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

Ontario

Market Surveillance Panel

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2006 - October 2006

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Preface

The 9th Market Surveillance Panel monitoring report covers the period May 1 – October 31, 2006. We provide standard data on market operations and performance in Chapter 1 and the Statistical Appendix. Chapter 2 surveys 'high' and 'low' prices and identifies other matters worthy of comment. Chapter 3 discusses some of the issues raised in previous reports and new matters related to interties and the renegotiation of an ancillary services contract. The chapter also reviews demand response programs. The final chapter summarizes key market indicators for the period and addresses the role of the real-time spot market in the 'new' hybrid market.

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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 May–October 2006. The Market Surveillance Panel (MSP) found no evidence of gaming, abuse of market power or other inappropriate conduct by market participants or the market and system operator, the Independent Electricity System Operator (IESO). Spot market prices generally reflected demand and supply conditions and the discrepancy between pre-dispatch and spot market prices declined. A variety of actions taken by the IESO to improve market performance appear to be having a positive impact.

Market Prices and Uplift

The average HOEP, May – October 2006, was about $30/MWh lower than the same period in 2005 because of increased supply in Ontario and more moderate weather causing lower demand for electricity. Hourly uplift payments associated with the market were 60 percent lower than in 2005. These are the Import Offer Guarantee, Congestion Management Settlement Credit, Operating Reserve and transmission losses payments. Since market opening in May 2002 the trend in total market-related uplift payments has been downward and uplift payments per MWh of load have fallen still faster.

For much of the May – October 2006 period, Ontario's HOEP was, on average, the lowest price among the neighbouring markets of New York, New England, PJM and the Midwest Independent System Operator. Calculations of the 'net revenue' from the market that would be required to make investment in new generation in Ontario economic show that it continues to fall short (this was also true of other markets). Applying a standardized model developed in the U.S. we found that, on average over the past three years, a combined cycle generator would have earned net revenue from the market of $76,750/MW per year, well short of the roughly $100,000/MW required.

In one off-peak hour, September 3, 2006, the HOEP was actually negative, $-3.10/MWh. This was the offer price of a baseload nuclear unit selected when demand (exports) dropped suddenly with the halving of the New York scheduling capacity because of transmission circuit problems. While consumers on the Regulated Price Plan paid $58-$66/MWh for electricity consumed in that hour, we calculate that interval-metered loads paid an effective price of $9.30/MWh, when the Global Adjustment and OPG Rebate are included. This example illustrates how price regulation and OPA contracts now insulate consumers from changes in the HOEP.

Demand and Supply Conditions

A principal cause of the lower HOEP was weaker demand in Ontario over the period; it declined by 2.9 TWh or 3.7 percent compared to the previous year. Despite the lower average demand, a new summer peak record of 27,005 MW was set during a heat wave on August 1, 2006. This one event appears to have been induced by air conditioning load. It underlines the trend of peak load growing more rapidly than average load in recent years and the resulting challenge to respond to ever higher peak demands that occur in only a few hours each year.

The lower HOEP experienced in 2006 also reflected the availability of additional nuclear units and a reduction in outages. Forced outages have declined continuously since May 2003. The combination of this increased supply with lower demand increased the frequency with which the market cleared on the flatter portion of the supply curve and this led to a lower and less volatile HOEP. These circumstances resulted in a higher frequency of the HOEP being set by coal-fired generators. The increase in inframarginal (nuclear) supply had the effect of pushing gas and peaking hydroelectric generation out of the money, making coal the marginal supplier.

The increase in the domestic supply cushion also had an effect on Ontario's energy trade. While it has been common for Ontario to be a net exporter in off-peak hours and a net importer in on-peak hours, depending on the month and the demand/generation pattern, Ontario was a net exporter both on and off peak during the period May-October 2006.

Pre-dispatch Price Signals

The difference between the one hour pre-dispatch price and the real-time price is an important market performance indicator; 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 was lower in four of the six months in 2006 compared to 2005. This appears to reflect concerted efforts by the IESO to address the causes of the differences – out of market control actions, demand forecast error, and inter-jurisdictional transaction failures. The introduction in June 2006 of a settlement charge approach to intertie transaction failures and the Day Ahead Commitment Process coincided with a drop in export and import failures and fears that these changes would distort trade flows have not been borne out in the first months. With the operation of the real-time transaction failure charge, almost $1 million has been returned directly to loads in settlement.

Locational Prices and Transmission Constraints

Zonal prices for the 10 zones within Ontario take into consideration transmission losses and congestion as distinct from the province-wide HOEP which ignores these costs. While these ‘shadow’ prices, which are just average nodal prices in the zone, are not used for settlement they do provide useful indicators of system performance. Over the period May – October 2006 the large differences between the zonal prices in the Northwest and Northeast compared to the rest of the province remained but in southern Ontario, zonal prices were closer to each other than in previous periods indicating less congestion between these zones. On average zonal prices everywhere are considerably lower than six months and a year ago as a result of more supply and lower demand.

Zonal prices in southern Ontario were also closer to the HOEP. A key factor contributing to this convergence is the increased congestion at or near the New York and Michigan interties. This increased congestion resulted in a reduction in exports from Ontario to these jurisdictions (lower demand in the south). The congestion is not captured in the unconstrained schedule and hence does not have the same price reducing impact on the HOEP. While the convergence of the HOEP with zonal prices during the period May – October, 2006 had the effect of reducing the inefficiencies associated with the uniform price regime, this trend could easily reverse itself. There is nothing in recent events to change the basic case, made by the Panel in its last report, for replacing the uniform price regime with some form of locational pricing.

An increase in loop flow in the last year has been identified as the major cause of the higher level of constrained off exports. Loop flow is a naturally occurring phenomenon resulting from power flowing on parallel paths. Loop flow appears across the interties as well as across transmission interfaces within Ontario, reducing the transmission available for intertie scheduling and efficient dispatching of Ontario generation. For the 12 months starting in April 2003, loop flow averaged about 200,000 MWh per month. In the 12 months ending September 2006, the monthly values average about twice that amount, moving as high as 580,000 MWh.

Increased loop flow has several consequences for efficiency and reliability, for example losing opportunities for efficient trade and potentially reducing import capability during shortage conditions. One concrete step that could be taken is for Hydro One and the IESO to finalize an agreement with MISO and the International Transmission Company for the operation of the Michigan phase shifters. If this were to occur, a large portion of the observed loop flow could be controlled and total loop flow reduced substantially. In the interim, the IESO should review its procedures for modifying intertie limits when there are loop flows.

Operational Issues

Issues of intertie congestion and coordination between markets have also arisen with respect to New York. Over the period January to August 2006 the IESO applied a higher scheduling limit on its interface with New York than was applied by NYISO because it was unaware that its counterpart had lowered its scheduling limit in January. This caused export transaction failures and adversely affected market performance The Panel is encouraged to learn that a joint review by the two system operators is underway and it recommends that they work together to maximize the scheduling capability of the intertie.

Another issue that the Panel has suggested for consideration by the IESO is the proper treatment of shared activation operating reserve and the loss of transmission elements. In reviewing the events leading to the HOEP of $258.60/MWh on May 30, 2006, we noted that the addition of emergency supply in the form of activated shared operating reserve depressed the real-time price. We would prefer that in these circumstances all forms of incremental supply be treated in a manner that reflects the scarcity conditions in the market at the time.

Demand Response Programs

We reviewed six demand response programs (four offered by the IESO, one by the OPA and one by Toronto Hydro) available to Ontario consumers and identified some potential shortcomings in all but the IESO 5-Minute Dispatchable Load program. The problem relates to a lack of recognition that incentive programs that induce customers to curtail consumption at times when the value they derive from the service is greater than the incremental cost of providing, do not conserve in the truest sense of the word. In addition, to avoid the over scheduling of imports and generation, the programs also need to be integrated into the wholesale market's dispatch decision process.

Allowing loads to be price-responsive remains of crucial importance in ensuring that both consumption decisions and capacity investment decisions are efficient. Much can be achieved by ensuring that interval metered energy users receive accurate and timely information about prices, before embarking on specific demand response programs. The events of August 1, 2006 provide a concrete illustration of this point. On this day, four large metered customers reduced their consumption about 25 MW in each of four hours in response to an IESO issued Power Warning and projected high hourly prices of more than $200 per MWh. The response of these consumers aided the IESO in its management of grid reliability. The reduced consumption also prevented the hourly prices from rising further; market prices would have been higher than observed prices by as much as $9. The Panel notes that these participants responded efficiently to market price expectations without any additional payments from the IESO or the Ontario Power Authority (OPA). It is precisely these kinds of demand response programs that should be encouraged to promote demand response in Ontario.

MSP Oversight in the New Hybrid Market

The oversight activities of the Panel focus on the consumption, investment and dispatch efficiency of IESO-administered markets. In this report, we recognize that the analysis and commentary in which we have been engaged since market opening must be placed in the context of Ontario's new hybrid market in which centralized planning and regulation have a much more important role.

In the new hybrid market, dispatch decisions continue to be made in the spot market but decisions affecting consumption efficiency and investment efficiency have been largely subsumed by the government's policy initiatives. The Government has set targets for conservation and demand management and has asked the OPA to achieve these targets through various incentive programs. The Ontario Energy Board (OEB) also has a role in the efforts to encourage conservation through its development of time-of-use pricing. Similarly, the direct contracting for new sources of Ontario-based generation has supplanted the market as the vehicle to attract new investment, at least for a transitional period.

In the Panel's opinion, the spot market has a central role to play in ensuring that consumption, investment and dispatch decisions in Ontario's new hybrid market are efficient. The Panel believes strongly that both hybrid and spot market design should be such as to allow spot market prices to provide an accurate reflection of underlying supply and demand conditions. The Panel further believes that there are changes in the design of the spot market which would increase the quality of the signals it can provide to planners and regulators as well as to producers and consumers and that now is a good time to make these changes. Finally, the Panel believes that to the extent that the cost of OPA contracts and demand management decisions can be reflected in real-time prices rather than eventually showing up as a non-market uplift cost to consumers, the efficiency of the hybrid market would also be served.

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Chapter 1: Market Outcomes: May 2002 – October 2006

1. *Introduction*

This Chapter provides an overview of the main outcomes of the IESO-administered markets over the period May 1, 2006 to October 31, 2006. It contains the usual data analysis and time series presented in past reports with comparisons to the same period a year earlier. In some cases we have also looked at trends over the four and a half years since market opening.

As well, we have updated the information on both zonal prices and congestion payments in the ten zones we identified in our report of June 2006. This section has proved helpful in discussions about locational pricing.

The period May–October 2006 was characterized by moderate weather and thus moderate demand. There was also good generator performance. New entry, as well as improved performance of generation already in the market increased the supply cushion. As a result of reduced demand combined with increased supply, there was no repetition of the record high prices experienced during the summer of 2005. Indeed, the average monthly price over the period May–October 2006 was $45.26/MWh, roughly $30 lower than it was during the period May–October 2005. Market uplift payments also declined.

In addition to being lower, real-time market prices showed less variation around the pre-dispatch price, leading to more efficient decision-making by both generators and loads. Two factors that have contributed to the greater fidelity of market price signals are the elimination of out of market control actions by the IESO and a reduction in failed import and export transactions. These developments are discussed later in this chapter.

2. *Ontario Energy Price*

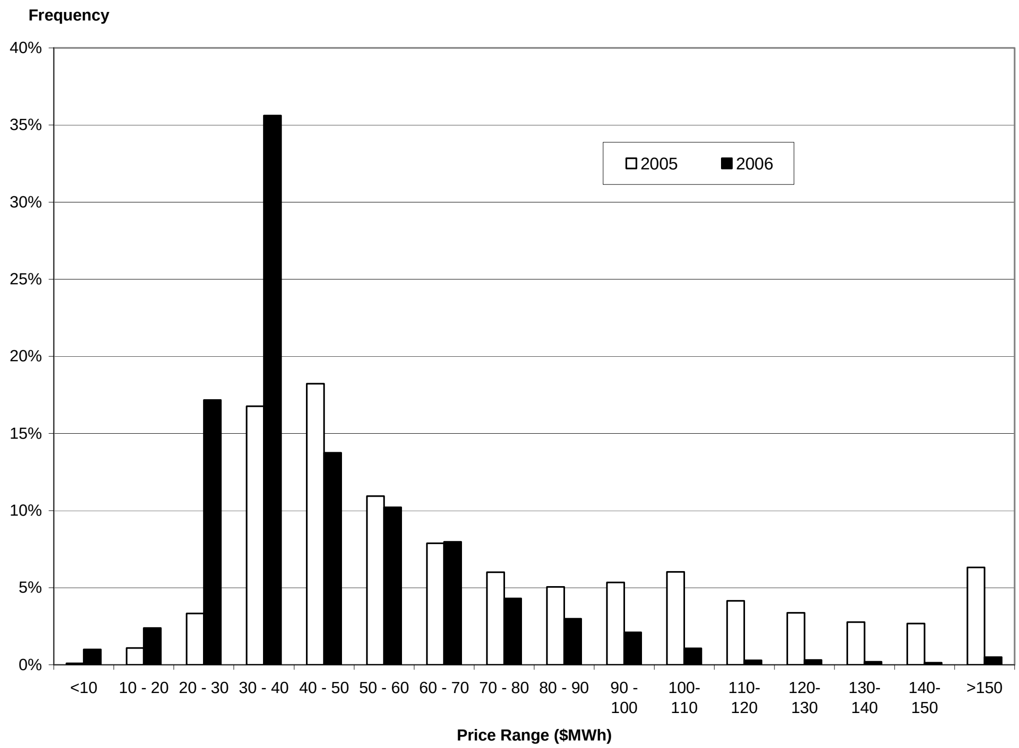
Table 1-1 shows that the monthly average HOEP was lower both on-peak and off-peak in each month of the period May–October 2006 than during the corresponding months a year ago. The lowest average monthly HOEP during the period was $35.42/MWh in September. There was also one hour in September when the HOEP was negative. This is discussed in Chapter 2.

Table 1-1: Average HOEP, On-Peak and Off-Peak
May-October, 2005 and 2006
($/MWh)

	Average HOEP		Average On-Peak HOEP		Average Off-Peak HOEP	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**
May	53.05	46.32	63.78	59.18	44.21	34.77
June	65.99	46.08	83.57	56.04	49.18	37.36
July	76.05	50.52	102.84	63.25	55.84	41.72
August	88.24	52.72	118.49	65.05	61.08	41.64
September	93.70	35.42	123.64	43.85	67.50	28.67
October	75.92	40.20	101.37	49.64	56.71	32.44
Average	75.44	45.26	98.93	56.24	55.72	36.13

Figure 1-1 shows the frequency distribution of the HOEP. Prices in the $30 - $40 range were much more common during the period May–October 2006 than during the same period a year ago. Prices in the $30 - $40 range are typical of coal-fired generation. The frequency of price spikes has also declined. The causes of this are discussed further in section 11.

Figure 1-1: Frequency Distribution of the HOEP
May-October, 2005 and 2006



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

Although the average HOEP was significantly lower during the summer of 2006 than in 2005, the actual amounts paid per MWh by Ontario loads as a whole did not decline as much, due to the regime of regulated prices and fixed price contracts that is now in place.

As required by the *Electricity Act, 1998*, the IESO has established accounts referred to as 'Global Adjustment' and 'OPG Rebate' to cover the difference between the HOEP and regulated/fixed prices. The total adjustment (Global Adjustment plus OPG Rebate) comes from several sources.

The OPG Rebate program is the simplest of these. Most of OPG's output (85 percent) from its peaking hydroelectric and coal-fired plants is paid a fixed price (currently $46/MWh). OPG is required to pay back revenue above the fixed price for this generation and gets a credit when the HOEP is below the fixed price.[1] As of May 1, 2006, the rebate is calculated every three months and is apportioned to Ontario loads according to their energy consumption in the period.

There are many programs which lead to payments through the Global Adjustment. The Ontario Power Authority manages the majority of these, including the following:

1. Contracts with Bruce Power.[2]
2. Contracts with early mover generators under which they are required to pay back some of their revenue to the OPA when the HOEP is high and receive a top-up payment from the OPA when the HOEP is low. We understand these contracts have a life of 5 years.
3. Contracts for future generation that OPA has signed with generators coming to market over the next few years are structured similarly with a contract life in the order of 20 years.
4. The OPA has several demand response programs and is planning additional conservation programs, which add additional costs to non-market uplift. More details on these programs can be found in Chapter 3 of this report.

Also included in the Global Adjustment are contracts with non-utility generators (NUGs). These contracts, signed in the early 1990's, provide NUGs a unit-specific fixed price.

The OPG Rebate only applies as a credit to loads. If the OPG Rebate calculation implies a charge to loads, this will be carried forward to offset any future rebates. However, the Global Adjustment can be positive or negative so the combined Global Adjustment and

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[1] Under this set of regulations, OPG's generation assets are split into two groups: prescribed and non-prescribed. The prescribed assets include all nuclear and baseload hydro generation stations. Nuclear power is paid a fixed price of $49.50/MWh, and baseload hydro $33/MWh up to the first 1,900 MW per hour. That is, revenues of these assets are independent of the market price. When the hourly output is above 1,900 MW on baseload hydro stations, the portion above 1,900 MW is paid the market price. All peaking hydro and coal generation stations are non-prescribed assets; OPG is required to rebate revenues above $46/MWh (a yearly average, which is slightly adjustable from year to year) on 85 percent of its output from these stations.

[2] Bruce Power is paid a price of about $63/MWh on output from the A station and a monthly minimum price $45/MWh on output from the B station.

OPG Rebate can be positive or negative. This depends mainly on the HOEP. When the HOEP is relatively high, generators receive more from the market than their contract prices and thus have to pay back a portion of their revenues. When the HOEP is relatively low, generators are compensated for their revenue shortfall.

The net total adjustments (positive and negative amounts) associated with the Global Adjustment are determined each month. That monthly total is then applied equally to every MWh of energy that was consumed by Ontario loads in the month. This is then credited to or charged to consumers. Loads paying the wholesale rates actually pay or receive these adjustments shortly after the end of each month. This includes wholesale loads which are IESO market participants and some loads which are customers of Local Distribution Companies (LDC). LDC customers under the Regulated Price Plan (RPP), which covers residential consumers and small business continue to pay their fixed rate. The difference between the fixed retail rate and the HOEP plus Global Adjustment and OPG Rebate is accumulated and is taken into account by the OEB when it sets the RPP fixed rates for the next six month period.

Thus the effective price that Ontario loads pay or ultimately pay is the HOEP plus or minus the Global Adjustment minus the OPG Rebate. For customers paying wholesale rates, the adjustment occurs at the end of the month and is based on their actual consumption during the period. For RPP customers, the adjustment is delayed and applied to future consumption.

Figure 1-2 depicts the monthly HOEP and adjustment components.[3] In 2005 when the HOEP was relatively high, the combined OPG Rebate and Global Adjustment was negative, implying that Ontario loads were cushioned in one way or another from the high HOEP. In 2006, however, the combined OPG Rebate and Global Adjustment are positive, indicating loads are paying or will ultimately pay a price that is higher than the

[3] In this figure the Global Adjustment and OPG Rebate are shown as positive amounts if consumers paid more, such that the effective price paid by the consumer was the sum of HOEP and the adjustments. This is opposite to the convention used on the IESO web-site and in settlement statements where a positive amount means the consumer paid less.

HOEP. As a result, the price that loads pay or will likely ultimately pay is smoother (the pink line) than the market price (the blue line) in Figure 1.2.

Figure 1-2: Monthly Average HOEP and Adjustment Components
April 2005 – October 2006
($/MWh)

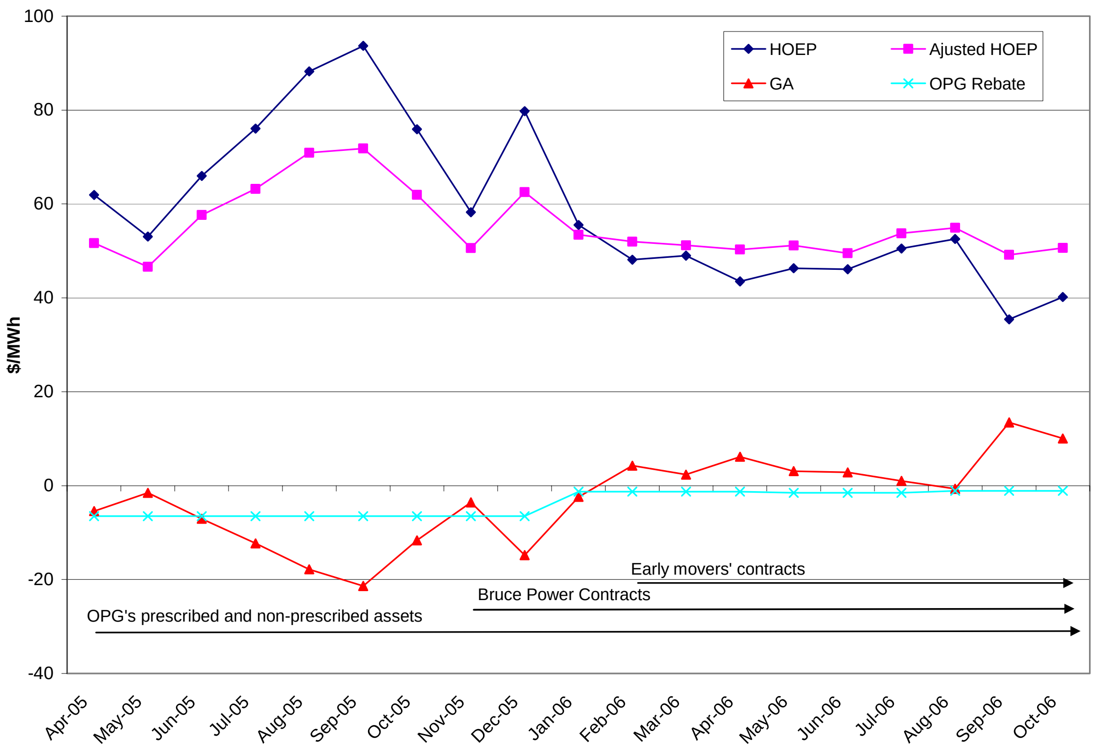


Table 1-2 shows the average year-to-year effect of HOEP changes and the Global Adjustment / OPG Rebate over the period May to October. Here we use load-weighted average values to show the impact or potential impact across all Ontario consumers.

Table 1-2: Impact of Adjustments on Weighted Average Payment
May-October, 2005 and 2006
($/MWh)

Year	Average HOEP	Load-Weighted HOEP	Global Adjustment and OPG Rebate	Load-Weighted and Adjusted HOEP
2005	75.44	80.97	18.65	62.32
2006	45.26	48.24	-3.40	51.64
Difference	30.18	32.73	22.05	10.68

It is apparent from the table that the simple average HOEP was $30.18 lower during the summer of 2006 than it was a year ago, and that the load weighted HOEP was $32.73 lower in 2006. Offsetting this, however, was a reduction of $22.05/MWh in the amount available in the Global Adjustment and OPG Rebate accounts to be paid or credited to Ontario loads. Indeed, during the period May-October 2006, the balance in these two accounts amounted to -$3.40/MWh, implying that Ontario loads will, in effect, be paying into these accounts in order to top-up the revenues of generators. Whether this continues or not depends on whether the HOEP remains below the contractual and regulatory prices guaranteed to generators.

The Panel also notes that in discussions of the myriad of issues between loads and generators regarding the effects of various proposed changes in the IESO-administered markets (such as the proposed change to the 12 times ramp rate) on the HOEP, it is important to recognize that the redistributive effects of potential changes in the HOEP are significantly dampened by the Global Adjustment and OPG Rebate.

2.2 Load Weighted HOEP

Table 1-3 shows the HOEP and the load-weighted average price for different consumer groups for the period of May to October ignoring the Global Adjustment and OPG Rebate. We look at three categories of loads: all loads as a whole; dispatchable loads that bid/offer into the wholesale market; and other wholesale loads who are IESO market participants which tend to be directly connected to the IESO grid.

Table 1-3: HOEP and Load-Weighted Average HOEP
Without Adjustment
May–October, 2005 and 2006

Year	HOEP	All Loads Weighted HOEP	Dispatchable Load Weighted HOEP	Other Wholesale Loads Weighted HOEP
2005	75.44	80.97	70.82	75.40
2006	45.26	48.24	43.52	45.37
Difference	30.18	32.73	27.30	30.03

For all loads, the weighted price is about 7 percent higher than the hourly average HOEP in each year. This indicates that there tends to be more consumption on-peak when prices are higher. Wholesale customers as a group exhibit weighted prices which are almost identical to the un-weighted average HOEP suggesting their load profile is fairly flat across the day and year, that is, these consumers have roughly the same weighting or load in all hours. The lowest weighted-prices are observed for the dispatchable load, with weighted average prices less than the average HOEP. The low price they pay comes from the fact that these loads tend to consume less than the market as a whole in high price hours and more in low price hours, and as well they can be dispatched down and even off to avoid some price spikes.

3. *Demand*

Ontario demand during the period May–October 2006 declined by 2.94 TWh or 3.7 percent compared with the same period a year earlier. Only in the month of May was Ontario demand higher than in the previous year. In all other months demand declined. See Table 1-4.

Table 1-4: Monthly Energy Demand (TWh)
May-October, 2005 and 2006

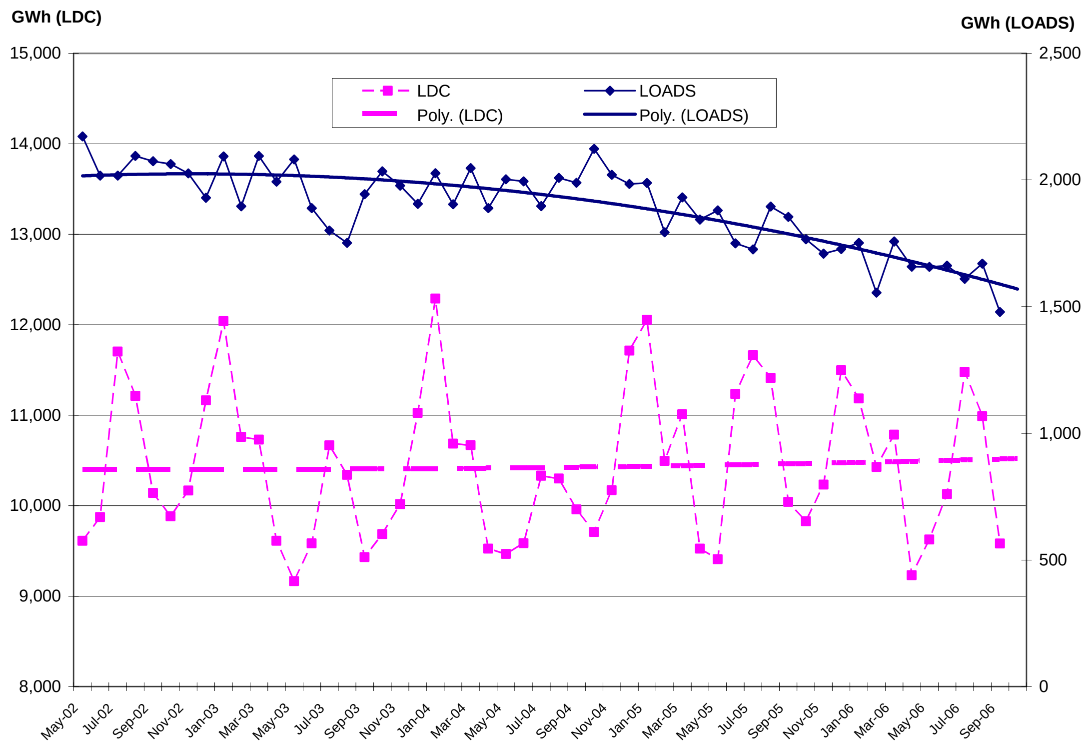
	Ontario Demand			Exports			Total Market Demand		
	2005	**2006**	**% Difference**	**2005**	**2006**	**% Difference**	**2005**	**2006**	**% Difference**
May	11.77	11.99	1.87	0.99	1.2	21.21	12.76	13.19	3.37
June	13.51	12.59	(6.81)	0.75	0.91	21.33	14.26	13.50	(5.33)
July	14.10	13.89	(1.49)	0.73	1.03	41.10	14.83	14.92	0.61
August	14.06	13.32	(5.26)	0.83	1.21	45.78	14.89	14.53	(2.42)
September	12.61	11.58	(8.17)	0.91	0.83	(8.79)	13.52	12.41	(8.21)
October	12.25	11.99	(2.12)	0.93	0.98	5.38	13.18	12.97	(1.59)
Average	13.05	12.57	(3.71)	0.86	1.03	20.00	13.91	13.59	(2.25)

The reduction in Ontario demand appears to be mainly weather related. The average temperature during the period May–October 2006 was 1.1^{o} Celsius lower than for the same period a year earlier. In the summer months lower temperatures led to lower demand because of a reduced requirement for air conditioning. In May 2006, however, the average temperature was slightly higher than in May 2005, as was demand. (See Table A-2 of the Statistical Appendix.)

