentive to bid below incremental cost in DACP to ensure it is scheduled.

[46] The IESO's Market Manual No. 9 stipulates that if a DA- GCG eligible generator is scheduled in the Pre-dispatch of Record to at least its registered minimum loading point and registered minimum generation block run-time it is eligible for the cost guarantee.
[47] December 2006 Monitoring Report, p. 120.

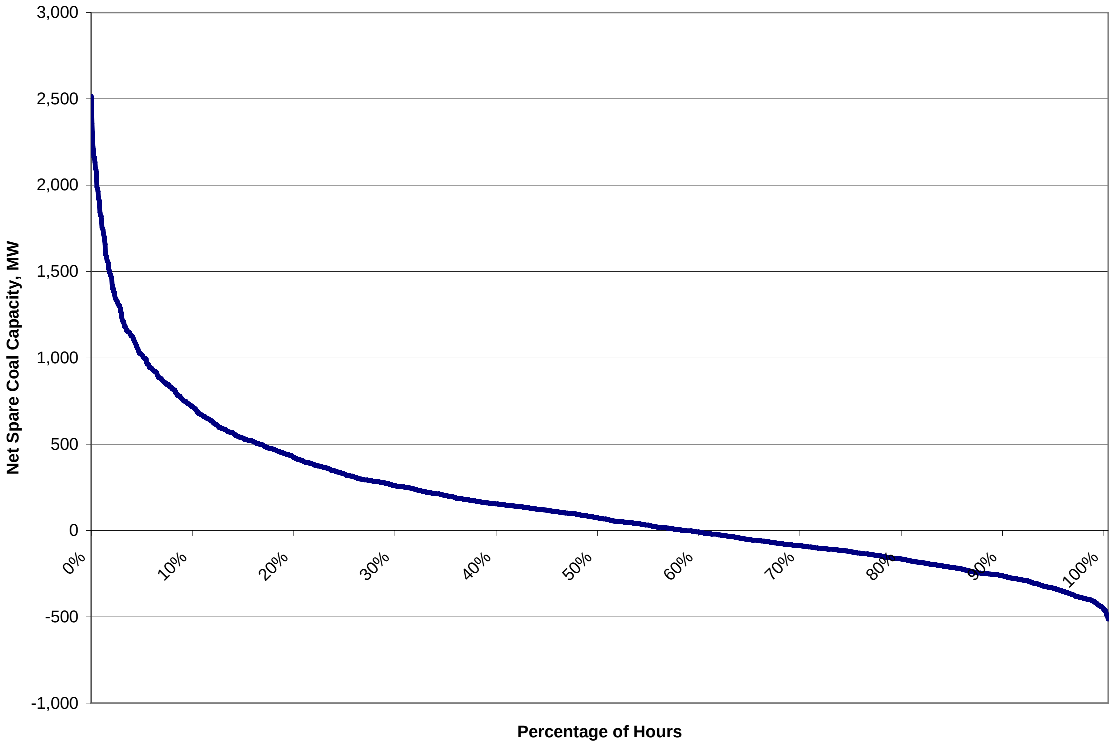
This incentive to gain the variable O&M guarantee motivates behaviour which diverges from basing offers on incremental cost. It also appears this incentive leads to two potential sources of over-payment of the reliability premium:

- A generator may come online earlier than needed and receive payments to cover its start during low-priced hours. As the claw-back is restricted to the revenue accrued over the generator's minimum run-time, it is free to keep all the benefits from higher prices in later hours. The efficiency loss depends on the magnitude of the minimum loading point and the marginal costs of the unit relative to the displaced generation (usually coal-fired generation).

- A generator may come online even when there is no reliability problem simply to hedge its risk of being required in real-time. If it believes it may be required, being scheduled in DACP makes it eligible for the DA-GCG including the variable O&M component. The total cost in this case is higher, since it includes the cost of an additional unit start-up and the higher incremental costs for the unit. For example, an extra gas-fired unit may be started even though there was sufficient committed (lower cost) coal capacity to meet Ontario demand.

The MAU has estimated how much coal capacity was unused when one particular large gas-fired generator was committed on many days through DACP for the period of June 2006 to April 2007. Figure 3-2 depicts the duration curve of the hourly net spare coal capacity which is the difference between spare capacity of coal units and the output of the gas-fired station for the MRT (Minimum Run Time) when the latter was on the DACP schedule. The MRT is chosen because efficiency loss is most likely to occur during these hours. A positive MW indicates that there was still sufficient coal capacity to meet demand even without the gas-fired station, while a negative number implies there was not sufficient coal capacity to meet the demand and thus the gas fired station was needed. Although the results are not conclusive, 60 percent of the time there was spare coal online in excess of the gas-fired gas production, suggesting much of the gas-fired generation was not needed for reliability.

Figure 3-2: Duration Curve of Hourly Net Spare Coal Capacity On-line June 2006 to April 2007



To assess how much dispatch efficiency was lost in that 60 percent of time, the MAU assumed a heat rate of 7,000 Btu/KW and a variable O&M cost of $3.07/MWh for the gas station, consistent with the assumptions that were made in our June 2005 report.[48] Based on the offer price of coal units and the spot Henry Hub gas price, the MAU estimated that the efficiency loss may have amounted to $6.3 million.[49]

The IESO believes that the DACP has significantly enhanced reliability within the Ontario market and will be continued until such a time as some other program is

[48] See the Panel's June 2005 Monitoring Report, p. 42.
[49] The estimated efficiency loss is the output of the station times the difference between the incremental cost of the station (the heat rate times the gas price plus the O&M costs) and the offer price of coal units. Because the estimation ignores the transportation cost and other costs, the incremental cost of the station is understated and thus the true efficiency loss is likely understated.

developed that provides at least equivalent reliability benefits.[50] The Panel's understanding is that the DACP was intended as a transitional program in advance of a full day-ahead market. The Panel has emphasized the importance of a well designed day-ahead market, which would provide better price signals and would reduce the need for other real-time reliability programs.[51] A significant difference between the DACP and a day-ahead market is that a generator can opt out of its DACP schedule without any financial consequence, while under a day-ahead market with two settlements (day-ahead and real-time), a generator would face financial consequences if it fails to deliver power as scheduled day-ahead. As a result, a day-ahead market should provide better incentives and allow the desired level of reliability to be obtained more efficiently.

The Panel believes that reliability should be provided with minimum cost and should not significantly interfere with dispatch efficiency. Until the implementation of a day-ahead market, changes in the DACP could be adopted that would continue the reliability benefits of the DACP while reducing the reliability premium associated with the program. When the IESO is making day-ahead commitments, it bases selections on the generators' and importers' DACP offer prices. However, a large portion of generators' costs are not transparent and are not taken into account in the DACP commitment decision, rather they are paid after the fact via guarantees. It would appear that a more active management of the DACP process by the IESO could reduce reliability premiums and improve efficiency while retaining reliability.

As an alternative to the present one-part bid auction in the DACP, with the DA-GCG cost exposures not being accounted for in the commitment decisions, it may be more appropriate to utilise a commitment process similar to that undertaken in the NYISO in its day-ahead market. In the NYISO DAM, generators offer a three-part bid, which consists of an energy component, start costs and speed-no-load costs as well as a generator's minimum run-time. In determining commitment the NYISO DAM also uses a 24 hour optimisation to maximize the total benefit over the entire day taking into

[50] See the IESO's "Day-Ahead Commitment Process Recommendation" to its Board of Directors, October 18, 2006.
[51] See the Panel's March 2003 Monitoring Report, p. 95.

account the four factors just mentioned. As an example, the optimisation may at times decide it is more efficient to purchase a higher priced import for a shorter period of time than to actually start a unit for its MRT and incur the total cost of such a commitment decision. At other times it may decide to commit a generator for its MRT and in doing so not choose a cheaper hourly import. Such a process in the IESO DACP, in which all costs are understood at time of commitment, should allocate resources more effectively and reduce uplifts associated with reliability.

A potential interim alternative until the implementation of a three part bid would be for domestic generators to submit information on the magnitude of costs that will be submitted for a DA-GCG when making DACP offers. The IESO in turn would determine a schedule that provides the desired level of reliability at least cost.

> ***Recommendation 3-2***
> ***The Panel recommends the IESO review the DACP in order to reduce the costs and improve the effectiveness of the Generator Cost Guarantee. Three-part bidding with 24 hour optimization, similar to the NYISO methodology, may be one such approach. We further recommend as an interim alternative that the IESO consider mechanisms which allow the full magnitude of domestic generator costs to be taken into account in DACP scheduling decisions.***

2.3.2 Spare Generation On-line (SGOL)

The SGOL program was launched by the IESO in August 2003 as a result of generators typically pricing at average avoidable cost and thus not being committed at times when the system faced a large disturbance. These generators are typically fossil generators who have a lengthy start-up time and large costs to commit to come online. Although these generators are available to the market, they are not online at the time of the disturbance and therefore not in a position to be dispatched with short notice. The SGOL provides incentives to these generators to be online when the profit opportunity is marginal at best.

Similar to DA-GCG, SGOL generator costs are submitted by the participant two days after the fact and do not have to be reflective of the participant's offers in the SGOL. In turn the IESO determines revenue that the generator received and compares it to its submitted costs. Any deficiency is paid out to the generator and is recovered as a monthly uplift payment from load.

While SGOL is a real-time program with a design similar to the DACP, there are two key differences between the programs:

1. the DACP provides variable O&M cost guarantees, whereas SGOL does not; and
2. a generator must be scheduled in consecutive hours for at least its minimum run time (perhaps 8 hours or more) to be eligible for DA-GCG, while in SGOL a generator is eligible for a cost guarantee for its minimum run time as long as it is pre-dispatched in one *single* hour.

Table 3-4 indicates that, since its implementation, the SGOL has paid generators over $67 million. Monthly data can be found in Statistical Appendix A-51. In the first eight months of operation, the period September 2003 – April 2004, the average cost of the SGOL programs was only $0.07/MWh of Market Demand, but it increased significantly to $0.16-$0.19/MWh in the following two years. This was mainly due to a generator with a long MRT and a large MLP that came in service during this period.

Table 3-4: SGOL and DA-GCG Payments, September 2003 - April 2007
($ Millions and $/MWh)

Period	SGOL		DACP[52]		Total	
	$ Million	$/MWh	$ Million	$/MWh	$ Million	$/MWh
September 2003 - April 2004 (8 months)	7.09	0.07	N/A	N/A	7.09	0.07
May 2004 - April 2005	26.20	0.16	N/A	N/A	26.20	0.16
May 2005 - April 2006	31.60	0.19	N/A	N/A	31.60	0.19
May 2006 - April 2007	2.66	0.02	20.31	0.13	22.97	0.14
Total	67.55	0.11	20.31	0.13	87.85	0.15

With the implementation of the DACP, generators have shifted substantially towards the DA-GCG instead of the SGOL, as can be seen from the most recent year's payments in Table 3-4. If a generator believes it may be required in real-time, the DA-GCG is the more attractive program because the generator can be compensated for its variable O&M.

Given its similar structure to the DACP, with actual costs provided after the fact and not factored into incremental dispatch decisions, we have similar concerns regarding the efficiency impacts for the SGOL as discussed for the DA-GCG. In addition, the programs overlap significantly in that there could be multiple starts on a given day and payments under each program. Any re-design of the DACP to improve its efficiency should also include a review of the present SGOL program.

Recommendation 3-3

In parallel with the recommended review of the DA-GCG, the Panel believes that it would be useful for the IESO to review the interface between the SGOL and DA-GCG as well as mechanisms for considering the full amounts of SGOL cost reimbursements in scheduling decisions.

[52] Note, the DACP commenced June 1, 2006, so total payments and payments per MWh are for the 11 month period.

2.3.3 Real-Time and Day-Ahead Intertie Offer Guarantee

The real-time IOG was implemented at market opening, to encourage energy imports, "to help maintain the reliability of the IMO-controlled grid". The IOG guarantees that importers "will always be kept financially whole by being settled at their offer as a minimum".[53]

Since market opening, the real-time IOG has been continuously dropping except for the extreme conditions in 2005. Table 3-5 provides the on-peak (hours 6 to 22), off-peak (hours 1 to 5 and hours 23 to 24) and total real-time IOG paid by the IESO for the five years since the market opened.

Table 3-5: Peak and Off-Peak Real-Time IOG
May 2002 – April 2007

Period	On-Peak (HE 6-22)		Off-Peak (HE 1-5, 23-24)		Total	
	$ millions	$/MWh	$ millions	$/MWh	$ millions	$/MWh
May 02 – April 03	242.7	2.04	11.8	0.29	254.5	1.59
May 03 – April 04	40.9	0.35	10.4	0.26	51.2	0.33
May 04 – April 05	26.9	0.22	4.5	0.11	31.4	0.19
May 05 – April 06	62.8	0.50	12.1	0.28	74.9	0.44
May 06 – April 07	26.8	0.22	4.5	0.11	31.3	0.19
Total	400.1	0.66	43.3	0.21	443.4	0.54

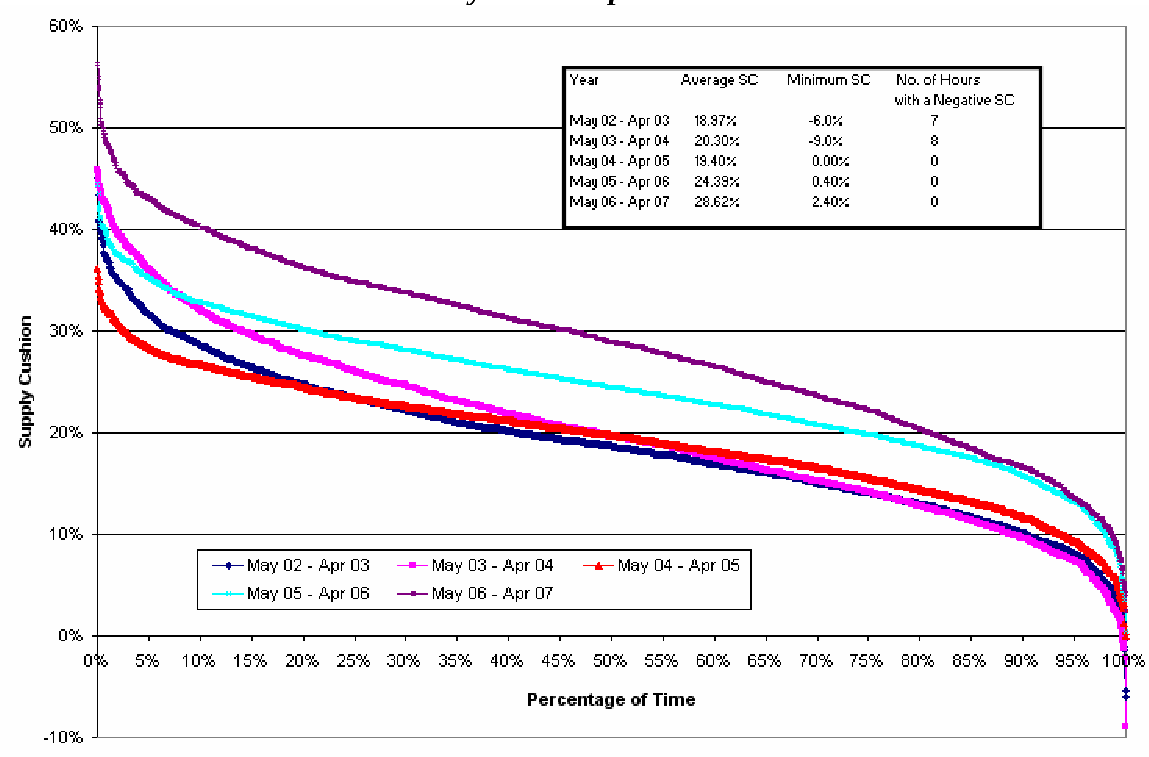
The total IOG payments have been as high as $254.5 million in May 2002 – April 2003 and as low as $31.3 million in May 2006 – April 2007, for a total across all years of $443.4 million. About 10 percent ($43.3 million) was paid for imports during night-time hours.[54] Although the total IOG is decreasing, the Panel still questions whether the IOG paid for off-peak hours is necessary given the large total supply cushion typical of off-peak hours.

[53] Rule Amendment MR-00177.
[54] The total does not include a relatively small corresponding adjustment due to CMSC which can be negative when a constrained off import receives IOG.

By way of comparison, DA-IOG payments in the 11 months ending April 2007 were identified in Table 3-3 as $9.3 million which is only $0.06/MWh in that period, about one-third the magnitude of the corresponding RT-IOG payments. The majority of imports are still first scheduled in pre-dispatch, which appears to be more attractive for imports because of the higher market demand and prices induced by the inclusion of exports in pre-dispatch but not in the DACP.

Figure 3-3 plots the average duration curves of the real-time domestic supply cushion for HE 23 to HE 5 by year. The improving market supply conditions are reflected in the improving supply cushion data. In May 2002 - April 2003 and May 2003 - April 2004, there were 7 or 8 hours each year in which the off-peak domestic supply cushion was negative, implying imports were necessary to meet the Ontario demand in these hours. However, since May 2004 there was not a single off-peak hour with negative supply cushion, implying imports were not needed to meet Ontario requirements. The domestic market supply condition has significantly improved to the point where it appears that an off-peak IOG may no longer be required.

Figure 3-3: Yearly Duration Curves of Real-Time Off-Peak Domestic Supply Cushion May 2002 – April 2007



In our June 2004 Monitoring Report, the Panel noted the persistently high IOG payments made to importers during the delivery hours from 22 to 24.[55] The Panel raised concerns that:

1. the IESO over-forecasts demand in these hours;
2. pre-dispatch to real-time price differences induced increased exports and imports which did not improve market efficiency but did increase payments from load to traders; and
3. the IOG payment was not performing its intended role in these hours (i.e. the market may be paying more for this 'insurance policy' than it should be).

While the first two concerns have diminished because of forecasting changes implemented by the IESO, the last concern still applies at least for HE 23 and 24 and HE 1 to 5.

[55] June 2004 Monitoring Report, pages 69-82.

While the IESO has not articulated a benchmark for assessing the magnitude and benefits of reliability, the data suggest that the overnight premiums being paid may not be warranted since there does not appear to be a need to guarantee the availability of imports during these time periods.

Recommendation 3-4
The Panel recommends the IESO review off-peak conditions to determine if the RT-IOG and DA-IOG programs are providing an improvement in reliability commensurate with the payments being made. The IESO should consider discontinuing off-peak IOG payments where these no longer appear to provide corresponding reliability benefits.

3. New Matters to Report

3.1 Segregated Mode of Operation

Some hydroelectric facilities in Ontario have the ability to switch from the IESO grid to the Quebec grid. Some Quebec facilities have a similar capability. This is referred to as Segregated Mode of Operation (SMO). That is, the generating stations can be connected or disconnected to either jurisdiction when approved by the IESO and the Quebec transmission operator. Within the IESO system, SMO operation by an Ontario facility is not technically considered an export from the Ontario market as no bid or offer is associated with SMO within the DSO. However, when Quebec generating units are switched onto the Ontario grid, these generators offer into the Ontario market as imports.

To indicate its intention to operate in SMO, the owner of an Ontario facility simply submits a request no earlier than 12:00 on the pre-dispatch day and no later than 2 hours prior to the start of the first dispatch hour to which such a request pertains. Unless the IESO determines that such action will pose a risk to internal reliability, SMO will be allowed. Typically, Ontario generators operate in the SMO during off-peak hours when Ontario prices are usually low and there is no internal reliability issue.

During November 2006, SMO also occurred in on-peak hours, with approximately 400 MW shipped in off-peak hours and up to 240 MW in on-peak hours. At certain times when on-peak SMO transactions were occurring, the SMO facility owner was also importing on other interfaces and occasionally receiving a real-time Intertie Offer Guarantee (RT-IOG) payment for the imports.

An import with a coincident export is considered to be an 'implied wheel'. At the onset of the market an urgent rule was put in place to eliminate RT-IOG payments for implied wheels, because Ontario received no benefit from the net effect of such activity. RT-IOG payments are made to enhance reliability by removing the risk to importers of HOEP being lower than the pre-dispatch price, but when power is cycled in and out of Ontario the risk does not exist since the lower HOEP reduces the payment for the export. The RT-IOG offset rule simply reduces an importer's RT-IOG payment by the amount of its exports in the same hour.

The market rules currently do not view SMO as an export because there is no bid to buy MW from the Ontario market. When drafted, the RT-IOG offset rule was specific in referring to offers and bids. In this particular case, since the SMO is not considered to be an export, the RT-IOG is not offset by the amount of energy shipped outside the province in SMO.

It is simply a peculiarity of the rules that transfers from Ontario to Quebec under SMO are not deemed to be exports against which imports by the same market participant would be off-set. On other Ontario – Quebec interfaces where SMO is not used and offers/bids are made, RT-IOG off-sets are implemented when implied wheels occur.

The payments tracked so far are relatively small and the Panel has no reason to believe that this anomaly in the rules has intentionally been exploited by market participants.

We have referred this matter to the IESO market rules group for consideration of whether this apparent inconsistency in the treatment of market participants with SMO facilities should be corrected by a market rule amendment.[56]

Recommendation 3-5

The Panel recommends the IESO review the treatment of energy exported through Segregated Mode of Operation with a view to including this energy in the determination of RT-IOG offsets for implied wheeling.

4. *Implications of Nodal Pricing on Revenues and Efficiency*

This section is relatively long and detailed but its purpose is simple. We have long advocated moving from the current uniform price system to some form of locational pricing as a spur to economic efficiency and market-based investments in generation capacity at relatively low cost to consumers. We use available data to examine whether a shift to nodal pricing – one form of locational pricing - would bring efficiency benefits to Ontario and create incentives for investment. Like most projections of future market outcomes, we cannot be definitive because of the assumptions and limitations of the model. Nevertheless, the analysis suggests that both allocative and dynamic efficiency benefits are available with some nodal prices falling and others rising relative to the present notional levels as consumers and suppliers adjust to this new reality.

Section 4.1 examines notional dynamic efficiency by performing the net revenue analysis, the Panel has traditionally undertaken, but this time using the nodal (shadow) prices generated in the IESO's constrained schedule (instead of the HOEP as employed in previous reports and in the present Chapter 1). It appears that the revenue from observed

[56] Market Rules, Chapter 9, section 3.8A.3

nodal prices would be sufficient to justify new capacity investment in various locations – i.e. a positive impact on dynamic efficiency.

Next, section 4.2 takes the analysis a step further by comparing our estimate of the current revenue of existing generators, adjusted for the OPA contract terms and regulated prices ('regulated prices' is the shorthand term for OPG's prescribed and non-prescribed assets revenue), with the potential revenues implied by the observed nodal prices. This allows us to estimate the potential impact on the final prices to consumers if observed nodal prices were paid, which appears to be an increase of well under $1/MWh (without adjusting for any price reductions that may occur after new capacity comes on-line).