In response to both lower Ontario demand and a lower HOEP during the period May-October 2006, exports increased by 1.04 TWh or 20 percent over the same period a year ago. However, taken together, Ontario demand plus exports (total demand) during the period May–October 2006 was 2.25 percent lower than during the same period a year ago.

In late July and early August, Ontario and all of eastern North America experienced its one heat wave of the summer. Demand in Ontario set a new summer peak record of 27,005 MW, an increase of 845 MW over the previous summer peak (which was 26,160 MW, set on July 13, 2005). This one event appears to have been induced by air conditioning load. The generation required to actually satisfy this kind of load is said to have a low capacity factor in that it will be run rarely, if ever, throughout the rest of the year.

Figure 1-3: Wholesale and LDC Monthly Energy Demand
May 2002 – October 2006
(GWh)



3.1 Wholesale and LDC

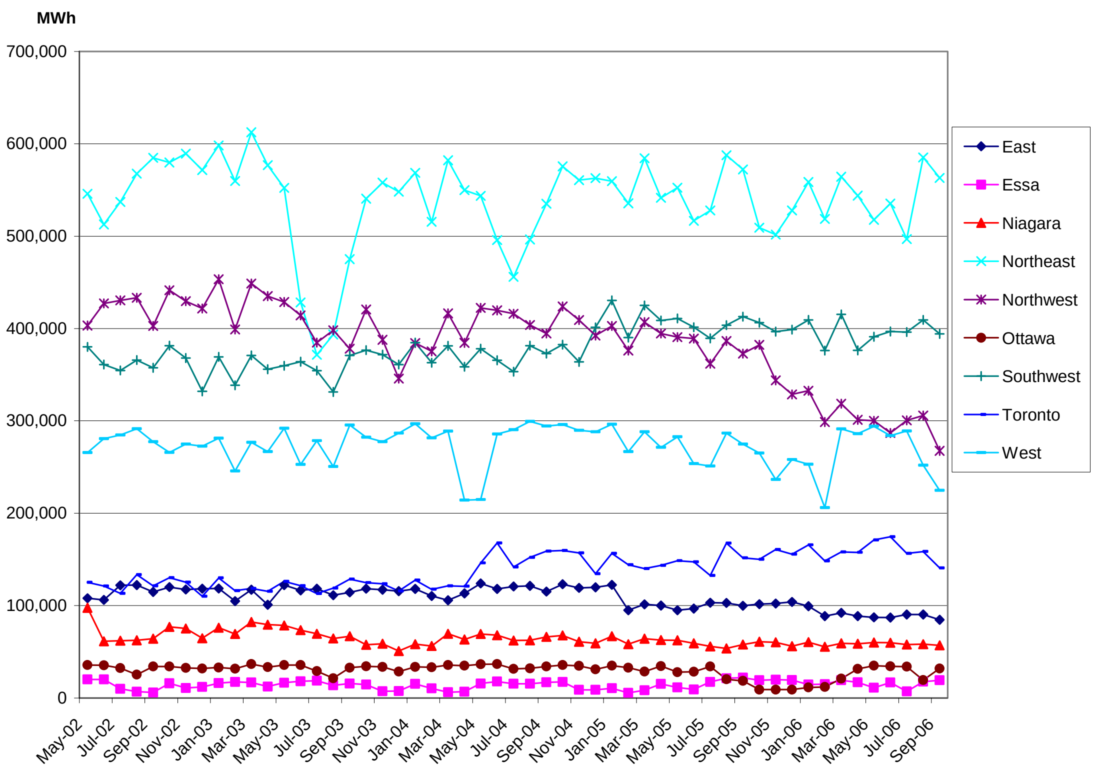
Figure 1-3 compares wholesale consumption to consumption by Local Distribution Companies (LDCs) since market opening in 2002. As noted in the Panel's June 2006 report, there is an opposing trend in these two loads. On average, we have seen a reduction of approximately 400 MW by wholesale customers while LDC load continued to trend up. The decline in wholesale consumption could be a result of any or all of: more efficient use of electricity; a change in the mix of wholesale customers; declining levels of activity by wholesale customers or; declining numbers of wholesale customers.

In order to understand whether the reduced consumption by wholesale loads is specific to a particular area of the province, in Figure 1-4 we break down wholesale load by zone.[4] The ten zones into which the province has been divided are shown on the maps (Figures

[4] The Bruce zone is not included since there are only a few small loads there.

25 and 26) in section 15. The time paths of zonal wholesale loads in Figure 1-4 show that most of the erosion in wholesale load has been in the Northwest zone. Given that transmission between the Northwest zone and the rest of the province is often congested, a reduction in load would have the effect of further reducing the zonal price in the Northwest relative to the HOEP and of increasing both congestion and constrained off payments to generators in that area of the province.[5]

Figure 1-4: Total Monthly Wholesale Load by Zone
May 2002 – October 2006
(MWh)



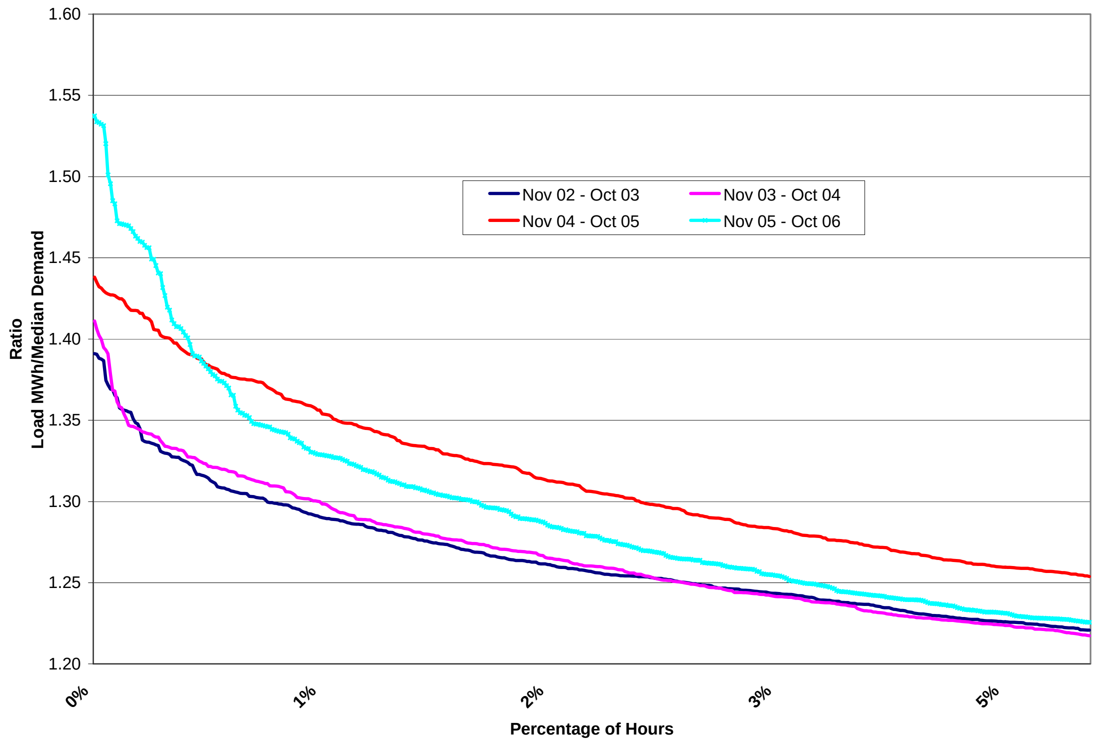
3.2 Load Duration

Figure 1-5 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. Each of these is expressed as a ratio to the median load. Year over year, the peak load

[5] Zonal prices and CMSC payments are shown in Figures 1-24 and 1-25 respectively.

has grown relative to the median. In other words, we are observing that the top one percent of hourly loads (about 90 hours per year) is growing faster than the median hourly load, especially during the last year. This change in the load pattern could have implications for investment decisions in the province. As peak load levels increase relative to the normal load levels, the province may need more investment in peaking capacity – low capital cost but high operating cost facilities - that will be required to be run in only a few hours of the year, but will still have to cover their investment costs. Alternatively, relatively higher price levels in these hours may induce many metered customers with time-of-use pricing plans to shift their consumption from these peak periods to lower priced periods. The more effective loads are at time-shifting (or conserving) in these hours, the greater is the extent to which investment in peaking capacity can be avoided, provided generation planners recognise that demand response will occur.

***Figure 1-5: Normalized Load Duration Curve –
Highest 5 Percentage of Hours Normalised to Median Load
November 2002 – October 2006***



4. *Outages*

Changes in supply resulting from planned and forced outages have an impact upon the HOEP. Generators require outages for maintenance and it is normal to see an increase in planned outages for maintenance in the spring and fall shoulder months in which demand and thus the impact of the outage on the HOEP is lower. Forced outages occur without warning and they have an immediate impact upon the HOEP until the lost output can be replaced.

Figure 1-6 illustrates planned outages relative to domestic capacity since 2003. As expected, outages are seasonal (e.g., most planned outages are scheduled in spring and fall) and have increased marginally relative to total capacity since market opening.

Figure 1-6: Planned Outages Relative to Total Capacity
May 2003 – October 2006

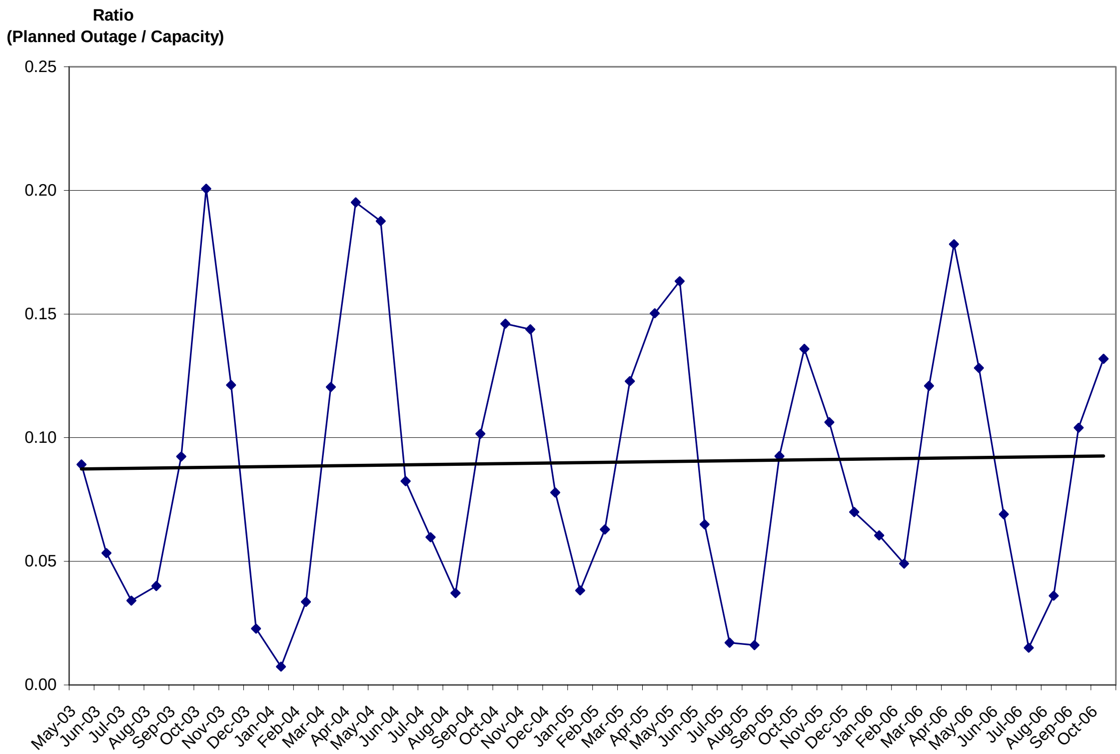


Figure 1-7: Forced Outages Relative to Total Capacity May 2003 – October 2006

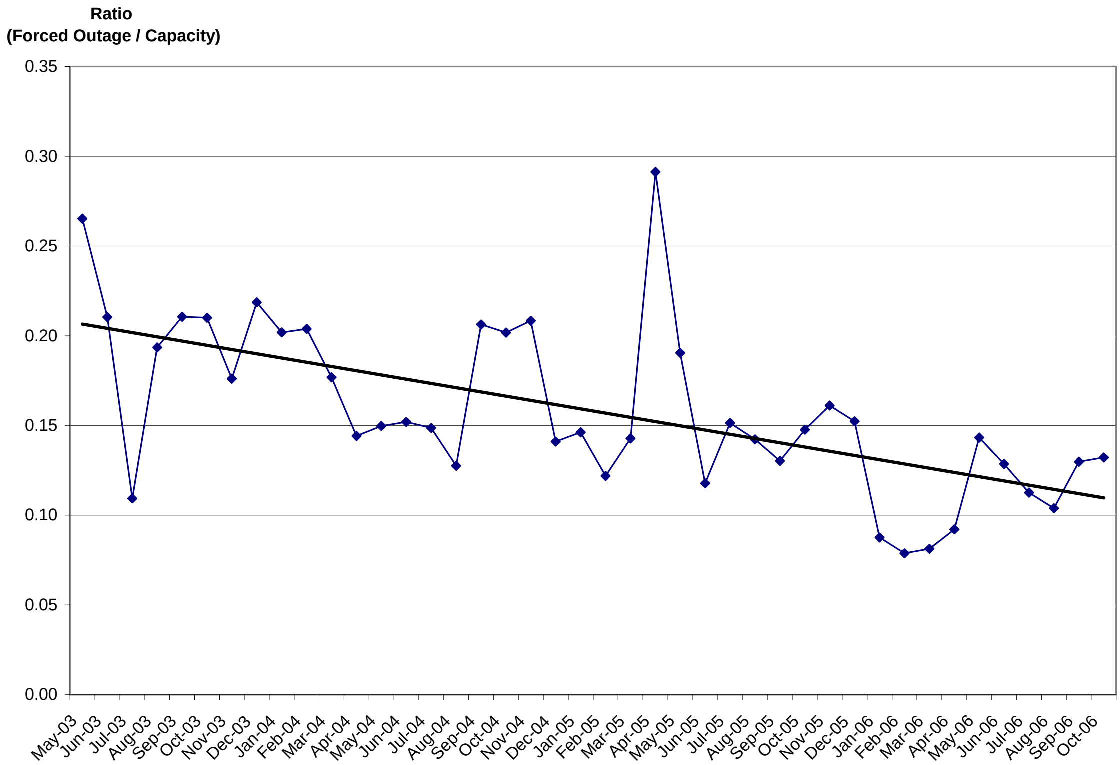
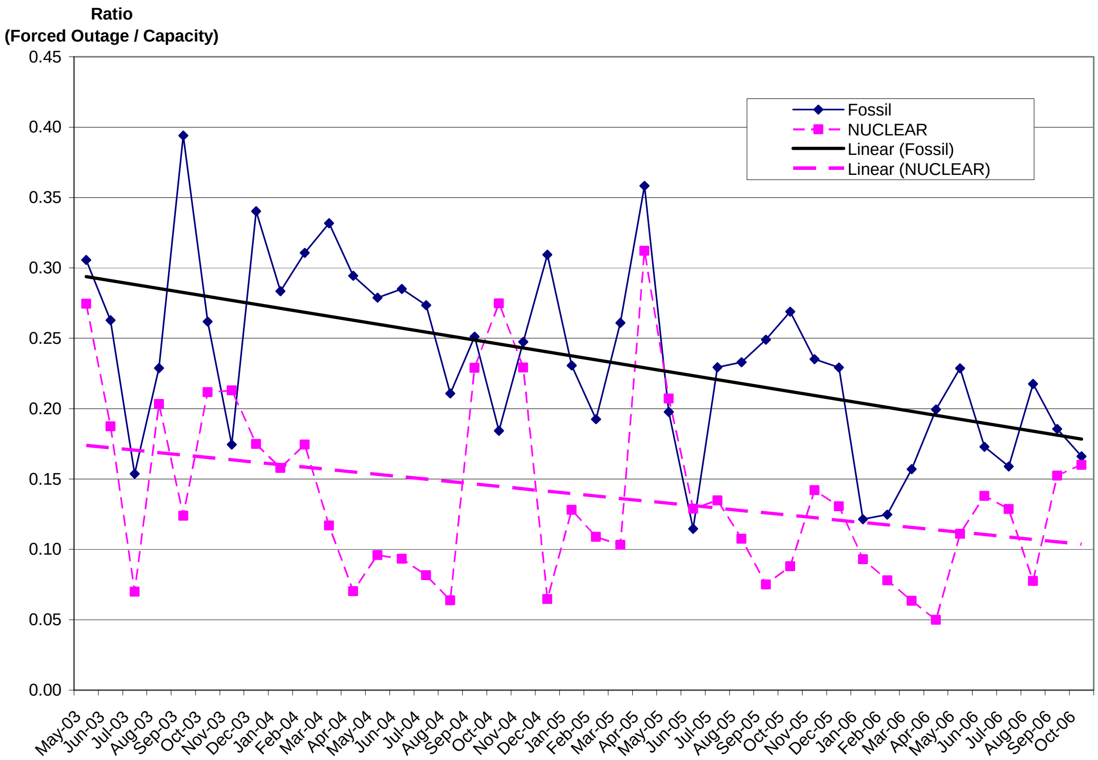


Figure 1-7 shows that *forced* outages have declined continuously since May 2003. The chart displays the monthly ratio of total forced outages to the total domestic generating capacity net of capacity on planned outage. We are not sure of the reasons for this decline in forced outages but it would not appear to support concerns that the Ontario generation fleet is becoming less reliable.

Figure 1-8 shows the ratio forced outages to available generation by fuel type. Fossil and nuclear generating units were chosen as they are typically large and a forced outage can have a significant impact on the HOEP. The trend of both nuclear and fossil forced outage rates is down showing that there are relatively fewer supply shocks from these sources than there have been in the past. The reduction in the nuclear forced outage rate may be attributable to the return of several refurbished units that should have lower forced outage rates, at least initially.

Figure 1-8: Forced Outages Relative to Total Capacity by Fuel Type
May 2003 – October 2006



5. *Supply Conditions and the Supply Cushion*

The supply cushion is a measure of the unused domestic generation that is available for dispatch in a particular hour.[6] There tends to be upward pressure on the HOEP and a greater potential for price spikes when the supply cushion falls below 10 percent. When the supply cushion falls below 10 percent, this is a warning that demand in Ontario is reaching the steep part of the domestic supply curve. During periods of very high market demand when insufficient domestic generation is available, the supply cushion is negative and the market must rely on imports.

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

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

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

The size of the supply cushion depends on both available generation and market demand. When we look at Table 1-5, we observe that the supply cushion was greater in all months of the May–October 2006 period than it was in the corresponding period in 2005. Other than in May 2006, there was a decrease in the number of hours in which the domestic supply condition was negative and thus in which a price spike would be more likely.

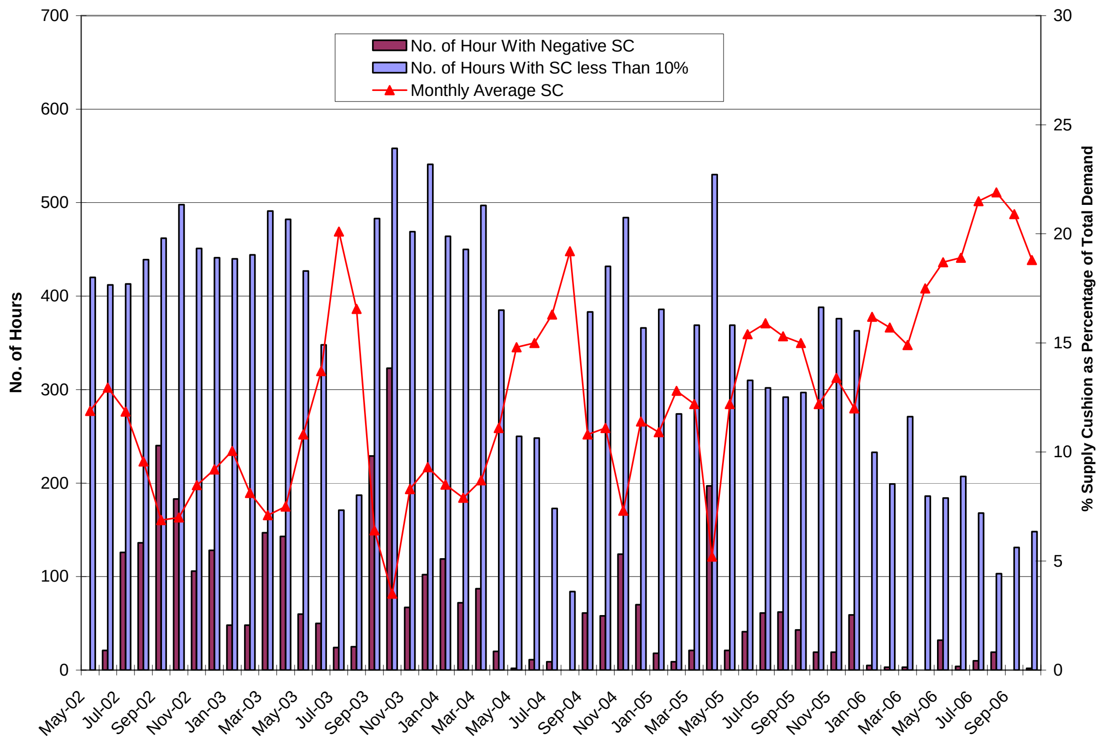
Table 1-5: Real-Time Domestic Supply Cushion May–October*

	Average Supply Cushion % requirement		Negative Supply Cushion # of Hours		Supply Cushion Less Than 10% # of Hours	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**
May	12.2	18.7	21	32	369	184
June	15.4	18.9	41	4	310	207
July	15.9	21.5	61	10	302	168
August	15.3	21.9	62	19	297	103
September	15.0	20.9	43	0	388	131
October	12.2	18.8	19	2	376	148

* The supply cushion has been adjusted to remove the Richview offer which consists of export curtailment and voltage reductions

Taking the longer view, Figure 1-9 shows that the domestic supply cushion has been increasing since the opening of the market. The number of hours with either a negative supply cushion or a supply cushion under 10 percent has also declined. The increase in the domestic supply cushion implies that both reliance on imports and the potential for price spikes has decreased since market opening.

Figure 1-9: Average Monthly Domestic Supply Cushion from May 2002 - October 2006



5.1 Supply Curves

Figure 1-10 shows average domestic supply curves for the periods May-October 2005 and 2006 respectively. The supply curve is an average of domestic supply offers in all hours in the study period. One can see that the supply curve for 2006 has shifted to the right, indicating increased offers to supply by Ontario generators. The reasons for the shift include the availability of additional nuclear units and a reduction in outages.

Figure 1-10: Average Domestic Supply Curve
May–October, 2005 and 2006

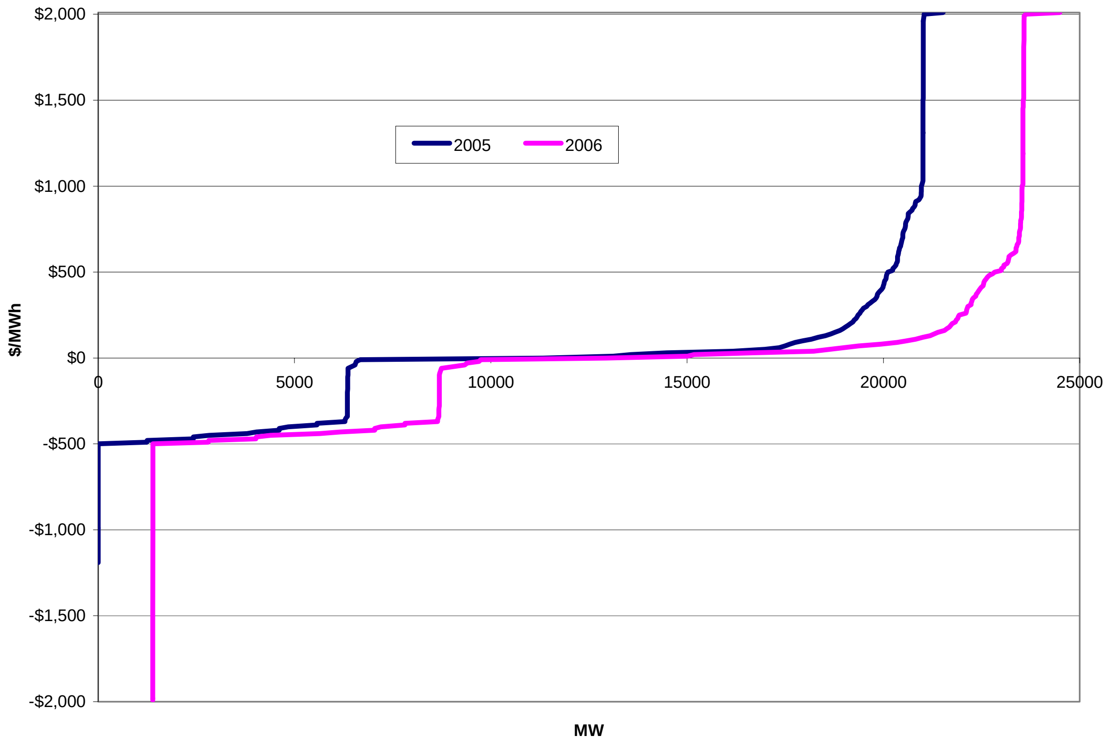


Table 1-6 shows the average hourly market schedule by selected resource type as well as Ontario demand for the periods May–October 2005 and 2006 respectively. These forms of generation are typically inframarginal so that the MWh scheduled does not depend on the HOEP. One can see that: (1) nuclear supply increased in all months (except September 2006) due to the addition of Pickering G1 in October 2005 and the improved performance at some other units; (2) baseload hydro supply was slightly lower in May through August 2006 but marginally higher in September and October; (3) self-scheduling supply was essentially the same in May to August but higher in September and October due to increased output by wind-powered generators, and; (4) demand was lower in all months except May 2006. The increase in nuclear supply, together with the reduction in demand tended to increase the frequency with which the market cleared on the flatter portion of the supply curve, and this led to a lower and less volatile HOEP.