Finally, section 4.3 considers one particularly notable type of allocative efficiency gain by estimating the likely change in exports to the New York market as a result of changing from the uniform price system to a nodal pricing regime. These efficiency gains can come from lowering exports at times to reduce inefficient exports or increasing exports at other times to take advantage of efficient opportunities that are currently being missed.

4.1 Net Revenue Analysis using Observed Nodal Prices

4.1.1 Background

Previous MSP reports include an analysis of net revenues, which are revenues a generating plant could have earned after all associated variable fuel, operating and maintenance costs are covered. Revenues for this analysis are assumed to arise from the energy market only and are based on the Hourly Ontario Energy Price (HOEP).[57] Yearly net revenue persistently below the annualized investment and fixed costs puts significant

[57] There are other possible opportunities for generators to receive revenue from Ancillary Services or CMSC but these are estimated to provide relatively little additional net revenue. Fossil generation only supplies a small portion of the operating reserve, so would receive little revenue for that. For other ancillary services, payment tends to be close to costs with limited opportunity for contributions to net revenue. We also do not attribute any additional net revenue for CMSC payments. Since offers normally reflect incremental costs, when constrained on there would be little or no contribution to net revenues; theoretically the CMSC payment would just cover costs. Constrained off payments are already assumed by attributing net revenue whenever HOEP exceeds the marginal costs, independent of a generation unit being constrained off. Net revenues for all these are small and excluded from this analysis. On a system-wide basis ancillary service, must-run contract and CMSC payments are on the order of $250 million annually, or about 3 percent of total energy payments.

financial pressure on existing generation and discourages entry of new generation into the electricity market. A persistent net revenue shortfall may indicate that the market is not functioning properly or that other factors outside the market are in play. In contrast, yearly net revenues persistently above the annualized investment and fixed costs should attract new investment and in turn put a downward pressure on market prices.

To date, our findings in several previous Monitoring Reports,[58] and again in Chapter 1 of this report, suggest that net revenues earned by a hypothetical new generator under the existing uniform price (HOEP) regime, would not be high enough to recover the fixed costs of building a new plant. In this chapter, we perform a similar analysis but assume that generators face nodal prices. The observed Richview nodal price is substituted for the HOEP as an initial measure of net revenue. The Richview nodal price is chosen because it is located in Toronto, which is the central load area in Ontario, and new capacity investment would most likely take place in the Toronto area. Our analysis suggests that, everything else being equal, average yearly net revenue from observed nodal prices would be high enough to justify new capacity investment by combined cycle and combustion turbine generators in this area. We then extend the analysis to the ten standard Ontario zones that are delineated by the IESO and obtain similar results in several of the zones.

The analysis in this section looks at implied generator revenues based on observed nodal prices, without any adjustments for contract or regulated prices. As such these results really only apply to those current or new generators without contracts. The subsequent section, System Revenue Analysis for Existing Generation, deals with existing generation in aggregate accounting for any contracts or regulated prices.

It should noted that this analysis ignores the possibility that market participants may offer and bid differently if paid or charged nodal prices. The changes in behaviour would likely lead to more efficient decisions. This is turn would likely decrease the resulting

[58] E.g., December 2006 Monitoring Report, pages 61-65

nodal prices where they are higher than HOEP and reduce the revenue to generators in most cases.

4.1.2 The Model

We use a standardized model developed by the Federal Energy Regulatory Commission of the United States (FERC) for comparison across markets, which is also the basis for the net revenue analysis in Chapter 1 using HOEP. The model specifies two types of potential entrants: a highly efficient combined cycle plant with a heat rate of 7,000 Btu/KWh and a less efficient combustion turbine plant with a heat rate of 10,500 Btu/KWh. The estimated variable operating and maintenance cost is $1.10/MWh for the combined cycle and $3.30/MWh for the combustion turbine.[59] For both types, we assume an outage rate of 5 percent[60] and apply the price limit of $2,000 to the reported nodal price corresponding to the limit for HOEP.

Unit variable cost is the assumed heat rate times the daily spot price of natural gas at Henry Hub plus the assumed operating and maintenance cost. The use of a spot fuel price tends to overstate the net revenue because transportation and distribution costs are ignored.[61]

The Richview price is more representative than HOEP of the marginal cost of meeting demand in the major load centre near Toronto. The Richview price would reflect the higher costs induced by congestion (which bottles supply in some areas) and transmission losses (which significantly reduce the energy delivered from the northern parts of Ontario). Since no generators or intertie traders receive the Richview price under the

[59] FERC assumes US$1/MWh for the more efficient unit and US$3/MWh for the less efficient one. (For details, see 2004 State of the Markets Report, Docket MO05-4-000). To translate the numbers to Canadian dollars, we presume an exchange rate of US$1=CDN$1.10. This may be high relative to the last 5 years but is in line with current exchange rates. With a stronger US dollar such as US$1=CDN$1.20, variable costs would equate to $0.10 and $0.30 higher, which would not change the net revenue results materially.

[60] This is based on the previously referenced FERC assessment. It is representative of the forced outage rate of a relatively new generating unit. Planned outages are assumed to be taken at times when the unit is not likely to be economic.

[61] One component of cost excluded here is the transportation cost as represented by the difference in price at the Henry Hub and the closer Dawn Hub. It typically represents less than $1 to $2/MWh difference.

current uniform pricing system and the Richview price does not take into account the price responsiveness of supply and demand, using the Richview price currently tends to overstate the revenue that a potential entrant may receive. As a result, estimates based on the Richview shadow price may only provide an upper bound for net revenues. To capture the effect of lower nodal prices in other parts of the province we also provide similar calculations for ten zones across the province, including those where observed nodal prices were much lower.

4.1.3 Net Revenue for Observed Richview Nodal Prices

Table 3-6 compares estimated net revenues for the past four years using both the HOEP (as presented in Chapter 1) and the observed Richview nodal price. Richview is just one of several locations in the province where net revenue could be calculated to identify what might occur under nodal pricing. We consider other locations in the next section.

When we use the HOEP, yearly net revenues for the efficient combined cycle plant range from $47,400/MW to $111,500/MWwith an average of $76,800/MW, well below the estimated $100,000/MW needed to cover fixed operating and capital costs.[62] Net revenues for a combustion turbine unit average $20,400/MW, again well below the requirement of about $77,000/MW to cover fixed costs. When we substitute the observed Richview nodal price into the analysis, net revenue for an efficient combined cycle plant ranges from $271,200/MW in the first year to $136,400/MW in the last year, well above the $100,000/MW threshold. On average, net revenues since market opening at observed nodal prices would be $201,300/MW for the combined cycle unit and $119,600/MW for the less efficient combustion turbine generator.

[62] The Federal Energy Regulatory Commission of the United States (FERC) estimates that a combined cycle generator would require annual net revenue of approximately US$80-90/kW-year or CDN$100,000/MW in order to meet its debt and equity requirements. For a combustion turbine unit US$60-70/kW-year or about CDN$77,000/MW would be needed to meet debt and equity requirements. (Op. cit.) The adjusted Canadian amounts reflect an exchange rate of about US$1=CDN$1.10 on the higher cost in each range. These amounts are also roughly equivalent to the FERC mid-range cost and an exchange rate of US$1=CDN$1.15.

Table 3-6: Yearly Estimated Net Revenue by Efficiency Type 2002-2006 Using the HOEP and Richview Nodal Price ($/MW per Year)

Time Period	7,000 Btu/kWh of Combined Cycle with Variable O&M Cost of $1.10/MWh		10,500 Btu/kWh of Combustion Turbine with Variable O&M Cost of $3.30/MWh	
	HOEP	Richview Nodal Price	HOEP	Richview Nodal Price
Nov 2002 - Oct 2003	$111,500	$271,200	$31,700	$159,500
Nov 2003 - Oct 2004	$53,000	$154,300	$11,100	$84,900
Nov 2004 - Oct 2005	$95,200	$243,400	$28,100	$150,600
Nov 2005 - Oct 2006	$47,400	$136,400	$10,700	$83,600
Average	$76,800	$201,300	$20,400	$119,600

There is a noticeable increase in net revenues for all years for both generator types compared to the analysis using HOEP. The results suggest that with observed nodal pricing, all else held constant, net revenues can be sufficiently high enough to justify new capacity investment at Richview.

As previously mentioned, using observed nodal prices when these are higher than HOEP tends to overstate the potential revenues a new generator may receive. If market participants were faced with payments based on a higher nodal price, loads and intertie traders may change their offer strategies, for example to reduce consumption or export when prices are much higher. We expect that this would result in a lower nodal price (closer to but still above HOEP), although we have not been able to estimate the magnitude of such changes. In reality, net revenues to a new generator may be expected to fall somewhere between the observed Richview nodal price and HOEP price estimates found in our report.

4.1.4 Net Revenue by Zone

We have extended our analysis to compare net zonal revenues on an annual basis for all 10 Ontario zones. Similar to the above analysis, we use FERC's standardized model to compare net revenues for an efficient combined cycle plant as well as a less efficient combustion turbine plant across zones.

Net zonal revenues are presented in Tables 3-7 and 3-8 for the combined cycle and combustion turbine plant and based on a zonal hourly price limit of $2,000/MWh. With the exception of the Northwest (NW), Table 3-7 shows that net revenues appear to be sufficiently high to warrant new investment for efficient combined cycle generation. Average net revenues are highest in the Toronto zone ($202,400/MW) and lowest in the Northwest ($57,700/MW). Based on the recent one-year results from November 2005 – October 2006, all regions would have provided net revenue in excess of $100,000/MW except in the north (Northeast and Northwest).

Although net revenues for the combustion turbine unit for the last year are below $80,000/MW in all zones, average zonal net revenues prices are above $100,000/MW for most zones except the two in the north. Compared with the $77,000/MW required for investment and fixed cost recovery, the average net revenues might be sufficiently high to induce new combustion turbine investment.

We note from Table 1-22 in Chapter 1 that there were only 47 hours in the past six months where actual Richview nodal prices were higher than $200/MWh, and this has been decreasing since the previous year. This suggests that the net revenue results we report here are not skewed by a large number of hours with high prices. Very high prices (for example greater than $500/MWh[63]) contribute only about 10 percent of the net revenues for the combined cycle units.

[63] At lower price levels there might be very limited significant demand response, but we would anticipate more significant demand response at the $500 per MWh and higher price range.

Table 3-7: 7,000 Btu/kWh of Combined Cycle with Variable O&M Cost of $1.10/MWh ($/MWh)

Period	BRUCE	EAST	ESSA	NE	NIAGARA	NW	OTTAWA	SW	TORONTO	WESTERN
Nov. 2002 – Oct. 2003	261,200	262,400	253,800	209,200	278,000	129,600	263,900	264,900	278,500	261,600
Nov. 2003 – Oct. 2004	139,100	140,500	126,300	103,800	147,500	55,800	142,700	142,600	151,400	141,400
Nov. 2004 – Oct. 2005	220,000	231,100	206,200	147,500	222,100	25,400	227,800	229,400	248,100	240,200
Nov. 2005 – Oct. 2006	113,100	120,200	106,100	90,100	132,300	20,100	113,600	123,300	131,400	128,900
Average	183,300	188,600	173,100	137,700	195,000	57,700	187,000	190,000	202,400	193,000

Table 3-8: 10,500 Btu/kWh of Combustion Turbine with Variable O&M Cost of $3.30/MWh ($/MWh)

Period	BRUCE	EAST	ESSA	NE	NIAGARA	NW	OTTAWA	SW	TORONTO	WESTERN
Nov. 2002 – Oct. 2003	152,300	154,200	150,000	122,500	165,800	76,700	154,900	155,600	164,900	154,300
Nov. 2003 – Oct. 2004	74,500	75,600	69,300	59,800	79,400	40,400	78,300	77,000	82,000	76,300
Nov. 2004 – Oct. 2005	132,100	141,500	125,400	82,500	131,200	18,200	138,500	139,700	153,100	149,500
Nov. 2005 – Oct. 2006	63,100	69,500	61,900	47,800	79,100	9,500	63,500	71,400	77,200	74,100
Average	105,500	110,200	101,700	78,100	113,900	36,200	108,800	110,900	119,300	113,500

4.2 System Revenue Analysis for Existing Generators - HOEP versus Observed Nodal Pricing – and Impact on Ontario Loads

4.2.1 Introduction

In Ontario's hybrid market, we have a system that will increasingly allow the market price to rise without an immediate proportional change to customers' costs. From the preceding analysis of net revenue based on observed nodal prices, it also appears that sufficient revenue could arise to support investment in several of the zones. In this section we explore the net impact of nodal pricing on overall wholesale and retail consumption charges recognizing that the Global Adjustment and OPG Rebate would mitigate a significant portion of the energy price change.

We attempt to reproduce the revenues to generators in the energy market (an estimate of what they currently receive) and compare them to potential revenues implied by the observed nodal prices. When estimating these latter revenues, we use the observed nodal prices which reflect the existence of congestion, losses and other assumptions of the constrained dispatch process. To perform the analysis we consider payments to all generators and examine the impact across the entire domestic consumer base. After examining 2006, our results suggest that, holding everything else constant, there would be little change in the cost to wholesale customers when we compare the HOEP and observed nodal prices. The implication for retail customers would be similar, even though those under the Regulated Price Plan (RPP) do not directly see HOEP or adjustments, because they are ultimately affected by such changes.

Similar to the observation made in the previous section on Net Revenue analysis, if payments to producers and importers and charges to consumers and exporters were based on nodal prices, these participants would be expected to respond to the changes adjusting supply and demand depending on the local prices. These responses would tend to move the nodal prices closer to the HOEP and would further mitigate the impact of the postulated change in spot prices. However, the current analysis does not model this type of dynamic response.

Regardless of whether customers make payments based on the uniform HOEP or the mixture of higher and lower nodal prices, existing adjustments and rebates in the market would make the total payments for all Ontario loads under uniform pricing or based on observed nodal prices roughly the same. Note, this assumes the 2006 mix of contract, regulated and market price payments to generators. At some point in the future if new generation were not under contract, the contract and regulated price adjustments would have a smaller impact and Ontario loads could start to see higher effective prices than suggested here (although new capacity would also be expected to put downward pressure on prices, another dynamic response not modelled here).

Nodal pricing offers potential increased gains to society as a whole (in the form of combined consumer and supplier surplus) because energy would be consumed and produced more efficiently (improving allocative efficiency) and would likely lead to dynamic (investment) efficiency as well. Wholesale customers will also benefit because they have the ability to efficiently respond to proper price signals in the market. The implication of this is that under nodal pricing the existing Global Adjustment and OPG Rebate mechanisms would mitigate most of the wealth transfer effects while allowing the efficiency gains and corresponding benefits to society to be realized.

In the June 2006 report we observed that if market prices were increased (e.g. by $1/MWh in every hour), approximately 80 percent would be returned as Global Adjustment or OPG Rebate to customers.[64] In this report we have considerably refined the analysis, but acknowledge the result is still just an approximation. Perhaps the most significant limitation of the current approach, as noted above, is that no dynamic market response is modeled. Such response can not only change the magnitude of imports, exports and load, and thus generation dispatched, but could also affect the resulting nodal

[64] June 2006 Monitoring Report, pages 115-118.

prices. We expect that the dynamic market response would tend to move the nodal price closer to HOEP, with the possibility that the results calculated here based on observed nodal prices could be an upper bound of the average impact on customers.

4.2.2 Calculating Revenues

Due to the existence of various contracts currently in place, generators can be grouped into one of eight categories: nuclear, baseload hydro, peaking hydro and coal, Bruce, non-utility generators (NUGs), OPA contracted generation, Reliability Must Run (RMR) generation and non-contracted dispatchable generation. The first 3 categories represent OPG generation – their prescribed assets (nuclear and baseload hydro) and non-prescribed assets (peaking hydro and coal).

We calculate "Straight Revenues" and "Contract Revenues" for both the HOEP and observed nodal prices. Actual energy production (in MWh) is used to measure quantities supplied to the market in each hour. Straight Revenues (titled 'Revenue' in the results tables) simply ignore all contracts and multiply prices and quantities together on an hourly basis. The formulas used to compute straight revenues for each hour are as follows:

HOEP: Revenue = Quantity (MW) * HOEP

Observed Nodal Prices: Revenue = Quantity (MW) * Shadow Price

Contract Revenues are the revenues received by generators currently established in the marketplace based primarily on the publicly known contract and regulated rate information. The difference between the two columns, (titled 'Contract/Regulated Adjustment' in the results table) is the estimated component of the Global Adjustment, OPG Rebate or RMR contract adjustment for the generation group. Where there is no contract, Contract Revenue equals the Straight Revenue. Contract Revenues for the two pricing scenarios may or may not vary by category depending on whether a generator's contract has any exposure to market prices. An example of a category that will not display a difference between Contract Revenues under uniform versus nodal pricing is OPG's nuclear category, which includes the Pickering and Darlington generating facilities. These facilities receive $49.50/MWh for all production regardless of market prices.[65]

4.2.3 Assumptions and Limitations

Due to the large number of and complexity of the individual contracts and regulated arrangements, we do not model all the details of each separate arrangement. However, the calculations we have performed have been compared with actual Global Adjustments and OPG Rebates, indicating that these are reasonable approximations.

The question of the accuracy of the overall assessment has two dimensions – the accuracy of modeling the Contract Revenues given observed nodal prices and dispatches, and the implication of not modeling behavioural or market responses, which could change nodal prices. The limitations and assumptions regarding the contract revenues include:

a) The actual Global Adjustment and OPG Rebate are calculated in five-minute intervals for OPG assets. We calculate revenues on an hourly basis. This has virtually no impact on OPG's nuclear assets which produce an almost constant amount in any hour. It could have a minor effect on estimated revenues for OPG's baseload hydro and non-prescribed assets, given that there may be a correlation between more production and higher priced intervals (but only to the extent that this is more exaggerated for the observed nodal prices relative to uniform pricing).
b) We have not used generator-specific detailed cost information for RMR generation and OPA contracted dispatchable generation. Instead we have estimated revenues in a more aggregated fashion. This should have no impact on

[65] Detail of the specific assumptions and formulation is available from the MAU upon request by email to MACD@ieso.ca

RMR payments, but could introduce some estimation error for the others, although production by those plants is relatively small (less than 2 percent of total production).

c) Renewable energy generators with OPA contracts have been ignored because of their smaller size and the lack of information about the price each facility receives. However, since these facilities' revenues are not exposed to the market price, there should be no change in Contract Revenue between the uniform versus observed nodal prices being analyzed.

d) Imports and exports have been excluded. Most imports are paid their offer price, either through IOG or CMSC, so there should be little change in payments for these under the observed nodal versus uniform prices. Some imports would receive a higher nodal price and this would increase overall payments by customers. On the other hand, some exports would pay more under nodal prices. This not only offsets some of the higher payments to imports but also offsets some of the higher generator payments. Since the magnitude of exports is larger than imports, and much larger than imports receiving HOEP, ignoring imports receiving higher nodal payments and exports making payments based on higher nodal prices, more likely tends to overstate the net impact on charges for consumption as the result of moving to nodal prices.

e) We included CMSC payments to generators as a final item in the revenue under the uniform pricing regime (see the last row of Table 3-9) because these would be additional to the HOEP payments captured in our estimated numbers. They would essentially disappear under nodal pricing.

The above assumptions do not introduce any significant discrepancies relative to actual 2006 OPG Rebates or Global Adjustments except for OPA contracts. For OPA contracts our HOEP-based calculation of Global Adjustments and Contract Revenue is high (according to a MAU comparison with actuals) but the overestimate for the nodal-based calculation should be similar. This suggests that even though the error in estimating contract revenues for each price scenario is not insignificant, the changes in the Contract Revenues between scenarios are reasonably accurate.

The assumption of no change to imports or exports, or other competitive response in the marketplace by generation or dispatchable loads, is an important limitation. Higher nodal prices in southern Ontario could reduce exports, and imports to a lesser extent, but lower nodal prices in Northwest Ontario could have the opposite effect. (In section 5.3 we explore the efficiency gains potentially induced as the result of less export to New York.) Although these effects are not insignificant, we are not able to model them at this time since we do not have a constrained model capable of dynamically adjusting imports and exports hourly followed by recalculation of the constrained model every five minutes.

To the extent that net exports decrease, less generation would be dispatched in Ontario. This could lower some generators' Straight Revenues which in turn leads to increased Global Adjustments and lower OPG Rebates. However, these responses also lead to lower nodal prices, which would reduce total Straight Revenues to all generators under nodal pricing. These factors – lower Straight Revenues for most generation but increased Global Adjustments and lower OPG Rebates – would have offsetting effects on generation payments. Overall these would likely lead to smaller increases in total Contract Revenues under nodal pricing than estimated here.

It is not certain but these considerations suggest that by not modeling these dynamic effects, the current estimate may be an upper limit of the overall increase in the net charges to consumers given nodal pricing. Moreover, given that some locations in the province experience nodal prices less than HOEP and less than the average nodal prices, the impact on this smaller group of wholesale customers in those regions might be a reduction in net charges for consumption, with only a slight further increase in other areas to the majority of wholesale customers.

4.2.4 Revenues for Existing Generation

With some generator categories combined for confidentiality reasons, Table 3-9 shows the estimated revenues earned in the current market and the revenues that would have been earned based on observed nodal pricing between January and December 2006. Production in the energy market totalled 155.7 TWh in 2006. Contract Revenues with HOEP were approximately $8.06 billion, which was $472 million more than the estimated Straight Revenues. The estimated Contract Revenues using observed nodal prices totalled approximately $8.18 billion or $223 million less than the estimated Straight Revenues.

Table 3-9: Estimated Generator Revenues by Category
January to December 2006
($ Millions)

Generator Category	Quantities (TWh)	HOEP			Observed Nodal Prices		
		Revenue	Contract Revenue	Contract / Regulation Adjustment	Revenue	Contract Revenue	Contract / Regulation Adjustment
Nuclear	47.8	2,214	2,364	150	2,554	2,364	(190)
Baseload Hydro	18.1	870	646	(225)	1,022	674	(348)
Peaking Hydro + Coal	39.4	2,016	1,856	(160)	2,153	1,877	(276)
OPA Contracts & NUGs	47.6	2,248	2,930	683	2,488	3,070	582
RMR + Non-contracted Dispatchable Generation	2.9	172	196	24	190	200	9
CMSC	N/A	71	71	0	0	0	0
Totals	155.7	7,592	8,064	472	8,408	8,185	(223)

For 2006, estimated Contract Revenues were $121 million higher using shadow prices than HOEP, or $0.78 per MWh of generation (i.e. 1.5 percent). Based on 145 TWh of domestic consumption this represents a potential increased payment of $0.83 per MWh of domestic consumption.[66] Roughly $50 million of the $121 million increase would be attributable to OPG facilities. Much of this revenue would be paid back to all load through OPG dividends to its shareholder and the corresponding reduction of the Ontario Hydro stranded debt and eventual reduction of the Debt Retirement Charge.[67] Assuming that level of dividend, the net difference would be $71 million in net payments to other generators, or approximately $0.46 per MWh of generation (i.e. 0.9 percent) or $0.49 per MWh of Ontario consumption.