Table 1-6: Average Hourly Market Schedules, Ontario Demand May-October, 2005 and 2006 (MWh)

	Nuclear		Baseload Hydro		Self-Scheduling Supply		Ontario Demand (NDL)	
	2005	2006	2005	2006	2005	2006	2005	2006
May	7642	8849	2,265	2,009	862	766	15,213	15,548
June	8,938	9,408	2,153	1,911	872	881	18,100	16,915
July	9,394	10,169	2,130	2,086	824	823	18,377	18,063
August	9,802	10,825	1,997	2,013	833	837	18,248	17,398
September	9,673	9,556	1,916	2,041	684	877	16,878	15,550
October	8,705	8,840	1,799	2,083	771	949	15,955	15,644

6. *Changes in Fuel Prices*

As is shown in Table 1-7, both the price of natural gas and the price of coal have declined by roughly 20 percent since 2005. In September and October, the natural gas price was as much as 60 percent lower compared to a year ago.

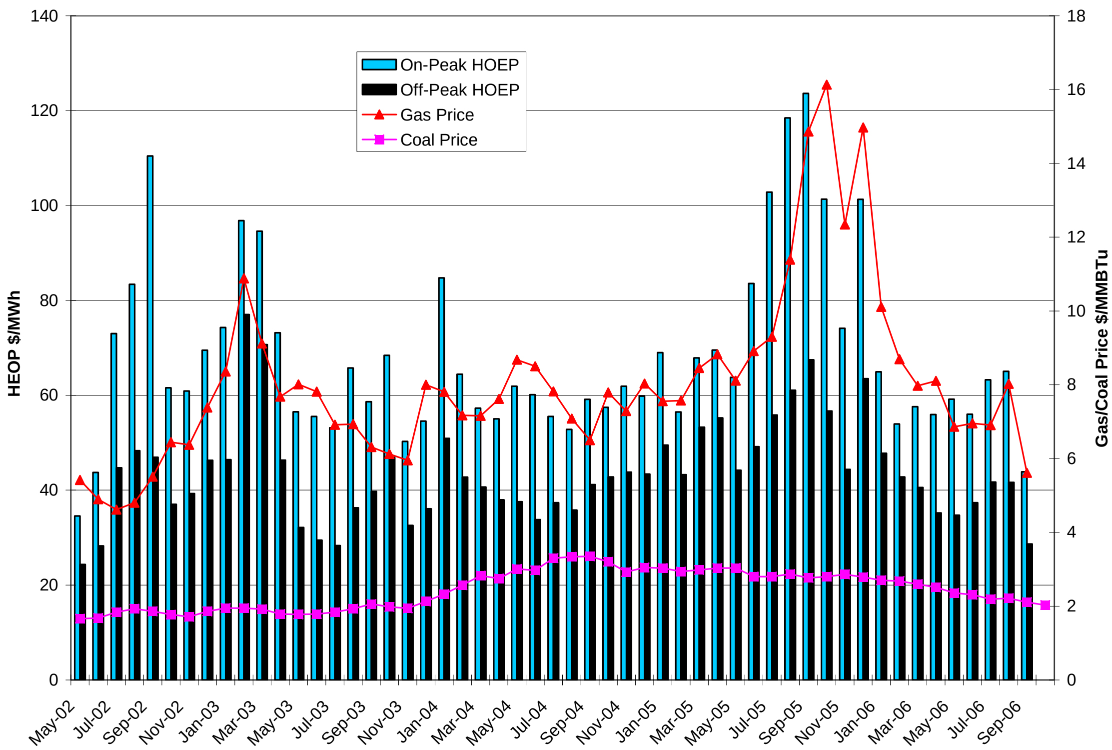
Table 1-7: Average Monthly Fuel Prices May-October, 2005 and 2006 ($CDN/MMBtu)

	Natural Gas Price (Henry Hub Spot Price)			Coal Price (NYMEX OTC for Central Appalachian Region)		
	2005	2006	% Change	2005	2006	% Change
May	8.14	6.92	(14.99)	3.04	2.36	(22.37)
June	8.89	6.94	(21.93)	2.8	2.31	(17.50)
July	9.3	6.91	(25.70)	2.8	2.18	(22.14)
August	11.4	8.03	(29.56)	2.87	2.22	(22.65)
September	14.51	5.62	(61.30)	2.77	2.11	(23.80)
October	15.9	6.66	(58.10)	2.8	2.03	(27.50)

The close relationship between both the on-peak and off-peak HOEP and the price of natural gas since market opening is shown in Figure 1-11. The figure also shows that there is no such relationship between the coal price and HOEP.

The connection between the HOEP (both on-peak and off-peak) and the natural gas price is driven by two factors. First, the offers of natural gas-fired generators sometimes set the HOEP. Second, gas-fired generators frequently set prices in neighbouring United States' markets which are linked to Ontario by import and export flows.

Figure 1-11: Average Fossil Prices and HOEP Market Opening May 2002 to October 2006



7. *Analysing Year over Year Changes in the HOEP*

The MAU, under the direction of the Panel, has developed an econometric model to analyse the causes of year over year changes in the monthly average HOEP. The results of this analysis are reported in this section.

The econometric model is estimated using monthly observations over the period November 2002 to October 2006. The dependent variable is the monthly average HOEP. The explanatory variables are: Ontario non-dispatchable load, the output from nuclear generators, the output from self-scheduling generators, the price of natural gas and the New York price. The research design allows these explanatory variable to have different effects on the HOEP in on-peak and off-peak periods. We expect increases in the Ontario load, and the price of natural gas and the New York price to increase the HOEP. Increases in the output of nuclear and self-scheduling generators should reduce the HOEP. The inclusion of the natural gas price as well as the New York price in the model poses some estimation difficulties because of the strong correlation between the two variables. In essence, it is difficult to separate the respective effects of the New York price and the price of natural gas on the HOEP. This is because the New York price is itself driven by the price of natural gas. To show what the effect of the natural gas price on the HOEP would be if the New York price were driven entirely by the price of natural gas, we estimate another model that excludes the New York price variable. To show what the effect of the New York price on the HOEP would be if natural gas-fired generation never set the HOEP, we also estimate a model that does not include the price of natural gas.

The estimation results for the on-peak and off–peak models are presented in columns 1 to 3 of Table 1-8.

Table 1-8: Estimation Results of the Peak and Off-peak Models[7]

	Column 1: Model with New York price		Column 2: Model with Natural Gas Price		Column 3: Model with both New York and Natural Gas price	
Peak Model						
Variable	Coefficient	P-Value	Coefficient	P-Value	Coefficient	P-Value
Constant	-1.31	0.24	-8.66	0.00	-1.47	0.20
LOG(Nuclear Output)	-0.54	0.00	-0.89	0.00	-0.55	0.00
LOG(Self Scheduler output)	-0.13	0.02	-0.37	0.04	-0.12	0.04
LOG(Ontario Demand)	0.71	0.00	2.24	0.00	0.74	0.00
LOG(Natural Gas price)	n/a	n/a	0.69	0.00	0.04	0.63
LOG(New York price)	0.99	0.00	n/a	n/a	0.95	0.00
Model Diagnostics						
R-squared	0.96		0.78		0.96	
Adjusted R-squared	0.94		0.72		0.94	
LM test of Serial Correlation	Absent		Present		Absent	
JB test of normality of residuals	Normal		Normal		Normal	
Number of observations	48		54		48	
Off-Peak Model						
Variable	Coefficient	P-Value	Coefficient	P-Value	Coefficient	P-Value
Constant	-8.12	0.00	-10.71	0.00	-8.12	0.00
LOG(Nuclear Output)	-0.41	0.00	-0.62	0.00	-0.41	0.00
LOG(Self Scheduler output)	-0.26	0.01	-0.36	0.02	-0.26	0.02
LOG(Ontario Demand)	1.50	0.00	2.22	0.00	1.51	0.00
LOG(Natural Gas price)	n/a	n/a	0.51	0.00	0.03	0.84
LOG(New York price)	0.72	0.00	n/a	n/a	0.69	0.00
Model Diagnostics						
R-squared	0.85		0.77		0.85	
Adjusted R-squared	0.81		0.70		0.80	
LM test of Serial Correlation	Absent		Absent		Absent	
JB test of normality of residuals	Normal		Normal		Normal	
Number of observations	48		54		48	

We used the third model (column 3) to explain the sources of the observed changes in the monthly average HOEP between the summer of 2005 and the summer of 2006. In other words we ask the following question: what the monthly average HOEP would have been in 2005 if Ontario demand, nuclear and self-scheduler output in 2005 were replaced with

[7] 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 small p-value leads to rejection of the null hypothesis implying that the coefficient is statistically significant in the model.

their 2006 monthly values. We change the value of one explanatory variable at a time in order to show the respective effects of each of these variables on the HOEP. We do not simulate the marginal effects of the New York and natural gas prices since we cannot separate their effects in the current model. The results of this analysis are reported in Table 1-9.

The estimates in Table 1-9 imply that lower Ontario demand in 2006 led to a drop of almost $3 in the average HOEP in the May-October 2006 period (compared to the same period in 2005) during both peak and off-peak hours. Increased nuclear and self-scheduler output in 2006 contributed to a reduction of between $1 and $3 in the average HOEP during the period May-October 2006 compared to the same period in 2005.

In future analyses we hope to include New York supply and demand variables in the reduced form equation for the HOEP. This should allow us to infer the influence of the natural gas price on the HOEP while properly controlling for the effects of export demand from the New York market.

Table 1-9: Price Effects of Setting 2005 Monthly On-peak and Off-peak Factors at 2006 Levels ($/MWh)

Peak Period	Ontario Demand	Nuclear Output	Self-scheduler Output
May	$1.11	($4.10)	$0.75
June	($3.94)	($2.16)	($0.17)
July	($0.78)	($4.03)	($0.08)
August	($3.65)	($5.58)	($0.07)
September	($6.87)	$0.80	($3.09)
October	($1.48)	($0.76)	($2.20)
Average	**($2.60)**	**($2.64)**	**($0.81)**
Off Peak Period	**Ontario Demand**	**Nuclear Output**	**Self-scheduler Output**
May	$0.50	($2.13)	$1.17
June	($4.09)	($1.04)	$0.05
July	($2.10)	($1.71)	$0.16
August	($3.66)	($2.32)	($0.06)
September	($6.39)	$0.30	($4.53)
October	($2.73)	($0.43)	($3.79)
Average	**($3.08)**	**($1.22)**	**($1.17)**

8. *Implied Heat Rate*

The implied heat rate shows the efficiency with which a thermal generator converts heat into electrical energy. The implied heat rate is calculated as the difference between the offer price and operating and maintenance cost (assumed to be $5/MWh) divided by the fuel price on the delivery day. The heat rate allows a comparison of the efficiency of different generators at a given point in time and also shows how the offers of a given generator change over time in response to changes in operating circumstances (other than changes in fuel prices) or if there is a change in bidding strategy.

Figure 1-12: Implied Heat Rate
May 2005 – October 2006

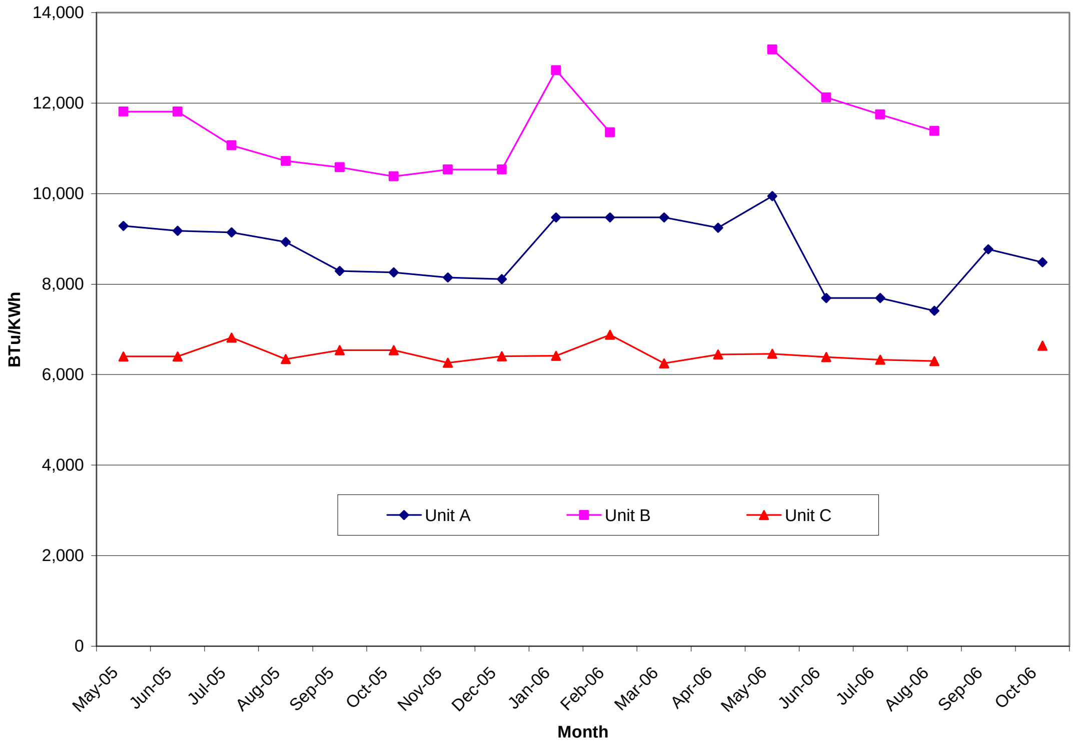


Figure 1-12 illustrates the monthly average implied heat rate for three natural gas fired units. As discussed in the June 2006 MSP report, two of these units, units A and B, showed significant increases in their implied heat rates starting in January 2006. As these units were rarely dispatched due to low demand, they had to offer at higher prices to recover their start-up and speed-no-load costs. Unit B, which is a relatively inefficient unit, had a higher implied heat rate during the period May–October 2006 than it did during the same period in 2005 because it had significantly fewer starts and fewer hours of operation over which to recover its costs. Unit A's implied heat rate declined starting in June 2006 and rose in September.

9. *Imports and Exports*

Imports and exports are key components of the Ontario electricity market. High Ontario prices induce imports from regions with lower costs. The term 'high priced imports', frequently used to describe Ontario imports, is a misnomer. Imports of power generated outside Ontario compete with domestic Ontario generation in a bidding market which determines the most efficient choice of generation to meet Ontario demand. When imports are chosen, they displace more costly generation in Ontario. In times of tight supply when the supply cushion is negative, Ontario has to be a net importer in order to service its load and maintain reliability.

Power exports also benefit the Ontario market. First, they allow the utilization of otherwise idle capacity thereby contributing to the recovery of fixed costs. Without this contribution from exports, these fixed costs would have to be covered by Ontario consumers. Second, exports signal that power can be put to higher valued uses elsewhere and this helps to prevent its wasteful use by domestic consumers, especially those with interval meters. Third, the existence of export opportunities reduces demand volatility allowing marginal generators to better manage their operations and improving system reliability.

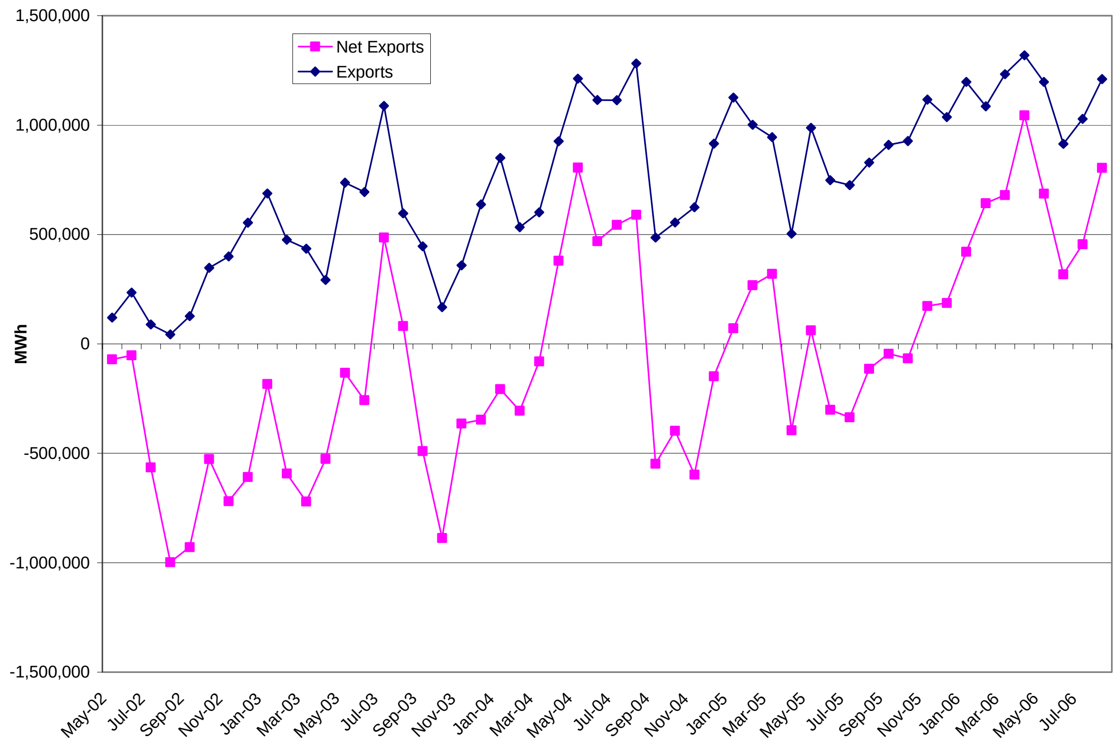
While it is common for Ontario to be a net exporter in off-peak hours and a net importer in on-peak hours, depending on the month and the demand/generation pattern, Ontario was a net exporter both on and off peak during the summer of 2006 as shown in Table 1-10. This was a result of an improved domestic supply/demand balance due to moderate Ontario demand as well as to both new generation and reduced forced and planned outages.

Table 1-10: Net Exports On-peak and Off-peak
May–October, 2005 and 2006
(MWh)

	Off-peak		On-peak		Total	
	2005	2006	2005	2006	2005	2006
May	62,414	454,918	(539)	231,286	61,875	686,204
June	(41,718)	227,996	(259,946)	89,601	(301,664)	317,597
July	49,339	384,413	(385,437)	70,645	(336,098)	455,058
August	108,893	521,687	(222,398)	282,463	(113,505)	804,150
September	184,093	304,446	(228,831)	164,847	(44,738)	469,293
October	49,794	370,919	(116,347)	251,698	(66,553)	622,617

Reviewing Ontario's net export position since market opening, we observe that Ontario has moved from the position of being a net importer to one of being a net exporter. This is shown in Figure 1-13.

Figure 1-13: Exports and Net Exports Since Market Opening



The existence of import and export congestion helps to explain price differences between Ontario and adjacent markets. A significant amount of import congestion implies that the price in Ontario must be higher than the prices in neighbouring markets.[8] Table 1-11 shows that the number of hours in which the interties were congested by imports was much lower during the period May–October 2006 than during the same period in 2005. Indeed, with the exception of the Minnesota to Ontario interface, import congestion was rare.

[8] The unconstrained market schedule models potential congestion only at the interties. When congestion occurs in the market schedule a difference is induced between the uniform Ontario price and the intertie zonal price. The zonal price can be closer to the price in the external market. This zonal price difference induces payments for Transmission Rights (TR) at the intertie. Constrained schedule congestion may occur at interties or elsewhere within Ontario and induces CMSC payments for differences between constrained and unconstrained schedules. For a given intertie it is possible that there is no congestion in the market schedule but transactions may reach their limit in the constrained schedule. This does not trigger TR payments.

Table 1-11: Import Congestion in the Market Schedule May-October, 2005 and 2006 (Number of Hours)

	NY to ON		MI to ON		MB to ON		MN to ON		PQ to Ontario		Total	
	2005	2006	2005	2006	2005	2006	2005	2006	2005	2006	2005	2006
May	0	8	358	19	46	0	74	114	3	8	481	149
June	5	0	237	33	23	9	249	245	28	0	542	287
July	28	0	97	0	10	2	109	4	18	44	262	50
August	40	1	97	0	16	4	28	46	1	4	182	55
September	20	0	249	0	3	3	296	95	0	2	568	100
October	9	0	145	8	0	0	445	26	0	6	599	40

While export congestion decreased marginally from the summer of 2005 as shown in Table 1-12, we note a large increase in this congestion on the Ontario to New York interface in August and September. Most of this congestion happened in off-peak hours as a result of Ontario reducing the export limits to New York to 2,000 MW. In August 2006, the IESO learned that the New York ISO had reduced its import scheduling limit from Ontario to 2,000 MW from its previous limit of 2,200 MW.[9] The IESO's policy, reflecting industry practice, is to set the intertie limits at the lower of the IESO's or the inter-connected partner's scheduling limit. The lowering of the export limit meant that scheduled exports reached that limit more often, resulting in the observed congestion and higher zonal prices at the New York intertie as shown in Table 1-12. Prior to August the higher limit permitted more exports being scheduled without reaching the IESO limit, but these were subsequently failed by NYISO. This will be discussed in more detail in Chapter 3, subsection 3.1.

[9] The scheduling limit differs from the physical capability of the intertie.

Table 1-12: Export Congestion in the Market Schedule May-October, 2005 and 2006 (Number of Hours)

	ON to NY		ON to MI		ON to MN		ON to PQHZ		Total	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**
May	28	66	0	2	3	2	6	16	37	86
June	13	10	0	0	0	2	9	10	22	22
July	57	38	5	0	0	11	2	2	64	51
August	82	194	0	5	0	15	37	0	119	215
September	94	163	0	0	0	16	32	45	126	224
October	207	105	0	0	6	3	176	50	389	158

9.1 Analysis of Trade Flows between Ontario and New York

In this section we present an analysis of the determinants of the volume of export flows between Ontario and New York. Our approach focuses on the estimation of a simple econometric model for export trades. We use the average monthly data to estimate a model for peak hours and another one for off-peak hours. Economic theory indicates that export trades respond to the price differences between the Ontario and New York markets. Therefore in a structural model, we would include the monthly HOEP (Ontario price) and the monthly New York price as explanatory variables. However the HOEP is not entirely satisfactory as an explanatory variable because it is caused by exports as well as causing them. As a remedy we estimate what is known as a reduced form model in which the HOEP is replaced as an explanatory variable by a set of variables that cause the HOEP but are not caused by it. Estimates of this model using monthly data are reported in Table 1-13.

Table 1-13: Estimation Results,
Ontario-New York Export Flows
August 2003 – October 2006

	PEAK		OFF-PEAK	
Variable	**Coefficient**	**Prob.**	**Coefficient**	**Prob.**
C	518.84	0.01	296.98	0.56
ONLOAD	-0.04	0.10	-0.06	0.12
NUCLEAR	0.08	0.00	0.14	0.00
NYPRICE	-0.80	0.50	3.96	0.12
TLRe	-0.91	0.01	-0.53	0.57
LOOP	-0.42	0.04	-0.45	0.12
SELF	-0.10	0.48	-0.15	0.48
HYDRO	0.08	0.52	0.11	0.45
JAN	230.67	0.00	197.85	0.03
FEB	-72.98	0.47	105.21	0.32
MAY	43.30	0.28	137.65	0.03
JUNE	-16.24	0.77	59.65	0.43
JUL	-100.50	0.11	-105.53	0.15
AUG	-44.45	0.27	110.16	0.24
SEP	-90.56	0.17	-79.08	0.57
OCT	-33.40	0.48	-58.95	0.49
NOV	6.78	0.94	63.19	0.63
Model Diagnostics				
R-squared	0.89		0.86	
Adjusted R-Sq	0.82		0.75	
LM Serial Correlation Test	Absent		Absent	
JB test of normality residuals	Normal		Normal	
Number of observations	39		39	

This analysis shows the value of net exports is an increasing function of nuclear output during peak and off-peak periods. The New York price variable is statistically insignificant in both models. The TLRe (external Transmission Loading Relief) variable is an administrative tool used by the system operator to limit exports for reasons related to reliability in the New York market. The coefficient on this variable is negative and statistically significant during peak hours. In off-peak hours it has the correct sign but it is imprecisely estimated. The loop flow variable (see subsection 3.2 in Chapter 3) reduces the final export volume in the constrained schedule and it has the effect of increasing the New York locational price. It is statistically significant during peak hours.

This simple model yields important insights into the determinants of exports from Ontario to New York. It is surprising that the New York price is insignificant during peak and off-peak hours. This would imply there are reasons other than the New York-Ontario price differential that drive the export trades to the New York market. The Panel has asked the MAU to continue to refine this approach for future reports.

10. *Wholesale Electricity Prices in Neighbouring Markets*

Ontario has four transparent neighbouring electricity markets with which power can be traded. These are New York, PJM, New England and the Midwest Independent System Operator (MISO). Typically, MISO and New York are Ontario's two largest trading partners. While the other markets are not directly connected to Ontario, there is a close linkage as traders attempt to arbitrage price differences among markets. Ontario also buys power from and sells power to Manitoba and Quebec.

As we have explained in our other reports and as Figures 1-14 to 1-16 imply, transmission constraints, bid lead times between markets, imperfect information and scheduling/protocol issues (seams issues), among other things, prevent traders from arbitraging away all inter-market price differences.

Figures 1-14 to 1-16 compare monthly average price as well as average on and off-peak prices for the period May–October 2006. In the past, Ontario has typically had lower prices than New York, PJM and New England. With the opening of the MISO market in April 2005, it appeared that it would be the lowest priced market and typical arbitrage would be from MISO through to the other markets.

The price gap between Ontario and MISO which we noted in our report for the period May-October 2005, has practically disappeared.[10] We attributed this gap to impediments to arbitrage arising from scheduling protocol difficulties in MISO. The protocol issues

[10] In our June 2006 report we referred to MISO as Michigan or Michigan Hub.

included acquiring physical transmission as well as scheduling ramping capacity before delivery. The reason for the disappearance of the price gap needs further investigation.

With the disappearance of the price gap with MISO, Ontario became the lowest priced market of the four during much of the May-October 2006 period. The relationship between the HOEP and the New York price was also consistent: there were small differences when there was less export congestion (in June and July) and large differences when there was more export congestion (in May and August).

Figure 1-14: Average HOEP Relative to Neighbouring Markets May–October 2006 ($/MWh)

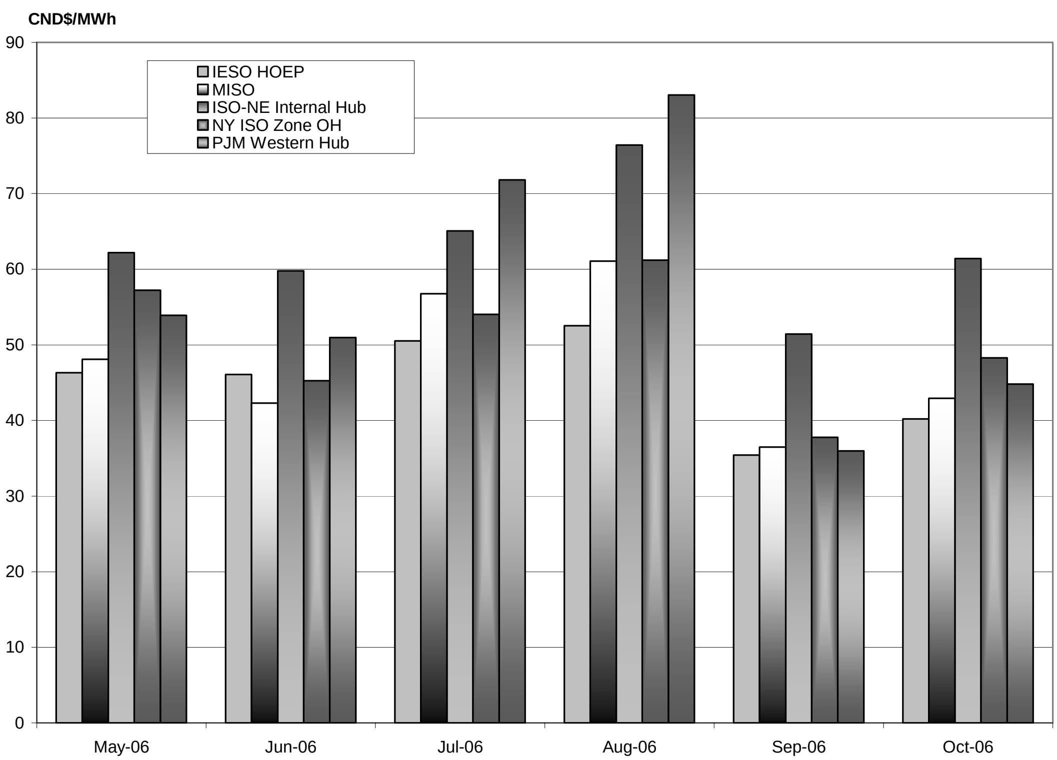


Figure 1-15: Average HOEP Relative to Neighbouring Markets: On-peak May–October 2006 ($/MWh)

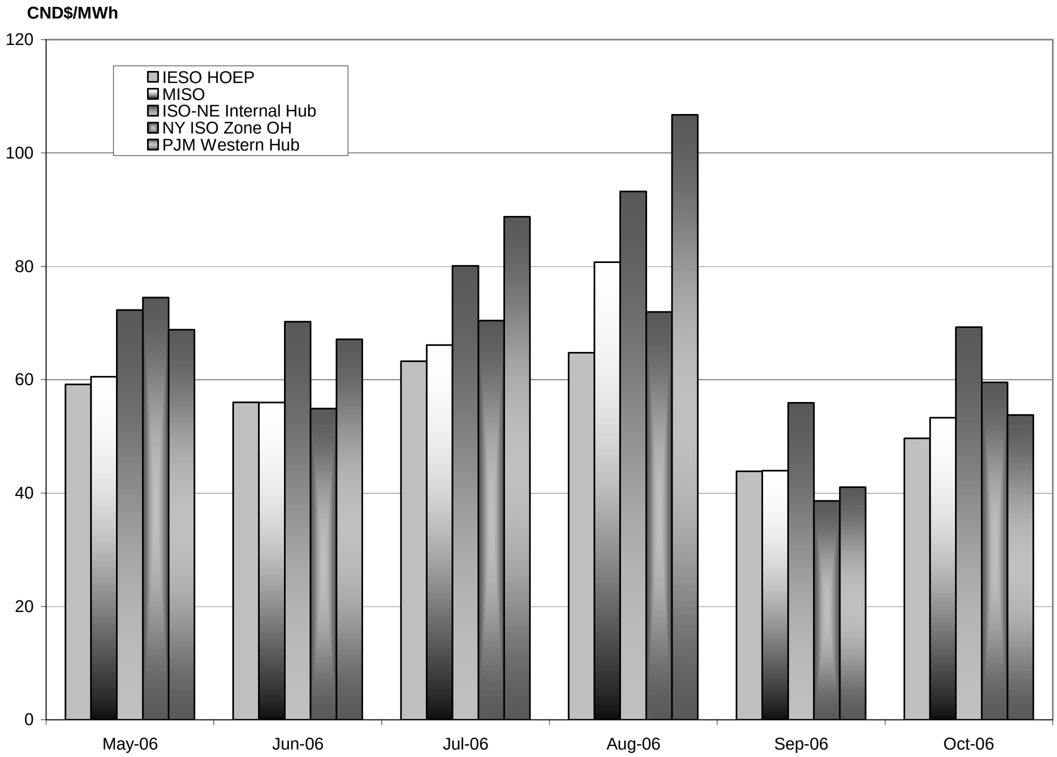
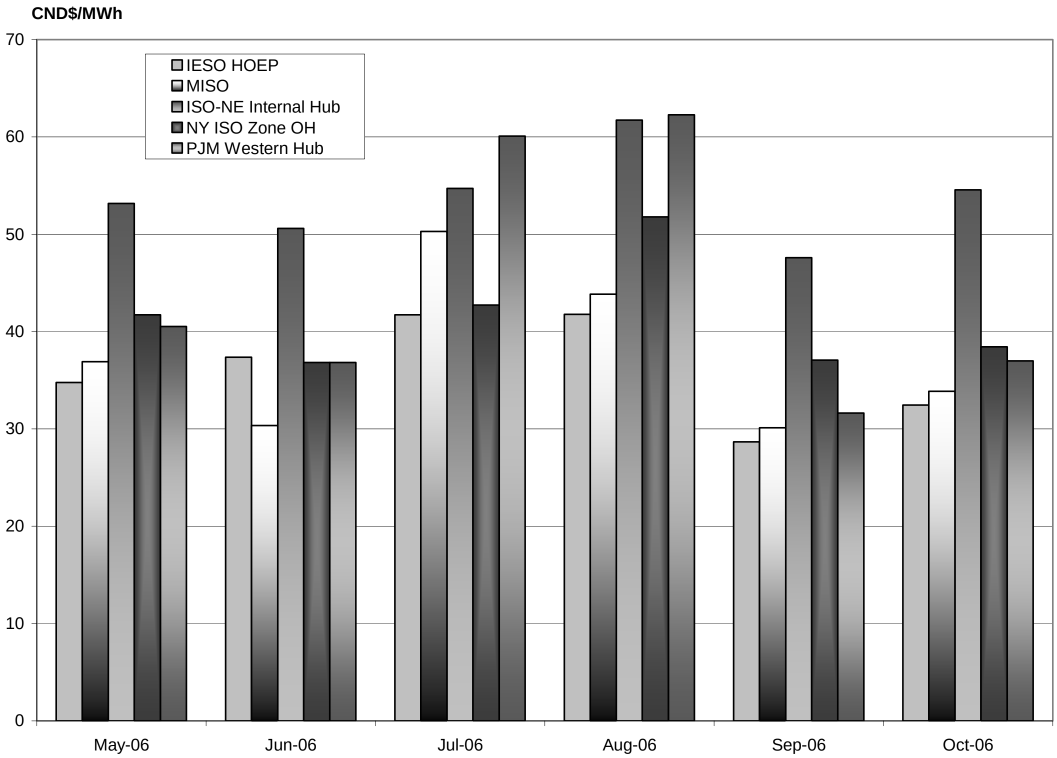


Figure 1-16: Average HOEP Relative to Neighbouring Markets: Off-peak May–October 2006 ($/MWh)



11. *Price Setters*

Analysis of period-to-period differences in the respective frequencies with which each type of generation is the marginal supplier in the market is helpful in understanding the determinants of changes in the HOEP over time. The frequency with which a given type of generation sets the market price depends on the supply/demand balance. When demand is moderate, the offers of coal-fired generation typically set the price. When demand is high, the market price is likely to be set by the offer of a gas-fired or of a peaking hydro generator. An implication of this is that changes in the price of gas are more likely to affect the HOEP under conditions of high demand than under conditions of moderate demand. The opposite would be true of changes in the price of coal.

On average, the market price tended to be set more frequently by coal during the period May-October 2006 than during the corresponding period in 2005, as shown in Tables 1-14 to 1-16. Indeed, in every month with the exception of May, the frequency with which coal-fired generation set the real-time market clearing price increased. This appears to have been caused in part by increased supply from nuclear generators. This increase in inframarginal supply had the effect of pushing gas and peaking hydro generation out of the money, making coal generation the marginal supplier. A consequence of the greater frequency with which coal generation sets the price is that we see a greater clustering of prices in the typical price range for coal-based offers (see Figure 1-2 Frequency Distribution of the HOEP). This is especially apparent in off-peak hours.

Some departure from the overall tendency of coal generation to set the market price more frequently can be seen in May 2006 where large demand increases resulted in increased reliance on hydroelectric production and gas-fired generation on-peak (Table 1-15).

Table 1-14: Share of Real-time MCP Set by Resource May-October, 2005 and 2006 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**
May	67	63	0	0	9	14	24	23
June	51	61	0	0	30	22	19	17
July	43	52	0	0	38	29	20	20
August	46	57	0	0	33	22	21	22
September	45	56	0	0	34	18	20	26
October	58	62	0	0	15	17	27	21

Table 1-15: Share of Real-time MCP Set by Resource On-peak, May–October, 2005 and 2006 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**
May	61	45	0	0	18	26	21	29
June	34	37	0	0	48	39	18	24
July	18	30	0	0	59	48	23	22
August	23	37	0	0	51	34	25	29
September	21	41	0	0	54	32	25	27
October	36	40	0	0	30	32	33	28

Table 1-16: Share of Real-time MCP Set by Resource Off-peak, May–October, 2005 and 2006 (%)

	Coal		Nuclear		Oil/Gas		Water	
	2005	2006	2005	2006	2005	2006	2005	2006
May	72	79	0	0	1	4	27	17
June	67	81	0	0	12	7	20	12
July	61	66	0	0	21	16	17	18
August	66	74	0	0	16	10	18	16
September	66	68	0	0	17	7	17	24
October	74	80	0	0	3	5	23	15

While the tables indicate that nuclear generators never set the market price, a nuclear generator did in fact set the market price during one hour in September. In Hour 5 on September 3, 2006 the offer of a nuclear generator set a negative market price. This event is discussed further in Chapter 2.

12. *Operating Reserve Prices*

Comparisons of monthly on-peak and off-peak prices of each of the three classes of operating reserve for the periods May–October 2005 and 2006 are reported in Tables 1-17 and 1-18. This comparison shows that there was little year over year change in OR prices.

In January 2006, the IESO reduced its total operating reserve requirement by 50 MW. This was a result of the introduction of a regional reserve sharing program introduced by the Northeast Power Coordinating Council (NPCC). This change was discussed in our June 2006 report and we will report on the impact of this change to date in Chapter 2. The NPCC is discussing extension of the program to allow 100 MW of reserve sharing and to treat this as 10 minute spinning reserve.

Ten minute spinning reserve prices continue to be substantially higher than the other two forms of operating reserve. Ten minute spin is a class of operating reserve presently restricted to on-line generators. Our understanding is that the NPCC is in the process of authorizing changes which allow the treatment of loads as being frequency responsive and thus eligible to provide 10 minute spinning reserve. This practice is followed in some markets and is about to be adopted in others. The IESO has indicated it will be seeking stakeholder approval for implementing this in the Ontario market. Its adoption here would likely reduce the price of this form of reserve and may also reduce the HOEP by a small amount.

Table 1-17: Operating Reserve Prices Off-Peak May–October, 2005 and 2006 ($/MWh)

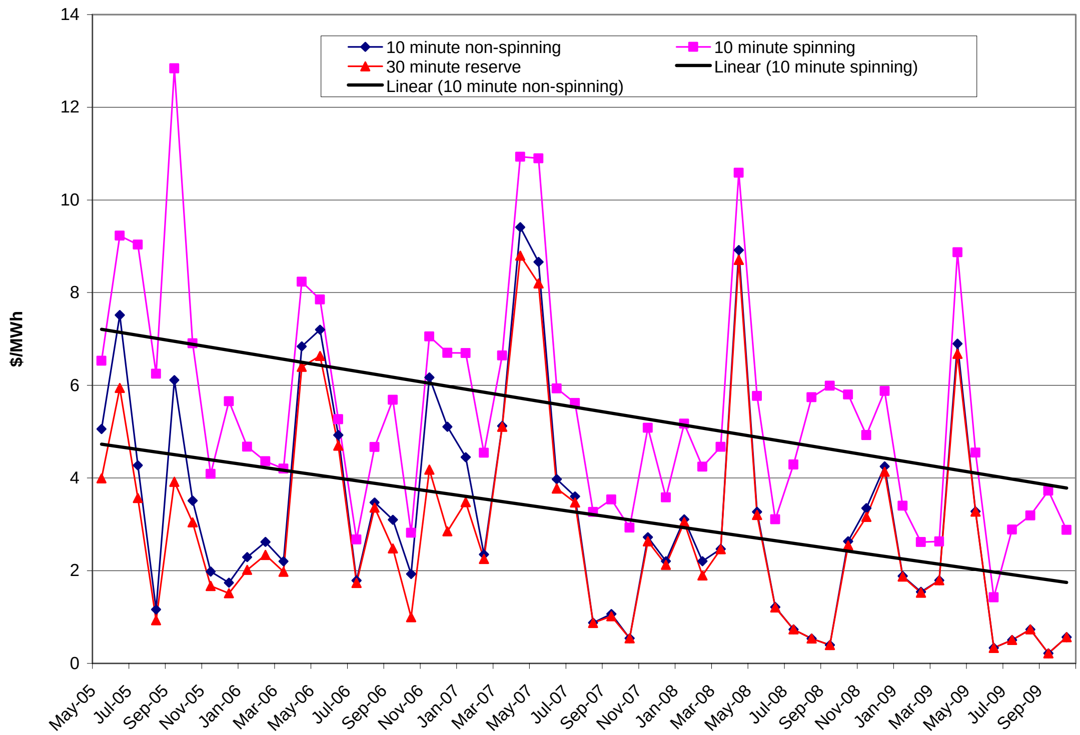
	10N		10S		30R	
	2005	2006	2005	2006	2005	2006
May	1.41	1.42	4.83	3.00	1.31	1.42
June	0.23	0.29	2.90	2.19	0.23	0.29
July	0.20	0.55	3.40	3.65	0.20	0.55
August	0.20	0.20	5.14	3.33	0.20	0.20
September	0.20	0.21	5.07	3.52	0.20	0.21
October	1.00	0.21	4.90	2.80	0.99	0.21
Average	0.54	0.30	4.37	3.11	0.52	0.30

Table 1-18: Operating Reserve Prices On-Peak May–October, 2005 and 2006 ($/MWh)

	10N		10S		30R	
	2005	2006	2005	2006	2005	2006
May	5.53	5.34	6.92	6.27	5.50	5.34
June	2.24	0.38	3.32	0.55	2.22	0.38
July	1.44	0.44	5.46	1.78	1.44	0.44
August	0.91	1.32	6.41	3.03	0.91	1.32
September	0.62	0.21	7.04	3.98	0.62	0.21
October	4.80	1.00	7.01	2.98	4.61	1.00
Average	2.59	0.69	6.03	2.47	2.55	0.69

Figure 1-17 illustrates monthly average operating reserve prices since market opening. Since the Ontario market is a cross-optimised market between energy and operating reserve, the fact that operating reserve prices continue to fall implies that there is also downward pressure on the HOEP. In previous reports we have attributed this decrease in the price of OR to increases in supply from both generators and from dispatchable loads.

Figure 1-17: Monthly Operating Reserve Prices
Market Opening May 2002 to October 2006
($/MWh)



There are indications that some dispatchable loads may be exiting the Ontario market (becoming non-dispatchable) in response to Ontario Power Authority (OPA) demand response programs. Reductions in the supply of operating reserve would increase both OR prices and the HOEP. The design and consequences of OPA demand response programs are discussed further in Chapter 3, section 5 of this report.

13. *One Hour Ahead Pre-Dispatch Price and HOEP*

The difference between the one hour ahead pre-dispatch price and the real-time price is an important market performance indicator. In earlier reports, we have explained how inaccurate or unreliable pre-dispatch prices can lead to inefficient production and consumption decisions which, in turn, can cause real-time scheduling inefficiencies.

The introduction of the real-time transaction failure charge and various demand response programs has further increased the importance of accurate pre-dispatch pricing.

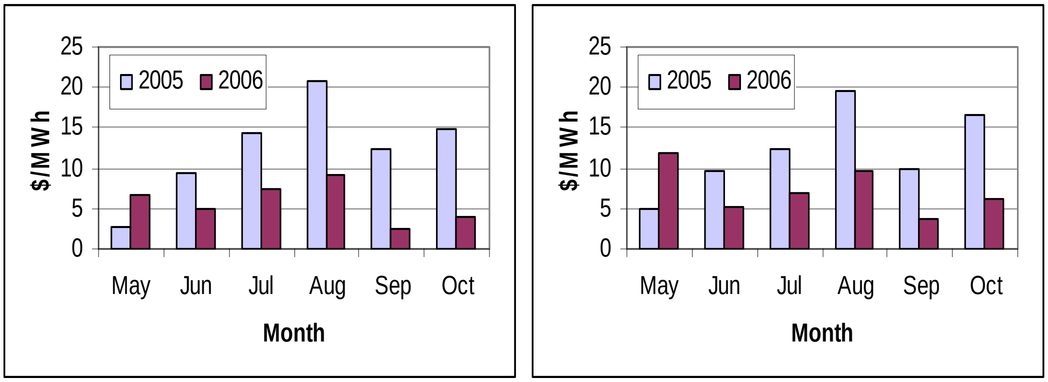
Table 1-19 describes the differences between the 1-hour ahead pre-dispatch price and the HOEP in the period May–October 2006 versus the same period in 2005. The average difference over the past 6 months is $7.33 while the average difference as a percentage of HOEP is 21.73 percent. The difference between both the 1-hour ahead and the 3-hour ahead pre-dispatch prices and the HOEP was lower in the period June through October 2006 (except September) than in the same period a year ago (see Figure 1-18). This should lead to more efficient consumption and production decisions. It should also reduce the adverse efficiency consequences of programs such as the Transitional Demand Response Program, which we discussed in our June 2006 report.

Table 1-19: Measures of Differences Between 1-Hour Ahead Pre-Dispatch Prices and HOEP May-October, 2005 and 2006 ($/MWh)

	1-Hour Ahead Pre-Dispatch Price Minus HOEP									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Hourly Difference as a % of the HOEP	
	2005	2006	2005	2006	2005	2006	2005	2006	2005	2006
May	4.97	11.94	52.37	1,739.37	(175.32)	(297.46)	16.98	67.55	14.51	29.88
June	9.68	5.12	94.12	44.18	(238.58)	(66.34)	18.02	11.20	22.45	15.04
July	12.50	6.89	287.05	60.33	(417.67)	(174.98)	37.22	13.61	26.69	18.99
August	19.50	9.73	574.86	262.96	(267.59)	(67.76)	58.42	25.64	29.29	19.93
September	9.93	3.82	133.67	34.86	(474.82)	(67.49)	36.31	8.56	20.67	24.74
October	16.70	6.27	139.88	52.09	(372.26)	(42.27)	35.93	10.44	33.03	21.67

Figure 1-18: Average Pre-dispatch Price Differences
3 and 1-Hour Ahead to Real-time
May-October, 2005 and 2006
($/MWh)

(three hour ahead price difference) (one hour ahead price difference)



In its past reports the Panel has identified four factors that cause differences between pre-dispatch and real-time prices. These factors are:

- out of market control actions;
- demand forecast error;
- performance of self-schedulers and intermittent generators; and
- failure of scheduled imports and exports.

Below, we examine the role played by each of these factors in explaining the discrepancy between pre-dispatch prices and the HOEP. The first three no longer present significant issues and the IESO has recently taken steps to address the fourth. The early indication is that these steps are bearing fruit.

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

The adverse consequences for the fidelity of the market price signals resulting from reductions in operating reserve requirements by the IESO during periods of extreme scarcity have been discussed at length in earlier reports of the Panel. In essence, reductions in reserve requirements often turned out to be greater than the actual reserve shortage and this had the effect of depressing the HOEP to the point that it no longer reflected the tightness of the supply/demand balance in the market. In recognition of the concerns raised by the Panel and others, the IESO created a new category of operating reserve called Control Action Operating Reserve (CAOR) which is offered into the market at predetermined prices. With the completion of the implementation of its CAOR program in November 2005, out of market control actions in the form of reductions in OR requirements by the IESO were eliminated.

Table 1-20 indicates that there were no reductions in operating reserve requirements during the period May–October 2006. The Panel no longer considers this one of the issues that causes discrepancies between pre-dispatch and real-time prices. In future the Panel will report any reduction in operating reserve requirements as an anomalous event rather than as a factor contributing to the discrepancy between pre-dispatch prices and the HOEP.

Table 1-20: Percentage of Intervals with Manual Operating Reserve (Market Schedule) May-October, 2005 and 2006

	No Reduction		>1 MW and <200MW		>=200MW and <400 MW		>=400 MW and <800 MW		>=800MW	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**
May	98.44	100.00	0.48	0.00	0.65	0.00	0.43	0.00	0.00	0.00
June	98.7	100.00	0.09	0.00	0.47	0.00	0.65	0.00	0.08	0.00
July	98.97	100.00	0.60	0.00	0.12	0.00	0.3	0.00	0.00	0.00
August	99.81	100.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
September	100.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
October	98.81	100.00	0.02	0.00	0.63	0.00	0.41	0.00	0.12	0.00
Average	99.12	100.00	0.23	0.00	0.31	0.00	0.30	0.00	0.03	0.00

Demand forecast error

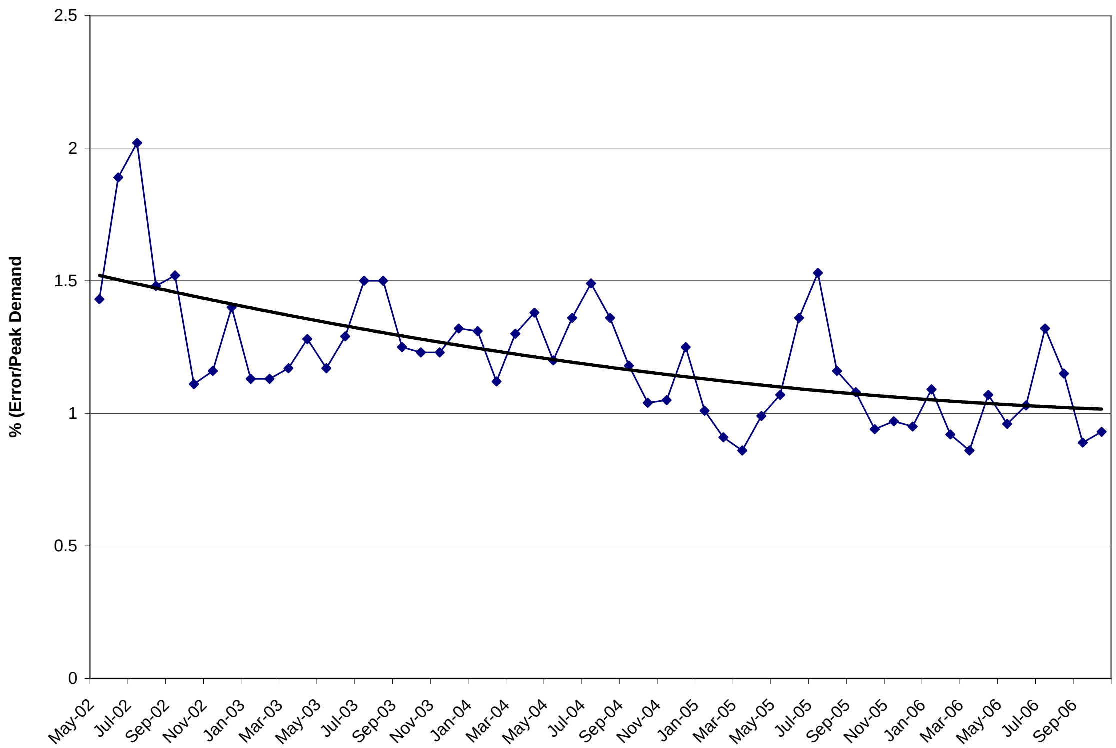
Demand forecast errors cause pre-dispatch prices to differ from the HOEP and this leads, in turn, to inefficient production and consumption decisions. For this reason, reductions in demand forecast error have been welcomed by the Panel. At this point, the IESO's forecasts are well within the range of the 2 percent error that is typical of other ISO's in the Northeast Power Coordinating Council.

During the period May-October 2006, we observed a slight improvement over the corresponding period a year ago in the measures of forecast accuracy reported in Table 1-21. This is part of a downward trend in demand forecast error since market opening. This is shown in Figure 1-19.

Table 1-21: Forecast Error in Demand
May-October, 2005 and 2006

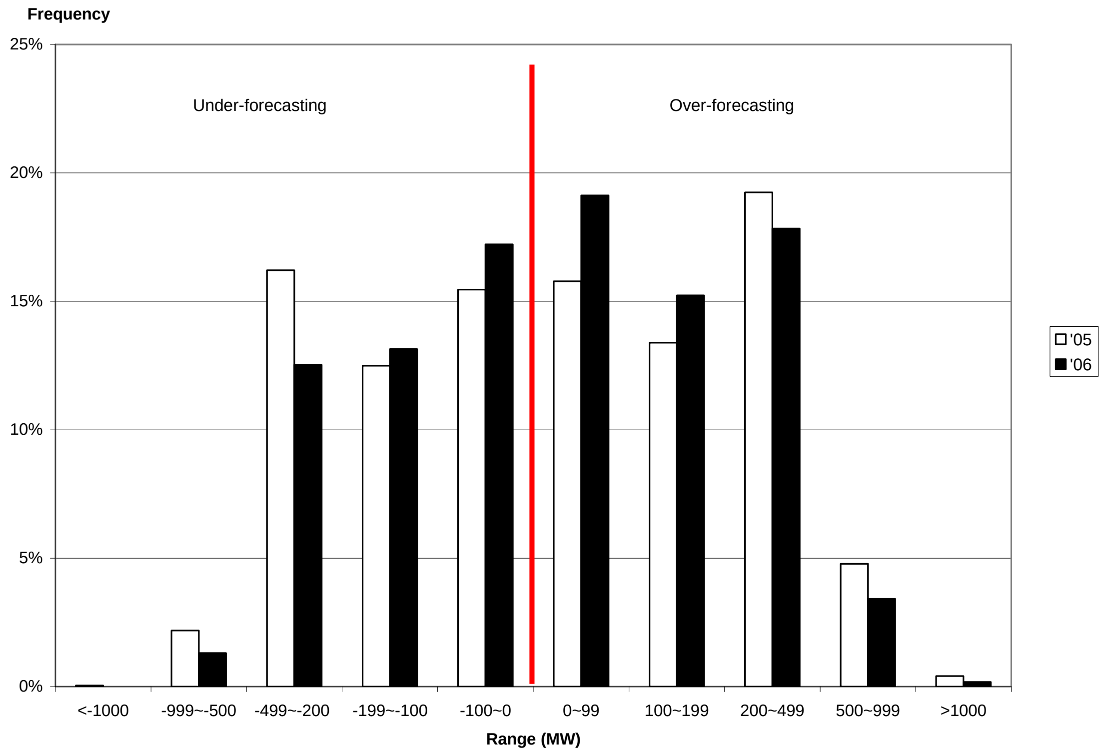
	Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	2005	2006	2005	2006	2005	2006	2005	2006
May	2.01	2.03	1.77	1.9	1.44	1.19	1.07	0.96
June	2.92	2.19	2.55	1.95	1.93	1.36	1.36	1.03
July	3.11	2.62	2.54	2.26	2.25	1.8	1.53	1.32
August	2.22	2.35	1.96	2.0	1.64	1.64	1.16	1.15
September	1.89	1.86	1.63	1.67	1.40	1.12	1.08	0.89
October	1.67	1.94	1.51	1.78	1.22	1.16	0.94	0.93

Figure 1-19: Absolute Average Monthly One Hour Ahead Forecast Error Market Opening May 2002 to October 2006 (% of Peak Demand)



The sources of observed changes in the average forecast error can be found by examining changes in the frequency distribution of demand forecast errors which is presented in Figure 1-20. The figure compares May-October 2006 with the corresponding period in 2005. It shows a decline in the incidence of relatively large negative forecast errors and an increase in the incidence of relatively small positive forecast errors. This decline was mainly due to a less volatile demand this year as a result of mild weather. This implies a slight increased tendency to over-forecast coupled with a slight decline in the average (absolute) forecast error.