When the MAU compared our Global Adjustment and OPG Rebate estimates using HOEP with actual payouts, our estimates prove to be quite close for several categories although less so for OPA Generation Contracts. For combined adjustments including OPG Rebate the difference is 9 percent.

The overstatement of the estimated Global Adjustment suggests we have overstated the Contract Revenues for OPA generation contracts. The overestimated Contract Revenue in turn is likely due to an overestimate of some of the parameters we have approximated for the contracts. However, overstatement of HOEP Contract Revenues in this manner would lead to almost the same magnitude of overstatement using observed nodal prices.[68]

4.2.5 Conclusions

We estimate the total revenue that generators receive in the current HOEP market and in a hypothetical nodal pricing regime based on observed nodal prices. Assuming that behaviour of the market participants remained constant, we find that Contract Revenues

[66] The adjustment assumes only domestic load since exports do not receive / pay the Global Adjustment or OPG Rebate. Some of the increase however would be born by exports who would pay the nodal price at the point of export.
[67] Dividends to the Ontario Government, the shareholder, are to be used to pay down the Ontario Hydro/OPG debt held by the OEFC. This would likely lead to a reduction or earlier termination of the stranded debt payment, the Debt Retirement Charge, applied to all Ontario electricity consumption.
[68] For example for Bruce A, if the actual effective contract price is below our assumed value ($63/MWh) by $1/MWh, this would reduce estimated Contract Revenue and Global Adjustment by almost $11 million. Similarly, if the actual monthly revenue requirement per MW of contracted dispatchable generation (assumed to be $100,000/MW annually) were 5 percent less, this would reduce the estimated Contract Revenue and Global Adjustment by more than $6 million. Although there may be other factors influencing the overstated Global Adjustment, the above two factors are considered to represent the primary causes. To the extent other factors are also in play, we expect the impact on Contract Revenues under HOEP and nodal prices would also be similar. Accordingly, we would expect any error in the estimated differences in Contract Revenues to be small.

are approximately $121 million higher (or $0.83 per MWh of Ontario consumption in 2006). Approximately $50 million of this is increased revenue to OPG. Since OPG is 100 percent owned by the Government of Ontario, one could represent this increased revenue as offsetting the stranded debt and future debt retirement charges, leaving a differential of $71 million and effectively lowering the cost to Ontario consumers to $0.49 per MWh under observed nodal pricing**.**

4.3 Assessment of Efficiencies Gains from Exports with Nodal Pricing

In our June and December 2006 reports, we noted the existence of socially inefficient exports on the New York interface.[69] It is likely there are export inefficiencies at the MISO interface as well, which may become significant in light of recent increased exports there. However, the New York interface was chosen for review because it has the larger amount of export transactions. Export inefficiency is just one of the inefficiencies that can occur when the the Ontario-wide uniform price differs from the shadow price which represents the incremental cost of energy at a given point in the province. In this report, we update the statistics on inefficient exports and quantify the efficiency loss of exports to New York using the relationship between price and exports estimated by our export model in Chapter 1.

As in our December 2006 report, we make a distinction between the private and social efficiency of an export. A privately efficient export on the New York interface is defined as an export that is scheduled in an hour when the New York price is greater than the HOEP plus transmission charges,[70] and a socially efficient export as an export that is

[69] June 2006 Monitoring Report, pp. 68-79; December 2006 Monitoring Report, pp. 104-110.
[70] New York, like Ontario, provides importers with an Import Offer Guarantee which guarantees that the importer receives the higher of their offer price or the real-time price when scheduled and delivered. For this reason, when measuring private efficiency we assume the external price received in New York is the higher of the New York hour-ahead price or the real-time price. We assume a $5/MWh transmission charge, which approximates various fees that exporters pay including a transmission charge, an IESO charge and uplift.

scheduled when the New York real-time price is greater than the nodal price at the Beck Ebus.[71,72]

In this sense, we estimate *ex post* efficiency. We assume that all transactions are privately efficient *ex ante* because traders offer into the markets based on their expectation of real-time price and will not schedule an export if the transaction is expected to be unprofitable. Therefore, an export is deemed privately inefficient as a result of 'guessing wrong'. This can happen as the result of decisions by exporters which prove to be incorrect, and can also be influenced by imperfect information or price signals or other price distorting actions by the system operator. Improvement in the accuracy of price signals and information over time and minimizing system operators' out-of-market control actions would tend to increase the frequency of privately efficient exports.

There are two major causes of socially inefficient exports from Ontario to New York. First, 'guessing wrong' by exporters can lead to socially inefficient exports just as it can lead to privately inefficient exports. Second, socially inefficient exports can occur if there are defects or distorted incentives in the market design, intentional or not. As the Panel has discussed in past reports, Ontario's uniform pricing regime allows for the possibility that the prices that exporters pay do not reflect the incremental cost of supply.[73] Other aspects of the unconstrained pricing algorithm such as the 12-times ramp rate assumption can further misalign the HOEP and the relevant nodal prices, thereby contributing to the potential for *ex post* socially inefficient exports. The New York market, on the other hand, provides an importer a guarantee similar to the IESO's IOG, which induces privately efficient exports even though *ex ante* or *ex post* they appear to be socially inefficient. These factors tend to lead to the frequency of privately efficient exports being persistently larger than the frequency of socially efficient exports.

[71] There are very small incremental costs for transmitting the exports to New York, such as variable costs and losses. Ignoring these costs tends to provide a slightly conservative estimate of socially inefficient exports.
[72] As explained in our June 2006 Monitoring Report at p.71, the Beck Ebus is the node closest to New York and thus best represents the cost of satisfying additional exports to New York.
[73] December 2006 Monitoring Report, p.104.

Figure 3-4 plots the monthly percentage of scheduled exports which were privately efficient and the monthly percentage of scheduled exports which were socially efficient for the period of January 2004 to April 2007.[74] If the Ontario and New York markets were perfectly designed and information was timely and accurate, the two series should have been the same. Although both series have a slightly increasing trend, the trend of privately efficient exports is statistically insignificant whereas the trend of socially efficient export is significant.[75] The trend lines indicate the nodal price at the Beck Ebus has been moving closer to the HOEP over time. The frequency of privately efficient exports was roughly 70 percent, while the frequency of socially efficient exports has just reached the 60 percent level. The persistent difference of greater than 10 percent provides strong evidence that the Ontario market design likely has led to socially inefficient exports.

[74] The MAU recently identified a labelling error in the New York hour-ahead price that was supplied by an external supplier. The numbers in the current graph have therefore been adjusted from those in our December 2006 Monitoring Report.

[75] For the privately efficient export, the equation for the trend line is:

$$\underset{}{\text{Percentage}} = \underset{(31.2361)}{0.665} + \underset{(1.0628)}{0.001\text{*Trend}}$$

For the socially efficient export, the equation for the trend line is:

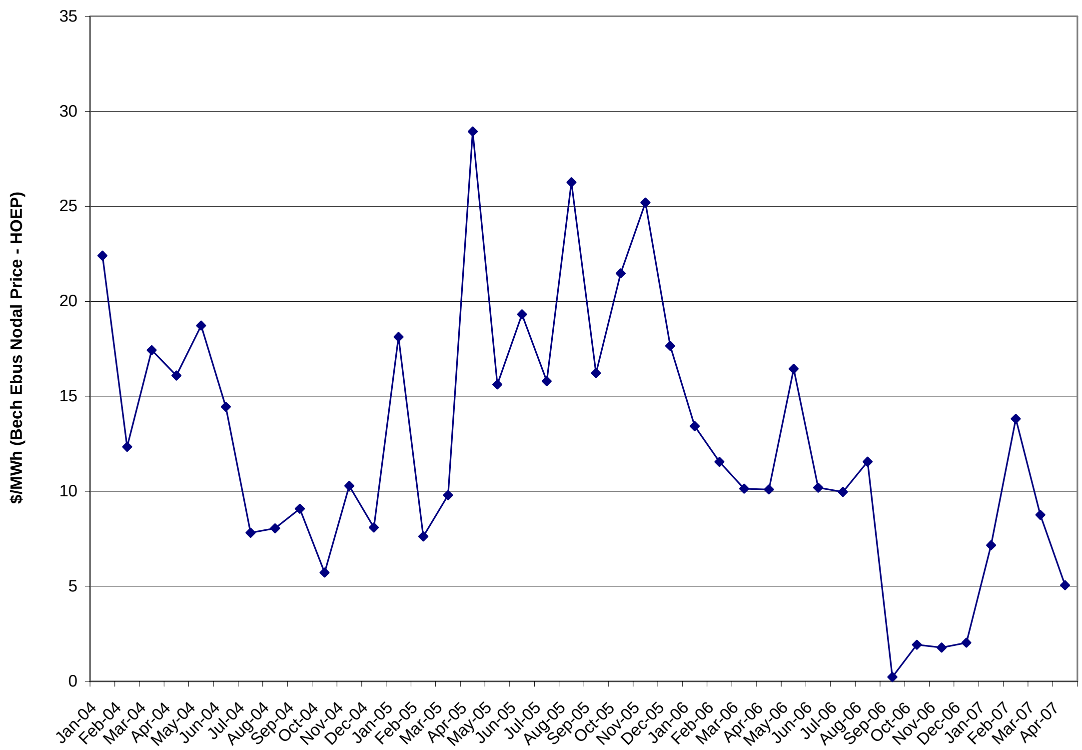
$$\text{Percentage} = \underset{(20.245)}{0.510} + \underset{(2.189)}{0.002\text{*Trend}}$$

Data in parenthesis are t ratios.

Figure 3-4: Privately Efficient and Socially Efficient Exports to New York January 2004 – April 2007

The root of export inefficiency comes from the discrepancy between the price that exporters pay and the production cost of their purchase. Figure 3-5 illustrates the monthly average difference between the Beck Ebus nodal price and the HOEP. The series shows a significant month-to-month fluctuation, but with a decreasing trend since the beginning of 2006, which has contributed to the partial convergence between social efficiency and private efficiency.

Figure 3-5: Monthly Average Difference Between the Beck Ebus Nodal Price and the HOEP January 2004 – April 2007 ($/MWh)



In our December 2006 report, the Panel noted three main factors that lead to the price convergence, including constrained-off (net) exports, under-forecast of demand and constrained-on generation. The Panel asked the MAU to conduct a more detailed study on the price convergence for this monitoring report.

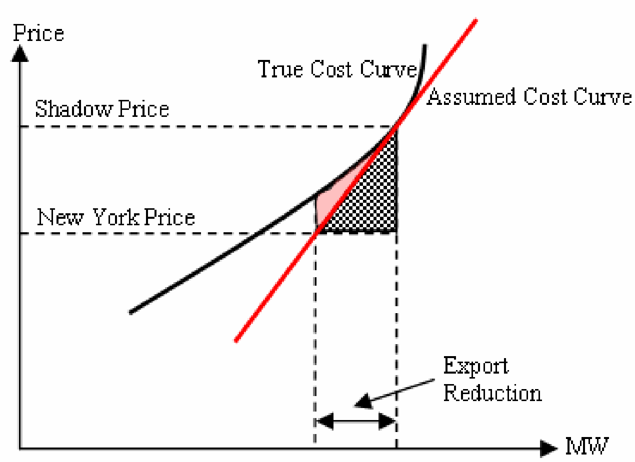
To better understand how much efficiency was lost (or gained) due to the Ontario uniform pricing regime, the MAU used the estimated export elasticities in Chapter 1 to approximate an hourly export reduction (or increase) if exporters had to pay the nodal price at the Beck Ebus. In this case, we assume the real-time price in New York is not significantly affected by the change in exports because western New York is a congested area and has redundant capacity but cannot export power to the eastern area. The efficiency loss or gain was estimated as half of the product of the estimated export change and the absolute difference between the New York real-time price (the lost value to New York consumers) and the nodal price at the Beck Ebus.[76] We assume a linear supply curve, and thus halving the product provides a rough estimation of efficiency loss.[77] We also note that the estimated export reduction is an upper bound since the lower exports would induce lower nodal prices and thus less export response. This means the resulting efficiency impact is also an upper bound.

Table 3-10 provides the estimates for 2006 and 2007 by month had the exporters on the Beck intertie been facing the observed nodal prices in this area. The baseline estimates are the efficiency gain using the mean export elasticity estimates (-5.99 for on-peak and -2.14 for off-peak), the upper bound estimates using the upper elasticity at the 96 percent confidence interval (-7.44 for on-peak and -3.88 for off-peak) and the lower bound estimates using the lower elasticity at the 96 percent confidence interval (-4.54 for on-peak and -0.4 for off-peak). In total, had observed nodal prices been applied, the markets (both Ontario and New York) would have had an estimated efficiency gain ranging from

[76] When the Beck Ebus price is smaller than the New York price nodal pricing could increase exports, and increase efficiency.

[77] Figure 3-5 illustrates graphically how the efficiency gain from reduced exports is estimated. The true cost curve is the incremental cost of supplying energy in Ontario, the assumed cost curve is the approximated cost function for our estimation, '*Shadow price*' is the nodal price at the Beck Ebus, and '*Export Reduction*' is the amount of export reduction if exporters had to pay the nodal price rather the HOEP. Assume exports have no impact on the New York price. The hatched triangle is the estimates that are provided in Table 3-10, although total efficiency gain would be the solid area plus the hatched area. If the cost curve is relatively flat, this approach will understate the efficiency gain, while if the cost curve is relatively steep, it will overstate the gain.

Figure 3-5: Efficiency Gains from Export Reductions



a high of $66 million to a low of $47 million, based on the estimated average export reduction amounting to 768 GWh.

Table 3-10: Estimated Efficiency Gain if Exporters Paid the Observed Nodal Price at the Beck Station January 2006 – April 2007 ($ Millions)

Year	Month	Efficiency Gain (Baseline)	Efficiency Gain (Upper Bound)	Efficiency Gain (Lower Bound)	Export Reduction for Baseline (GWh)
2006	January	5	6	4	237
	February	4	4	3	167
	March	4	4	3	138
	April	6	6	4	126
	May	4	4	3	55
	June	4	5	3	29
	July	7	7	5	(1)
	August	7	7	5	67
	September	1	2	1	(35)
	October	1	1	1	17
	November	3	4	3	(124)
	December	2	3	2	(80)
2007	January	1	2	1	4
	February	5	5	4	171
	March	3	3	2	31
	April	3	4	2	(33)
Total		61	66	47	768

In summary, the discrepancy between the Beck Ebus nodal price and the HOEP creates a systematic arbitrage opportunity for exporters and contributes to significant volumes of socially inefficient exports. The efficiency gain of moving from the uniform pricing to nodal pricing is significant, amounting to an estimated $49 million in 2006 and a further $12 million in the first four months of 2007.

4.4 Summary and Conclusion

The Panel has always been attentive to identifying opportunities to improve the economic efficiency of the wholesale market. In this section we have attempted to systematically consider whether there are apparent efficiencies to be gained by moving from the established uniform price system to a form of locational pricing in which markets clear at prices determined by the particular demand and supply conditions, including transmission congestion, at the location in question. For convenience because the IESO's dispatch scheduling optimizer generates a series of shadow prices at numerous nodes across the province, we have used these nodal prices to attempt to estimate potential efficiency gains compared to the existing uniform price market.

The results of our analysis reported in section 4.3 support the expectation that a move to locational pricing will bring efficiency improvements, both allocative (the short-run efficient use of resources) and dynamic (evolution of a market-based generation investment over time). We make no claims that these results are certain or definitive (the assumptions and limitations of our analysis are described in the body the section) but we believe they are directionally correct and add to the growing evidence for policy makers to consider in the menu of desirable market design changes.

In brief, we find that a nodal price regime in Ontario would mitigate the flow of inefficient exports to New York caused by exporters paying a HOEP lower than the actual production cost of their purchase; alternately if on occasion nodal prices are lower than HOEP exports might increase with overall efficiency gains. In 2006 these efficiency gains would have been about $50 million. We also find that net revenues under observed nodal prices could be sufficient to induce investment in particular locations in the Province, which would support the potential for dynamic efficiency gains.

We appreciate that there are different drivers for new capacity investment in the electricity sector; this is not just a simple question of the apparent existence of adequate market-based revenues. For example, our understanding is that the established electricity markets in the United States, all of which have some variation of locational pricing, have not in fact seen acceptable levels of new investment induced by energy revenues alone.

Nevertheless, in our view, the net revenue results for nodal pricing are important and bear further consideration.

After determining that the prospect of efficiency gains from locational pricing seems likely we then tested to see if such a change would be associated with a significant wealth transfer effect, that is, if the cost of electricity to consumers would rise considerably. We found, after taking into consideration the mechanisms in place to smooth the final price to consumers – the Global Adjustment and the OPG Rebate – that the likely upper bound of the average annual increase is only about $0.80/MWh. Since some of the extra generator revenue accrues to OPG, it can be used by the shareholder, the Government of Ontario, to offset the stranded debt. Based on the magnitude of extra OPG revenue, this can be represented as an effective reduction in the estimated $0.80/MWh increase to something in the range of $0.50/MWh.

Based on the exploratory analysis and simulations undertaken, the Panel is not claiming that this estimate of the relatively small increase in the cost of electricity to the consumer is certain (and new capacity would be expected to have a price depressing effect which is not included in these estimates). However, it appears that the efficiency benefits from an improved market design could be achieved with relatively small price increases, since dampening of the transition cost would occur because of the existence of the Global Adjustment and OPG Rebate. This is another factor that deserves consideration in the evolution of the sector.

> ***<u>Recommendation 3-6</u>***
> ***The panel recognizes that adopting locational pricing would be a fundamental design change; however, we encourage the IESO to assess the efficiency benefits and costs of such an approach to provide a sound analytic basis for the consideration of future policy decisions.***

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Chapter 4: The State of the IESO-Administered Markets

1. General Assessment

This is our 10th semi-annual monitoring report on the IESO-administered markets. It coincides with the fifth anniversary of the opening of the Ontario electricity market. As in our previous reports we conclude that the market has operated well according to the parameters set for it.

The average monthly HOEP, November 2006 to April 2007, were lower relative to the corresponding period a year ago and indeed represent the lowest average prices since the market has been operating. Market-related uplift payments for congestion, supply guarantees and other matters were also lower than the corresponding period a year ago. Lower prices are a natural outcome of the increased energy supplies seen in Ontario in the last few years. Relative to the last winter period, prices are lower mostly due to much lower gas prices and slightly reduced market demand caused by a drop in exports.

Consistent with lower overall prices, there were fewer high priced hours (only one hour with HOEP over $200/MWh) and more low priced hours (HOEP less than $20/MWh), as well as 3 hours of HOEP below zero. Our review of these and other apparently anomalous hours led us to conclude that the price movements in these hours were consistent with the supply/demand conditions prevailing at the time. As is customary the MAU communicated with market participants from time to time to understand market behaviour. We found no evidence of gaming or abuse of market power during the review period.

The rest of the chapter is organized as follows: section 2 summarizes our findings on the IESO's financial guarantee programs in support of reliability. Section 3 briefly revisits the significance of the nodal pricing simulations in Chapter 3. Section 4 provides a status report of our work to develop an analytic framework to identify the exercise of market power. Finally, section 5 excerpts and lists the various recommendations made in the body of our report.

2. Review of Financial Guarantees for Generation and Imports

In Chapter 3 we reviewed three programs used by the IESO to induce improved reliability by offering financial guarantees to generation and imports. In Table 4-1, we summarize the role played by these important programs in promoting reliability and identify some potential market or efficiency shortcomings. While the Panel does not purport to be an expert on reliability, we believe the benefits of reliability should be accomplished at the lowest cost and with minimal impact on market efficiency. The design or integration of these programs into the market is important and it appears that there may be scope for improvement by looking more rigorously at the costs and benefits of overlapping programs.

Table 4-1: Summary of Market or Efficiency Impacts of Financial Guarantee Programs

Program or Activity	Role in Achieving Reliability	Market or Efficiency Impact
DACP	Provides day-ahead financial guarantees to generators and importers for confirmed supply	Program may impact efficiency by creating generator incentives to: • underbid marginal costs • come on-line early • come on-line even if not needed Amount of guaranteed costs are not considered in scheduling decisions.
SGOL	Provides current day financial guarantees to generators for supply in real-time	Program can bring generation on-line for several hours even if needed only for one hour. Amount of guaranteed costs are not considered in scheduling decisions.
IOG	IOG provides a financial guarantee to importers if HOEP falls relative to pre-dispatch price.	These support mechanisms may be useful on-peak, but off-peak domestic supply appears sufficient without IOG inducing additional import supply

Given these observations on market and efficiency impacts, we suggest the IESO review these programs individually and collectively for potential improvements. This is addressed in Recommendations 3-2, 3-3 and 3-4, referenced in the last section of this chapter.

3. Market Design

While the market is operating relatively well given its design, we continue to be of the view that there is a case for altering its design to allow some form of locational pricing. This would induce more efficient behaviour by both suppliers and consumers and would provide better signals for the location of new investment. With the exception of the much smaller Alberta market, Ontario is unique among North America's established electricity markets in maintaining a uniform price across its service territory.

The exploratory analysis presented in Chapter 3 shows that there would have been apparent efficiency benefits if the nodal prices generated in the IESO's constrained sequence had been substituted for the uniform HOEP. And, at the same time, because of the smoothing effect of the Global Adjustment and OPG Rebate, the average cost to consumers would have been well under $1/MWh. As underlined in Chapter 3 there are various caveats that need to be applied to these findings because of assumptions and transitional considerations; however we believe the results are directionally correct and support further exploration of locational pricing in the policy mix as the sector evolves to a more self-sustaining and efficient structure.

4. Market Power Framework

At the beginning of December 2006 the Panel initiated stakeholder consultations regarding a proposed framework for identifying the exercise of market power.[78] During January and February 2007 we held three meetings with interested stakeholders to provide an overview of the proposed framework and detailed examples of the intended application. Participation at the meetings was open to all interested parties. The attendees were primarily traders and generators.

Stakeholders raised many questions about the theoretical underpinnings of the framework and details of implementation. In order to provide full transparency, the Panel invited stakeholders to submit written comments which have been published on the Market Surveillance Panel's section of the OEB web site.[79]

The purpose of the proposed framework is to enhance the quality and consistency of monitoring when assessing market outcomes or anomalous situations by the Panel and the Market Assessment Unit. While several stakeholders commented there was no need or benefit to be gained from all or parts of the proposed framework, the Panel continues to be of the view that it is desirable to have a clear analytical framework as a base for rigorous assessments of market outcomes. The Panel believes that it is important to enhance the tools for distinguishing between market outcomes that are due to the exercise of market power and those that have other causes.

Following the Panel's review of the stakeholder comments we will decide how to proceed in respect of the framework and will communicate this to stakeholders. The specific timetable for doing so has not yet been determined.

[78] "Market Power Framework For the IESO-Administered Electricity Market: Proposed Framework for Identification of the Exercise of Market Power" November 2006
http://www.oeb.gov.on.ca/documents/msp/market_power_framework/market_power_framework_discussion_paper_011206.pdf
[79] Refer to submissions and other consultation material at
http://www.oeb.gov.on.ca/html/en/industryrelations/msp_marketpowerframework.htm

5. Summary of Recommendations

In the Panel's view, the wholesale market has a vital role to play in the new Ontario hybrid market regime. The Panel has identified certain issues in the design and operation of the market that should be reviewed in order to improve its efficiency and effectiveness. The following recommendations have been motivated by the discussions earlier in this report and deal with issues of price fidelity, market efficiency and ensuring that payments for reliability are made with as little cost and inefficiency as possible.

Recommendation 1-1 (pp. 25-28)

Given the persistent large number of intertie failures not under a market participant's control, the Panel urges the IESO to continue to review this issue with New York ISO to better understand why there are such high failure levels and determine whether there are solutions which could reduce such failures to the benefit of both markets.

Recommendation 2-1 (pp. 86-90)

The Panel recommends the IESO review the time lags which it currently employs for replenishing the OR requirements following a contingency. Replenishment as quickly as possible would be consistent with the treatment of other operating reserve or energy obtained through out-of-market control actions and similar to the NYISO practice. This would result in prices which more accurately reflect the loss of supply and encourage market participants to respond as quickly as possible.

Recommendation 2-2 (pp. 97-100)

The Net Interchange Scheduling Limit of 700 MW has been in effect since the market opened. In the light of 5 years' experience with market-based trading, the NISL's potential to limit efficient trade and changes in both the number of generators and their combined ramp capability, the Panel encourages the IESO to review whether the 700 MW limit could be increased.

<u>Recommendation 2-3   (pp. 100-106)</u>

The Panel recommends the IESO should explore improvements to the load predictor tool in order to reduce forecast errors associated with sudden changes in dispatchable load consumption, and the resulting dispatch inefficiencies.

<u>Recommendation 3-1   (pp. 108-113)</u>

The Panel encourages the IESO and OPA to continue to improve coordination between dispatchable load and demand response programs in order to promote the efficient use of dispatchable loads' OR capability.

<u>Recommendation 3-2   (pp. 114-121)</u>

The Panel recommends the IESO review the DACP in order to reduce the costs and improve the effectiveness of the Generator Cost Guarantee. Three-part bidding with 24 hour optimization, similar to the NYISO methodology, may be one such approach. We further recommend as an interim alternative that the IESO consider mechanisms which allow the full magnitude of domestic generator costs to be taken into account in DACP scheduling decisions.

<u>Recommendation 3-3   (pp. 121-123)</u>

In parallel with the recommended review of the DA-GCG, the Panel believes that it would be useful for the IESO to review the interface between the SGOL and DA-GCG as well as mechanisms for considering the full amounts of SGOL cost reimbursements in scheduling decisions.

<u>Recommendation 3-4 (pp. 124-127)</u>

The Panel recommends the IESO review off-peak conditions to determine if the RT-IOG and DA-IOG programs are providing an improvement in reliability commensurate with the payments being made. The IESO should consider discontinuing off-peak IOG payments where these no longer appear to provide corresponding reliability benefits.

<u>Recommendation 3-5 (pp. 127-129)</u>

The Panel recommends the IESO review the treatment of energy exported through Segregated Mode of Operation with a view to including this energy in the determination of RT-IOG offsets for implied wheeling.

<u>Recommendation 3-6 (pp. 129-153)</u>

The Panel recognizes that adopting locational pricing would be a fundamental design change; however, we encourage the IESO to assess the efficiency benefits and costs of such an approach to provide a sound analytic basis for the consideration of future policy decisions.

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Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
November 2006 – April 2007

PUBLIC

July 2007

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

List of Tables

*Table A-1: Monthly Energy Demand, May 2005 – April 2007 (TWh)**

	Ontario Demand		Exports		Total Market Demand	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	11.77	11.99	0.99	1.20	12.76	13.18
Jun	13.51	12.59	0.75	0.91	14.26	13.51
Jul	14.10	13.89	0.73	1.03	14.83	14.92
Aug	14.06	13.32	0.83	1.21	14.89	14.53
Sep	12.61	11.58	0.91	0.83	13.52	12.41
Oct	12.25	11.99	0.93	0.98	13.17	12.97
Nov	12.48	12.22	1.12	0.53	13.59	12.75
Dec	13.77	12.92	1.04	0.67	14.80	13.58
Jan	13.62	13.79	1.20	0.78	14.81	14.57
Feb	12.57	13.04	1.09	1.19	13.66	14.24
Mar	13.22	13.21	1.23	0.91	14.45	14.12
Apr	11.53	11.86	1.32	1.16	12.85	13.02
May – Oct	78.30	75.36	5.14	6.16	83.43	81.52
Nov - Apr	77.19	77.04	7.00	5.24	84.16	82.28
May - Apr	155.49	152.40	12.14	11.40	167.59	163.80

* Data includes dispatchable loads

Table A-2: Average Monthly Temperature*, March 2002 - April 2007*
(℃Celsius)

	2002	2003	2004	2005	2006	2007
Jan	N/A	(7.68)	(9.13)	(6.78)	0.30	(2.65)
Feb	N/A	(7.02)	(3.29)	(3.60)	(3.56)	(7.99)
Mar	0.39	(0.57)	2.26	(1.29)	1.21	0.59
Apr	7.27	5.53	6.88	8.18	8.36	6.29
May	11.21	12.23	13.31	12.14	14.59	N/A
Jun	19.18	18.53	17.78	22.54	19.76	N/A
Jul	24.14	21.71	20.65	24.09	23.50	N/A
Aug	22.63	21.85	19.57	22.53	21.22	N/A
Sep	20.09	17.12	18.40	18.33	15.79	N/A
Oct	9.16	9.04	10.85	11.01	9.07	N/A
Nov	3.18	4.91	5.29	5.06	5.25	N/A
Dec	(1.82)	(0.03)	(2.54)	(3.13)	1.94	N/A

* Temperature is calculated at Toronto Pearson International Airport

Table A-3: Number of Days Temperature Exceeded 30℃, March 2002 - April 2007*

	2002	2003	2004	2005	2006	2007
Jan	N/A	0	0	0	0	0
Feb	N/A	0	0	0	0	0
Mar	0	0	0	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	2	N/A
Jun	5	4	2	9	3	N/A
Jul	16	4	1	11	9	N/A
Aug	8	4	0	7	3	N/A
Sep	4	0	0	2	0	N/A
Oct	0	0	0	0	0	N/A
Nov	0	0	0	0	0	N/A
Dec	0	0	0	0	0	N/A

* Temperature is calculated at Toronto Pearson International Airport

*Table A-4: Outages, May 2005 - April 2007**
(TWh)

	Total Outage		Planned Outage		Forced Outage	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	6.01	5.06	3.07	2.63	2.93	2.43
Jun	3.50	3.89	1.38	1.51	2.12	2.37
Jul	3.50	2.82	0.51	0.40	2.99	2.42
Aug	3.64	3.22	0.57	0.96	3.08	2.26
Sep	4.75	4.82	2.26	2.46	2.49	2.36
Oct	5.60	5.34	3.09	2.93	2.51	2.41
Nov	4.99	5.75	2.23	3.34	2.76	2.41
Dec	4.26	4.37	1.46	2.47	2.80	1.90
Jan	3.03	3.74	1.38	1.83	1.65	1.90
Feb	2.47	3.03	1.10	1.13	1.37	1.89
Mar	4.05	5.17	2.60	2.86	1.45	2.32
Apr	4.89	4.99	3.36	3.11	1.52	1.88
May – Oct	27.00	25.15	10.88	10.89	16.12	14.25
Nov - Apr	23.69	27.05	12.13	14.74	11.55	12.30
May - Apr	50.69	52.20	23.01	25.63	27.67	26.55

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

Table A-5: Average HOEP, On and Off-Peak, May 2005 - April 2007
($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	53.05	46.32	63.78	59.18	44.21	34.77
Jun	65.99	46.08	83.57	56.04	49.19	37.36
Jul	76.05	50.52	102.84	63.25	55.84	41.72
Aug	88.24	52.72	118.49	65.05	61.08	41.64
Sep	93.70	35.42	123.65	43.85	67.50	28.67
Oct	75.92	40.20	101.37	49.64	56.71	32.44
Nov	58.25	49.71	74.11	60.13	44.39	39.75
Dec	79.77	39.25	101.29	53.06	63.52	29.71
Jan	55.54	44.48	64.95	53.44	47.79	36.43
Feb	48.12	59.12	53.98	70.93	42.80	48.39
Mar	49.01	54.85	57.62	68.31	40.59	42.67
Apr	43.52	46.05	55.96	57.58	35.23	37.63
May – Oct	75.49	45.21	98.95	56.17	55.76	36.10
Nov - Apr	55.70	48.91	67.99	60.58	45.72	39.10
May - Apr	65.60	47.06	83.47	58.37	50.74	37.60

Table A-6: Average Richview Slack Bus Price, On and Off-Peak, May 2005 - April 2007 ($/MWh)

	Average Richview Slack Bus Price		Average On-Peak Richview Slack Bus Price		Average Off-Peak Richview Slack Bus Price	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	67.38	64.45	85.13	96.58	52.76	35.60
Jun	94.51	52.09	130.91	61.00	59.71	44.29
Jul	98.98	55.71	139.47	68.17	68.42	47.11
Aug	118.09	59.78	155.02	73.72	84.98	47.26
Sep	114.00	35.32	145.04	44.01	86.83	28.38
Oct	100.98	41.83	133.89	50.96	76.14	34.32
Nov	78.25	55.24	102.68	68.11	56.87	42.93
Dec	94.85	40.97	124.83	56.03	72.22	30.57
Jan	67.37	51.24	83.80	61.90	53.84	41.67
Feb	57.23	69.49	67.15	83.83	48.22	56.45
Mar	57.44	66.40	69.01	86.19	46.12	48.64
Apr	53.12	50.63	68.33	60.15	42.98	43.67
May – Oct	98.99	51.53	131.58	65.74	71.47	39.49
Nov - Apr	68.04	55.66	85.97	69.37	53.38	43.99
May - Apr	83.52	53.60	108.77	67.55	62.42	41.74

Table A-7: Ontario Consumptionby Market Segmentation,
May 2005 - April 2007
(TWh)

	LDC's		Wholesale Loads		Generation		Metered Energy Consumption		Transmission Losses		Total Energy Consumption	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	9.41	9.63	1.88	1.66	0.18	0.18	11.47	11.46	0.28	0.47	11.75	11.93
Jun	11.24	10.13	1.75	1.66	0.17	0.19	13.16	11.99	0.34	0.56	13.50	12.54
Jul	11.66	11.48	1.73	1.61	0.19	0.19	13.58	13.27	0.51	0.58	14.10	13.85
Aug	11.41	10.99	1.90	1.67	0.21	0.16	13.52	12.82	0.52	0.49	14.03	13.31
Sep	10.04	9.43	1.85	1.53	0.20	0.16	12.09	11.12	0.46	0.40	12.55	11.52
Oct	9.83	9.77	1.77	1.50	0.18	0.15	11.77	11.42	0.42	0.54	12.19	11.96
Nov	10.23	9.97	1.71	1.49	0.17	0.16	12.11	11.63	0.33	0.55	12.44	12.18
Dec	11.50	10.73	1.73	1.47	0.20	0.16	13.42	12.36	0.32	0.52	13.75	12.88
Jan	11.19	11.38	1.75	1.58	0.19	0.16	13.12	13.12	0.47	0.64	13.60	13.76
Feb	10.43	10.97	1.56	1.40	0.16	0.14	12.15	12.51	0.42	0.53	12.57	13.04
Mar	10.79	10.83	1.76	1.57	0.17	0.18	12.72	12.58	0.48	0.62	13.20	13.19
Apr	9.25	9.58	1.66	1.53	0.15	0.17	11.06	11.28	0.45	0.55	11.51	11.83
May – Oct	63.59	61.42	10.87	9.64	1.12	1.03	75.58	72.08	2.53	3.03	78.11	75.11
Nov - Apr	63.37	63.46	10.16	9.03	1.04	0.97	74.57	73.46	2.49	3.42	77.07	76.88
May - Apr	126.96	124.87	21.03	18.67	2.16	2.00	150.15	145.54	5.02	6.45	155.18	151.99

Table A-8: Frequency Distribution of HOEP, May 2005 - April 2007
(Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	< 10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	0.00	0.67	1.48	1.61	1.88	12.77	22.04	**40.73**	**34.41**	16.26	10.62	10.48	13.04	7.26	13.71	7.39	2.42	2.42	0.40	0.40
Jun	0.28	0.42	3.19	1.53	5.42	9.44	14.44	**39.03**	**19.44**	13.61	11.81	14.44	8.33	10.69	17.78	10.28	18.89	0.56	0.42	0.00
Jul	0.13	0.54	0.40	3.49	6.18	10.89	17.20	**33.87**	9.81	12.37	10.48	8.74	7.39	7.93	23.12	18.95	**23.25**	3.09	2.02	0.13
Aug	0.13	0.13	0.27	0.40	3.49	19.22	16.40	**30.38**	11.02	8.47	10.22	9.01	6.59	12.37	15.59	12.10	**32.93**	7.66	3.36	0.27
Sep	0.00	3.33	0.00	5.42	1.81	28.61	15.42	**31.67**	10.69	16.81	11.25	9.58	4.72	2.64	13.89	1.67	**39.31**	0.28	2.92	0.00
Oct	0.00	0.94	1.21	1.88	1.34	22.72	14.78	**37.77**	24.19	14.78	10.89	9.14	7.26	7.12	14.11	5.51	**25.67**	0.13	0.54	0.00
Nov	0.00	0.97	0.56	2.50	2.64	11.25	20.56	**33.33**	**28.75**	11.81	17.08	8.89	8.19	9.17	12.64	19.72	9.58	19.72	0.00	0.00
Dec	0.00	6.32	0.27	7.53	0.81	18.01	10.89	**36.69**	22.98	9.81	14.52	5.65	9.27	5.11	12.90	8.33	**28.09**	8.33	0.27	0.00
Jan	0.00	1.08	0.40	1.34	1.34	9.68	11.02	**43.15**	**33.20**	15.32	29.44	10.08	11.96	7.26	7.80	11.29	4.84	11.29	0.00	0.00
Feb	0.00	0.00	0.89	0.00	1.79	0.15	17.41	**31.99**	**47.62**	13.54	18.45	11.01	9.38	12.50	3.72	26.04	0.74	26.04	0.00	0.00
Mar	0.00	0.00	0.13	0.00	2.55	5.78	30.65	**37.10**	**31.85**	9.68	15.86	10.62	10.08	8.06	6.85	22.18	2.02	6.59	0.00	0.00
Apr	5.97	2.36	7.22	3.61	9.72	15.14	**26.81**	**32.22**	20.69	11.94	12.64	7.36	9.31	13.89	5.97	10.28	1.11	3.06	0.56	0.14
May –Oct	0.09	1.01	1.09	2.39	3.35	17.28	16.71	**35.58**	18.26	13.72	10.88	10.23	7.89	8.00	16.37	9.32	**23.75**	2.36	1.61	0.13
Nov - Apr	1.00	1.79	1.58	2.50	3.14	10.00	19.56	**35.75**	**30.85**	12.02	18.00	8.94	9.70	9.33	8.31	16.31	7.73	12.51	0.14	0.02
May -Apr	0.54	1.40	1.34	2.44	3.25	13.64	18.14	**35.66**	**24.55**	12.87	14.44	9.58	8.79	8.67	12.34	12.81	15.74	7.43	0.87	0.08

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2005 - April 2007
(Percentage of Hours within Defined Range)

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<10.00		**10.01 - 20.00**		**20.01 - 30.00**		**30.01 - 40.00**		**40.01 - 50.00**		**50.01 - 60.00**		**60.01 - 70.00**		**70.01 - 100.00**		**100.01 - 200.00**		**> 200.01**	
	2005/2006	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**	**2005/2006**	**2006/2007**
May	0.13	0.67	0.54	1.34	2.28	9.27	16.94	**36.96**	**35.75**	20.03	11.02	11.16	12.37	8.06	16.80	9.01	3.76	2.82	0.40	0.67
Jun	0.14	0.56	3.33	1.11	4.17	6.53	12.50	**38.06**	19.17	14.72	11.25	13.75	9.17	11.67	17.78	12.08	**22.08**	1.53	0.42	0.00
Jul	0.13	0.40	0.40	2.42	3.90	10.35	13.17	**31.85**	12.63	13.17	10.22	9.68	6.99	8.06	23.52	18.55	**26.48**	5.24	2.55	0.27
Aug	0.27	0.27	0.13	0.40	3.09	9.54	12.63	**35.89**	11.42	10.89	10.62	8.74	6.59	11.96	15.46	13.44	**35.35**	8.33	4.44	0.54
Sep	0.14	3.19	0.00	5.00	0.97	21.25	9.86	**36.25**	13.75	18.06	11.11	9.86	5.83	4.17	14.17	1.94	**41.11**	0.28	3.06	0.00
Oct	0.13	0.94	0.67	1.88	1.34	15.99	10.22	**41.26**	23.92	16.13	12.63	8.47	7.93	8.06	14.38	6.85	**28.09**	0.40	0.67	0.00
Nov	0.14	0.97	0.56	2.22	2.22	7.36	18.19	**31.67**	**24.44**	14.72	19.03	10.42	10.56	6.53	13.47	20.69	11.39	5.42	0.00	0.00
Dec	0.13	5.65	0.27	7.53	0.54	13.71	10.35	**38.31**	19.22	11.29	14.11	5.78	11.16	5.11	14.38	8.87	**28.90**	3.76	0.94	0.00
Jan	0.13	1.21	0.40	1.21	0.40	8.06	10.62	**40.46**	23.52	17.07	**33.87**	11.02	15.99	7.12	9.14	12.63	5.91	1.21	0.00	0.00
Feb	0.15	0.15	0.60	0.00	0.89	0.00	13.39	**28.42**	**46.43**	15.18	22.02	9.23	9.97	13.84	5.65	25.60	0.89	7.59	0.00	0.00
Mar	0.13	0.13	0.13	0.00	1.61	3.90	24.46	**32.80**	**34.54**	13.58	16.53	9.81	11.16	9.27	9.14	22.18	2.15	8.33	0.13	0.00
Apr	5.97	2.08	6.53	3.47	8.19	12.36	19.86	**32.78**	**26.11**	11.94	10.56	8.06	10.83	14.72	9.72	10.69	1.67	3.75	0.56	0.14
May- Oct	0.16	1.01	0.85	2.03	2.63	12.16	12.55	**36.71**	19.44	15.50	11.14	10.28	8.15	8.66	17.02	10.31	**26.15**	3.10	1.92	0.25
Nov - Apr	1.11	1.70	1.42	2.41	2.31	7.57	16.15	**34.07**	**29.04**	13.96	19.35	9.05	11.61	9.43	10.25	16.78	8.49	5.01	0.27	0.02
May -Apr	0.63	1.35	1.13	2.22	2.47	9.86	14.35	**35.39**	**24.24**	14.73	15.25	9.67	9.88	9.05	13.63	13.54	17.32	4.06	1.10	0.14

* Bolded values show highest percentage within month.

Table A-10: Total Hourly Uplift Charge as a Percentage of HOEP, On and Off-Peak, May 2005 - April 2007
(%)

	On-Peak and Off-Peak		On-Peak		Off-Peak	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	4.12	5.37	5.80	6.10	2.74	4.70
Jun	5.46	4.34	5.30	4.75	5.61	3.98
Jul	7.08	4.06	7.98	4.35	6.41	3.86
Aug	6.96	4.12	8.23	4.32	5.81	3.95
Sep	4.94	3.36	5.54	3.57	4.41	3.20
Oct	5.84	3.69	6.66	4.03	5.22	3.40
Nov	4.79	5.05	5.82	5.93	3.90	4.20
Dec	4.32	4.52	4.93	4.92	3.86	4.24
Jan	4.09	4.14	4.40	4.63	3.83	3.69
Feb	3.90	3.86	3.99	4.20	3.81	3.55
Mar	3.93	4.04	4.49	4.62	3.39	3.52
Apr	7.00	3.81	7.59	4.38	6.61	3.40
May- Oct	5.73	4.16	6.59	4.52	5.03	3.85
Nov - Apr	4.67	4.24	5.20	4.78	4.23	3.77
May -Apr	5.20	4.20	5.89	4.65	4.63	3.81

Table A-11: Total Hourly Uplift Charge by Component, May 2005 - April 2007 ($ Millions)

	Total Hourly Uplift		RT IOG*		DA IOG*		CMSC**		Operating Reserve		Losses	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	32.44	35.52	2.55	3.85	N/A	N/A	10.75	14.93	3.27	3.03	15.87	13.71
Jun	53.07	28.23	5.32	2.03	N/A	0.35	21.46	12.53	1.37	0.51	24.93	12.82
Jul	86.93	31.69	11.80	1.85	N/A	0.55	43.26	11.65	1.31	0.84	30.56	16.81
Aug	110.14	36.83	20.28	2.91	N/A	0.72	54.96	16.20	1.41	1.05	33.48	15.95
Sep	62.35	15.22	7.43	0.59	N/A	0.16	23.50	5.27	1.33	0.81	30.10	8.40
Oct	56.07	18.88	8.08	1.65	N/A	0.16	22.50	5.72	3.53	0.96	21.96	10.39
Nov	40.24	33.84	7.47	3.38	N/A	4.18	11.26	10.72	3.91	1.34	17.60	14.23
Dec	51.92	24.95	8.52	2.56	N/A	1.08	13.31	7.18	4.21	1.49	25.88	12.64
Jan	34.07	26.73	2.65	2.53	N/A	0.50	11.43	7.28	2.00	2.13	18.00	14.29
Feb	25.29	31.04	1.77	4.21	N/A	0.16	8.40	8.54	1.43	2.24	13.68	15.90
Mar	28.28	31.00	3.66	4.55	N/A	1.31	8.20	8.62	1.76	1.03	14.66	15.49
Apr	35.91	22.74	1.38	2.41	N/A	0.08	15.22	7.15	6.07	1.49	13.25	11.62
May- Oct	401.00	166.37	55.46	12.88	0.00	1.94	176.43	66.30	12.22	7.20	156.90	78.08
Nov - Apr	215.71	170.30	25.45	19.64	0.00	7.31	67.82	49.49	19.38	9.72	103.07	84.17
May -Apr	616.71	336.67	80.91	32.52	0.00	9.25	244.25	115.79	31.60	16.92	259.97	162.25

* The IOG numbers are not adjusted for IOG offsets, which was implemented in July, 2002. IOG offsets are reported in Table A-16. All IOG Reversals have been applied to RT IOG.
** Numbers are adjusted for Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments.