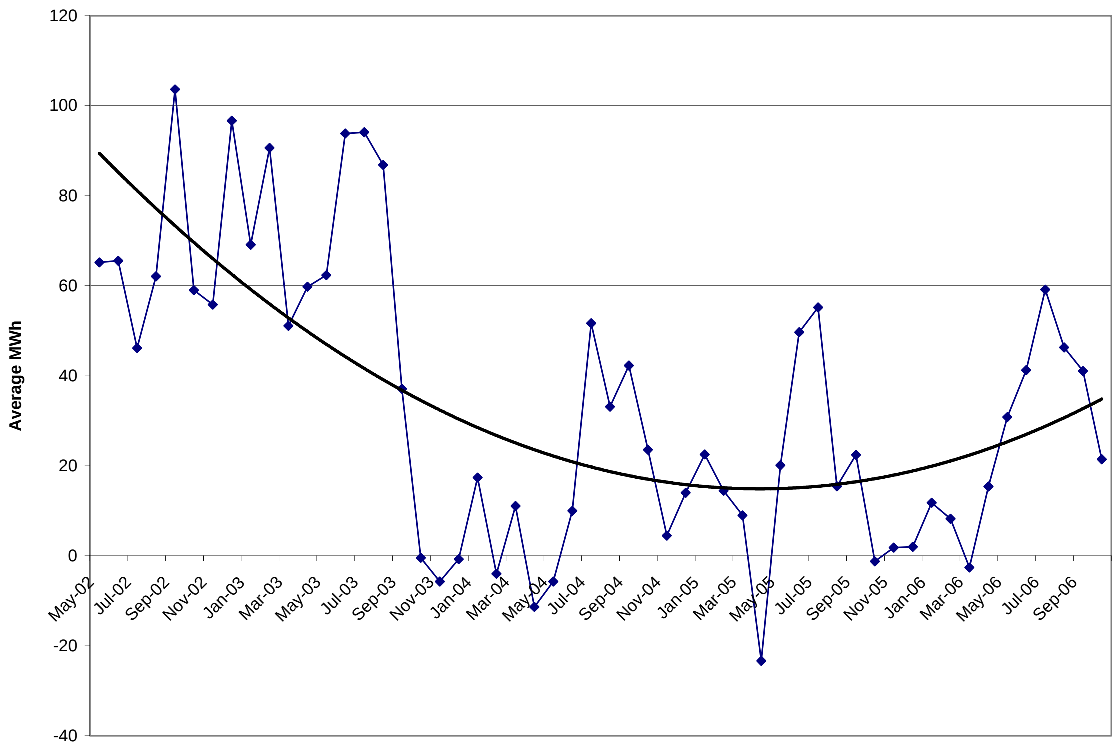
Figure 1-20: Frequency Distribution of Ontario Demand Forecast Error (1-Hour Ahead versus Real-time) May-October, 2005 and 2006



Performance of Self-Scheduling and Intermittent Generation

Figure 1-21 shows the trend of the average monthly differences between the offers of self-scheduling and intermittent generators and their delivered quantities since market opening. While the magnitude of this difference has decreased over time, there appears to have been a reversal of this trend in the last six months. The MAU's analysis indicates that roughly 25 percent of the error can be attributed to wind generation and about 75 percent due to traditional self-scheduling generation. In any event, the magnitude of the differences between offered and delivered quantities is generally small enough that it has little impact on the difference between pre-dispatch prices and the HOEP.

Figure 1-21: Average Difference Between Self-Schedulers' Offered and Delivered MW
Market Opening May 2002 to October 2006

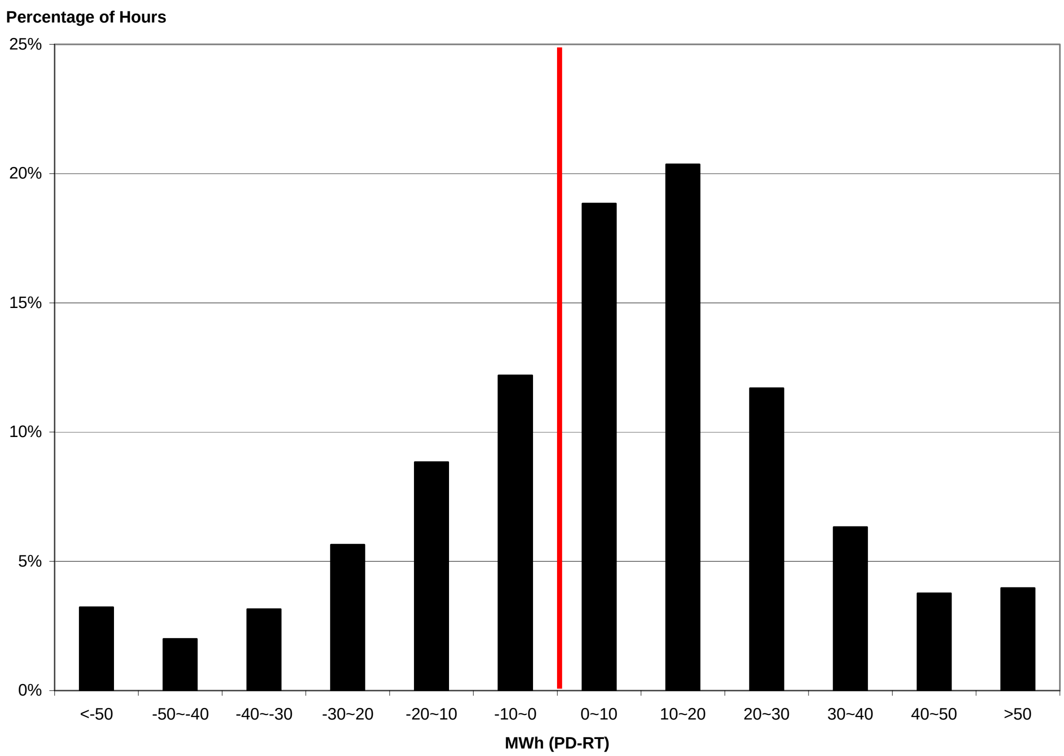


Wind Generation Performance

While overall self-scheduler error still tends to be small, and has been declining since market opening, this trend may have been reversed in recent months. This may be attributable to the rapid growth in wind generation over the past 8 months in Ontario. Presently there are 395 MW of wind power capacity installed in Ontario and this is scheduled to increase substantially in the near future. The wind power generators had a record high production 179 MW in hour ending 23 October 28, 2006.

Figure 1-22 indicates that wind generators tend to be biased toward over-forecasting. While the average discrepancy in terms of MW is small, both the percentage error and the maximum discrepancy are growing (see Table A-40 in the Statistical Appendix). This implies that wind generation could be a source of differences between pre-dispatch prices and the HOEP in the future.

Figure 1-22: Frequency Distribution of Wind Power Generator Forecast Error (1-Hour Ahead versus Real-time) May-October 2006



Real-Time Failed Intertie Transactions

In its June 2006 report, the Panel concluded that the failure of import and export transactions had become the major source of differences between pre-dispatch prices and the HOEP.

Tables 1-22 and 1-23 report the number of incidents and rates of import and export failure for all reasons in 2005 and 2006. The import failure rate was marginally lower in summer 2006, while the export failure rate dropped significantly in June through October with the exception of September.

Table 1-22: Incidents and Average Magnitude of Failed Imports to Ontario May–October, 2005 and 2006

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)***	
	2005	2006	2005	2006	2005	2006	2005	2006
May	355	121	650	818	168	135	6.07	3.10
June	348	187	916	848	190	153	5.94	4.58
July	349	207	1,110	1,020	192	123	5.95	4.25
August	301	171	1,025	405	188	113	5.7	4.53
September	316	54	885	300	173	76	5.43	1.12
October	335	109	810	240	134	69	4.33	2.08

* 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

Table 1-23: Incidents and Average Magnitude of Failed Exports from Ontario May–October, 2005 and 2006

	Number of Incidents*		Maximum Hourly Failure (MW)		Average Hourly Failure (MW)**		Failure rate (%)***	
	2005	2006	2005	2006	2005	2006	2005	2006
May	483	564	991	1,136	267	318	11.55	13.03
June	457	324	1,128	817	238	176	12.71	5.87
July	337	354	1,350	850	275	201	11.34	6.47
August	368	399	1,478	914	226	187	9.16	5.80
September	341	422	1,000	788	241	192	8.28	8.88
October	477	412	1,188	874	231	185	10.63	7.25

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

The drop in import and export failures coincided with the introduction by the IESO of the Real-Time Failure Charge and the Day Ahead Commitment Process. These changes are discussed in section 4 of Chapter 3 of this report.

14. *Hourly (Market) Uplift Components*

Hourly uplift includes payments for Import Offer Guarantees (IOG), Congestion Management Settlement Credit (CMSC) payments, Operating Reserve and transmission losses. These are market induced uplifts as opposed to the non-market uplifts described in Section 2.1. As shown in Table 1-24, total hourly uplift charges were almost 60 percent lower during the period May-October 2006 than during the same period a year earlier.

IOG payments shown in Table 1-24 include Day Ahead IOG (DA-IOG) as of June 2006. Both IOG and DA-IOG depend on the difference between pre-dispatch conditions and real-time. For DA-IOG it is the difference between day ahead offer prices for scheduled imports and HOEP that results in a payment. For IOG the difference between pre-dispatch price and the HOEP defines the payment. The total DA-IOG and IOG payments during the period May-October 2006 were about one-quarter of what IOG payments alone were during the same period the year before. This is a consequence of decreases in both imports, which were less than half of the previous period's imports, and the difference between the pre-dispatch or day-ahead prices and the HOEP.

CMSC payments depend on the amount of transmission congestion and on the difference between nodal prices and the HOEP. The decrease in CMSC payments is due to the reduced incidence of extremely tight supply conditions and / or increases in supply in areas vulnerable to transmission congestion. In essence, there were fewer incidents in which generation that was otherwise out of the money was constrained on due to transmission congestion, and because of lower HOEP, generation that was constrained off received lower payments. Both constrained on payments and constrained off payments dropped to about 35 percent of the previous period's amount, as can be observed in Table A-17 of the Statistical Appendix.

Loss payments were also substantially lower in 2006 as a consequence of the lower HOEP, and lower demand which resulted in smaller flows and thus lower transmission losses.

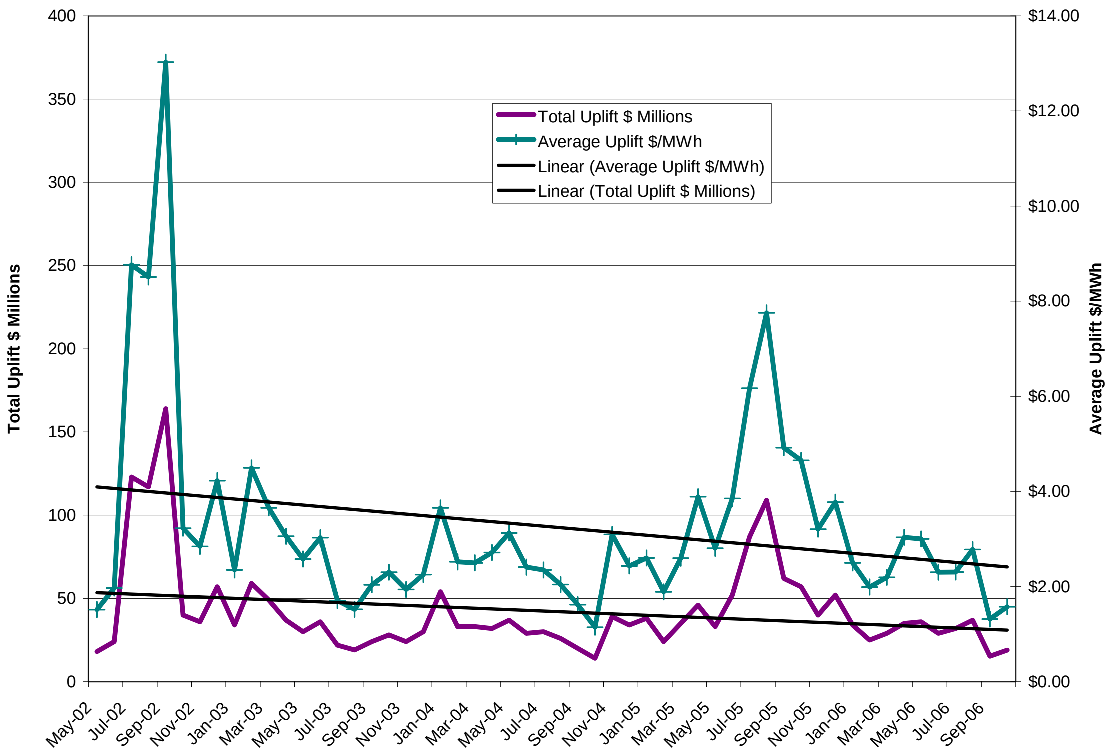
Table 1-24: Monthly Total Hourly Uplift Charge ($ million)
May–October, 2005 and 2006

	Total Hourly Uplift		IOG*		CMSC		Operating Reserve		Losses	
	2005	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**	**2006**
May	32	36	3	4	11	15	3	3	16	14
June	53	28	5	2	21	13	1	1	25	13
July	87	32	12	2	43	12	1	1	31	17
August	110	37	20	4	55	16	1	1	33	16
September	62	15	7	1	24	5	1	1	30	8
October	56	19	8	2	23	6	4	1	22	10
Total	400	166	55	15	177	66	12	7	157	78

*includes Day Ahead IOG as of June 2006 and onwards.

The hourly uplift is paid by consumers as a charge on their bills based on the MWh they consume. Since market opening the trend in total uplift payments has been downward and these market-related uplift payments per MWh of load have fallen still faster. This is shown in Figure 1-23.

*Figure 1-23: Total Hourly Market Uplift and Average Hourly Market Uplift since Market Opening**



*Excludes non-market related adjustments described in section 2.1

15. *Internal Zone Prices and CMSC Payments*

In the past two monitoring reports, we have provided information on both zonal prices and CMSC payments. The MAU has observed that this information has been useful in prompting discussion on locational prices and on the potential efficiency gains from this type of reform. It has also been suggested that such data may be useful for indicating the cost of congestion, thereby helping to inform possible decisions on transmission investment. We review the data here to identify how it can be used for this purpose.

15.1 Internal Zonal Prices

Average zonal prices for the period May–October 2006 are shown in Figure 1-24 while Table 1-25 compares these with prices from the last two MSP reports.[11] Prices in southern Ontario from Ottawa to the Western Zone are relatively close to one another, ranging from $49.67 per MWh to $53.59 per MWh. Zonal prices in both northern zones are much lower, $44.21 in the Northeast and $23.53 in the Northwest. All of these average prices are lower than the corresponding zonal prices reported in the last two reports, with average prices (not weighted) across the zones dropping almost 25 percent compared with the previous six months, from $64.47 to $48.44, and almost 50 percent when compared with last year's values. The continued drop in zonal prices in southern Ontario is the result of more supply and lower demand. This also appears to have resulted in fewer occurrences of congestion, which accounts for convergence of zonal prices in southern Ontario. The southern Ontario zonal prices are also closer to the HOEP, as explained in Chapter 2 section 4.2.

Table 1-25: Zonal Prices ($/MWh)
May 2005 – November 2006

Zone	May05-Oct05	Nov05-Apr06	May06-Oct06
BRUCE	94.93	66.95	49.67
EAST	100.09	68.01	51.15
ESSA	96.43	64.51	49.69
NORTHEAST	82.22	60.78	44.21
NIAGARA	96.65	70.65	53.24
NORTHWEST	33.17	34.43	23.53
OTTAWA	107.22	71.48	53.56
SOUTHWEST	98.49	68.41	52.36
TORONTO	106.18	70.08	53.44
WESTERN	100.82	69.41	53.59
AVG	91.62	64.47	48.44

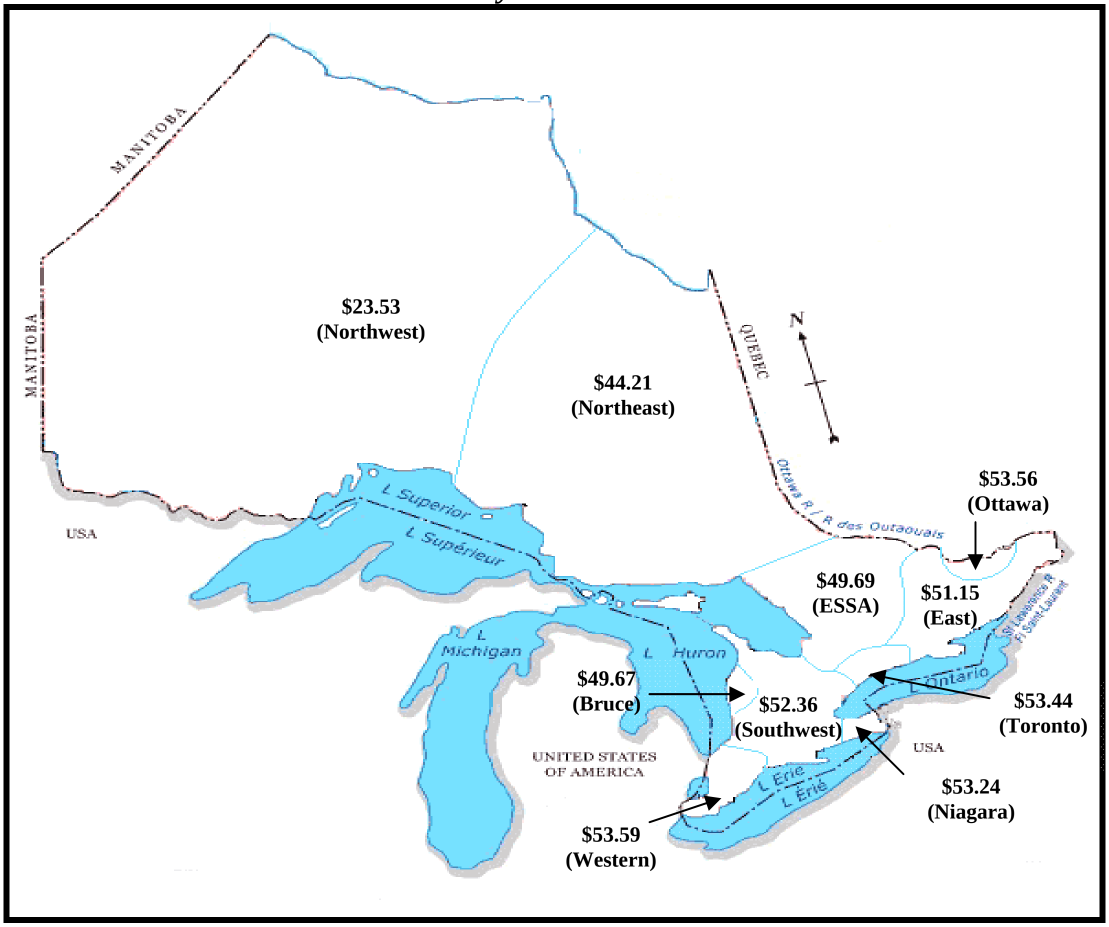
We have stated before that the difference in shadow prices between zones is due to a combination of transmission losses and internal congestion. Table 1-26 is one way to demonstrate the relative effect of each. It shows average loss and congestion components

[11] Zonal prices are calculated here as the un-weighted average of nodal prices for all generation facilities in a zone.

for each of the zones. These components have been calculated using the equation described in the Market Rules:[12]

$$\lambda_n = \lambda_s + (DF_n - 1)*\lambda_s + \Sigma DF_n * a_{nk} * \mu_k$$

Figure 1-24: Average Internal Zonal Prices May–October 2006



where the nodal price at node n, λ_n , is separated into 3 components, representing the reference bus (Richview) nodal price, a loss component and a congestion component. With this formulation, we can see that:

[12] Appendix 7.5 section 6.7: where: λ_n is the nodal price at node *n*; λ_s the system marginal cost at the reference bus; D_{Fn} delivery factor for node *n* (reciprocal of the loss factor or penalty factor); a_{nk} sensitivity factor representing what portion of the injection at node *n flows* on *transmission* line *k;* μ_k shadow price for *transmission* constraint *k.*

Nodal Price = Richview Nodal Price + Losses + Congestion

To get the corresponding zonal values we have simply averaged the values for each generation node in the zone.

A positive value for losses means that supplying an increment of energy from the Richview bus increases losses because this would increase energy flows, for situations where the prevailing flow is from Richview to the node of interest. A negative value implies that supplying an increment of energy from the Richview bus decreases losses as a result of lowering flows, for situations where the prevailing flow is toward Richview from the node of interest. Similarly, if there is congestion between the node and Richview which constrain flows to the node, the congestion component is seen as positive. If the incremental flow to the node relieves congestion by some small amount, the congestion component is negative. If there is no congestion the value is zero. The first term from the above equation is the Richview nodal price. By taking averages, the average shadow price for a zone is the sum of the average losses and congestion losses for the zone and the average Richview price. For example, in Table 1-26 for the Bruce zone, the zonal price can be seen as the sum of the Richview price, the loss component and the congestion component, i.e. \$49.67 = \$54.99 – 0.92 – 4.40.

Table 1-26: Loss and Congestion Components
May–October 2006
($/MWh)

	Shadow Price	Losses	Congestion
BRUCE	49.67	(0.92)	(4.40)
EAST	51.15	(0.66)	(3.17)
ESSA	49.69	(3.59)	(1.71)
NORTHEAST	44.21	(7.21)	(3.43)
NIAGARA	53.24	0.53	(2.28)
NORTHWEST	23.53	(16.03)	(15.42)
OTTAWA	53.56	2.29	(3.71)
SOUTHWEST	52.36	(0.06)	(2.57)
TORONTO	53.44	0.75	(2.29)
WESTERN	53.59	1.15	(2.54)
RICHVIEW	54.99[13]	N/A	N/A

The table shows that losses in southern Ontario are fairly small, but start to be significant for Essa and Ottawa, and are much larger and negative in the north, the areas furthest from Richview. The congestion component is more constant and less than 10 percent of the Richview price, in the negative $2 to $4 range, except for the Northwest where the value is negative $15 per MWh.[14] The small negative congestion amount for each southern zone indicates there is little congestion for flows in these zones.

The congestion component of the nodal price represents the marginal cost of congestion, at the node.[15] If the marginal cost were applicable to all the bottled generation, roughly speaking then, the overall cost of congestion for a zone can be estimated as the average congestion component in the nodal price multiplied by the average energy in the zone

[13] The average Richview price as calculated for generation in the Northeast is $54.85, because of the averaging technique used and the changing number of generating facilities in the zone over the 6 months.

[14] A significant portion of the congestion component appears to occur in 11 hours when the Richview nodal price is very high. Although the nodal price can exceed $2000, for the purpose of analysis the nodal price is treated as limited to MMCP. Even with this limitation, much of the implied cost of congestion, an average of $1 to $4 per MWh depending on the zone, occurs in these hours.

[15] Assuming that offer (and bid) prices are representative of the actual cost or value of the energy, even in cases where the prices may be quite high or large negative values. However, we know this is not always the situation, given that the MAU often recovers CMSC under conditions of local market power. Also, negative prices may tend to understate the cost of supply, as implied by the CMSC calculation which effectively replaces negative prices with a zero price for constrained off supply. As a consequence nodal prices could be understated or overstated (at a given node or even for the Richview reference node), with the implication that congestion costs based on offer (/ bid) prices could be overstated or understated.

constrained on or off. For example, for the six months the Northwest experienced 164 MW constrained off on average across all hours. Then an estimate of the cost of congestion in the Northwest is 164 MW* $15.42/MWh * 4,416 hours = $11.2 million.

Unfortunately, the use of averages alone can be misleading for a few reasons. First, in a given hour, average congestion is calculated for all generating nodes in the area, even though only a few nodes may have bottled energy. Secondly and more significantly, in each hour the congestion component applies to the marginal unit of supply; this is likely to overstate the cost associated with other constrained generation, as prices between the zone concerned and Richview would converge somewhat (although sometimes not very much) as the congestion is relieved.

Finally, the average congestion component masks the fact that congestion during the period can be positive or negative, since flows can reverse and cause constraints in the opposite direction. Table 1-27 shows the average absolute congestion component compared with the average reported above. Average absolute values for the two northern zones are much higher that the simple (net) average. For the Northeast for example, the absolute value is about 3 times as large, at $11.46, compared with the net value of $3.43. This means there are many periods in which flow north is constrained and pushes the zonal prices higher.

Table 1-27: Congestion Component by Zone
May–October 2006
($/MWh)

	Congestion	Absolute Congestion	Frequency (%)	Absolute Congestion per Event
BRUCE	(4.40)	4.47	1.0	352.49
EAST	(3.17)	3.31	2.7	121.81
ESSA	(1.71)	2.06	0.6	245.86
NORTHEAST	(3.43)	11.46	24.4	45.88
NIAGARA	(2.28)	2.80	2.8	85.27
NORTHWEST	(15.42)	22.59	50.8	43.95
OTTAWA	(3.71)	4.34	1.2	336.24
SOUTHWEST	(2.57)	2.60	1.0	255.15
TORONTO	(2.29)	2.37	1.1	186.89
WESTERN	(2.54)	3.47	3.1	102.16

These last two factors, the difference of the average and marginal costs and the netting of positive and negative congestion, are most significant and work in opposite directions. Because these factors are offsetting it means the congestion cost as estimated by multiplying the MWh constrained in the period by the average congestion component may be at least indicative of the cost of congestion. We certainly can conclude from this that there are significant congestion costs being incurred in the two northern zones, although we cannot assess based on the above analysis how accurate or inaccurate this is.

Of additional interest, the table above also shows the frequency with which congestion affected nodes in a zone and the average (absolute) congestion cost when it occurred.[16] Most zones experienced limited occurrences of congestion, up to about 3 percent of the time. However, consistent with much higher absolute congestion values, the Northeast and Northwest were affected 24 percent and 51 percent of the time respectively. By contrast, the marginal cost of the congestion when it occurred was lowest in the two northern zones, around $45 per MWh, compared with much higher values in the rest of the province.[17]

[16] An hour was counted as experiencing congestion if at least one node in the zone was observed with congestion between it and the Richview reference node.

[17] Again a large portion of the implied congestion component is induced by 11 hours of Richview price at $2,000. For zones with a low frequency of congestion, the 11 hours represents a higher fraction of the congestion events, and dominates the average congestion cost per event. Without those 11 hours, the

Above we estimated congestion in the Northwest may have cost in the order of $11.2 million in the last six months. In the next section on CMSC payments by zone we note that constrained off payments in the Northwest amounted to $12.3 million in the same period. The similarity is not entirely coincidental, however, neither value is a correct estimate by itself, although the congestion component of the nodal price has the potential to provide better information. An improvement of the congestion cost estimate may be possible by performing the nodal decomposition hourly and considering the constrained MW at the node in each hour. We have asked the MAU to review and possibly revise the calculation for future reports.