Table A-12: Operating Reserve Prices,
May 2005 - April 2007
($/MWh)

	10N		10S		30R	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	3.27	3.28	5.77	4.55	3.20	3.28
Jun	1.21	0.33	3.11	1.42	1.21	0.33
Jul	0.73	0.50	4.29	2.89	0.73	0.50
Aug	0.53	0.73	5.74	3.19	0.53	0.73
Sep	0.40	0.21	5.99	3.73	0.40	0.21
Oct	2.63	0.56	5.80	2.88	2.55	0.56
Nov	3.35	1.06	4.92	3.73	3.16	1.06
Dec	4.25	1.39	5.88	2.89	4.13	1.39
Jan	1.88	2.09	3.40	3.38	1.87	2.08
Feb	1.54	2.63	2.61	3.64	1.52	2.56
Mar	1.79	0.97	2.63	1.94	1.79	0.95
Apr	6.90	1.40	8.87	2.69	6.68	1.39
May- Oct	1.46	0.94	5.12	3.11	1.44	0.94
Nov - Apr	3.29	1.59	4.72	3.05	3.19	1.57
May -Apr	2.37	1.26	4.92	3.08	2.31	1.25

Table A-13: Exogenous Factors Affecting HOEP, Off-Peak, May 2005 - April 2007* (Average Hourly MW)

	Nuclear		Base-load Hydroelectric		Self-Scheduling Supply		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	7,640	8,857	1,997	1,725	783	688	13,440	13,565	40.20	33.04
Jun	8,938	9,403	1,823	1,642	806	803	15,381	14,522	42.88	33.52
Jul	9,391	10,169	1,788	1,768	760	751	15,723	15,298	48.60	35.09
Aug	9,813	10,823	1,628	1,699	747	750	15,647	14,979	51.17	36.28
Sep	9,690	9,582	1,644	1,812	594	799	14,567	13,570	57.67	25.79
Oct	8,700	8,852	1,573	1,821	684	887	13,997	13,571	47.21	30.35
Nov	9,180	8,226	1,738	1,858	734	890	14,835	14,520	42.68	35.49
Dec	9,448	9,455	1,743	2,114	683	871	16,160	15,093	66.50	28.61
Jan	9,950	9,216	1,759	1,844	679	958	15,871	16,165	46.06	35.45
Feb	10,639	9,721	1,789	1,925	755	929	16,363	17,235	41.94	48.25
Mar	10,040	8,986	1,951	1,977	848	920	15,549	15,589	40.69	43.92
Apr	9,432	8,860	1,911	1,944	667	761	13,741	14,220	28.01	32.83
May- Oct	9,029	9,614	1,742	1,745	729	780	14,793	14,251	47.96	32.35
Nov - Apr	9,782	9,077	1,815	1,944	728	888	15,420	15,470	44.31	37.43
May -Apr	9,405	9,346	1,779	1,844	728	834	15,106	14,861	46.13	34.89

* In this table, off-peak hours are defined as HE22 to HE7, inclusive, for all days of the week.

Table A-14: Exogenous Factors Affecting HOEP, On-Peak,
*May 2005 - April 2007**
(Average Hourly MW)

	Nuclear		Base-load Hydroelectric		Self-Scheduling Supply		Ontario Demand (NDL)		Average HOEP ($/MWh)	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	7,643	8,843	2,456	2,212	918	822	16,478	16,963	62.23	55.80
Jun	8,938	9,412	2,389	2,103	920	936	20,043	18,264	82.51	55.05
Jul	9,395	10,169	2,375	2,314	869	875	20,271	20,038	95.67	61.54
Aug	9,794	10,826	2,261	2,236	895	900	20,106	19,125	114.72	64.45
Sep	9,662	9,538	2,109	2,205	748	932	18,529	16,964	119.43	42.29
Oct	8,708	8,830	1,960	2,270	833	993	17,356	16,996	96.42	47.24
Nov	9,167	8,247	2,301	2,315	915	1,032	18,173	17,820	69.38	59.87
Dec	9,448	9,446	2,359	2,462	837	1,008	19,266	18,189	89.25	46.85
Jan	9,950	9,188	2,169	2,378	843	1,088	19,070	19,345	62.30	50.92
Feb	10,627	9,745	2,329	2,338	900	1,090	19,364	20,029	52.54	66.88
Mar	10,051	8,984	2,440	2,390	987	1,070	18,337	18,340	54.96	62.66
Apr	9,403	8,865	2,279	2,349	798	921	16,580	17,109	54.60	55.50
May- Oct	9,023	9,603	2,258	2,223	864	910	18,797	18,058	95.16	54.40
Nov - Apr	9,774	9,079	2,313	2,372	880	1,035	18,465	18,472	63.84	57.11
May -Apr	9,399	9,341	2,286	2,298	872	972	18,631	18,265	79.50	55.75

* In this table, on-peak hours are defined as HE8 to HE21, inclusive, for all days of the week.

Table A-15: RT IOG Payments, Top 10 Days, November 2006 - April 2007*

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
2007/03/21	18,555	0.49	26.30	20,609
2007/03/09	17,530	0.35	20.17	22,156
2006/11/09	16,994	0.35	20.78	19,953
2006/11/17	13,024	0.32	24.49	20,818
2006/12/04	13,253	0.30	22.79	23,339
2007/03/18	17,934	0.30	16.46	19,607
2006/11/04	15,938	0.29	18.17	18,623
2007/02/22	13,272	0.28	20.73	23,464
2007/03/02	8,156	0.28	34.73	22,266
2007/02/09	13,158	0.27	20.61	24,367
	Total Top 10 days	**3.23**		
	Total for Period	**20.33**		
	% of Total Payments	**15.89**		

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

Table A-16: IOG Offsets due to Implied Wheeling, May 2005 – April 2007

	IOG Payments ($'000)		IOG Offset ($'000)		IOG Offset (%)	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	2,554	3,848	259	39	10.14	1.01
Jun	5,319	2,029	477	158	8.97	7.66
Jul	11,802	1,854	652	63	5.52	3.39
Aug	20,284	2,914	1,118	106	5.51	3.64
Sep	7,426	591	844	24	11.37	4.06
Oct	8,082	1,650	716	79	8.86	4.70
Nov	7,467	3,379	836	190	11.20	5.15
Dec	8,520	2,563	642	283	7.54	10.72
Jan	2,647	2,529	258	199	9.74	7.74
Feb	1,773	4,207	59	319	3.34	7.43
Mar	3,660	4,548	68	401	1.85	8.52
Apr	1,376	2,412	55	144	3.98	5.91
May- Oct	55,467	12,886	4,066	469	8.40	4.08
Nov - Apr	25,443	19,638	1,918	1,536	6.28	7.58
May -Apr	80,910	32,524	5,984	2,005	7.34	5.83

Table A-17: CMSC Payments, Energy and Operating Reserve,
May 2005 - April 2007
($ Millions)

	Constrained Off		Constrained On		Total CMSC for Energy*		Operating Reserves		Total CMSC Payments**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	10.87	9.68	1.96	3.99	12.92	14.61	1.06	1.83	13.98	16.44
Jun	13.55	7.78	6.83	3.76	22.46	12.76	0.37	0.58	22.84	13.34
Jul	29.77	7.78	17.15	4.26	48.66	12.74	0.24	0.41	48.90	13.15
Aug	28.63	6.70	25.56	8.77	56.20	17.34	0.09	0.40	56.29	17.74
Sep	17.04	5.04	7.22	1.32	25.89	6.51	0.13	0.14	26.02	6.65
Oct	17.27	4.11	5.18	1.98	23.52	6.36	0.69	0.64	24.21	6.99
Nov	8.14	5.97	3.53	4.12	12.53	10.67	0.94	1.62	13.48	12.28
Dec	7.46	4.05	4.77	2.81	13.46	7.37	0.92	0.83	14.38	8.20
Jan	7.26	5.00	3.10	2.52	11.94	8.18	0.45	0.90	12.39	9.08
Feb	5.98	4.36	2.56	3.47	9.36	8.35	0.35	1.08	9.72	9.43
Mar	6.11	5.25	2.15	3.35	8.86	9.02	0.45	0.79	9.31	9.81
Apr	11.23	4.36	2.15	2.22	14.78	6.87	1.19	0.82	15.96	7.68
May- Oct	117.13	41.09	63.90	24.08	189.65	70.32	2.58	4.00	192.24	74.31
Nov - Apr	46.18	28.99	18.26	18.49	70.93	50.46	4.30	6.04	75.24	56.48
May -Apr	163.31	70.08	82.16	42.57	260.58	120.78	6.88	10.04	267.48	130.79

* The sum for energy being constrained on and off does not equal the total CMSC for energy in some months**.** This is due to the process for assigning the constrained on and off label to individual intervals not yet being complete**.** Note that these numbers are the net of positive and negative CMSC amounts.
** The totals for CMSC payments do not equal the totals for CMSC payments in Table A-11: Total Hourly Uplift Charge as the values in the uplift table include adjustments to CMSC payments in subsequent months. Neither table includes Local Market Power adjustments.

Table A-18: Share of Constrained On Payments Type of Supplier, May 2005 - April 200 (%)

	Domestic Generators		Imports	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	78	62	22	38
Jun	81	77	19	23
Jul	39	61	61	39
Aug	29	29	71	71
Sep	75	74	25	26
Oct	63	77	37	23
Nov	55	71	45	29
Dec	62	77	38	23
Jan	52	76	48	24
Feb	46	79	54	21
Mar	42	80	58	20
Apr	36	65	64	35
May- Oct	61	63	39	37
Nov - Apr	49	75	51	25
May -Apr	55	69	45	31

Table A-19: Share of CMSC Payments Received by Top Facilities, May 2006 - April 2007 (%)

	Share of Total Payments Received by Top 10 Facilities		Share of Total Payments Received by Top 5 Facilities	
	Constrained Off	**Constrained On**	**Constrained Off**	**Constrained On**
May 06	50.87	48.39	34.08	33.50
Jun 06	56.30	52.09	45.72	39.47
Jul 06	54.69	53.18	39.90	37.61
Aug 06	45.46	67.07	31.34	53.52
Sep 06	61.36	53.48	43.57	36.53
Oct 06	52.05	50.27	38.33	34.97
Nov 06	54.76	59.80	40.09	43.48
Dec 06	57.64	51.97	41.64	38.30
Jan 07	58.93	55.80	40.44	39.19
Feb 07	55.44	65.89	44.3	50.43
Mar 07	65.46	51.99	51.66	37.26
Apr 07	51.31	58.03	39.73	38.21
May – Oct	53.46	54.08	38.82	39.27
Nov - Apr	57.26	57.25	42.98	41.15
May - Apr	55.36	55.66	40.90	40.21

Table A-20: Domestic Supply Cushion Statistics,
*May 2002 - April 2007**

	Pre-Dispatch			Real-time		
	Avg. Supply Cushion (%)	Negative Supply Cushion (# of Hours)	Supply Cushion < 10% (# of Hours)	Avg. Supply Cushion (%)	Negative Supply Cushion (# of Hours)	Supply Cushion < 10% (# of Hours)
May 02	10.9	1	458	11.1	1	442
Jun 02	11.0	58	439	12.1	33	418
Jul 02	10.7	135	445	11.1	139	432
Aug 02	9.8	135	458	8.8	171	456
Sep 02	6.8	235	477	6.1	263	478
Oct 02	6.5	212	508	6.4	221	503
Nov 02	7.0	141	490	7.8	124	467
Dec 02	9.0	122	449	8.5	133	458
Jan 03	11.1	30	427	9.3	56	463
Feb 03	8.5	51	449	7.4	65	465
Mar 03	8.0	93	489	6.6	156	507
Apr 03	7.9	99	493	7.0	143	494
May 03	9.8	57	464	10.1	69	452
Jun 03	13.8	45	330	13.1	58	364
Jul 03	20.3	13	128	20.0	21	163
Aug 03	16.9	12	180	16.1	23	190
Sep 03	10.8	41	433	6.5	211	487
Oct 03	6.7	208	512	3.5	324	563
Nov 03	8.4	71	474	9.1	63	459
Dec 03	9.4	125	426	8.8	97	457
Jan 04	9.6	80	442	8.6	96	468
Feb 04	8.5	54	443	8.7	54	446
Mar 04	9.3	59	472	10.7	70	427
Apr 04	12.0	13	354	10.8	17	389
May 04	15.0	2	225	13.3	2	278
Jun 04	15.5	15	221	13.5	11	284
Jul 04	16.5	8	190	14.5	11	221
Aug 04	18.5	0	98	17.3	0	110
Sep 04	10.3	38	416	9.2	69	416
Oct 04	10.9	13	445	10.5	29	434
Nov 04	7.1	150	493	6.7	145	492
Dec 04	12.0	54	362	10.5	75	379
Jan 05	11.5	21	368	10.4	21	402
Feb 05	13.2	13	247	12.1	11	286
Mar 05	13.3	8	283	12.4	9	316
Apr 05	6.2	156	505	4.5	211	561
May 05	14.0	7	300	10.8	29	392

	Pre-Dispatch			Real-time		
	Avg. Supply Cushion (%)	Negative Supply Cushion (# of Hours)	Supply Cushion < 10% (# of Hours)	Avg. Supply Cushion (%)	Negative Supply Cushion (# of Hours)	Supply Cushion < 10% (# of Hours)
Jun 05	14.0	45	346	13.8	50	328
July 05	15.7	56	294	14.8	63	311
Aug 05	16.7	46	251	14.5	65	303
Sep 05	16.9	27	236	14.3	46	311
Oct 05	13.6	5	342	11.5	12	394
Nov 05	14.2	22	311	12.2	19	382
Dec 05	13.6	37	311	11.2	52	404
Jan 06	18.0	2	170	15.5	6	245
Feb 06	18.0	1	150	16.3	3	180
Mar 06	16.2	4	242	14.7	3	284
Apr 06	19.2	0	154	17.2	0	194
May 06	20.0	34	161	18.4	30	196
Jun 06	22.4	2	146	18.5	6	218
July 06	22.8	1	147	20.9	11	179
Aug 06	24.3	10	80	21.5	20	108
Sep 06	23.9	0	71	20.5	0	135
Oct 06	20.4	3	106	18.4	1	170
Nov 06	13.8	25	310	10.5	52	416
Dec 06	15.5	21	261	14.9	22	270
Jan 07	14.9	1	294	13.6	7	336
Feb 07	17.8	0	102	15.2	0	184
Mar 07	14.7	27	284	12.7	45	341
Apr 07	22.0	0	68	17.6	3	160
May 02 – April 03	8.9	1,312	5,582	8.5	1,505	5,583
May 03 – April 04	11.3	778	4,658	10.5	1,103	4,865
May 04 – April 05	12.5	478	3,853	11.2	594	4,179
May 05 – April 06	15.8	252	3,107	13.9	348	3,728
May 06 – April 07	19.4	124	2,030	16.9	197	2,713

* Revised from previous reports. See the Appendix at the end of Chapter 1 for a detailed description of the changes made to the supply cushion formula.

Table A-21: Share of Real-time MCP Set by Resource, May 2005 - April 2007 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	67	63	0	0	9	14	24	23
Jun	51	61	0	0	30	22	19	17
Jul	43	52	0	0	38	29	20	20
Aug	46	57	0	0	33	22	21	22
Sep	45	56	0	0	34	18	20	26
Oct	58	62	0	0	15	17	27	21
Nov	71	52	0	0	12	25	16	23
Dec	61	62	0	0	23	16	16	22
Jan	84	60	0	0	6	24	11	16
Feb	85	41	0	0	4	39	11	20
Mar	73	49	0	0	9	27	18	24
Apr	65	56	0	0	8	16	27	28
May – Oct	52	59	0	0	27	20	22	22
Nov - Apr	73	53	0	0	10	25	17	22
May - Apr	62	56	0	0	18	22	19	22

Table A-22: Share of Real-time MCP Set by Resource, Off-Peak, May 2005 - April 2007 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	72	79	0	0	1	4	27	17
Jun	67	81	0	0	12	7	20	12
Jul	61	66	0	0	21	16	17	18
Aug	66	74	0	0	16	10	18	16
Sep	66	68	0	0	17	7	17	24
Oct	74	80	0	0	3	5	23	15
Nov	84	66	0	0	2	10	14	24
Dec	72	66	0	0	10	5	18	29
Jan	88	74	0	0	2	8	10	18
Feb	89	55	0	0	1	21	9	24
Mar	86	68	0	0	3	12	11	20
Apr	63	64	0	0	2	9	35	26
May – Oct	68	75	0	0	12	8	20	17
Nov - Apr	80	66	0	0	3	11	16	24
May - Apr	74	70	0	0	8	10	18	20

Table A-23: Share of Real-time MCP Set by Resource, On-Peak,
May 2005 - April 2007
(%)

	Coal		Nuclear		Oil/Gas		Water	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	61	45	0	0	18	26	21	29
Jun	34	37	0	0	48	39	18	24
Jul	18	30	0	0	59	48	23	22
Aug	23	37	0	0	51	34	25	29
Sep	21	41	0	0	54	32	25	27
Oct	36	40	0	0	30	32	33	28
Nov	57	37	0	0	24	41	19	22
Dec	45	57	0	0	41	30	14	13
Jan	79	44	0	0	10	41	11	15
Feb	81	25	0	0	6	59	13	16
Mar	59	26	0	0	16	44	25	29
Apr	67	45	0	0	17	25	15	30
May – Oct	32	38	0	0	43	35	24	27
Nov - Apr	65	39	0	0	19	40	16	21
May - Apr	48	39	0	0	31	38	20	24

Table A-24: Resources Selected in Real-time Market Schedule,
May 2005 - April 2007
(%)

	Injections		Offtakes		Coal		Oil/Gas		Hydroelectric		Nuclear	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	8	4	8	10	17	15	7	6	28	27	48	52
Jun	8	5	6	7	22	19	8	7	21	21	49	53
Jul	8	4	5	7	22	21	8	7	19	18	51	53
Aug	7	3	6	9	22	19	8	7	17	17	53	58
Sep	8	3	7	7	20	17	7	7	17	19	56	58
Oct	8	3	8	8	19	17	6	7	21	23	53	53
Nov	7	7	9	4	17	17	6	8	24	26	52	50
Dec	6	3	7	5	20	13	6	7	23	26	51	54
Jan	6	3	9	6	20	20	5	7	22	24	53	49
Feb	3	3	8	9	18	23	5	8	22	21	54	48
Mar	4	5	9	7	16	19	6	8	24	23	54	51
Apr	2	2	11	9	11	19	6	6	29	24	54	51
May – Oct	8	4	7	8	20	18	7	7	21	21	52	55
Nov - Apr	5	4	9	7	17	18	6	7	24	24	53	51
May - Apr	6	4	8	7	19	18	7	7	22	22	52	53

Table A-25: Resources Selected in the Real-time Market Schedule, May 2005 - April 2007 (TWh)

	Injections		Offtakes		Coal		Oil/Gas		Water		Nuclear		Domestic Generation*	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	0.93	0.51	0.99	1.20	1.95	1.90	0.79	0.73	3.34	3.34	5.69	6.58	11.76	12.55
Jun	1.05	0.60	0.75	0.91	2.85	2.47	1.01	0.89	2.80	2.63	6.44	6.77	13.10	12.77
Jul	1.06	0.57	0.73	1.03	2.96	3.03	1.14	1.00	2.57	2.59	6.99	7.57	13.65	14.19
Aug	0.94	0.41	0.83	1.21	3.08	2.63	1.16	0.92	2.31	2.40	7.29	8.05	13.84	14.00
Sep	0.95	0.36	0.91	0.83	2.55	2.00	0.89	0.79	2.10	2.22	6.96	6.88	12.51	11.90
Oct	0.99	0.36	0.93	0.98	2.35	2.16	0.79	0.88	2.55	2.80	6.48	6.58	12.16	12.41
Nov	0.94	0.77	1.12	0.53	2.19	1.95	0.81	0.91	3.01	3.01	6.60	5.93	12.61	11.80
Dec	0.85	0.43	1.04	0.67	2.74	1.71	0.88	0.86	3.27	3.31	7.03	7.03	13.92	12.92
Jan	0.78	0.44	1.20	0.78	2.78	2.74	0.75	1.00	3.08	3.31	7.40	6.84	14.01	13.89
Feb	0.44	0.41	1.09	1.19	2.38	3.13	0.70	1.02	2.96	2.88	7.14	6.54	13.18	13.57
Mar	0.55	0.65	1.23	0.91	2.21	2.50	0.86	1.03	3.28	2.99	7.47	6.68	13.83	13.20
Apr	0.28	0.28	1.32	1.16	1.36	2.38	0.70	0.76	3.68	3.02	6.78	6.38	12.52	12.55
May – Oct	5.92	2.81	5.14	6.16	15.74	14.19	5.78	5.21	15.67	15.98	39.85	42.43	77.02	77.82
Nov - Apr	3.84	2.98	7.00	5.24	13.66	14.41	4.70	5.58	19.28	18.52	42.42	39.40	80.07	77.93
May - Apr	9.76	5.79	12.14	11.40	29.40	28.60	10.48	10.79	34.95	34.50	82.27	81.83	157.09	155.75

* Domestic generation is the sum of *Coal, Oil/Gas, Water, and Nuclear*.

*Table A-26: Offtakes by Intertie Zone, On-peak and Off-peak, May 2005 - April 2007**
(GWh)

		MB		MI		MN		NY		PQ	
		2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	Off-peak	0.0	0.0	16.4	32.0	0.3	1.2	511.2	625.5	59.5	52.4
	On-Peak	0.1	0.0	31.0	54.0	0.1	0.7	334.5	404.8	34.2	26.4
Jun	Off-peak	0.0	0.0	4.9	9.4	0.1	1.6	406.8	513.3	41.9	46.9
	On-Peak	0.2	0.1	36.4	45.7	0.6	0.1	229.1	274.6	27.4	22.4
Jul	Off-peak	0.0	0.6	20.2	47.2	0.4	7.9	505.2	606.5	42.0	47.8
	On-Peak	0.0	0.5	45.1	75.3	0.2	8.4	100.7	218.7	12.1	15.6
Aug	Off-peak	0.0	0.1	17.4	36.5	1.5	2.6	510.9	668.7	42.7	34.3
	On-Peak	0.0	0.1	43.2	95.4	1.0	1.5	183.1	355.1	28.7	15.5
Sep	Off-peak	0.0	2.0	4.2	14.8	1.1	1.9	602.7	441.7	54.7	48.4
	On-Peak	0.0	0.1	5.9	16.5	0.8	2.7	203.0	282.7	37.5	22.3
Oct	Off-peak	0.0	18.3	18.5	25.4	0.3	4.8	515.1	480.6	59.6	54.4
	On-Peak	0.0	7.6	19.2	38.0	0.2	4.8	280.0	320.9	33.9	25.0
Nov	Off-peak	0.0	30.8	8.8	9.5	0.6	0.8	583.3	275.4	58.3	28.4
	On-Peak	0.0	16.4	23.5	12.0	0.3	1.5	395.3	147.8	46.8	8.4
Dec	Off-peak	0.5	28.4	34.4	27.4	1.0	3.1	593.0	362.0	58.7	37.1
	On-Peak	8.5	13.2	60.7	42.9	1.1	0.9	240.5	138.0	38.6	12.5
Jan	Off-peak	0.0	25.6	5.8	21.2	0.2	2.2	596.8	346.6	54.5	54.6
	On-Peak	0.3	22.9	16.0	44.6	0.4	3.4	488.7	215.5	34.6	46.1
Feb	Off-peak	0.0	25.6	24.5	82.8	0.0	4.4	550.0	480.2	51.1	45.0
	On-Peak	0.1	8.4	58.5	102.0	0.2	2.3	366.9	403.5	34.1	40.3
Mar	Off-peak	0.0	16.8	19.2	38.8	0.1	0.7	639.5	457.9	47.8	55.0
	On-Peak	0.0	7.6	58.3	65.3	1.2	1.9	439.7	221.9	27.0	41.1
Apr	Off-peak	0.0	33.1	121.1	139.5	1.0	7.5	684.2	436.4	43.5	48.9
	On-Peak	0.0	11.6	109.3	240.7	0.5	8.7	347.3	206.9	12.2	29.6
May - Oct	Off-peak	0.0	21.0	81.6	165.2	3.8	20.0	3,051.8	3,336.4	300.4	284.2
	On-Peak	0.3	8.5	180.8	324.9	2.9	18.2	1,330.3	1,856.7	174.0	127.2
	Total	0.3	29.5	262.3	490.1	6.7	38.2	4,382.2	5,193.1	474.3	411.4
Nov–Apr	Off-peak	0.5	160.3	213.8	319.2	2.9	18.8	3,646.7	2,358.5	313.9	269.1
	On-Peak	8.9	80.2	326.3	507.5	3.7	18.7	2,278.4	1,333.6	193.2	178.0
	Total	9.4	240.5	540.0	826.7	6.6	37.5	5,925.1	3,692.1	507.1	447.1
May - Apr	Off-peak	0.5	181.3	295.3	484.4	6.6	38.8	6,698.5	5,694.9	614.2	553.3
	On-Peak	9.2	88.7	507.0	832.4	6.7	36.9	3,608.7	3,190.3	367.1	305.2
	Total	9.7	270.0	802.3	1,316.8	13.3	75.7	10,307.3	8,885.2	981.4	858.5

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

*Table A-27: Injections by Intertie Zone, On-peak and Off-peak, May 2005 - April 2007**
(GWh)

		MB		MI		MN		NY		PQ	
		2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	Off-peak	105.0	58.6	378.4	177.3	32.7	1.2	7.5	5.7	1.2	1.4
	On-Peak	81.4	50.0	258.1	125.6	22.5	13.3	16.1	23.7	22.5	41.7
Jun	Off-peak	88.8	69.7	334.0	243.0	26.4	13.8	27.8	11.7	18.5	5.0
	On-Peak	78.5	62.2	260.2	117.6	23.0	16.0	88.3	25.1	103.6	32.3
Jul	Off-peak	106.2	98.9	307.9	139.8	27.9	23.4	27.9	22.0	48.6	41.5
	On-Peak	72.5	41.9	200.7	60.8	24.4	12.8	126.3	31.6	119.8	100.7
Aug	Off-peak	101.8	78.3	271.7	105.3	29.4	17.1	31.6	7.6	29.2	12.2
	On-Peak	84.3	34.9	227.5	41.5	29.0	11.8	96.1	27.2	41.5	69.9
Sep	Off-peak	88.2	63.7	344.2	115.2	25.8	10.6	20.3	14.4	0.1	0.3
	On-Peak	67.8	47.0	293.6	88.4	21.1	9.5	78.1	6.5	15.4	8.1
Oct	Off-peak	83.6	27.2	433.0	158.4	14.0	15.1	12.9	8.5	0.3	3.5
	On-Peak	60.4	5.9	329.7	92.8	11.3	7.4	33.7	10.1	14.4	28.4
Nov	Off-peak	85.8	7.5	380.1	328.7	21.5	17.6	13.9	17.2	1.7	9.0
	On-Peak	61.1	2.7	308.1	271.0	17.6	12.4	28.6	34.4	25.0	66.2
Dec	Off-peak	82.8	14.9	333.2	111.4	22.0	15.0	32.5	13.1	16.3	39.7
	On-Peak	42.3	3.9	218.7	77.7	13.2	6.5	40.1	45.0	48.8	106.6
Jan	Off-peak	82.0	24.6	356.1	146.0	20.4	18.7	4.7	17.8	1.6	18.5
	On-Peak	61.8	11.0	201.5	87.2	15.9	10.6	12.9	25.0	19.1	81.2
Feb	Off-peak	57.5	8.5	174.4	82.3	15.5	10.3	3.6	16.7	1.2	44.7
	On-Peak	47.0	5.8	104.8	99.6	12.1	11.9	11.5	33.7	15.3	96.6
Mar	Off-peak	54.6	26.8	185.6	220.8	18.8	21.9	2.5	14.8	11.3	33.9
	On-Peak	49.8	25.3	130.1	147.2	20.4	13.3	16.0	45.8	63.6	103.9
Apr	Off-peak	65.5	21.8	91.9	41.7	5.8	15.2	9.7	11.2	5.7	43.3
	On-Peak	41.5	9.8	27.2	21.4	4.7	6.5	4.5	15.5	18.7	89.0
May - Oct	Off-peak	0.0	396.5	2,069.1	938.9	156.2	81.2	127.9	69.9	97.9	63.9
	On-Peak	444.9	241.8	1,569.9	526.6	131.3	70.8	438.6	124.3	317.1	281.1
	Total	1,018.4	638.3	3,639.0	1,465.5	287.5	152.0	566.6	194.2	415.1	344.9
Nov - Apr	Off-peak	428.2	104.0	1,521.4	931.0	104.1	98.7	66.8	90.8	37.8	189.1
	On-Peak	303.5	58.5	990.4	704.1	83.8	61.1	113.7	199.4	190.5	543.5
	Total	731.7	162.5	2,511.8	1,635.1	187.9	159.8	180.4	290.2	228.4	732.5
May - Apr	Off-peak	1,001.6	500.5	3,590.5	1,869.8	260.3	179.8	194.7	160.7	135.8	252.9
	On-Peak	748.4	300.3	2,560.3	1,230.7	215.1	132.0	552.3	323.7	507.7	824.5
	Total	1,750.1	800.7	6,150.8	3,100.6	475.4	311.8	747.0	484.4	643.5	1,077.5

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

Table A-28: Net Exports, May 2002 – April 2007
(MWh)

Year	On-Peak	Off-Peak	Total
May 02	(72,514)	1,745	(70,769)
Jun 02	(23,366)	(29,356)	(52,721)
July 02	(406,531)	(158,218)	(564,749)
Aug 02	(582,328)	(414,927)	(997,255)
Sep 02	(578,164)	(351,175)	(929,339)
Oct 02	(426,990)	(99,699)	(526,690)
Nov 02	(485,625)	(233,782)	(719,408)
Dec 02	(399,211)	(209,584)	(608,795)
Jan 03	(140,277)	(42,945)	(183,221)
Feb 03	(366,361)	(226,394)	(592,755)
Mar 03	(402,052)	(319,095)	(721,147)
Apr 03	(290,996)	(235,224)	(526,219)
May 03	(179,189)	46,864	(132,325)
Jun 03	(201,943)	(55,468)	(257,411)
July 03	179,938	306,194	486,132
Aug 03	(65,822)	147,089	81,267
Sep 03	(322,343)	(167,701)	(490,044)
Oct 03	(476,636)	(411,010)	(887,647)
Nov 03	(142,459)	(222,417)	(364,876)
Dec 03	(249,783)	(97,080)	(346,863)
Jan 04	(174,322)	(32,596)	(206,917)
Feb 04	(239,477)	(66,647)	(306,124)
Mar 04	(67,595)	(12,846)	(80,440)
Apr 04	156,329	223,503	379,832
May 04	350,620	455,317	805,936
Jun 04	233,037	236,563	469,601
July 04	276,589	266,961	543,549
Aug 04	333,185	256,730	589,915
Sep 04	(295,232)	(253,139)	(548,370)
Oct 04	(175,493)	(221,560)	(397,053)
Nov 04	(329,824)	(267,649)	(597,473)
Dec 04	(139,370)	(8,289)	(147,660)
Jan 05	25,133	45,765	70,898

Year	On-Peak	Off-Peak	Total
Feb 05	176,943	91,037	267,980
Mar 05	138,751	180,724	319,475
Apr 05	(207,975)	(187,057)	(395,031)
May 05	(539)	62,414	61,875
Jun 05	(259,946)	(41,718)	(301,664)
July 05	(385,437)	49,339	(336,099)
Aug 05	(222,398)	108,893	(113,506)
Sep 05	(228,831)	184,093	(44,738)
Oct 05	(116,347)	49,794	(66,553)
Nov 05	25,506	148,094	173,600
Dec 05	(13,734)	200,714	186,980
Jan 06	228,771	192,403	421,174
Feb 06	269,666	373,287	642,952
Mar 06	246,164	433,664	679,828
Apr 06	372,724	671,245	1,043,969
May 06	231,286	454,918	686,204
Jun 06	89,601	227,996	317,597
Jul 06	70,645	384,413	455,058
Aug 06	282,463	521,687	804,150
Sep 06	164,847	304,446	469,293
Oct 06	251,726	370,919	622,645
Nov 06	(200,386)	(35,002)	(235,388)
Dec 06	(32,210)	263,848	231,638
Jan 07	117,584	224,741	342,325
Feb 07	309,106	475,559	784,665
Mar 07	2,242	250,960	253,201
Apr 07	355,182	532,213	887,395
May 02 – April 03	(4,174,415)	(2,318,654)	(6,493,069)
May 03 – April 04	(1,783,302)	(342,114)	(2,125,416)
May 04 – April 05	386,364	595,402	981,766
May 05 – April 06	(84,403)	2,432,221	2,347,818
May 06 – April 07	1,642,085	3,976,697	5,618,782

Table A-29: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP, May 2005 - April 2007

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	2.70	6.60	62.46	419.55	(177.13)	(320.42)	17.20	30.00	10.21	20.83
Jun	9.31	4.85	68.73	48.06	(188.58)	(75.35)	19.15	12.76	21.99	14.02
Jul	14.46	7.51	305.94	114.61	(373.17)	(126.79)	41.90	15.25	28.28	17.92
Aug	20.70	9.18	787.29	168.10	(244.47)	(70.41)	64.38	27.51	30.26	16.67
Sep	12.30	2.43	175.45	41.59	(469.99)	(68.61)	39.90	8.99	23.93	17.98
Oct	14.82	3.86	152.39	62.51	(396.93)	(42.27)	40.25	10.85	30.64	13.59
Nov	15.59	8.85	133.49	62.20	(107.11)	(57.01)	28.53	14.87	31.25	25.36
Dec	19.94	8.16	128.93	83.82	(139.24)	(73.61)	32.23	14.21	32.25	15.19
Jan	7.83	6.48	95.15	46.19	(55.84)	(89.72)	16.72	13.18	15.52	20.38
Feb	7.10	12.93	91.97	73.34	(63.38)	(74.95)	13.21	17.30	16.31	29.42
Mar	8.58	11.31	98.99	88.29	(76.97)	(67.96)	16.97	16.83	20.14	28.05
Apr	3.71	6.76	223.01	81.19	(651.03)	(145.64)	31.42	18.26	30.78	24.35
May – Oct	12.38	5.74	258.71	142.40	(308.38)	(117.31)	37.13	17.56	24.22	16.84
Nov - Apr	10.46	9.08	128.59	72.51	(182.26)	(84.82)	23.18	15.78	24.38	23.79
May - Apr	11.42	7.41	193.65	107.45	(245.32)	(101.06)	30.16	16.67	24.30	20.31

Table A-30: Measures of Difference between 1-Hour Ahead Pre-dispatch Prices and HOEP, May 2005 - April 2007

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	4.97	11.94	52.37	1,739.37	(175.32)	(297.46)	16.98	67.55	14.51	29.88
Jun	9.68	5.12	94.12	44.18	(238.58)	(66.34)	18.02	11.20	22.45	15.04
Jul	12.50	6.89	287.05	60.33	(417.67)	(174.98)	37.22	13.61	26.69	18.99
Aug	19.50	9.73	574.86	262.96	(267.59)	(67.76)	58.42	25.64	29.29	19.93
Sep	9.93	3.82	133.67	34.86	(474.82)	(67.49)	36.31	8.56	20.67	24.74
Oct	16.70	6.27	139.88	52.09	(372.26)	(42.27)	35.93	10.44	33.03	21.67
Nov	14.62	8.34	109.26	59.00	(95.91)	(54.45)	24.08	14.52	30.18	24.82
Dec	17.99	8.77	115.79	91.68	(170.48)	(67.32)	29.64	13.50	31.06	22.68
Jan	7.76	7.69	98.88	40.71	(54.91)	(82.87)	15.46	12.08	15.99	23.88
Feb	8.33	14.00	85.36	80.63	(58.70)	(74.28)	12.23	16.26	18.82	32.21
Mar	10.25	11.06	92.99	87.12	(89.21)	(67.96)	15.45	16.30	24.13	28.46
Apr	7.74	9.57	107.75	95.48	(621.55)	(119.44)	29.19	17.18	40.88	31.65
May – Oct	12.21	7.30	213.66	365.63	(324.37)	(119.38)	33.81	22.83	24.44	21.71
Nov - Apr	11.12	9.91	101.67	75.77	(181.79)	(77.72)	21.01	14.97	26.84	27.28
May - Apr	11.66	8.60	157.67	220.70	(253.08)	(98.55)	27.41	18.90	25.64	24.50

Table A-31: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP, May 2005 – April 2007

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	(3.64)	4.34	3.8	15.2
Jun	(1.20)	(0.82)	8.0	2.2
Jul	(4.21)	(0.36)	8.5	4.4
Aug	(3.54)	1.08	8.9	5.1
Sep	(10.75)	(0.60)	0.6	6.4
Oct	(4.81)	0.51	8.4	8.3
Nov	1.79	(1.26)	10.9	5.0
Dec	(0.47)	0.73	9.5	18.7
Jan	0.29	0.27	5.2	7.8
Feb	2.98	4.13	9.3	13.2
Mar	2.31	1.11	11.0	9.5
Apr	(1.50)	0.68	20.9	12.8
May – Oct	(4.69)	0.69	6.4	6.9
Nov - Apr	0.90	0.94	11.1	11.2
May - Apr	(1.90)	0.82	8.8	9.1

* This is an average of hourly differences relative to hourly peak MCP.

Table A-32: Average Monthly HOEP Compared to Average Monthly Peak Hourly MCP, May 2005 – April 2007 ($/MWh)

	Hourly Peak MCP		HOEP		Peak minus HOEP	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	61.66	53.92	53.05	46.32	8.62	7.61
Jun	76.86	52.02	65.99	46.08	10.87	5.95
Jul	92.84	57.79	76.05	50.52	16.78	7.26
Aug	111.25	61.37	88.24	52.72	23.01	8.65
Sep	114.44	39.84	93.70	35.42	20.74	4.42
Oct	97.45	45.91	75.92	40.17	21.53	5.74
Nov	71.09	59.25	58.25	49.71	12.84	9.54
Dec	98.20	47.37	79.77	39.25	18.43	8.12
Jan	63.01	51.90	55.54	44.48	7.47	7.42
Feb	53.44	68.99	48.09	59.12	5.35	9.87
Mar	57.15	64.80	49.01	54.85	8.14	9.95
Apr	52.77	54.94	43.52	46.05	9.25	8.89
May – Oct	92.42	51.81	75.49	45.21	16.93	6.61
Nov – Apr	65.94	57.88	55.70	48.91	10.25	8.97
May - Apr	79.18	54.84	65.59	47.06	13.59	7.79

*Table A-33: Frequency Distribution of Difference Between 1-Hour Pre-dispatch and HOEP, May 2005 - April 2007**

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)															
	< -$50.01		-$50.00 to -$20.01		-$20.00 to -$10.01		-$10.00 to -$0.01		$0.00 to $9.99		$10.00 to $19.99		$20.00 to $49.99		> $50.00	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	1.3	**0.8**	3.2	1.2	2.6	1.2	11.7	6.2	52.8	49.3	16.9	**23.0**	11.3	17.5	0.1	0.8
Jun	0.4	0.1	1.5	1.9	2.5	3.1	10.8	**15.7**	42.1	53.6	22.9	16.1	19.2	9.4	0.6	0.0
Jul	2.6	0.3	3.4	1.2	3.0	2.7	12.4	13.6	32.7	51.6	13.6	17.9	**25.7**	12.4	6.9	0.4
Aug	2.6	0.5	4.4	**3.2**	4.4	**3.9**	11.7	13.2	30.9	44.5	13.2	16.3	21.0	15.3	11.8	**3.1**
Sep	**4.2**	0.3	**7.1**	1.1	**4.7**	1.8	**14.4**	12.6	26.7	**67.5**	10.7	12.8	22.5	3.9	9.7	0.0
Oct	1.8	0.0	5.9	0.9	3.8	2.8	9.4	12.3	33.7	54.7	10.1	19.3	20.6	9.8	14.8	0.1
Nov	1.3	0.3	2.1	3.1	2.6	4.3	9.7	11.1	37.9	42.8	15.6	19.0	23.1	19.0	7.8	0.4
Dec	2.0	0.4	2.7	0.9	3.2	1.3	8.6	10.4	33.1	49.1	13.8	21.5	22.5	15.2	**14.1**	1.2
Jan	0.1	0.3	1.9	1.2	3.1	2.4	12.9	12.9	54.2	47.3	15.3	20.0	9.4	15.9	3.1	0.0
Feb	0.3	0.2	1.0	1.0	0.9	2.8	6.7	8.9	**59.2**	34.1	20.1	19.8	10.7	**31.0**	1.0	2.2
Mar	0.4	0.3	1.9	2.0	2.3	2.7	6.1	12.9	46.4	35.9	21.2	20.8	20.0	24.3	1.8	1.1
Apr	1.0	0.6	2.5	2.2	1.7	2.5	7.2	10.1	43.1	45.1	**27.6**	15.6	16.8	22.6	0.1	1.3
May – Oct	2.1	0.3	4.3	1.6	3.5	2.6	11.7	12.3	36.5	53.5	14.6	17.5	20.0	11.4	7.3	0.7
Nov – Apr	0.8	0.3	2.0	1.7	2.3	2.7	8.5	11.1	45.6	42.4	19.0	19.5	17.1	21.3	4.7	1.0
May - Apr	1.5	0.3	3.1	1.7	2.9	2.6	10.1	11.7	41.1	48.0	16.8	18.5	18.6	16.4	6.0	0.9

* Bolded values show highest percentage within price range.