Using some very simple stylized examples, the MAU has looked at nodal prices, loss and congestion components, as well as CMSC to understand their relationships and how they might be indicative of the cost of congestion. Based on that, we observe that the congestion component alone can overstate the cost of congestion (as noted above). The examples also demonstrate that CMSC payments are only loosely connected with congestion in situations where losses are large.[18]

15.2 CMSC payments

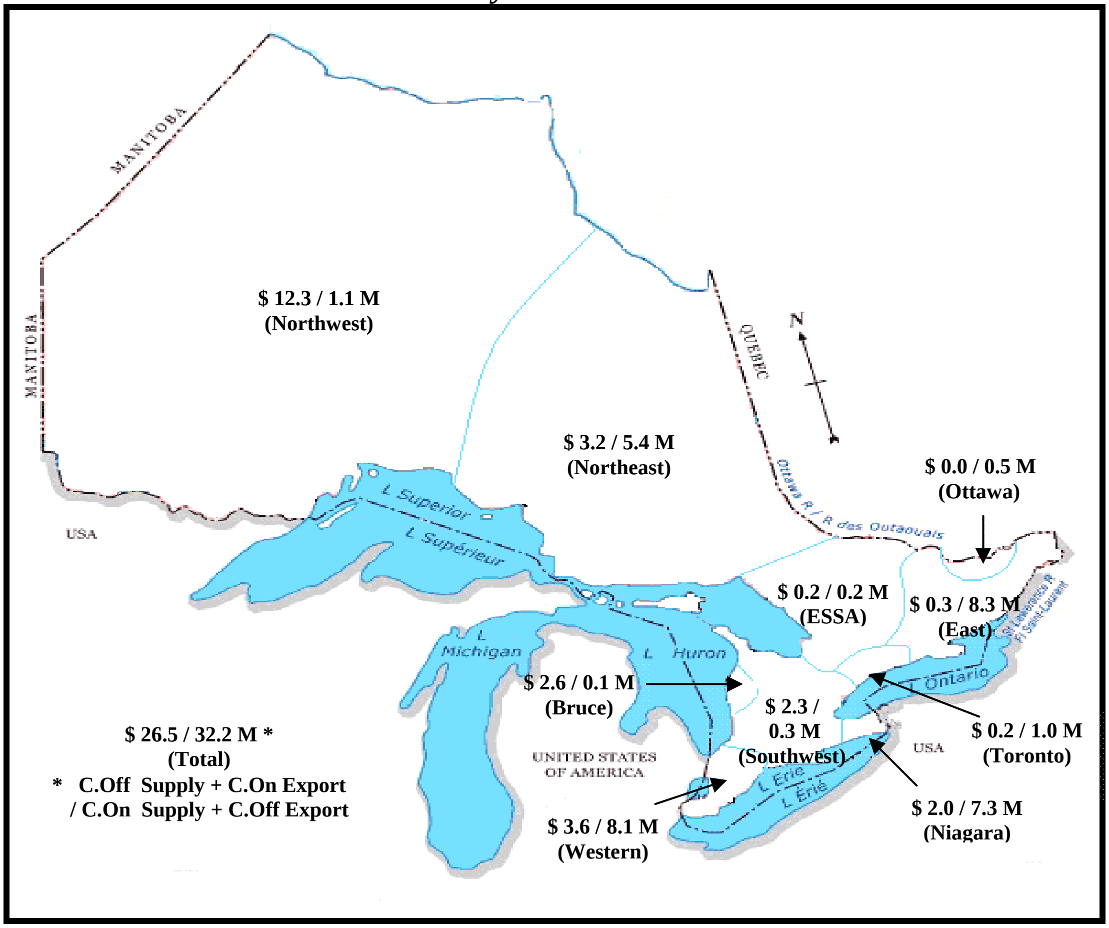
Figure 1-25 shows two sets of CMSC payments for the period May-October 2006. The first value reported for each zone is the sum of CMSC payments for constrained off generation, imports and constrained on exports. The second value is constrained on payments for generation, imports and constrained off exports. For simplicity, intertie CMSC is attributed to the zone that it is connected to. CMSC for dispatchable load has been omitted since the majority of this tends to be self-induced and is recovered.

average absolute congestion cost per event is no more than $85 in any zone, substantially lower than the imputed $250 to $350 in Table 1-27. However, the higher values should not be ignored entirely because there did appear to be some shortage or system problem at the time.

[18] The assessment is available upon request from the MAU. Contact: macd@ieso.ca

In the previous section we noted that CMSC is lower in total, relative to the same period last year. On a zonal basis this is generally also the case, with the zonal sub-totals in Figure 1-25 being typically about one-half to one-quarter of the corresponding values from May 2005 to October 2005. The total constrained off supply plus constrained on export, $26.5 million, is about 35 percent of last year's total of $75.0 million, while the total constrained on supply and constrained off export this year, $32.2 million, is about 39 percent of last year's $83.5 million. The better supply conditions this year have contributed to lower CMSC across the province.

Figure 1-25: Total CMSC Payments by Internal Zones May-October 2006*



* Based on preliminary data for October

Payments for constrained off supply are more than three times higher in the Northwest than in other zones. Constrained on supply and constrained off exports continue to be large in southern Ontario, in those zones with large intertie connections with neighbouring areas, i.e. the Western, Niagara and East zones. The patterns are entirely consistent with there being bottled supply in the northwest and the IESO compensating with supply or reduced exports from southern Ontario.

The zonal prices reported above, which reflect losses and congestion, are not that well correlated with the zonal CMSC payments. The lowest nodal prices are in the Northwest, consistent with the high CMSC paid for constrained off supply. However, the Northeast also has low nodal prices but CMSC to constrained off supply in that zone is similar to payments in several other zones.

There are a few factors contributing to the weak correlation of CMSC payments and nodal price differences. First, the congestion payment is affected by the magnitude of the energy constrained. Nodal prices are insensitive to magnitude, giving information only about the marginal MW. Moreover, CMSC can be induced by other factors, such as the multiple ramp rate treatment in the market schedule. Finally, a large portion of the CMSC is for imports and exports, which are fixed in real-time. Pre-dispatch nodal prices may be more closely related to import and export decisions, but real-time nodal prices are in a way insensitive to these.

16. *Net Revenue Analysis*

If capacity investment decisions are to be market-based as the Panel has always favoured, the HOEP and the price of OR must be such that the revenue earned from the energy, operating reserve and other ancillary service markets covers costs, including returns to investors. Yearly revenue that is persistently below levelized cost puts significant financial pressure on existing generation and discourages new investment. A persistent revenue shortfall may indicate that the market is not functioning properly or that other factors outside the market (e.g. government policy changes) are in play. In contrast, yearly revenues persistently above levelized cost should attract new investment and, in turn, put downward pressure on the HOEP.

Following the approach used in our past reports, we calculate the net revenue or margin that is available to contribute to the recovery of the fixed costs of a hypothetical generator. Net revenue is the hourly energy revenue of the generating unit minus its variable cost summed over the hours in which the HOEP is greater than the unit's variable cost. That is, we assume the generator has perfect information and can ramp up and down instantaneously. Since this approach ignores start-up costs and minimum run time requirements it tends to over-estimate actual revenue.[19] Of course, a generator may also receive operating reserve revenue and regulation revenue, but those revenues are very limited compared to the revenue from the energy market and should not materially impact net revenue estimates.

In this 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 $1.1/MWh for the combined cycle and $3.3/MWh for the combustion turbine.[20] For both types, an outage rate of 5 percent is assumed.

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 the use of a spot fuel price, tends to further overstate the net revenue because transportation and distribution costs are ignored.

Table 1-28 reports net revenue estimates for the past four years. The table illustrates how volatile the net revenue of a generator can be. For example, the net revenue for a combined cycle plant was $111,467 in the first year, then dropped to only $52,987 in the second year, then increased to $95,181 in the third year, and fell to $47,363 in the fourth year. On average, a combined cycle generator would make a contribution of $76,750/MW per year toward its fixed costs and a combustion turbine unit would make a contribution of $20,401/MW per year.

[19] A generator may receive CMSC payments on top of its energy revenue. CMSC does not affect our net revenue calculation provided that the generator offers competitively. The reason is that the generator receives zero net revenue for being constrained on or off if it offers at marginal cost.
[20] FERC assumes US$1/MWh for the efficient unit and US$3 for the inefficient one. To translate the numbers to Canadian dollars, we presume an exchange rate of US$1=CND$1.1.

Table 1-28: Yearly Estimated Net Revenue by Efficiency Type 2002-2006

Generator Type	7,000 Btu/KWh of Combined-cycle with variable O&M cost of $1/MWh	10,500 Btu/KWh of Combustion cycle with variable O&M cost of $1/MWh
Nov 2002 - Oct 2003	$111,467	$31,695
Nov 2003 - Oct 2004	$52,987	$11,128
Nov 2004 - Oct 2005	$95,181	$28,064
Nov 2005 - Oct 2006	$47,363	$10,717
Average	$76,750	$20,401

The contribution estimates for the past three years in Table 1-28 are comparable to the contribution for a hypothetical generator in New York's West Zone estimated by the New York Independent Market Advisor.[21] This estimated net revenue would not justify any new investment, either combined cycle or gas turbine.[22] Based on FERC's estimates, a combined cycle generator in Ontario would require roughly $100,000 CDN in order to meet its debt and equity requirements.

Figures 1-26 and 1-27 plot the duration curve of hourly net revenue for the hypothetical combined cycle plant and combustion turbine plant, respectively. The area under the curve shows the dollar amount available to cover fixed costs. The steepness of the curve shows the extent to which this contribution is derived from operation in peak periods. A flatter curve indicates less reliance on peak periods and price spikes for revenue adequacy. The duration curve for a combined cycle unit (Figure 1-26) for 2005-2006 implies that it is unprofitable to operate three-quarters of the time. The duration curves together with the contribution estimates in Table 1-28 imply that market revenues are not and have not been sufficient to induce the construction of any gas-fired generation in Ontario, peak load or otherwise. Any new entry would have to be subsidized either by load, through uplift charges or by Ontario taxpayers at large.

[21] New York ISO 2005 State of the Market Report: http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2005_NYISO_SOM_Final.pdf

[22] FERC estimates that a combined cycle unit requires US$80-90/kW-year and a combustion turbine unit US$60-70/kW-year to meet debt and equity requirements. For details, see 2004 State of the Markets Report, Docket MO05-4-000

Figure 1-26: Duration Curve of Hourly Net Revenue for a Combined Cycle Unit 2002-2006

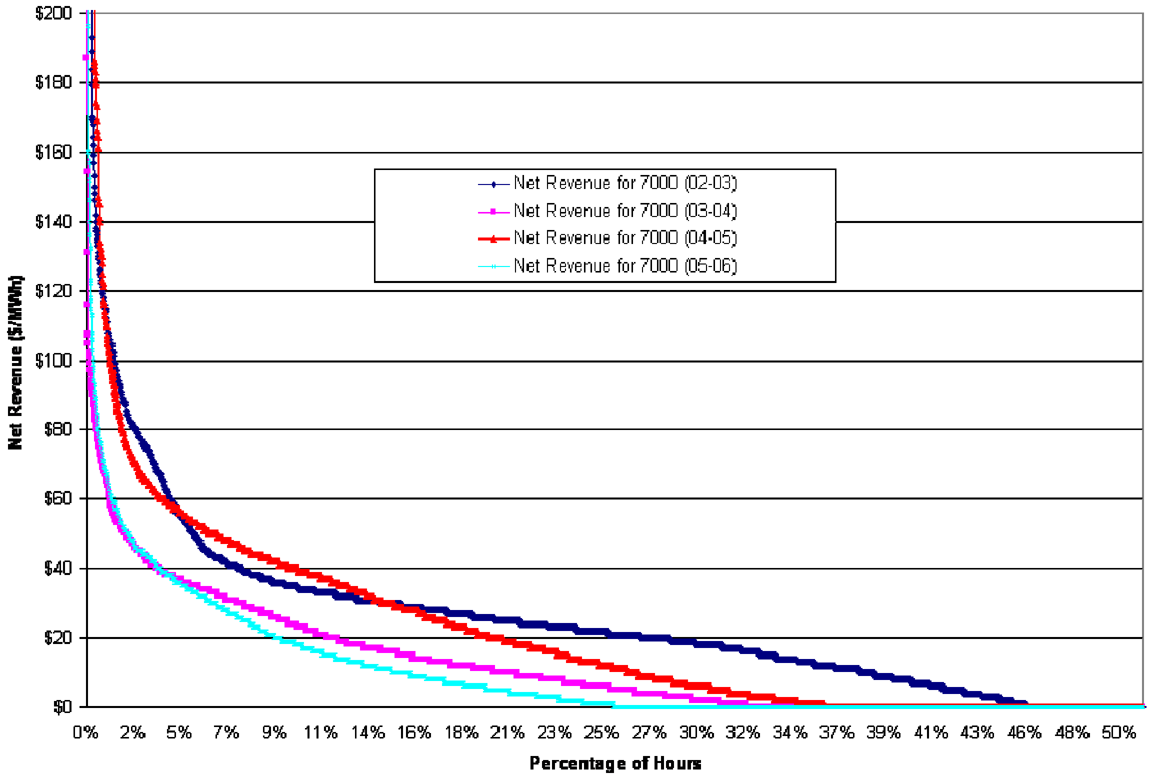
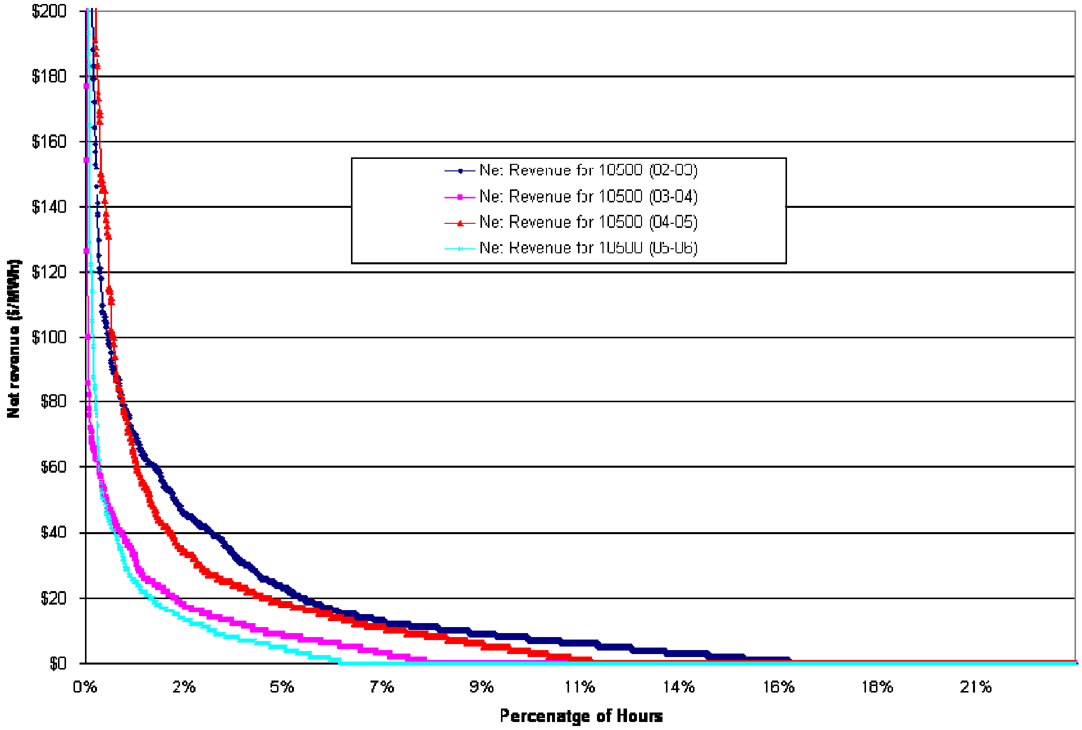


Figure 1-27: Duration Curve of Hourly Net Revenue for Combustion Turbine Unit 2002-2006



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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 events are actions by market participants and the IESO leading to market outcomes that fall outside of predicted patterns or norms.

The MAU reviews all high priced hours to identify the critical factors leading to the high prices and reports its findings to the Panel. For the purpose of this report, high priced hours are defined as all hours in which the HOEP was greater than $200/MWh or the hourly uplift exceeded the HOEP. The MAU also reviews all low priced hours and reports its findings to the Panel. For the purpose of this review, a low priced hour is defined as any hour in which the HOEP was less than $20/MWh.[23]

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

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

Regarding low priced hours, there were 149 hours in the period May 2006 to October 2006 in which the HOEP was less than $20/MWh. Section 3 of this chapter reviews the factors typically driving the prices in these hours.

[23] $200/MWh is an upper bound for the cost of a fossil generation unit. $20/MWh is a lower bound for the cost of a fossil unit.

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. *Analysis of High Priced Hours*

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

Table 2-1 shows the number of high priced hours monthly since market opening. There were 6 hours in which the HOEP exceeded $200/MWh during the period May to October 2006. During the same period in 2005, there were 71 hours in which the HOEP exceeded the $200/MWh. There were no instances where the uplift exceeded the HOEP in either 2005 or 2006.

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

	HOEP>$200			
	2003	2004	2005	2006
January	1	3	0	0
February	15	0	1	0
March	24	0	1	0
April	4	1	0	4
May	0	0	3	3
June	4	0	3	0
July	0	0	15	1
August	0	0	25	2
September	1	0	21	0
October	1	0	4	0
November	0	0	0	N/A
December	0	1	2	N/A

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

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

Each of these factors has the effect of tightening the real-time supply cushion relative to the pre-dispatch supply cushion.[24] Spikes of the HOEP above $200 are most likely to

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

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

EO = total amount of available energy offered
ED = total amount of energy demanded

occur when one or more of the factors listed above cause the real-time supply cushion to fall below 10 percent.[25]

Occurrences of High Priced Hours

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

- May 29, 2006 Hour 16 ($305.70)
- May 30, 2006 Hour 15 ($599.80)
- May 30, 2006 Hour 16 ($258.60)
- July 31, 2006 Hour 17 ($292.20)
- August 1, 2006 Hour 12 ($226.70)
- August 2, 2006 Hour 14 ($317.80)

In all six cases, the real-time supply cushion was well below the 10 percent level. In four cases, peak real-time demand was higher than the pre-dispatch forecast of demand. In one case, the unavailability of inframarginal domestic generation in real-time contributed to the high HOEP and, in another case, a forced outage contributed to the high HOEP. In the hour with the highest HOEP, import cuts related to transmission problems contributed to the high price. The specific circumstances surrounding each of these high price events are discussed below. Table 2-2 shows the pre-dispatch and real-time HOEP and the estimates of the supply cushion for these hours.

The high price events in July and August reflect the record demand conditions during that period. On August 1, the IESO along with the New York and PJM markets experienced record peak hourly demands. Under these load conditions, the interconnected grid is placed under severe strain and loadings on transmission lines often hover close to their allowable thermal limits. At the same time, these challenging conditions also shed light on transmission issues on the grid. Section 2.5 presents a discussion of this issue. In addition, the record demand conditions also emphasize the importance of price-

OR = operating reserve requirements.

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

responsive demand in the market. Section 4.1 examines the economic response of four participants on this record demand day.

Table 2-2: Supply Cushion for High Priced Hours May-October, 2006

		Supply Cushion		Energy Price	
Date	**Hour**	**Pre-dispatch (%)**	**Real-time (%)**	**Pre-dispatch ($/MWh)**	**HOEP ($/MWh)**
May 29	16	14.8	(1.8)	160.00	305.70
May 30	15	7.9	(1.9)	302.31	599.80
May 30	16	9.1	(0.2)	1,998.00	258.60
July 31	17	15.1	(1.5)	117.00	292.20
August 1	12	14.0	2.5	225.00	226.70
August 2	14	15.9	(1.0)	250.00	317.80

2.1 May 29, 2006 Hour 16

In this hour the HOEP rose to $305.70/MWh.

<u>Pre-dispatch market conditions</u>

Pre-dispatch market demand was projected at 22,550 MW with a price of $160. Between $161 and $1,000, there were 560 MW of gas and oil-fired generation and 652 MW of hydroelectric generation. The Ontario market was a net importer in the amount of 1,786 MW. The pre-dispatch supply cushion was 14.8 percent.

<u>Real-time market conditions</u>

In real-time, demand averaged 22,670 MW with a peak of 22,823 MW that was 273 MW higher than projected in pre-dispatch. Late in Hour 15, 105 MW of generation was forced out of service so that was not available in real-time, although it was available in pre-dispatch. Half-way through Hour 16, the IESO was unable to access Operating Reserve Sharing which led it to increase the OR requirement by 50 MW. The effect of these events was to reduce the domestic supply cushion to negative 1.8 percent. Peak MCP in the hour was $526.68 and the HOEP was $305.70, roughly $145 above the pre-dispatch price.

Assessment

The pre-dispatch supply cushion (PDSC) was at 14.8 percent because it included offers from a fossil unit, the output of which was not available in real time. Excluding the offers that would turn out not to be available in real-time, the PDSC dropped to 12.8 percent. The 273 MW excess of real-time demand over pre-dispatch demand, plus 105 MW of unavailable generation, plus a 50 MW increase in OR, reduced supply by 428 MW. With a pre-dispatch price of $160 already indicating offers were being accepted on the steeper part of the offer curve, a further 428 MW of change in net supply moved prices up sharply. As a result, the market had to turn to more expensive supply to meet demand in the hour and the HOEP rose to $306/MWh.

2.2 May 30, 2006 Hour 15

The HOEP in the hour reached $599.80/MWh.

Pre-dispatch Market Conditions

In pre-dispatch, demand was projected at 25,056 MW with a price of $302.31/MWh. Net imports amounted to 2,262 MW. At a market price of $302.31 all available coal, gas-fired and hydro generation was fully scheduled. Above $302, there were 40 MW of fossil-based generation and 362 MW of peaking hydroelectric supply. The pre-dispatch supply cushion was 7.9 percent. Clearly, the offer curve was very steep.

Real-time Market Conditions

In real-time, demand averaged 24,232 MW and was never above the pre-dispatch level in any interval. In fact, peak demand was 24,372 MW. Import cuts of 918 MW (Michigan 818 MW and NYSI 100 MW) led to a severe supply disruption. The real-time supply cushion dropped to negative 1.9 percent. The MCP, set by peaking hydroelectric generation, reached a maximum of $1,280 in interval 12 while the HOEP averaged $599.80 for the hour.

Assessment

This was a very hot day with forecast temperature of 31 Celsius and Humidex of 41 Celsius. Neighbouring markets were also experiencing heavy demand. The IESO declared an EEA1 at 13:34 meaning that all available resources were committed and the IESO was concerned about sustaining required operating reserves. NYISO and PJM were also operating under EEA1.[26] Transmission problems in PJM led to the curtailment of 918 MW of imports into the Ontario market. This resulted in a major supply disruption which increased both energy and reserve prices. Real time demand came 684 MW lower than forecast and this mitigated the price increase in the hour. Given the steepness of the offer curve, peaking hydroelectric plants were called upon to provide the necessary energy to meet demand.

2.3 May 30, 2006 Hour 16

In Hour 16 the HOEP was $258.60/MWh.

Pre-dispatch Market Conditions

Demand was projected at 25,199 MW with a price of $1,998. Net imports were 1,809 MW and the pre-dispatch supply cushion was 9.1 percent.[27] We caution however that in

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

[27] The high supply cushion when the pre-dispatch price is $1,998 requires an explanation. In hour ending 15, the Midwest ISO curtailed 818 MW of exports from Michigan to Ontario. As a result, imports into Ontario dropped by 818 MW for hour ending 15. When the pre-dispatch for HE 16 ran at 15:07, there was a shortfall of 818 MW of imports. This led to reserve shortages and the price jumped to $1,998/MWh. However in the offer stack itself there were almost 4,800 MW of import offers available to the market. The reason some of these import offers could not be scheduled was because of the net interchange schedule limit. This limit restricts the hour to hour change in intertie schedules across all interties to 700 MW. In

this case the pre-dispatch supply cushion is misleading because it includes all import offers in the market when in reality only a subset of these imports was available due to a binding net interchange scheduling limit (NISL). If we take the NISL limit into consideration, the pre-dispatch supply cushion was negative 1.4 percent.[28] At a price of $1,998 all available generation was scheduled. Above $1,998, there were 11 MW of peaking hydroelectric generation available.

We have asked the MAU to revise the methodology underpinning the pre-dispatch supply cushion calculation to determine whether other relevant factors such as the NISL limit, forced outages and deratings should be considered in its computation.

Real-Time Market Conditions

In real-time, demand reached a maximum of 24,528 MW and averaged 24,370 MW over the hour. The supply cushion dropped to negative 0.20 percent. Real-time demand was lower than forecast by 671 MW and this contributed to a lower than forecast HOEP. In addition, activation of shared reserve increased supply at the margin and this also drove the HOEP down in the hour. These events are discussed further below.

Assessment

The market cleared at $1,998 in pre-dispatch on the steepest portion of the offer curve. Several nuclear and fossil units were on outage and 918 MW of imports were removed from the offer stack because of transmission problems in PJM (this is the same import cut that occurred in Hour 15). The next offer above $700 was from a gas-fired generator with an offer of $1,998.

The HOEP in Hour 16 was $258.60, more than $1,700 below the pre-dispatch price. There are a number of reasons for the precipitous drop in the real-time price. Real time

the pre-dispatch the NISL was binding. Thus, although there were plenty of import offers, only a limited quantity could be used. However the computation of the supply cushion does not incorporate this NISL limit. As a result, all available import offers are used to calculate the supply cushion. In this case the additional import offers in the stack inflated the supply cushion to 9.1 percent.

[28] The DSO used 400 MW of CAOR to match supply and demand in pre-dispatch.

peak demand came in 671 MW lighter than forecast and average demand for the hour was below this, leading to lower prices. It is likely that a component of this drop in demand was caused by reduced consumption by non-dispatchable loads as a result of the pre-dispatch price forecast.

In addition, the IESO lost a 500 kV circuit which resulted in a generation loss of 746 MW in the constrained schedule. This transmission contingency reduced generation in the constrained schedule only, supply in the unconstrained schedule was not affected. To cover the contingency that occurred, the IESO activated 500 MW of operating reserve and requested 350 MW shared activation reserve (SAR) from the New York and PJM markets. At the same time, the IESO lowered operating reserve (OR) requirements in both the constrained schedule (last interval) and the unconstrained schedule (last 4 intervals). This amounted to an additional energy supply of 104 MW (net 850 MW supply minus 746 MW of loss) after the contingency in real-time in the constrained schedule while the unconstrained schedule (last 4 intervals) gained 850 MW of additional supply (350 MW of SAR and 500 MW of lowered OR requirement).

In this instance, the unconstrained schedule gained supply in the amount of 850 MW and this suppressed the HOEP:

- The use of SAR has an effect similar to an emergency import in that it simply reduces demand. The IESO should consider treating SAR similar to emergency imports whereby demand is added back to the unconstrained schedule.
- The reduction of Operating Reserve caused by the contingency is a more difficult issue. If the contingency was a generating unit failing, it is removed from both schedules. In such a case, reducing OR in the amount of the forced outage reduces OR demand in both schedules but the loss of generation will shift the offer curve for energy to the left. As the offer curve shifts to the left with equivalent energy demand the MCP will rise but there will be some offset caused by the reduction in the OR requirement. If the contingency is a loss of transmission, typically the generation is only removed from the constrained

schedule leaving the offer curve in the unconstrained schedule unaffected. In this case, OR demand is reduced in the unconstrained schedule and this suppresses both the energy and OR price.

To assess the impact of the reduced real time demand, the MAU added 671 MW to market demand in real time. Under this scenario, the HOEP would have been $1,851. To assess the impact of the lower OR requirement and shared activation reserve in real time, the MAU added 350 MW to market demand and restored the OR requirement to its normal level. Under this scenario the HOEP would have been $343. Therefore these actions suppressed the price by $84.

The Panel notes that the shared reserve received from New York and PJM is essentially a non-market transaction which had the effect of depressing the HOEP. In its December 2005 report, the Panel noted that the IESO introduced new measures to deal with the non-intuitive price impact of emergency imports and voltage reductions. The Panel is of the view that shared activation reserve as a means of incremental supply should be treated in a manner that reflects the scarcity conditions in the market. In this case, the IESO received 350 MW of shared activation reserve from the New York and PJM markets. Currently this incremental supply pushes the HOEP down. The Panel's preference is that these emergency supplies not affect the HOEP.

As to the issue of which type of contingency creates a generation loss in which schedule and in turn the treatment of reducing OR, this is certainly a more complicated issue. The Panel has always believed that from a reliability point of view, prices should reflect the scarcity at the time. Unfortunately, with the present fictions created in the unconstrained world with regards to transmission it would appear that prices will not be reflective of scarcity. The Panel suggests the IESO should discuss with participants if a more appropriate treatment is applicable for the loss of transmission elements. Ideally and to be consistent, the reduction in OR should not appear in the unconstrained schedule and affect the HOEP.

2.4 July 31, 2006, Hour 17

The HOEP was $292.20/MWh in the hour.

Pre-dispatch Market Conditions

Demand was projected at 25,188 MW with a price of $117. Net imports amounted to 653 MW. The supply cushion was 15.1 percent. Between $160 and $300 there were 701 MW of hydroelectric generation, and 150 MW of fossil fired generation. Above $300, there were 375 MW of hydroelectric generation available.

Real-Time Market Conditions

In real-time, demand averaged 25,639 MW with a peak of 25,740 MW. Thus, peak demand was 552 MW and average demand was 451 MW higher than forecast. There were no failed imports in the hour. Failed exports to Michigan (MISO) amounted to 426 MW. They failed because the Michigan price was lower than the Ontario price. The real time supply cushion was negative 1.5 percent. The HOEP was driven up to $292.20 and in six intervals the market clearing price was set by peaking hydroelectric units with offers at or above $200.

Assessment

This was a hot and humid day with a maximum Humidex forecast of 44 degrees Celsius. The IESO operated under EEA1 from midday till early evening. PJM and MISO were also under EEA1 alerts. It turned out that, after the loss of two fossil units in HE 12, the IESO faced severe thermal limit violations for most of the day on the New York-Ontario (East Zone) intertie. To address the local security concerns on this interface, the IESO purchased 40 MW of emergency energy, constrained on 45 MW of imports and activated 5 percent voltage reductions in Hour 17 for local conditions.[29] Altogether, the additional supply amounted to 40 MW of emergency imports, 45 MW of imported energy and 120 MW demand reduction through voltage reductions. With the new IESO procedures the

[29] It turns out there was no OR activation, the IESO applied an incorrect code to the transaction which it later rectified. The incorrect code had no impact on market prices.

emergency imports and the voltage reduction did not depress the market price.[30] The higher than forecast demand outweighed the export failure and the net effect was to cause the market to clear on the steep portion of the supply curve. The HOEP increased to $292.20.

2.5 August 1, 2006, Hour 12

In this hour, the HOEP was $226.70/MWh.

<u>Pre-dispatch market conditions</u>
Demand was projected at 26,238 MW with a price of $225. Net imports scheduled amounted to 1,759 MW. There were 552 MW of water, and 364 MW of fossil offers at prices between $225 and $325. There was also 815 MW of peaking hydroelectric generation offered at prices between $325 and $1,000. The pre-dispatch supply cushion was 14 percent.

<u>Real-time market conditions</u>
In real-time, Ontario demand averaged 26,135 MW with a peak demand of 26,329 MW in interval 11. Net imports were 1,669 MW. The real time supply cushion was 2.5 percent. Demand came in lower than forecast in nine out of the twelve intervals. The HOEP at $227 came close to the pre-dispatch price of $225 as shown in Table 2-3.

[30] See December 2005 report p. 73.

Table 2-3: Demand and Prices, August 1, Hour 12

Interval	MCP ($/MWh)	Real-time Demand Minus Pre-Dispatch Demand (MW)
1	208	(279)
2	159	(317)
3	212	(191)
4	210	(226)
5	226	(137)
6	226	(149)
7	242	(46)
8	256	(10)
9	258	1
10	256	(10)
11	258	91
12	212	39
Average	**227**	**(150)**

Assessment

On this day, real-time demand came in close to forecast demand and, as a result, the HOEP was close to the pre-dispatch price. The IESO as well as PJM, New England and MISO declared EEA1 for most of the day (all generation in service). On the Adirondack / Frontier interface, which is a component of the New York interface, there were transmission overloading concerns. The IESO declared a TLR1 (Transmission Loading Relief Level 1) on this interface. To manage the thermal limit on the Adirondack interface, the IESO manually constrained on 690 MW of imports from Quebec. This additional supply is reflected only in the constrained schedule where it lowers shadow prices. The unconstrained schedule and the HOEP are not affected. There were, however, large constrained on CMSC payments - $4.4 million for the day with $0.5 million for Hour 17.

The Panel notes that on a day when most of eastern North America was experiencing heavy demand conditions, the IESO was able to import 690 MW of additional supply to enable it to deal with transmission constraints and that this action did not distort the HOEP. Had the IESO not manually constrained on these imports and effectively moved them to the bottom of the offer stack, the nodal price at the Adirondack interface would have risen to the point where imports would have been accepted. In HE 11 the pre-dispatch nodal price was $198. The import offers ranged from $165 to $350. It is therefore likely that under a locational marginal price regime these imports would have been selected.

2.6 August 2, 2006, Hour 14

In this hour, the HOEP was $317.80/MWh.

<u>Pre-dispatch market conditions</u>

In pre-dispatch, demand was projected at 25, 411 MW with a price of $250. Net imports were 262 MW. Between $250 and $400, there were 132 MW of fossil-fired generation and 445 MW of peaking hydroelectric generation. The pre-dispatch supply cushion was 15.9 percent.

<u>Real-time market conditions</u>

In real time demand averaged 25,459 MW with a peak of 25,554 MW which was 143 MW higher than projected in pre-dispatch. In fact, demand was higher than forecast in nine out of twelve intervals. Real time prices were higher than forecast in all twelve intervals. The real time supply cushion was negative 1 percent. There were no failed imports/ exports in the hour. A fossil unit experienced production problems resulting in a 90 MW reduction in output.

<u>Assessment</u>

This was another heavy demand day in Ontario and surrounding markets. In addition the IESO declared EEA1 from 07:00 until 20:00 and it issued its second Power Warning for the year. PJM and MISO and New England also operated under EEA1 alerts for most of the day. New York set a new peak demand record at 33,900 MW. The IESO placed a number of ELRP (Emergency Load Reduction Program) participants on notification, However there were no activations on the day. The high demand situation caused the IESO market to clear on the steep portion of the supply curve and this was reflected in the prices. The loss of inframarginal generation from the fossil unit made things worse as shown in Table 2-4. In the intervals where this inframarginal supply was not available, prices rose by up to $104/MWh.

Table 2-4: Demand Discrepancy, Supply Loss and Prices: August 2, Hour 14

Interval	Real time Demand - Pre-dispatch Demand	Supply Loss	Real-time Price - Pre-dispatch Price
1	(24)	0	$4.14
2	(3)	0	$36.18
3	58	0	$75.00
4	143	0	$78.93
5	66	0	$74.55
6	89	90	$78.93
7	12	90	$75.00
8	50	90	$78.75
9	50	90	$78.75
10	118	90	$103.92
11	(18)	90	$53.97
12	31	90	$75.00

To assess the price impact of the lost output, the MAU simulated real-time prices with an additional 90 MW output from the fossil unit. In those intervals, prices would have been $29 to $94 lower than actual prices as shown in Table 2-5. At the Panel's request, the MAU contacted the participant to seek clarification of the nature of this short-term outage. The participant responded and clarified to the Panel that the reason for the unavailability of the plant over the seven relevant intervals, was because of short term technical problems with its fuel feeder system.

Table 2-5: Price Impact of Lost Output from an Inframarginal Generating Unit August 2, 2006, Hour 14

Interval	Real-Time Price $	Simulated Real-Time Price $	Average Price Impact $
1	254	254	0
2	286	286	0
3	325	325	0
4	329	329	0
5	325	325	0
6	329	286	43
7	325	286	39
8	329	286	43
9	329	286	43
10	354	325	29
11	304	210	94
12	325	286	39
Average	**318**	**290**	**47**

3. *Analysis of Low Priced Hours*

A 'low priced hour' is any hour in which the HOEP was less than $20/MWh. As Table 2-6 indicates, there were 149 hours during the period May 2006 to October 2006 for which the HOEP was less than $20. During the same months a year earlier, there were 52 low priced hours. The lowest HOEP since market opening occurred on September 3, 2006 in Hour 5. In this hour a negative HOEP occurred for the very first time in Ontario. Section 3.1 reviews this hour.

Table 2-6: Number of Hours with HOEP Less $20/MWh, May 2002 - October 2006

Time Period	Number of Hours HOEP <$20/MWh
May 2002 to October 2002	162
May 2003 to October 2003	78
May 2004 to October 2004	314
May 2005 to October 2005	52
May 2006 to October 2006	149

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

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

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

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

Occurrences of Low Priced Hours May 2006 – October 2006

The MAU's review of these low priced hours indicates that they were mainly a result of low Ontario demand in combination with failed exports and over-forecasts of demand. When real-time demand is this low, base-load generation may be sufficient to meet it. Table 2-7 summarises the average key data by month and Table A-51 in the Statistical Appendix has detailed hourly statistics on these hours.

Table 2-7: Key Data (Monthly Average) Low Priced Hours May–October 2006

Delivery Month	Failed Net Exports (MW)	Real Time Demand (MW)	Pre-dispatch Demand (MW)	HOEP $/MWh	Pre-dispatch Price $/MWh
May	517	12,477	12,736	13	31
June	230	12,699	12,978	14	26
July	150	12,851	13,110	16	23
August	180	12,790	12,982	14	25
September	214	12,620	12,747	11	20
October	257	12,091	12,268	12	24

3.1 September 03, 2006 Hour 5

The lowest HOEP since May 2002, $-3.10/MWh, occurred in this hour.

Pre-dispatch Market Conditions

Demand was projected at 11,612 MW with a price of $4.10. Net exports were 503 MW. The pre-dispatch supply cushion was 74 percent.

Real-time Market Conditions

In real-time, demand averaged 11,691 MW with a peak of 11,736 MW. Failed exports amounted to 400 MW. The real-time supply cushion was 37 percent. The price in all twelve intervals were set by a base load nuclear unit with offers at $-3.10 (this unit was dispatched down by the DSO, from 790 MW in pre-dispatch to 516 MW in real-time). As a result, the HOEP for the hour was $-3.10/MWh.

Assessment

With the failed exports in real time, the market demand curve intersected the offer curve at a lower point than it had in pre-dispatch and nuclear base load generation was sufficient to satisfy demand in real time. Export transactions can fail for economic and security reasons as well as because of participant errors in managing the transactions. On this day, problems with a circuit led to a halving of the New York export scheduling capacity (from 1,500 to 700 MW). This prompted the IESO to constrain off export transactions for HE 1 to HE 3 for security reasons. In HE 5, 310 MW of New York export transactions failed for economic reasons. Had the New York scheduling capacity been at the 1,500 MW level, our simulation shows the HOEP in the hour would have been $25/MWh, other things equal. Of note is the fact that consumers on the Regulated Pricing Plan (RPP) pay between $58-$66/MWh for electricity consumed in the hour. Interval-metered loads which pay the wholesale price faced an effective price of $9.30/MWh in the hour.[31]

[31] The wholesale loads received $3.10 from the market as well as $1.08 in OPG rebate. They however have to pay $13.46 for the Global Adjustment charge. The net cost to wholesale loads is therefore $9.30/MWh.

4. *Other Anomalous Events*

4.1 Record Peak Demand of 27,005 MW in Hour 16, August 1 2006

August 1, 2006 was a hot and humid day with a peak temperature forecast of 36 degrees Celsius and a Humidex of 47 degrees Celsius. The price in pre-dispatch was projected at $250 with a demand forecast of 27,318 MW. The pre-dispatch supply cushion was 11.3 percent. In real-time, the HOEP was $124.59 and peak real-time unconstrained demand was 27,039 MW. The real-time supply cushion was 0.40 percent. The reason the HOEP was lower than the pre-dispatch price is because average real-time demand was 280 MW lower than forecast. Had demand come as forecast, the HOEP would have been $209. The lower real-time demand was partly a consequence of public appeals issued by the IESO, asking consumers to reduce consumption of electricity. Price responsive consumers also contributed to the reduction of real-time demand, as did loads which participate in the OPA demand response programs.

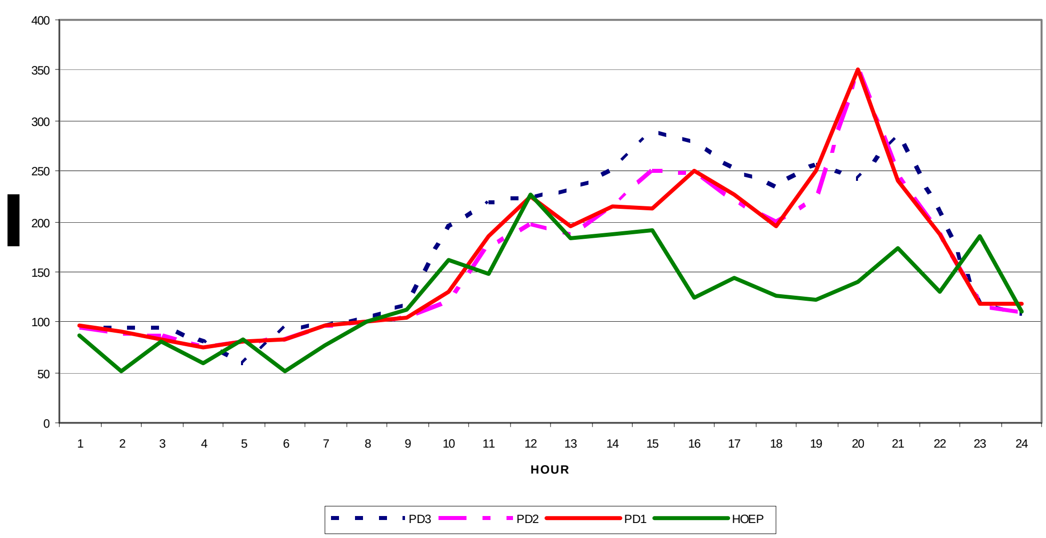
The IESO issued a Power Warning asking the public to reduce electricity consumption until 19:00. In fact, the IESO operated under EEA1 for most of the day. Surrounding markets - New England, MISO and TVA experienced heavy demand and they also operated under EEA1 for some hours of the day. The New York market witnessed an all-time record hourly demand of 33,879 MW in HE 17. PJM also recorded an all-time hourly peak demand of 144,059 MW in HE 17. The IESO, in HE 16, recorded its highest hourly demand since market opening, surpassing by 845 MW the previous demand record of 26,160 MW set on July 13, 2005.

On this day, the IESO requested participation in its new Emergency Load Reduction Program (ELRP). Four participants responded with a potential to cut 66 MW of load if activated to do so. The IESO did not need to activate load reduction from these participants on that day. The Panel discusses the ELRP program in Chapter 3.

Response of Directly Connected Non-dispatchable Loads on Peak Demand Day

The IESO issued a Power Warning asking consumers to reduce their electricity consumption. As shown in Figure 2-1, the price forecasts for the day indicated prices above $100 for most of the day. For Hours 12 to 18, prices were projected mostly above $200. To get an idea how some industrial customers responded to these price forecasts, the MAU examined the consumption patterns of four large industrial customers over the period from July 10 to August 20 (i.e. three weeks before and three weeks after August 1). All these loads have an on-site back up generation unit, with capacities varying from 10 MW to 29 MW. Typically, those on-site generation units are not economical to operate and thus only work during emergency situations or when the market price is very high. As none of the four loads participates in the IESO's or the OPA's demand response programs, they can be viewed as responding solely to price signals whenever they curtail consumption or switch to their own generation. Given the price expectations for the day, one might expect these customers to have reduced their purchases of energy from the market.

Figure 2-1: Price Forecasts and Actual HOEP
August 1, 2006.



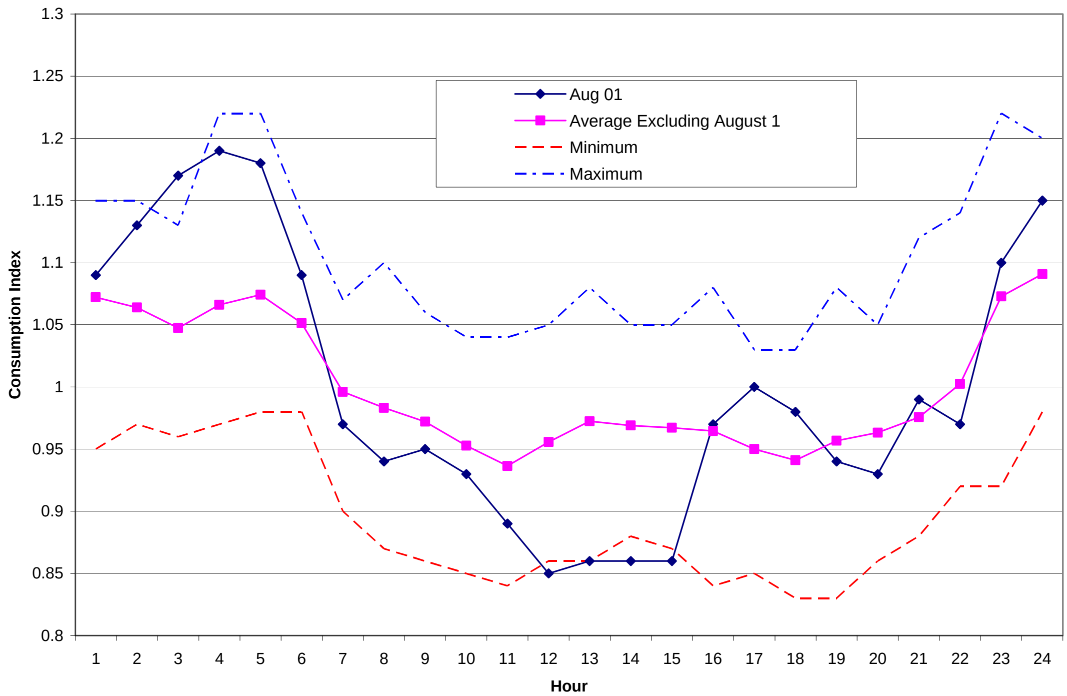
We calculate a consumption variation index (CVI) for each hour.[32] The CVI is calculated on a hourly basis as the ratio of the average consumption for hour *i* in day *j* to the average hourly consumption for day *j*. Algebraically, this is represented as:

$$CVI_i = \frac{C_i}{\sum_{i=1}^{24} (C_i)/24}$$

The index measures the portion of the daily consumption of a consumer's or a group of consumers that is consumed in a given hour. Figure 2-2 depicts the consumption variation index for August 1 and for three weeks before and after August 1, 2006. The maximum, average and minimum hourly values of the index for other days are also illustrated. It can be seen that the hourly index for HE 12 to HE 15 August 1 are below the minimum index for other days, indicating a significant drop in consumption by these industrial customers in those hours on August 1, compared to other days.

[32] We used this same index in our March 2003 report.

Figure 2-2: Consumption Variation Index Comparison
July 10 – August 20, 2006



To assess the impact of consumption reduction by these loads on the HOEP in Hours 12 through 15, the MAU first estimated the amount by which the four loads involved reduced their consumption during these four hours. The estimated load reduction for an hour is the difference between actual consumption and the baseline consumption. Baseline consumption is equal to the average consumption variation index for the hour times the daily average consumption. The price effect of this load reduction is then estimated by simulating what the HOEP would have been had there been no load reduction. The simulation results are presented in Table 2-8.

Although the estimated load reduction was only 24 to 25 MW per hour, the price impact is material. For example, had these loads not reduced their consumption, the price would have been $4.93 higher for Hour 12 and $9.02 higher for Hour 13. This is not a surprising result given the tight supply/demand conditions. The result highlights the role that demand response can play during tight supply conditions.

Table 2-8: Price Impact of Load Reduction by Four Large Loads August 1, 2006

Delivery Hour	Demand Reduction MW	Actual HOEP $/MWh	Simulated HOEP $/MWh	HOEP Reduction $/MWh
12	23.84	226.73	231.66	4.93
13	25.44	182.39	191.41	9.02
14	24.21	187.44	188.28	0.84
15	25.43	191.64	194.99	3.35

Assessment

In the above analysis, it is clear that the industrial loads shifted electricity consumption on this record demand day. In fact, the average HOEP in Hours 12 to 15 turned out to be $197 almost $52 lower than the average of the three hour ahead prices ($249) and $23 lower then the average of the one hour ahead prices. The reasons for the lower than forecast HOEP can be attributed in part to the public appeal to reduce electricity usage, to the load reduction from dispatchable and interval-metered loads as well as load reductions achieved through the OPA and IESO demand response programs.

As noted earlier, the loads analysed in this section are industrial non-dispatchable loads which are directly connected to the IESO grid. Since these participants do not submit bids to the IESO, it is difficult to estimate a schedule of prices at which they indicate their willingness to consume electricity. A demand schedule of this nature would be helpful in the efficiency analysis of demand responses. In this case, the three hour ahead pre-dispatch prices for Hours 12 to 15 were between $226 and $290/MWh with an average value of $249/MWh. Given that the loads went away at these prices, it is reasonable to assume that their reservation price was below $226/MWh. If the HOEP had been above $226/MWh, their decision to economize on electricity use would have been an efficient decision ex post.

In the present case, the HOEP was between $182 and $227/MWh for Hours 12 to 15 with an average value of $197/MWh. Therefore, if these loads went away based on an expected HOEP of $249, then their decision to reduce consumption may have been ex post inefficient.

The Panel has repeatedly emphasized the important role played by price responsive demand in a properly functioning electricity market. The credibility of price signals is crucial in this regard, as is a market design that allows participants to make informed economic decisions based on those price signals.

4.2 Increasing Frequency of HOEP Higher than the Richview Reference Price

The Ontario market generates two types of prices. The first is the HOEP which is a province-wide uniform price. It assumes an unconstrained grid and is used for settlement purposes. The second is a series of nodal prices across the province that is indicative of the marginal cost of energy at each particular node. These prices are generated by the constrained schedule.

The processes for generating the HOEP and the nodal prices differ in several important respects. The nodal prices solve for market equilibrium given transmission constraints and a forecast of demand. The HOEP solves for an Ontario-wide market equilibrium given no transmission constraints and actual demand. The constrained run which solves for the nodal prices is performed about ten minutes before the unconstrained run which solves for the HOEP.

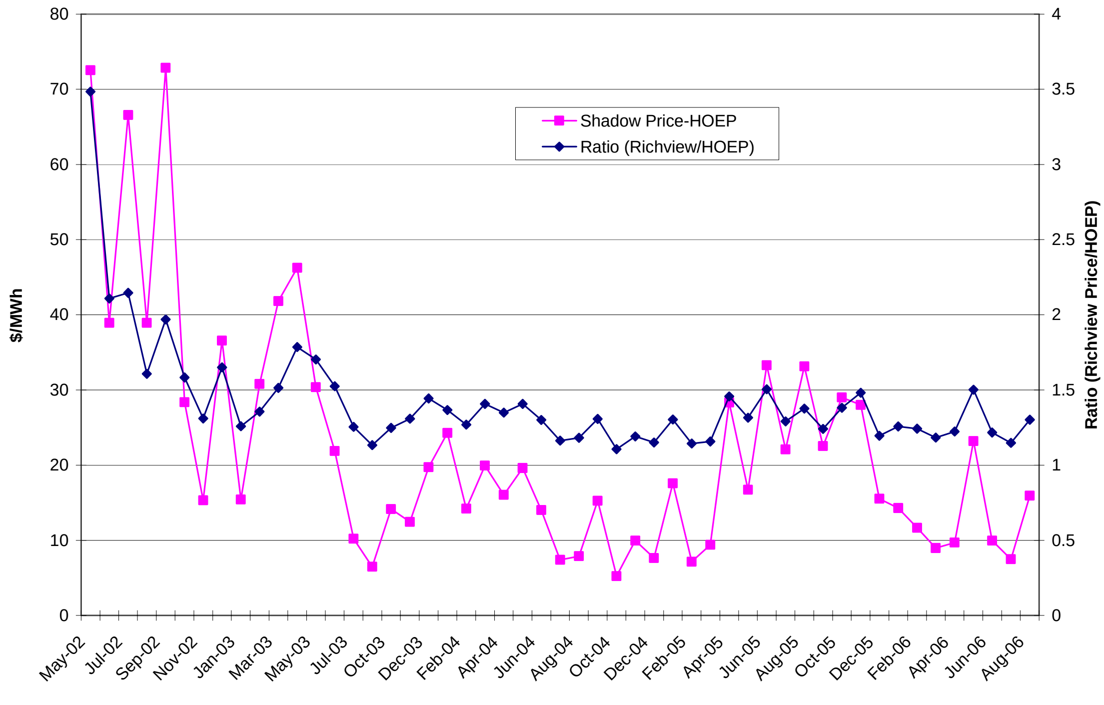
Given the differences in the way they are calculated, nodal prices can differ from the HOEP for a variety of reasons. We have identified some of those reasons in earlier reports, but lately we have seen the increasing importance of three of these factors:

- the pre-dispatch forecast of loop flows which can create differences in the dispatch of imports and exports between the two schedules

- differences between actual demand and the real-time (ten minutes ahead) demand forecast; and
- minimum loading points of fossil fuelled generators

In our reports we normally compare the HOEP to a node called the Richview Reference Bus, which is located on the 230 kV transmission system near Toronto. Richview was chosen as the reference bus because it is located near the major load centre in Ontario and it is well connected to most parts of the province. The loss factors and flow factors in the DSO are used to calculate nodal prices based on Richview as the reference bus. Nodal prices approximate the production cost of serving an extra MWh of load at a particular node or location on the IESO-controlled grid, taking into consideration both the physical limitations and the intertie constraints. The nodal price at Richview is the marginal cost of energy delivered to Richview. Except for the real-time demand forecast error, the other differences between the constrained run that solves for the Richview price and unconstrained run that solves for the HOEP reflect a poorer approximation of the real-world. Thus, the nodal price at the Richview bus is a more accurate indicator of supply and demand conditions in the Ontario market than the HOEP. Typically the Richview nodal price has exceeded the HOEP.

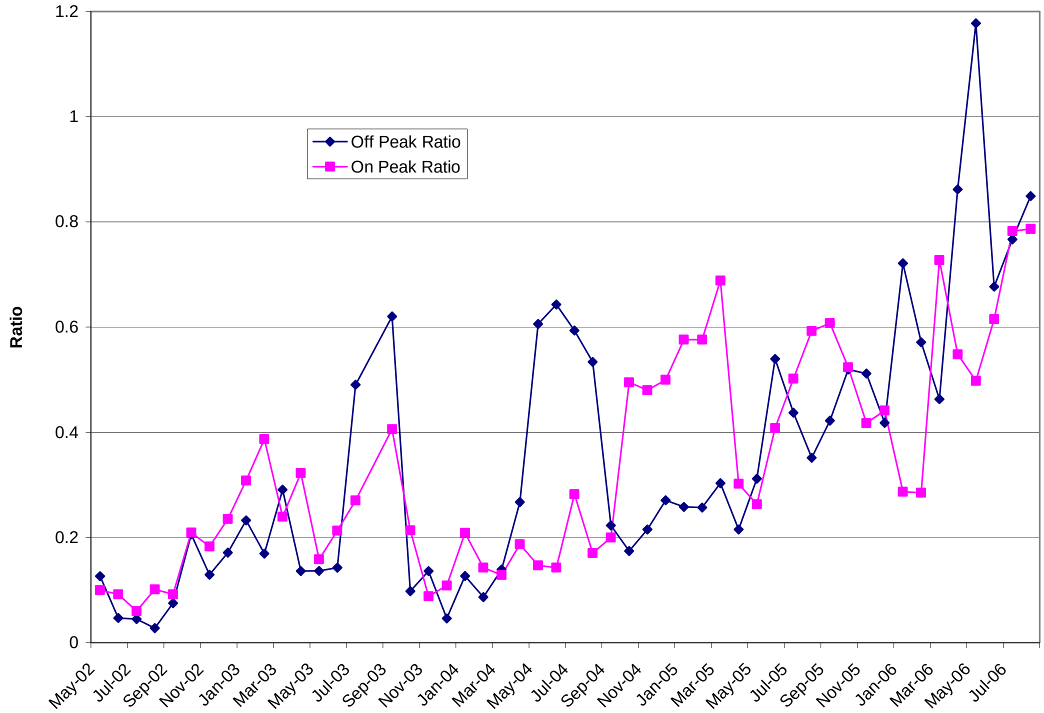
Figure 2-3: Monthly Average Difference between Richview Shadow Price – HOEP, May 2002 to August 2006



The MAU has observed (see Figure 2-3) that the difference between the HOEP and the Richview shadow price has declined recently. Indeed, there has been an increasing tendency for the HOEP to be above the Richview reference price, both on-peak and off-peak.