Table A-34: Difference between 1-Hour Pre-dispatch Price and HOEP within Defined Ranges, May, 2005 - April 2007

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	81.2	90.1	0.0	0.5	18.8	9.4
Jun	84.7	78.6	0.0	0.6	15.3	20.8
Jul	78.8	82.1	0.0	0.1	21.2	17.7
Aug	76.9	79.0	0.0	0.1	23.1	20.8
Sep	69.6	83.5	0.0	0.7	30.4	15.8
Oct	79.2	84.0	0.0	0.0	20.8	16.0
Nov	83.9	81.0	0.4	0.3	15.7	18.8
Dec	83.5	86.7	0.0	0.3	16.5	13.0
Jan	81.9	82.8	0.1	0.4	18.0	16.8
Feb	91.1	86.6	0.0	0.5	8.9	13.0
Mar	89.3	82.0	0.1	0.1	10.6	17.9
Apr	87.5	84.0	0.1	0.6	12.4	15.4
May – Oct	78.4	82.9	0.0	0.3	21.6	16.8
Nov – Apr	86.2	83.8	0.1	0.3	13.7	15.8
May - Apr	82.3	83.4	0.1	0.3	17.7	16.3

Table A-35: Difference between 1-Hour Pre-dispatch Price and Hourly Peak MCP within Defined Ranges, May, 2005 - April 2007

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	59.4	73.7	4.3	2.3	36.3	24.1
Jun	64.3	51.4	2.1	4.2	33.6	44.4
Jul	53.2	57.9	1.9	2.2	45.9	39.9
Aug	52.3	51.8	2.2	3.8	45.6	44.5
Sep	43.6	56.5	3.5	7.2	52.9	36.3
Oct	51.3	59.7	2.7	3.9	46.0	36.4
Nov	63.2	55.0	2.5	4.2	34.3	40.8
Dec	58.6	60.0	2.4	4.0	39.0	36.0
Jan	62.1	56.3	2.4	5.1	35.5	38.6
Feb	75.6	63.1	2.1	5.1	22.4	31.9
Mar	70.8	56.1	3.0	2.8	26.2	41.1
Apr	71.8	60.0	2.1	3.5	26.1	36.5
May – Oct	54.0	58.5	2.8	3.9	43.4	37.6
Nov – Apr	67.0	58.4	2.4	4.1	30.6	37.5
May - Apr	60.5	58.5	2.6	4.0	37.0	37.5

Table A-36: Percentage Intervals with Operating Reserve Reductions Due to Shortage (Market Schedule), May 2005 - April 2007

	No Reductions		>1 MW and <200 MW		>200 MW and <400 MW		>400 MW and <800 MW		>800 MW	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	98.4	100.0	0.5	0.0	0.7	0.0	0.4	0.0	0.0	0.0
Jun	98.7	100.0	0.1	0.0	0.5	0.0	0.7	0.0	0.1	0.0
Jul	99.0	100.0	0.6	0.0	0.1	0.0	0.3	0.0	0.0	0.0
Aug	99.8	100.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sep	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oct	98.8	100.0	0.0	0.0	0.6	0.0	0.4	0.0	0.1	0.0
Nov	99.0	100.0	0.4	0.0	0.5	0.0	0.1	0.0	0.0	0.0
Dec	99.9	100.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Jan	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feb	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mar	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Apr	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
May – Oct	99.1	100.0	0.2	0.0	0.3	0.0	0.3	0.0	0.0	0.0
Nov – Apr	99.8	100.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0
May - Apr	99.5	100.0	0.2	0.0	0.2	0.0	0.2	0.0	0.0	0.0

Table A-37: Demand Forecast Error; Pre-Dispatch versus Average and Peak Hourly Demand, May 2005 - April 2007

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	308	325	274	302	228	196	171	158	2.0	2.0	1.8	1.9	1.4	1.2	1.1	1.0
Jun	530	379	466	335	363	244	259	185	2.9	2.2	2.6	2.0	1.9	1.4	1.4	1.0
Jul	573	485	466	413	424	344	288	251	3.1	2.6	2.5	2.3	2.3	1.8	1.5	1.3
Aug	418	420	368	353	315	301	224	210	2.2	2.4	2.0	2.0	1.6	1.6	1.2	1.2
Sep	325	297	280	265	248	182	190	144	1.9	1.9	1.6	1.7	1.4	1.1	1.1	0.9
Oct	270	309	245	282	203	190	156	152	1.7	1.9	1.5	1.8	1.2	1.2	0.9	0.9
Nov	347	319	314	309	209	178	167	153	2.0	1.9	1.8	1.9	1.2	1.1	1.0	0.9
Dec	360	343	327	313	224	209	175	169	2.0	2.0	1.8	1.8	1.2	1.2	1.0	1.0
Jan	381	344	329	316	256	208	202	161	2.1	1.9	1.8	1.7	1.4	1.1	1.1	0.9
Feb	352	342	315	309	222	210	175	165	1.9	1.8	1.7	1.6	1.2	1.1	0.9	0.8
Mar	315	298	285	271	189	199	155	164	1.8	1.7	1.6	1.6	1.1	1.1	0.9	0.9
Apr	296	282	265	255	187	177	152	140	1.9	1.8	1.7	1.6	1.2	1.1	0.9	0.8
May – Oct	404	369	350	325	297	243	215	183	2.3	2.2	2.0	1.9	1.7	1.4	1.2	1.1
Nov – Apr	342	321	306	296	215	197	171	159	1.9	1.8	1.7	1.7	1.2	1.1	1.0	0.9
May - Apr	373	345	328	310	256	220	193	171	2.1	2.0	1.9	1.8	1.4	1.2	1.1	1.0

Table A-38: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges, May 2005 – April 2007*
(%)

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	1	2	16	16	17	16	18	23	18	19	15	13	15	11	1	0	52	57	48	43
Jun	12	4	30	19	15	15	14	18	10	18	8	14	10	11	1	1	71	56	29	44
Jul	12	9	26	23	13	15	12	15	11	11	9	10	14	14	3	3	63	62	37	38
Aug	5	5	21	18	12	13	15	17	15	15	12	14	17	15	3	2	53	53	47	47
Sep	1	0	13	14	12	15	18	23	16	19	13	15	22	12	4	1	44	53	56	47
Oct	0	1	8	16	12	17	18	19	22	21	18	13	20	12	1	0	39	54	61	46
Nov	2	1	15	15	15	19	18	20	20	21	16	12	14	11	1	1	50	54	50	46
Dec	2	1	18	17	15	16	17	19	20	17	13	14	15	13	0	1	52	54	48	46
Jan	3	1	18	17	12	15	18	21	15	20	14	12	17	12	3	1	51	54	49	46
Feb	2	3	17	17	14	17	19	21	17	17	14	12	14	12	1	0	54	58	46	42
Mar	2	2	14	15	16	14	20	20	21	19	14	15	12	14	0	1	52	50	48	50
Apr	1	0	14	14	15	15	20	24	22	21	16	16	13	10	0	0	49	53	51	47
May – Oct	5	4	19	18	14	15	16	19	15	17	13	13	16	13	2	1	54	56	46	44
Nov – Apr	2	1	16	16	15	16	19	21	19	19	15	14	14	12	1	1	51	54	49	46
May - Apr	4	2	18	17	14	16	17	20	17	18	14	13	15	12	2	1	53	55	48	45

* This data includes dispatchable loads.

*Table A-39: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities, May 2005 – April 2007**

	Pre-Dispatch (MW)		Difference (Pre-Dispatch – Actual) in MW						Fail Rate** (%)	
			Maximum		Minimum		Average			
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	722,187	688,775	187.1	292.0	(61.2)	(68.5)	20.1	30.8	2.2	3.1
Jun	724,804	737,975	242.5	188.8	(43.2)	(99.3)	49.7	41.2	4.7	4.4
Jul	701,810	722,572	244.3	239.2	(70.6)	(100.7)	55.2	59.2	6.1	6.4
Aug	667,215	709,496	200.7	206.1	(167.3)	(55.1)	15.4	46.3	1.4	5.6
Sep	543,183	727,818	258.6	250.6	(62.0)	(136.4)	22.4	41.0	3.2	4.8
Oct	629,537	827,835	170.6	164.7	(275.8)	(136.8)	(1.3)	21.5	(0.1)	2.1
Nov	670,401	826,319	185.0	221.2	(164.4)	(148.7)	1.8	16.6	(0.3)	1.9
Dec	638,461	861,556	233.2	181.9	(108.6)	(168.0)	2.0	(2.5)	0.4	0.1
Jan	645,993	927,931	141.6	141.2	(81.2)	(216.3)	11.8	8.9	1.7	0.9
Feb	618,271	843,514	134.3	187.2	(89.1)	(179.8)	8.2	0.1	1.1	0.2
Mar	767,993	914,915	131.6	244.2	(102.1)	(191.2)	(2.6)	(14.0)	(0.2)	(1.1)
Apr	636,415	766,192	175.1	185.8	(126.5)	(194.9)	15.4	8.3	2.7	1.2
May – Oct	664,789	735,745	217.3	223.6	(113.3)	(99.4)	26.9	40.0	2.9	4.4
Nov – Apr	662,922	856,738	166.8	193.6	(112.0)	(183.2)	6.1	2.9	0.9	0.5
May - Apr	663,856	796,242	192.0	208.6	(112.7)	(141.3)	16.5	21.5	1.9	2.5

* Self-scheduled generators comprise list as well as those dispatchable units temporarily classified as self-scheduling during testing phases following an outage for major maintenance.
** Fail rate is calculated as the average difference divided by the Pre-Dispatch offer

Table A-40: Discrepancy between Wind Generators' Offered and Delivered Quantities, May 2006 – April 2007

	Pre-Dispatch (MW)	Difference (Pre-dispatch – Actual) (MW)			Fail Rate* (%)
		Maximum	Minimum	Average	
	2006 2007	2006 2007	2006 2007	2006 2007	2006 2007
May	19,881	76.3	(61.7)	1.9	2.8
Jun	24,370	93.5	(124.7)	3.5	8.4
Jul	28,632	75.6	(97.8)	3.3	8.3
Aug	27,638	89.9	(91.5)	8.2	26.0
Sep	53,686	130.1	(115.1)	9.8	19.5
Oct	83,010	96.1	(116.2)	9.5	12.2
Nov	59,927	111.3	(113.2)	7.3	14.1
Dec	91,241	143.8	(94.1)	6.2	8.0
Jan	86,865	124.9	(129.4	11.5	17.3
Feb	98,331	134.9	(145.5)	7.6	9.3
Mar	86,182	144.9	(148.5)	(11.2)	(10.5)
Apr	73,971	101.7	(118.4)	2.8	9.5
May-Oct	39,536	93.6	(101.2)	6.1	12.9
Nov-Apr	82,753	126.9	(124.8)	4.0	8.0
May-Apr	61,145	110.2	(113.0)	5.0	10.4

* Fail rate is calculated as the average difference divided by the Pre-Dispatch offer

*Table A-41: Failed Imports into Ontario, May 2005 - April 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	355	121	650	818	168	135	6.1	3.1
Jun	348	187	916	848	190	153	5.9	4.6
Jul	349	207	1,110	1,020	192	123	6.0	4.3
Aug	301	171	1,025	405	188	113	5.7	4.5
Sep	316	54	885	300	173	76	5.4	1.1
Oct	335	109	810	240	134	69	4.3	2.1
Nov	273	242	539	595	112	114	3.2	3.5
Dec	293	137	667	384	141	102	4.6	3.1
Jan	212	138	910	553	126	110	3.3	3.3
Feb	211	230	525	502	107	92	4.9	4.9
Mar	174	217	405	550	102	112	3.1	3.6
Apr	84	105	421	250	104	89	3.1	3.3
May-Oct	334	142	899	605	174	112	5.6	3.3
Nov-Apr	208	178	578	472	115	103	3.7	3.6
May-Apr	271	160	739	539	145	107	4.6	3.4

* These data have been revised [from what?] to exclude transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-42: Failed Imports into Ontario, On-Peak,
*May 2005 - April 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	157	66	631	818	128	123	4.8	3.1
Jun	184	78	916	490	177	132	5.6	3.9
Jul	171	115	1,110	587	219	107	6.5	4.8
Aug	161	72	1,025	405	202	91	6.4	3.4
Sep	164	20	885	300	162	99	5.3	1.2
Oct	138	60	466	240	129	74	3.8	3.0
Nov	134	148	539	595	110	112	3.3	4.1
Dec	139	73	550	300	124	101	4.5	3.0
Jan	71	67	910	553	143	99	3.2	3.0
Feb	90	119	525	502	99	93	4.5	4.3
Mar	69	131	300	400	86	108	2.1	4.1
Apr	30	48	223	235	68	78	2.1	2.6
May-Oct	163	69	839	473	170	104	5.4	3.2
Nov-Apr	89	98	508	431	105	99	3.3	3.5
May-Apr	126	83	673	452	137	101	4.3	3.4

* These data have been revised to exclude transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-43: Failed Imports into Ontario, On-Peak,
*May 2005 - April 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	198	55	650	500	200	148	7.0	3.1
Jun	164	109	672	848	205	168	6.4	5.1
Jul	178	92	771	1,020	166	143	5.4	3.9
Aug	140	99	777	385	172	128	5.0	5.4
Sep	152	34	700	200	185	63	5.6	1.0
Oct	197	49	810	191	137	63	4.7	1.4
Nov	139	94	422	525	114	116	3.1	2.8
Dec	154	64	667	384	156	103	4.7	3.3
Jan	141	71	492	483	117	121	3.4	3.7
Feb	121	111	505	480	113	91	5.1	5.9
Mar	105	86	405	550	113	117	4.2	3.1
Apr	54	57	421	250	125	97	3.6	4.0
May-Oct	172	73	730	524	178	119	5.7	3.3
Nov-Apr	119	81	485	445	123	108	4.0	3.8
May-Apr	145	77	608	485	150	113	4.9	3.6

* These data have been revised to exclude transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed imports divided by the sum of pre-dispatch imports on a monthly basis

Table A-44: Failed Exports from Ontario, May 2005 - April 2007* (Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	483	564	991	1,136	267	318	11.6	13.0
Jun	457	324	1,128	817	238	176	12.7	5.9
Jul	337	354	1,350	850	275	201	11.3	6.5
Aug	368	399	1,478	914	226	187	9.2	5.8
Sep	341	422	1,000	788	241	192	8.3	8.9
Oct	477	412	1,188	874	231	185	10.6	7.3
Nov	503	317	850	765.5	224	157	9.2	8.6
Dec	461	387	1,098	865	221	169	9.0	8.9
Jan	543	415	1,132	801	216	153	8.9	7.5
Feb	541	375	1,190	1,220	282	130	12.3	3.9
Mar	527	404	975	671	260	142	10.0	5.9
Apr	543	455	1,000	1,028	291	160	10.7	5.9
May-Oct	411	413	1,189	897	246	210	10.6	7.9
Nov-Apr	520	392	1,041	892	249	152	10.0	6.8
May-Apr	465	402	1,115	894	248	181	10.3	7.3

* These data have been revised to exclude transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

*Table A-45: Failed Exports from Ontario, On-Peak, May 2005 - April 2007**
(Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	180	239	925	1,029	216	256	8.9	11.2
Jun	187	123	800	785	198	153	11.2	5.2
Jul	102	126	1,180	850	224	193	12.6	7.1
Aug	143	161	815	914	191	215	9.7	6.9
Sep	125	148	716	644	164	163	7.7	6.9
Oct	180	144	600	874	144	162	7.2	5.6
Nov	185	138	619	527	160	125	6.0	8.5
Dec	165	127	1,057	865	173	133	7.5	7.5
Jan	242	183	805	665	169	117	7.1	6.0
Feb	261	154	1,190	1,220	258	124	12.8	3.3
Mar	225	175	775	500	209	91	8.2	4.5
Apr	201	209	836	930	245	142	9.5	5.6
May-Oct	153	157	839	849	190	190	9.5	7.1
Nov-Apr	213	164	880	785	202	122	8.5	5.9
May-Apr	183	161	860	817	196	156	9.0	6.5

* These data have been revised to exclude transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-46: Failed Exports from Ontario, Off-Peak, May 2005 - April 2007* (Incidents and Average Magnitude)

	Number of Incidents		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)		Failure Rate (%)**	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	303	325	991	1,136	297	363	13.3	14.3
Jun	270	201	1,128	817	266	190	13.7	6.3
Jul	235	228	1,350	749	298	205	11.0	6.2
Aug	225	238	1,478	709	249	167	8.9	5.1
Sep	216	274	1,000	788	285	208	8.5	10.1
Oct	297	268	1,188	710	284	198	12.4	8.4
Nov	318	179	850	766	262	181	11.3	8.6
Dec	296	260	1,098	725	248	186	9.7	9.6
Jan	301	232	1,132	801	253	181	10.4	8.5
Feb	280	221	950	565	304	133	12.0	4.4
Mar	302	229	975	671	299	180	11.3	6.8
Apr	342	246	1,000	1,028	317	175	11.3	6.1
May-Oct	258	256	1,189	818	280	222	11.3	8.4
Nov-Apr	307	228	1,001	759	281	173	11.0	7.3
May-Apr	282	242	1,095	789	280	197	11.2	7.8

* These data have been revised to exclude transaction failures of less than 1 MW.
** The failure rate is calculated as the sum of failed exports divided by the sum of pre-dispatch exports on a monthly basis

Table A-47: Sources of Total Operating Reserve Requirements, On-Peak Periods, May 2005 – April 2007

	% of Total Requirements													
	Average Hourly Reserve (MW)		Dispatchable Load		Hydroelectric		Fossil		CAOR		Import		Export	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	1,413	1,366	23.6	23.9	64.3	61.7	7.2	6.7	0.9	0.9	2.1	1.6	1.9	4.8
Jun	1,395	1,368	24.6	22.3	68.7	67.0	5.1	5.4	0.2	0.0	1.0	2.4	0.5	2.8
Jul	1,402	1,370	19.5	24.0	73.5	65.8	4.8	6.3	0.1	0.0	1.7	1.8	0.4	2.1
Aug	1,387	1,380	18.6	17.1	76.1	74.4	4.3	5.8	0.1	0.3	0.3	0.4	0.7	2.0
Sep	1,398	1,367	19.7	20.4	75.1	71.8	4.8	4.7	0.1	0.0	0.1	0.4	0.2	2.8
Oct	1,463	1,384	16.2	18.4	75.9	71.2	5.7	5.1	0.4	0.0	0.2	1.3	1.6	2.9
Nov	1,524	1,379	19.3	20.8	68.5	69.7	8.0	6.0	0.8	0.0	0.1	0.5	3.3	0.9
Dec	1,430	1,365	20.0	18.4	65.2	71.2	8.1	6.1	1.4	0.2	0.6	1.8	4.2	0.6
Jan	1,370	1,373	22.4	20.4	65.6	67.2	4.9	7.4	0.4	0.2	2.7	0.0	3.9	4.1
Feb	1,367	1,399	23.4	21.1	59.4	66.9	5.4	6.2	0.2	0.3	7.0	0.2	4.4	4.3
Mar	1,368	1,387	23.0	21.8	61.9	68.1	6.7	4.1	0.3	0.2	3.1	1.4	4.6	4.0
Apr	1,367	1,379	25.2	20.6	49.6	69.1	20.4	5.2	1.2	0.3	0.8	0.9	2.5	2.7
May-Oct	1,410	1,373	20.4	21.0	72.3	68.6	5.3	5.7	0.3	0.2	0.9	1.3	0.9	2.9
Nov-Apr	1,404	1,380	22.2	20.5	61.7	68.7	8.9	5.8	0.7	0.2	2.4	0.8	3.8	2.8
May-Apr	1,407	1,376	21.3	20.8	67.0	68.7	7.1	5.7	0.5	0.2	1.6	1.1	2.4	2.8

Table A-48: Sources of Total Operating Reserve Requirements, Off-Peak Periods, May 2005 – April 2007

	Average Hourly Reserve (MW)		% of Total Requirements													
			Dispatchable Load		Hydroelectric		Fossil		CAOR		Import		Export	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	1,413	1,487	30.1	21.5	61.4	68.4	7.8	7.8	0.3	0.2	0.3	0.4	0.2	1.6
Jun	1,418	1,435	32.1	21.6	61.8	68.0	5.9	6.4	0.0	0.0	0.1	0.2	0.1	3.8
Jul	1,410	1,368	25.2	22.3	68.8	65.1	5.4	8.4	0.0	0.2	0.6	0.3	0.1	3.8
Aug	1,395	1,370	18.8	17.4	75.2	71.9	5.5	7.1	0.0	0.0	0.4	0.2	0.0	3.4
Sep	1,399	1,367	18.6	19.5	74.7	70.0	6.7	6.7	0.0	0.0	0.1	0.0	0.0	3.8
Oct	1,460	1,368	15.0	17.7	78.9	69.0	5.0	6.9	0.0	0.0	0.0	0.0	1.1	4.5
Nov	1,430	1,368	20.3	19.2	74.6	70.1	5.0	6.1	0.0	0.0	0.0	0.0	0.2	1.8
Dec	1,430	1,366	18.7	16.2	74.4	71.4	4.9	7.1	0.3	0.1	0.0	1.2	1.6	1.7
Jan	1,375	1,367	22.1	19.5	73.3	67.7	4.3	6.4	0.0	0.0	0.0	0.0	0.1	4.3
Feb	1,368	1,371	23.5	20.3	72.0	70.0	4.2	3.7	0.1	0.1	0.0	0.0	0.1	4.8
Mar	1,368	1,369	23.6	21.1	70.6	69.1	5.5	3.9	0.1	0.0	0.0	0.5	0.0	4.3
Apr	1,367	1,395	25.1	19.8	61.3	69.3	11.4	5.1	0.7	0.1	0.3	0.3	1.2	3.2
May-Oct	1,416	1,399	23.3	20.0	70.1	68.7	6.0	7.2	0.0	0.1	0.3	0.2	0.2	3.5
Nov-Apr	1,390	1,373	22.2	19.4	71.0	69.6	5.9	5.4	0.2	0.0	0.0	0.3	0.5	3.3
May-Apr	1,403	1,386	22.8	19.7	70.6	69.2	6.0	6.3	0.1	0.0	0.2	0.3	0.4	3.4

Table A-49: Day Ahead Forecast Error, November 2003 – April 2007 (as of Hour 18)

Year	Month	Average Forecast Error (MW)	Average Absolute Error (% of Peak Demand)	No. of Hours with Forecast Error ≥ 3%	Percentage of Hours with Absolute Error ≥ 3%
2003	Nov	160	2.09	183	25
	Dec	224	2.27	207	28
2004	Jan	158	2.33	215	29
	Feb	337	2.16	176	25
	Mar	148	2.27	220	30
	Apr	166	2.36	223	31
	May	123	2.21	208	23
	Jun	0	2.35	221	36
	Jul	328	3.35	345	49
	Aug	223	2.74	288	39
	Sep	89	2.27	212	28
	Oct	85	1.74	125	20
	Nov	184	1.88	144	20
	Dec	146	2.40	213	29
2005	Jan	213	2.04	170	23
	Feb	188	1.69	118	18
	Mar	45	1.83	139	19
	Apr	82	2.09	186	26
	May	44	1.85	137	23
	Jun	255	3.13	299	36
	Jul	450	4.30	382	49
	Aug	220	3.03	299	39
	Sep	72	2.22	198	28
	Oct	56	1.75	133	18
	Nov	(67)	1.86	151	21
	Dec	(20)	1.78	139	19
2006	Jan	11	2.21	215	29
	Feb	(11)	1.76	120	18
	Mar	28	1.49	80	11
	Apr	0	1.88	143	20
	May	(98)	1.87	151	20
	Jun	(100)	2.91	279	39
	Jul	178	3.02	317	43
	Aug	26	2.55	258	35
	Sep	101	1.70	127	18
	Oct	6	1.60	94	13
	Nov	(76)	1.52	83	12
	Dec	15	1.73	114	15
2007	Jan	(67)	1.52	70	9
	Feb	23	1.52	81	12
	Mar	(77)	1.61	94	13
	Apr	(38)	1.55	84	12

Table A-50: Average One Hour Ahead Forecast Error, November 2003 – April 2007

Year	Month	Peak Forecast Error (MW)	Average Absolute Error (% of Peak Demand)	No. of Hours with Forecast Error ≥ 2%	Percentage of Hours with Absolute Error ≥ 2%
2003	Nov	93	1.20	127	18
	Dec	118	1.28	159	21
2004	Jan	132	1.24	132	18
	Feb	145	1.10	106	15
	Mar	118	1.27	145	19
	Apr	124	1.36	165	23
	May	37	1.20	128	15
	Jun	29	1.37	170	23
	Jul	53	1.49	203	28
	Aug	48	1.36	179	21
	Sep	22	1.18	124	15
	Oct	21	1.04	107	13
	Nov	83	1.05	102	14
	Dec	60	1.25	146	20
2005	Jan	85	1.01	86	12
	Feb	36	0.91	58	9
	Mar	48	0.86	53	7
	Apr	31	0.99	85	12
	May	9	1.07	98	15
	Jun	148	1.36	160	23
	Jul	120	1.53	210	28
	Aug	30	1.16	127	21
	Sep	(52)	1.08	90	15
	Oct	(49)	0.94	70	9
	Nov	10	0.97	73	10
	Dec	19	0.95	74	10
2006	Jan	10	1.09	107	14
	Feb	17	0.92	59	9
	Mar	19	0.86	53	7
	Apr	4	0.94	73	10
	May	38	0.96	82	11
	Jun	45	1.03	92	13
	Jul	82	1.32	160	22
	Aug	38	1.15	123	17
	Sep	8	0.89	56	8
	Oct	23	0.93	59	8
	Nov	18	0.90	58	8
	Dec	20	0.98	75	10
2007	Jan	19	0.87	53	7
	Feb	42	0.84	41	6
	Mar	3	0.92	67	9
	Apr	8	0.84	42	6

Table A-51: Monthly Payment for Reliability Programs,
May 2002 – April 2007
($ millions)

Year	Month	DA IOG*	RT IOG*	OR	DA GCG	SGOL	TDRP	ELRP	HADL
2002	May		0.08	5.04					
	Jun		1.42	7.08					
	Jul		66.51	4.84					
	Aug		46.00	2.02					
	Sep		82.53	6.57					
	Oct		5.60	4.45					
	Nov		2.02	2.50					
	Dec		22.15	2.60					
2003	Jan		3.52	2.95					
	Feb		13.68	2.93					
	Mar		7.94	2.83					
	Apr		2.94	7.48					
	May		2.24	8.15					
	Jun		6.04	5.38					
	Jul		1.40	2.19					0.01
	Aug		1.58	2.96					0.00
	Sep		1.41	4.03		0.07			0.00
	Oct		1.88	1.90		0.11			0.00
	Nov		1.17	6.30		0.72			0.00
	Dec		7.63	4.99		1.18			0.00
2004	Jan		13.91	4.59		1.46			0.00
	Feb		7.29	2.51		1.52			0.00
	Mar		3.91	5.96		0.93			0.00
	Apr		2.76	8.60		1.10			0.00
	May		1.68	8.10		0.33			0.00
	Jun		1.33	3.79		0.78			0.00
	Jul		1.03	3.89		1.62			0.00
	Aug		0.78	1.30		2.33			0.00
	Sep		1.15	1.44		2.46			0.00
	Oct		1.12	0.97		2.15			0.00
	Nov		6.52	3.66		2.62			0.00
	Dec		3.74	2.55		2.69			0.00
2005	Jan		4.35	3.27		2.80			0.00
	Feb		1.89	2.10		2.54			0.00
	Mar		3.00	2.67		2.94			0.00
	Apr		4.81	7.75		2.94			0.00
	May		2.30	3.27		2.24	0.00		0.00
	Jun		4.84	1.37		2.77	0.00		0.00
	Jul		11.15	1.31		2.89	0.01		0.00
	Aug		19.17	1.41		2.75	0.09		0.00
	Sep		6.58	1.33		3.17	0.27		0.02
	Oct		7.37	3.55		3.65	0.31		0.01
	Nov		6.63	3.92		3.62	0.24		0.00

Year	Month	DA IOG*	RT IOG*	OR	DA GCG	SGOL	TDRP	ELRP	HADL
	Dec		7.88	4.23		4.07	0.06		0.00
2006	Jan		2.39	2.00		4.56	0.17		0.00
	Feb		1.71	1.44		0.77	0.03		0.00
	Mar		3.59	1.76		0.48	0.02		0.00
	Apr		1.32	6.07		0.61	0.01		0.00
	May		3.81	3.07		0.43	-0.01		0.00
	Jun	0.35	1.91	0.54	0.56	0.52	0.01	0.00	0.00
	Jul	0.55	1.81	0.84	1.89	0.18	0.00	0.00	0.00
	Aug	0.72	2.82	1.05	2.37	0.09	0.03	0.01	0.00
	Sep	0.16	0.57	0.81	1.69	0.13	0.07	0.00	0.00
	Oct	0.16	1.60	0.97	1.14	0.22	0.00	0.00	0.00
	Nov	4.18	3.50	1.34	2.00	0.18	0.00	0.00	0.00
	Dec	1.08	2.35	1.50	2.03	0.15	0.00	0.00	0.00
2007	Jan	0.50	2.37	2.13	2.35	0.17	0.00	0.00	0.00
	Feb	0.16	3.98	2.24	2.61	0.30	0.01	0.00	0.00
	Mar	1.31	4.34	1.04	1.97	0.20	0.01	0.00	0.00
	Apr	0.08	2.29	1.50	1.70	0.09	0.00	0.00	0.00
Total		9.25	443.29	199.02	20.31	67.55	1.34	0.01	0.03

* Note: A total of about $0.83 million was eventually clawed back but not excluded from the table.

*Table A-52: Low Price Hours, November 2006 - April 2007**

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2006/11/12	4	12,759	12,508	-2.0	210	30.59	17.01	-44.4
2006/11/17	4	13,389	13,178	-1.6	95	28.27	19.02	-32.7
2006/11/18	3	13,471	13,150	-2.4	0	27.87	17.18	-38.4
2006/11/19	4	12,745	12,675	-0.6	0	21.00	17.33	-17.5
2006/11/19	5	12,824	12,637	-1.5	0	22.50	15.54	-30.9
2006/11/19	6	13,014	12,802	-1.6	0	20.50	12.26	-40.2
2006/11/19	7	13,453	13,189	-2.0	0	20.50	12.18	-40.6
2006/11/19	8	14,350	13,783	-4.0	200	29.27	6.97	-76.2
2006/11/23	1	15,203	14,794	-2.7	100	27.53	18.14	-34.1
2006/11/23	2	14,715	14,303	-2.8	300	25.00	5.32	-78.7
2006/11/23	3	14,144	14,040	-0.7	250	20.00	5.20	-74.0
2006/11/23	4	13,987	13,923	-0.5	0	22.87	12.70	-44.5
2006/11/23	5	14,371	14,107	-1.8	0	22.00	9.79	-55.5
2006/11/23	6	15,540	14,760	-5.0	76	28.67	15.55	-45.8
2006/11/24	6	15,222	14,466	-5.0	0	28.70	19.08	-33.5
2006/11/26	2	13,308	12,862	-3.4	-2	28.18	17.13	-39.2
2006/11/26	3	12,882	12,451	-3.4	0	23.17	10.15	-56.2
2006/11/26	4	12,729	12,231	-3.9	0	20.00	5.07	-74.7
2006/11/26	6	12,966	12,361	-4.7	215	29.98	5.15	-82.8
2006/11/26	7	13,121	12,782	-2.6	275	28.47	19.74	-30.7
2006/11/27	3	13,032	12,901	-1.0	70	27.55	11.80	-57.2
2006/11/29	3	13,856	13,615	-1.7	0	27.80	18.01	-35.2
2006/11/30	3	13,490	13,064	-3.2	0	28.34	6.97	-75.4
2006/11/30	4	13,026	12,939	-0.7	100	27.27	17.79	-34.8
2006/11/30	5	13,162	13,044	-0.9	0	24.00	11.68	-51.3
Nov 2006**	25	13,630	13,303	-2.4	76	25.60	13.07	-48.9
2006/12/12	4	14,234	13,968	-1.9	450	27.69	4.63	-83.3
2006/12/12	5	14,485	14,065	-2.9	575	29.41	18.96	-35.5
2006/12/13	3	14,284	14,048	-1.7	200	25.19	18.81	-25.3
2006/12/13	4	14,040	13,837	-1.5	-15	16.01	19.02	18.8
2006/12/14	3	14,312	14,069	-1.7	100	24.59	19.76	-19.6
2006/12/14	4	14,063	13,888	-1.2	39	23.36	17.46	-25.3
2006/12/15	1	15,177	14,643	-3.5	100	28.33	5.52	-80.5
2006/12/15	2	14,452	14,046	-2.8	0	23.92	6.93	-71.0
2006/12/15	3	13,961	13,729	-1.7	256	21.00	4.60	-78.1
2006/12/15	4	13,666	13,616	-0.4	125	10.35	4.96	-52.1
2006/12/15	5	14,074	13,683	-2.8	0	11.15	4.68	-58.0
2006/12/15	6	15,181	14,330	-5.6	0	22.20	4.14	-81.4
2006/12/16	2	14,288	13,843	-3.1	175	27.39	15.98	-41.7
2006/12/16	3	13,625	13,505	-0.9	75	22.20	9.76	-56.0
2006/12/16	4	13,278	13,372	0.7	25	10.00	13.39	33.9
2006/12/16	5	13,455	13,423	-0.2	10	14.10	16.30	15.6
2006/12/17	2	13,753	13,548	-1.5	100	26.15	12.89	-50.7

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2006/12/17	3	13,380	13,137	-1.8	300	19.11	5.48	-71.3
2006/12/17	4	13,041	12,843	-1.5	409	20.68	5.09	-75.4
2006/12/17	5	12,922	12,734	-1.5	429	13.72	4.79	-65.1
2006/12/17	6	13,033	12,839	-1.5	307	25.00	10.36	-58.6
2006/12/17	7	13,530	13,212	-2.4	401	30.06	10.89	-63.8
2006/12/17	9	15,359	14,719	-4.2	509	31.85	4.56	-85.7
2006/12/17	10	16,007	15,397	-3.8	521	33.22	15.33	-53.9
2006/12/17	15	15,994	15,645	-2.2	400	35.00	4.85	-86.1
2006/12/18	1	14,307	13,905	-2.8	400	25.73	8.30	-67.7
2006/12/18	2	14,006	13,397	-4.4	368	27.65	10.44	-62.2
2006/12/18	3	13,466	13,232	-1.7	548	24.63	4.85	-80.3
2006/12/18	4	13,348	13,175	-1.3	202	24.00	13.38	-44.3
2006/12/18	5	13,618	13,337	-2.1	289	21.00	11.81	-43.8
2006/12/18	6	14,728	14,082	-4.4	186	33.07	17.63	-46.7
2006/12/19	2	15,422	14,606	-5.3	0	30.05	16.92	-43.7
2006/12/19	3	14,917	14,242	-4.5	0	28.72	5.49	-80.9
2006/12/19	4	14,423	14,135	-2.0	0	23.83	-0.18	-100.8
2006/12/19	5	14,607	14,172	-3.0	190	29.22	19.36	-33.7
2006/12/21	2	14,985	14,370	-4.1	200	29.08	14.04	-51.7
2006/12/21	3	14,526	14,004	-3.6	176	28.64	17.23	-39.8
2006/12/23	3	13,635	13,068	-4.2	150	24.00	5.89	-75.5
2006/12/23	4	13,480	12,866	-4.6	250	23.15	4.68	-79.8
2006/12/23	5	13,183	12,873	-2.4	0	23.07	19.21	-16.7
2006/12/23	6	13,390	12,955	-3.3	248	23.89	11.64	-51.3
2006/12/23	7	14,017	13,476	-3.9	339	27.77	6.43	-76.8
2006/12/23	8	14,725	14,405	-2.2	250	26.15	4.60	-82.4
2006/12/24	4	12,539	12,616	0.6	150	20.76	18.76	-9.6
2006/12/24	5	12,729	12,527	-1.6	300	23.15	4.83	-79.1
2006/12/24	6	12,897	12,562	-2.6	364	23.15	4.63	-80.0
2006/12/24	7	13,328	13,010	-2.4	0	23.15	18.82	-18.7
2006/12/24	9	14,952	14,311	-4.3	0	34.72	12.43	-64.2
2006/12/24	10	15,356	14,867	-3.2	150	28.19	14.64	-48.1
2006/12/24	15	14,983	14,865	-0.8	0	21.08	16.24	-23.0
2006/12/24	16	15,504	14,799	-4.6	75	24.09	4.51	-81.3
2006/12/24	17	16,565	15,502	-6.4	100	34.47	13.66	-60.4
2006/12/24	20	15,916	16,131	1.4	150	20.82	18.63	-10.5
2006/12/24	21	15,790	15,823	0.2	100	22.72	19.77	-13.0
2006/12/24	22	15,548	15,518	-0.2	0	23.60	19.19	-18.7
2006/12/24	23	15,070	14,999	-0.5	87	23.11	15.65	-32.3
2006/12/24	24	14,501	14,210	-2.0	80	21.31	9.68	-54.6
2006/12/25	1	13,794	13,310	-3.5	0	24.59	12.36	-49.7
2006/12/25	2	13,202	12,664	-4.1	0	23.34	4.78	-79.5
2006/12/25	3	12,601	12,266	-2.7	0	20.00	6.18	-69.1
2006/12/25	4	12,132	12,071	-0.5	0	16.35	18.43	12.7

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2006/12/25	5	12,267	12,047	-1.8	200	22.00	4.80	-78.2
2006/12/25	6	12,436	12,266	-1.4	100	20.93	13.42	-35.9
2006/12/25	7	12,879	12,646	-1.8	0	23.23	19.30	-16.9
2006/12/25	8	13,713	13,295	-3.1	150	23.93	11.45	-52.2
2006/12/25	9	14,432	13,906	-3.6	0	24.58	12.42	-49.5
2006/12/25	10	15,062	14,478	-3.9	0	28.60	9.53	-66.7
2006/12/25	14	14,993	14,971	-0.2	187	23.15	19.94	-13.9
2006/12/25	15	14,952	14,786	-1.1	219	25.00	8.03	-67.9
2006/12/25	16	15,270	14,786	-3.2	126	25.25	4.70	-81.4
2006/12/25	17	16,140	15,399	-4.6	132	35.35	16.30	-53.9
2006/12/25	19	16,139	15,743	-2.5	250	26.71	4.65	-82.6
2006/12/25	20	15,782	15,501	-1.8	89	23.15	4.82	-79.2
2006/12/25	23	14,808	14,630	-1.2	69	28.00	17.01	-39.3
2006/12/25	24	14,033	13,709	-2.3	180	26.23	10.45	-60.2
2006/12/26	1	13,342	12,858	-3.6	195	25.33	2.41	-90.5
2006/12/26	2	12,810	12,344	-3.6	425	20.78	-1.65	-107.9
2006/12/26	3	12,066	12,050	-0.1	360	3.10	-1.66	-153.5
2006/12/26	4	11,777	11,931	1.3	433	3.50	2.86	-18.3
2006/12/26	5	11,881	12,023	1.2	200	15.00	7.91	-47.3
2006/12/26	6	12,259	12,201	-0.5	114	21.08	9.52	-54.8
2006/12/26	8	13,405	13,364	-0.3	160	24.45	10.48	-57.1
2006/12/26	9	14,214	13,850	-2.6	213	23.15	3.67	-84.1
2006/12/26	10	15,011	14,542	-3.1	159	28.80	8.10	-71.9
2006/12/26	11	15,469	15,015	-2.9	88	31.29	13.12	-58.1
2006/12/26	24	14,826	14,323	-3.4	59	30.00	15.07	-49.8
2006/12/27	1	13,739	13,459	-2.0	0	27.25	10.55	-61.3
2006/12/27	2	13,379	12,948	-3.2	0	27.31	11.05	-59.5
2006/12/27	3	12,862	12,694	-1.3	0	23.15	12.44	-46.3
2006/12/27	4	12,602	12,665	0.5	513	23.15	9.91	-57.2
2006/12/28	1	14,569	14,280	-2.0	83	29.34	19.24	-34.4
2006/12/28	2	14,022	13,587	-3.1	0	27.79	6.21	-77.7
2006/12/28	3	13,719	13,246	-3.5	0	23.15	4.43	-80.9
2006/12/28	4	13,268	13,102	-1.3	116	24.28	18.48	-23.9
2006/12/28	5	13,400	13,174	-1.7	150	25.00	17.55	-29.8
2006/12/30	4	13,517	13,474	-0.3	455	28.85	14.51	-49.7
2006/12/31	2	13,696	13,785	0.7	273	24.92	17.01	-31.7
2006/12/31	4	13,237	13,222	-0.1	0	17.48	13.72	-21.5
2006/12/31	5	13,261	13,172	-0.7	0	20.00	9.86	-50.7
2006/12/31	6	13,426	13,260	-1.2	200	21.66	4.66	-78.5
2006/12/31	7	13,796	13,567	-1.7	200	28.59	7.73	-73.0
2006/12/31	9	15,185	14,637	-3.6	90	29.79	13.03	-56.3
2006/12/31	10	15,801	15,283	-3.3	150	30.42	15.16	-50.2
Dec 2006**	103	14,070	13,754	-2.3	167	24.16	10.84	-55.1
2007/01/01	9	13,292	13,093	-1.5	250	21.91	4.91	-77.6

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/01/01	10	13,975	13,574	-2.9	200	22.30	4.38	-80.4
2007/01/01	11	14,166	14,098	-0.5	300	13.22	4.45	-66.3
2007/01/01	12	14,211	14,528	2.2	99	13.87	19.41	39.9
2007/01/02	3	13,103	13,222	0.9	151	18.00	17.60	-2.2
2007/01/05	2	14,099	13,848	-1.8	485	28.00	4.60	-83.6
2007/01/05	3	13,639	13,543	-0.7	200	23.89	4.72	-80.2
2007/01/05	5	13,696	13,496	-1.5	10	27.32	14.60	-46.6
2007/01/05	6	14,452	13,928	-3.6	122	28.71	12.79	-55.5
2007/01/06	7	13,785	13,250	-3.9	427	30.01	7.53	-74.9
2007/01/06	8	14,468	14,091	-2.6	470	31.45	12.18	-61.3
2007/01/06	9	15,380	14,889	-3.2	400	29.39	8.87	-69.8
2007/01/06	24	15,184	14,730	-3.0	80	30.00	14.28	-52.4
2007/01/07	1	14,059	13,846	-1.5	515	26.21	14.81	-43.5
2007/01/07	2	13,439	13,311	-1.0	280	24.53	13.77	-43.9
2007/01/07	5	13,077	12,718	-2.8	350	26.21	10.75	-59.0
2007/01/07	6	13,248	12,864	-2.9	250	24.32	8.20	-66.3
2007/01/07	7	13,846	13,207	-4.6	70	30.00	17.21	-42.6
Jan 2007**	18	13,951	13,680	-1.9	259	24.96	10.84	-56.6
2007/04/01	2	12,965	12,609	-2.8	611	28.90	14.97	-48.2
2007/04/01	3	12,597	12,441	-1.2	258	24.62	17.07	-30.7
2007/04/01	4	12,439	12,444	0.0	227	23.25	13.28	-42.9
2007/04/20	2	13,209	12,947	-2.0	322	24.86	12.75	-48.7
2007/04/20	3	12,981	12,875	-0.8	321	22.78	12.47	-45.3
2007/04/20	24	13,597	12,981	-4.5	285	25.25	5.46	-78.4
2007/04/21	1	12,568	12,397	-1.4	500	23.53	13.40	-43.1
2007/04/21	2	12,393	12,116	-2.2	220	22.45	12.75	-43.2
2007/04/21	3	12,035	11,940	-0.8	0	15.00	15.68	4.5
2007/04/21	4	12,013	11,899	-1.0	0	15.00	14.37	-4.2
2007/04/21	5	12,211	12,130	-0.7	387	22.22	4.68	-78.9
2007/04/21	23	13,696	13,114	-4.3	200	28.94	8.29	-71.4
2007/04/21	24	12,833	12,319	-4.0	228	24.09	9.81	-59.3
2007/04/22	1	11,854	11,851	0.0	642	17.48	6.08	-65.2
2007/04/22	2	11,698	11,487	-1.8	202	8.72	8.05	-7.7
2007/04/22	3	11,396	11,389	-0.1	94	16.05	11.31	-29.5
2007/04/22	4	11,334	11,362	0.3	250	15.00	8.55	-43.0
2007/04/22	5	11,417	11,463	0.4	342	7.72	7.30	-5.4
2007/04/22	6	11,695	11,569	-1.1	191	8.72	8.72	0.0
2007/04/22	8	13,423	12,965	-3.4	0	24.40	9.76	-60.0
2007/04/22	24	13,109	12,597	-3.9	-100	23.24	17.56	-24.4
2007/04/23	1	12,427	12,205	-1.8	100	22.45	16.65	-25.8
2007/04/23	2	12,093	12,009	-0.7	250	18.21	7.55	-58.5
2007/04/23	3	12,123	11,940	-1.5	314	18.20	7.30	-59.9
2007/04/23	4	12,488	12,100	-3.1	319	18.79	6.37	-66.1
2007/04/23	5	13,194	12,659	-4.1	445	22.30	5.92	-73.5

Delivery Date	Delivery Hour	PD Demand (MW)	RT Demand (MW)	Difference (%)	Net Failed Export (MW)	PD Price ($/MWh)	HOEP ($/MWh)	Change (%)
2007/04/24	1	12,844	12,822	-0.2	135	10.00	11.78	17.8
2007/04/24	3	12,500	12,373	-1.0	0	20.01	16.99	-15.1
2007/04/24	4	12,695	12,479	-1.7	0	22.61	18.69	-17.3
2007/04/24	24	13,943	13,482	-3.3	177	27.73	19.53	-29.6
2007/04/25	1	13,175	13,001	-1.3	25	20.52	19.12	-6.8
2007/04/25	2	12,995	12,801	-1.5	155	19.94	13.90	-30.3
2007/04/25	3	12,694	12,670	-0.2	39	18.71	19.50	4.2
2007/04/25	5	14,138	13,328	-5.7	193	28.69	19.91	-30.6
2007/04/27	2	13,202	12,961	-1.8	150	21.78	19.09	-12.4
2007/04/27	3	13,024	12,723	-2.3	302	21.78	17.71	-18.7
2007/04/27	4	13,271	12,841	-3.2	100	22.30	18.62	-16.5
2007/04/30	1	12,271	12,186	-0.7	512	21.97	9.70	-55.8
2007/04/30	2	12,127	12,017	-0.9	322	16.73	15.18	-9.3
2007/04/30	3	11,959	11,947	-0.1	206	16.01	16.79	4.9
2007/04/30	4	12,531	12,087	-3.5	537	22.72	2.93	-87.1
2007/04/30	5	13,458	12,681	-5.8	220	26.59	17.73	-33.3
Apr 2007**	42	12,634	12,386	-2.0	231	20.48	12.70	-38.0
Nov - Apr	188	13,679	13,381	-2.1	178	23.61	11.55	-48.9

* Low priced hours are defined as hours when the HOEP less than $20/MWh. February and March 2007 did not have any instances of low priced hours
*Monthly sub-totals reflect the total number of low-priced hours and unweighted averages of the Net Failed Exports, PD and RT Demand, and PD and HOEP prices, during those hours.