Figure 2-4 plots the monthly ratio of the number of hours with the HOEP greater than the Richview reference price to the number of hours with the HOEP lower than the reference price. A higher ratio indicates that a higher HOEP is more frequent. For instance, the ratio for May 2006 off-peak is 1.17, implying there were more hours with a higher HOEP than with a lower HOEP. In the past, the factors which kept HOEP lower than the Richview price dominated. The recent tendency indicates the increasing influence of other factors which are pushing the HOEP price above the Richview price.

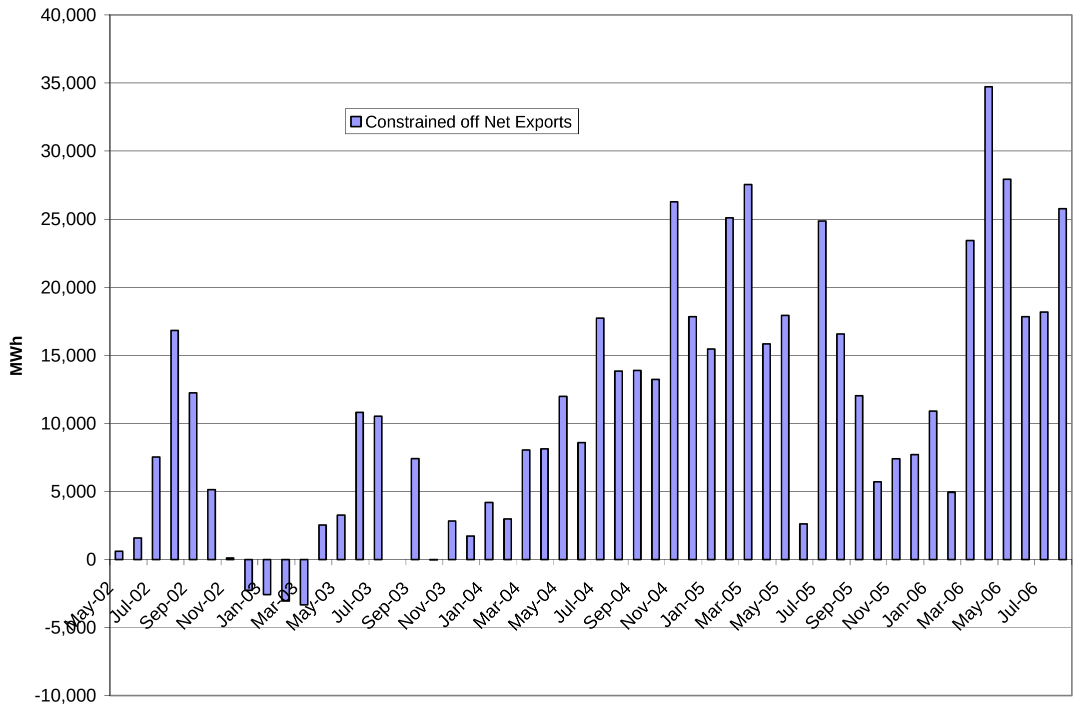
Figure 2-4: Ratio of Number of Hours With a Higher HOEP to Number of Hours With a Lower HOEP May 2002 to August 2006



The main factor pushing the HOEP above the Richview nodal price is constrained off net exports. Imports and exports cannot set the price either in the constrained run or in the unconstrained run. But when an export is included in the unconstrained schedule but not in the constrained schedule (a constrained off export), demand in the constrained schedule is lower and this reduces the Richview price relative to the HOEP. The increased incidence of constrained off exports is due to an increase in loop flow that is contributing to increased transmission congestion at the intertie zones in the constrained schedule. We describe this development in section 3.2 of Chapter 3.

Figure 2-5 illustrates the change in monthly on-peak constrained off net exports for those hours with the HOEP greater than the reference price since market opening.

Figure 2-5: Monthly Total Constrained Off Net ExportsMay 2002 to August 2006 (MWh)

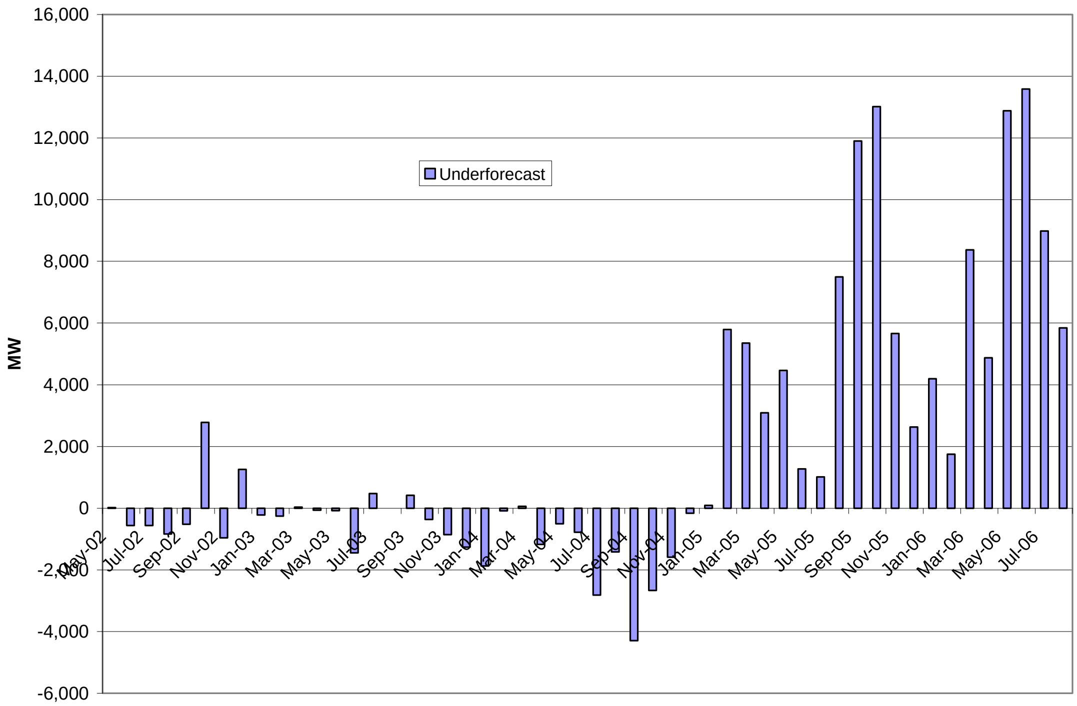


The fundamental point here is that when exports are constrained off, the Richview nodal price is reduced but not the HOEP. The increased incidence of constrained off exports has been the major factor in the decline in the Richview price relative to the HOEP. Constraining off exports will push other nodal prices down relative to the HOEP as well.

There may be other factors which reduce the Richview reference price relative to the HOEP:

- Under-forecast of demand: The demand used in the constrained run is a 10-minute ahead forecast of the actual demand while the demand used in the unconstrained run is the actual demand. If demand is under-forecast in the constrained schedule the calculated shadow price will be lower than with an accurate demand. Figure 2-6 illustrates the total monthly on-peak demand forecast error for those hours with the HOEP greater than the reference price. We have asked the MAU to investigate the underlying causes of the under-forecast in the constrained schedule that began to appear in early 2005

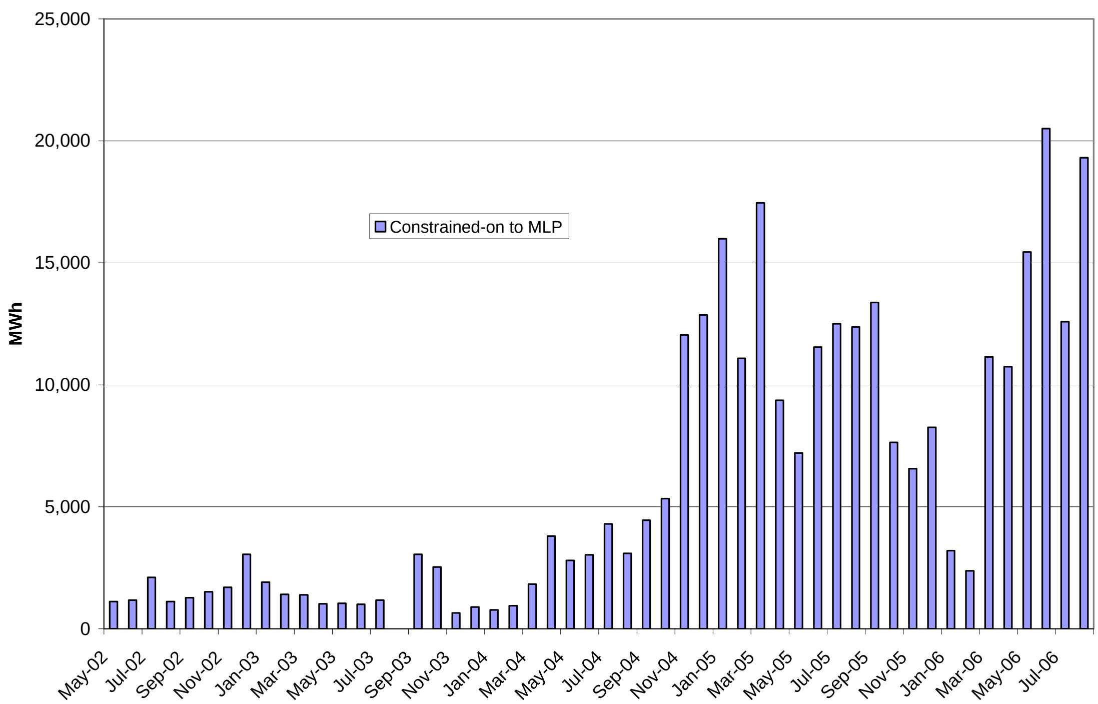
Figure 2-6: Average Monthly On-peak Demand Forecast Error, May 2002 to August 2006 (MW)



- Minimum loading point: Typically fossil fired generators have a minimum loading point (MLP) that they must be dispatched to. Natural gas-fired generators' MLP is 75 percent of their output. At the same time, for technical reasons generators have minimum run-times. When one of these units is dispatched, it is constrained both to its minimum MLP level as well as for its minimum run-time. This constraint is added in the constrained run, but not necessarily in the unconstrained run. That is, the portion up to MLP cannot set the nodal price, since it is dispatched whatever its price. Depending on its offer price, it may or may not set the HOEP. The outcome is that these generators may be supplying more in the constrained schedule than they were accepted for in the market. This treatment difference may lead to higher dispatch in the constrained run than in the unconstrained run, and therefore a lower reference price. As more gas-fired generators enter the market this tendency to suppress the nodal price may be aggravated.

Figure 2-7 illustrates the monthly volume of on-peak constrained on generation to the minimum loading points for those hours the HOEP is greater than the Richview reference price. The increasing influence of MLP comes from new gas-fired generation which typically has a large MLP compared to its capacity.

Figure 2-7: Monthly Total On-peak Constrained On Generation to Minimum Loading Point Market Opening May 2002 to August 2006 (MWh)



In summary, we are observing a tendency for the HOEP to converge with the Richview price. However, this convergence is not a result of a better matching of the unconstrained dispatch with the constrained dispatch, e.g., due to less transmission congestion. On the contrary, transmission lines have become more and more congested (in the constrained run) on many interties and, as Ontario becomes a net exporter, there have been more and more constrained off net exports (see Figure 2-5). The recent addition of new gas-fired generation has also pushed the Richview price down towards the HOEP because it has a higher minimum loading point and a higher minimum run time and this results in a greater supply in the constrained schedule than was actually accepted in the market.

The Richview price and the HOEP are presently converging but this does not imply that there are fewer sources of friction in the market or that the HOEP is more reflective of underlying market realities. Given recent trends, we could, in future, end up with the HOEP, which is the price paid by loads, consistently above the Richview price. This may change the views of some stakeholders as to the merits of locational marginal pricing.

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

1. *Introduction*

This chapter summarises changes to the marketplace since the last MSP report. In section 2 we discuss some of the issues raised in previous reports. In particular, we discuss the consequences of the measures that have been taken to reduce dispatch volatility. As well, we note the introduction of a regime to assess the legitimacy of constrained-off payments in congested zones. The issue of inefficient exports to New York, raised in our last report, is also revisited.

In terms of new matters to report in section 3, we examine the consequences of the reduction in the import and export limits on the New York interface and the transaction failures that flowed from it. Second, we comment further here on the implications for the efficiency of the Ontario market of the larger loop flows which have been observed recently. Third, we note the consequences of the IESO's renegotiation of the AGC Ancillary Services Contract and its reduction of its AGC requirements. This has resulted in a reduction in uplift and an increased supply of OR which have been beneficial to the Ontario market.

As a result of some of the reliability issues associated with the summer of 2005, the IESO and its participants implemented several reliability measures just ahead of the summer of 2006. In section 3 we also discuss the initial consequences of these reliability enhancements.

Finally, we review the myriad of demand response programs in service in Ontario at present and make comment both on their efficiency as well as provide general guidance for the future design of such programs.

2. *Status of Matters Identified in Previous Reports*

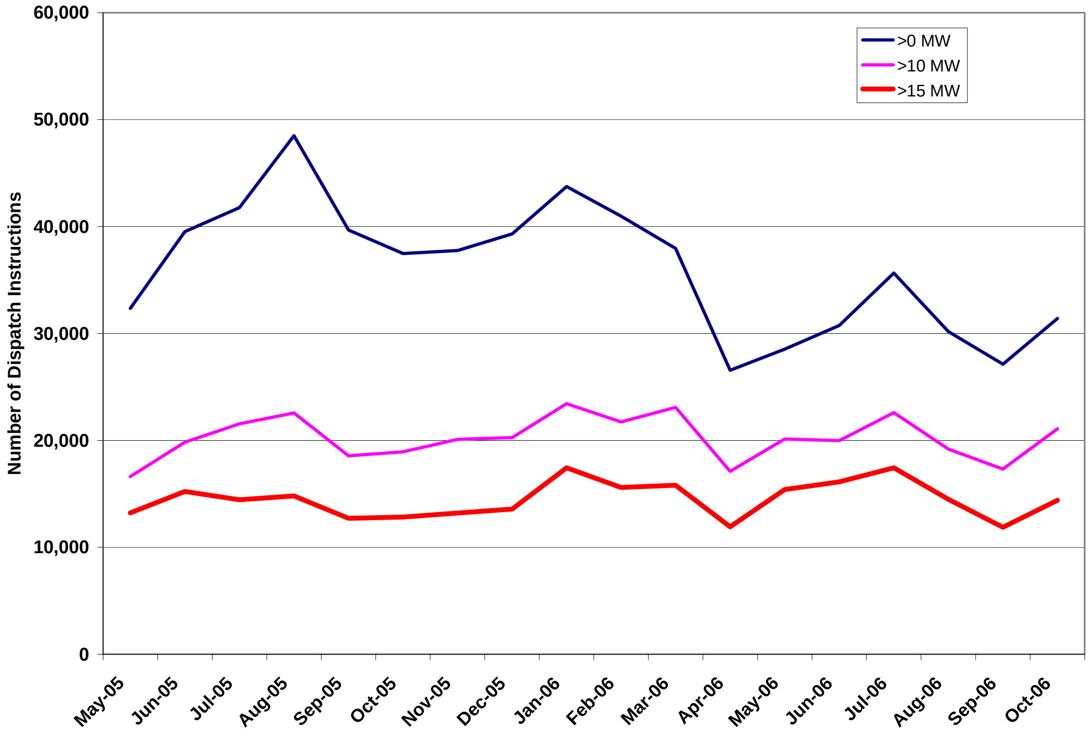
2.1 IESO Measures to Reduce Dispatch Volatility

Previous reports have acknowledged participants' concerns that the volatility of dispatch instructions can have an impact on technical efficiency. In our last report, we outlined some of the measures the IESO was introducing to deal with this issue. This section updates our assessment of the situation and the MAU has been asked to continue to assess areas for improvement in enhancing technical efficiency.

Compliance Deadbands

On May 8, 2006 the IESO's compliance interpretation bulletin was changed to permanently accommodate a 15 MW deadband tolerance. The MAU has found that, over the period May–October, 2006 the increase in the compliance deadband reduced the number of dispatch instructions fossil generators were required to follow by an average of 5,000 per month. This is shown in Figure 3-1.

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



There has been some concern that allowing generators more leeway in following dispatch instructions might reduce reliability. There are two commonly used indicators of an ISO's ability to match load and generation, CPS1 and CPS2. As Table 3-1 shows, by these measures, the IESO's performance has slipped marginally since market opening but it remains well in excess of industry standards.

Table 3-1: IESO CPS1 and CPS2 Performance Since Market Opening

Performance Measure	Performance Standard %	IESO Performance					
		2002 %	2003 %	2004 %	2005 %	Jan to April 2006 %	May to Aug 2006 %
CPS 1	≥100	171.65	170.4	163.6	161.0	160.72	160.39
CPS 2	≥90	96.98	98.38	97.8	96.4	96.89	94.55

The implication of these findings is that while the increase in the compliance deadband may have reduced the IESO's ability to match load and generation, it continues to exceed accepted industry performance standards. There is a trade-off between reliability and the cost of following dispatch instructions. At this point, however, the savings to market participants from reducing the number of dispatch instructions with which they must comply appear to have been realized without any material sacrifice in reliability.

Compliance Aggregation

On June 7, 2006 a compliance aggregation provision for cascade river systems was put in place by the IESO. This allowed participants to aggregate dispatch instructions and redistribute them within a river system to maximise technical efficiency. Market participants have indicated that the ability to aggregate dispatch instructions, in combination with the increased compliance deadband, has significantly reduced their concerns over dispatch volatility.

Replacement Energy Offers

On August 19, 2006, the IESO introduced a market rule amendment that allowed market participants to submit offers for replacement energy. This program allows the operator of a generating unit to operate a replacement unit when a unit receiving dispatch instructions is forced out of service. This program has rarely been used. IESO records indicate it has been used once since its introduction.

Assessment

While there is not much in the way of supporting evidence at this point, market participants view these programs as having been successful. The Panel looks forward to seeing evidence of reduced maintenance costs and fewer technical problems in the future.

We have heard from market participants that the ability to change offers and bids closer to real-time would also allow them to be able to more effectively deal with dispatch issues and enhance efficiency. In turn, this may lead to a closer fit between pre-dispatch and real-time prices as participants are better able to manage their resources. The Panel is pleased that the IESO is reviewing whether leaving the bid window open longer would enhance efficiency and reliability as participants would be more able to respond to market signals.

2.2 Constrained Off CMSC Payments in Designated Watch Zones

In our reports of December 2005 and June 2006, we examined some anomalous CMSC payments and discussed possible revisions in market rules to deal with them. The CMSC payments were associated with bids and offers that appeared to be structured so as to lead to the resource involved being constrained off and receiving CMSC payments rather than the delivery of energy. By offering supply at prices between the HOEP and the lower nodal price, imports could be selected in the market schedule but not the constrained schedule. Exports could achieve a similar result where nodal prices were higher than the HOEP.

At the time of our last report, there was a proposed rule revision, which was in fact approved by the IESO and came into effect at the beginning of July 2006. This new approach requires identifying constrained-off watch zones where nodal prices are regularly lower or higher than the HOEP and congestion payments could result with some regularity. Offers or bids within a designated watch zone are to be reviewed to determine if there have been persistent and significant CMSC payments over a recent period. If the offer (or bid) price of the market participant involved is not consistent with its cost or opportunity cost, some portion of the CMSC payments could potentially be recovered. For reasons of equitable treatment, this procedure applies to generation and dispatchable load in addition to imports and exports.

In July, the Northwest zone which includes generation in, and imports into the Northwest from Minnesota and Manitoba was designated as a watch zone for supply. No recovery of CMSC has occurred yet, although some recovery is anticipated.

It is interesting to note that CMSC for constrained-off supply in the Northwest has been falling in recent months, since the early summer. Lower levels of water in the north would have contributed to this, but it also coincides with the introduction of the revised procedures**.**

2.3 Inefficient Exports on the New York Interface

In our June 2006 report, we noted the existence of inefficient net exports on the New York interface. We explained that this is just one of the inefficiencies that can occur when the HOEP (the Ontario-wide) uniform price differs from the incremental cost of energy at a given point in the province. In this report, we note that the volume of inefficient exports declined during the May – October 2006 period relative to the same period a year ago and explain why this occurred.

An export from Ontario to New York is inefficient if the incremental cost of supplying the export is higher than the incremental cost of supplying load in New York. The incremental cost of supplying the export is measured as the nodal price adjacent to the New York interface (the Beck Ebus nodal price) plus the transmission charge.[33] The incremental cost of serving load in New York is measured as the real-time locational prices in the New York OH zone. The Panel argued that the inefficiency is induced by the fact that exporters pay a price (the HOEP) that is different from the incremental cost of supplying the export.

A transaction may also be inefficient because of uncertainty. It may be ex ante efficient but ex post inefficient. Exporters make bids in Ontario and offers in New York prior to real-time based on their expectations of prices in the two markets. A trade may appear to be efficient an hour prior to real time based on expected or forecasted prices (ex ante efficient). However, as unforeseen events occur, causing real-time prices to differ from the expected prices, the trade becomes ex post inefficient. In this section, our focus is on the ex post inefficiencies.

[33] We assume that the transmission charge for a transaction is $5 CDN.

In this report, we make a further distinction between the private and social efficiency of an export. We define a privately efficient export as an export that is scheduled in an hour when the external price is greater than the HOEP plus transmission charges. We define this as privately efficient as it represents (at least notionally) the return that an exporter would receive on an export.[34] Consistent with our previous report, we define a socially efficient export as an export that is scheduled in an hour when the external real time price is greater than the nodal price at the Beck Ebus.

Once again, our focus in this section is ex post efficiency. We assume that all transactions are privately efficient ex ante in the sense that a trader's decision to export will be based on the trader's expectations of the likely real-time prices and the trader would not schedule an export if it believed it would be unprofitable. However, exporters must make their decisions roughly 2 hours in advance of real-time (when the Ontario offer/bid window closes); at this time they have imperfect or incomplete information regarding eventual real-time conditions both in Ontario and in New York. With only imperfect and incomplete information, sometimes the traders will "guess wrong" ex ante so that the outcome is unprofitable or privately inefficient, ex post.

Therefore, the likely cause of ex post privately inefficient exports from Ontario to New York is the lack of accurate price signals or information that is available at the time that the exporter makes its decision to export. This includes price signals in both the Ontario and New York markets. One would expect that the more accurate the advance price signals and information, the more likely a trader can "guess right" and the more often will the trade be ex post privately efficient. Improvements in the accuracy of price signals and information over time would tend to increase the frequency of privately efficient exports.

[34] 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 (HAM) or the real time price. We assume that the transmission charge for a transaction is $5 CDN.

There are two major causes of socially inefficient exports from Ontario to New York. First, like privately inefficient exports, the lack of accurate price signals or information can lead to "guessing wrong" and hence socially inefficient exports ex post. Improvements in price signals should result in a higher frequency of socially efficient exports. Socially inefficient exports can also occur, however, if there are defects in the market design. Ontario's uniform pricing regime is poorly designed in the sense that it admits to the possibility that the prices that exporters pay do not reflect the incremental cost of supply.[35] 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. In a market with uniform pricing, the frequency of socially efficient exports should increase as the relevant nodal price (the Beck Ebus price in our case) and the uniform prices converge. As discussed in section 4.2 of Chapter 2, the nodal price and uniform price can converge for a variety of reasons, including structural changes such as changes in supply and demand conditions, as well as more administrative or operational reasons such as the setting of different interconnection limits in the constrained or unconstrained sequence to address loop flow concerns.

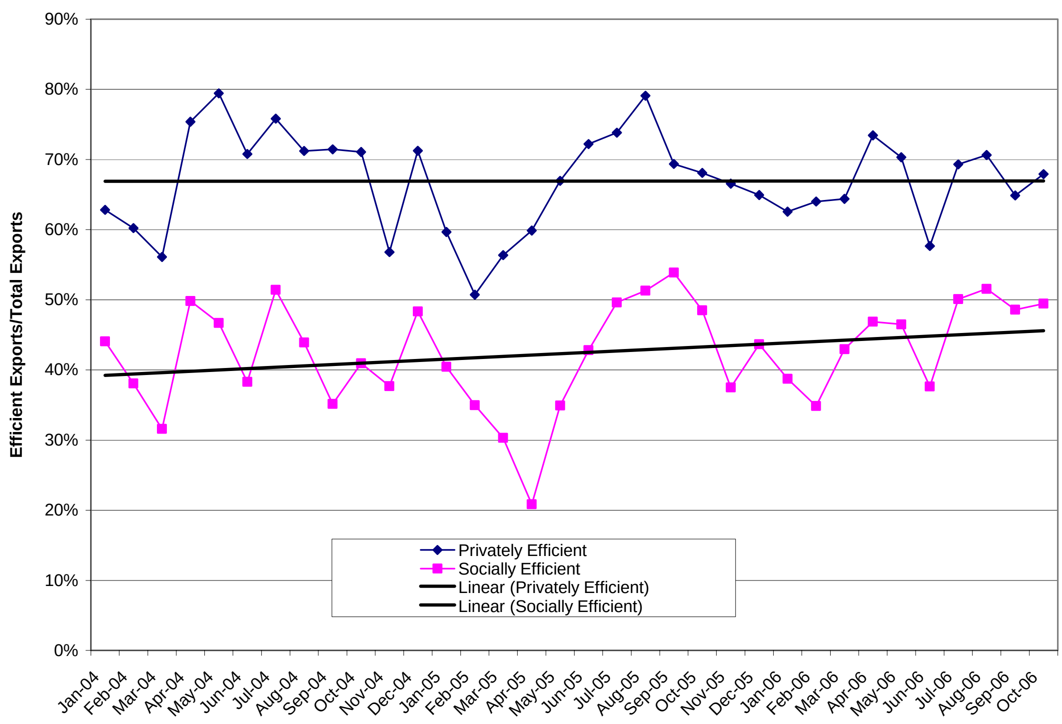
If a market is well designed, one would expect that most transactions would be both privately efficient and socially efficient and with equal frequency. And if a market is well designed with accurate advance price signals and information, one would expect that privately and socially efficient exports would be the rule.

Figure 3-2 plots two series, one illustrating the monthly percentage of scheduled exports which were privately efficient and one illustrating the monthly percentage of scheduled exports which were socially efficient. These series cover the period January 2004

[35] Inefficient trade could also be caused by market failures such as the presence of market power or the present of other externalities, or as the result of interventions by the system control operator (out-of-market control actions) that distort the actual cost of dispatch. Inefficiencies that occur as a result of market power or externalities or as a result of operator intervention could occur in either a uniform pricing regime or a locational pricing regime. Our definition of social efficiency assumes that the nodal price is the incremental cost of production and in this sense ignores these other possibilities.

through October 2006. The frequency with which exports were privately efficient has remained relatively stable at roughly 67 percent, particularly over the last year or year and a half. The stability of the portion of exports that is privately efficient could be taken to imply that exporters are doing business consistently and the market information provided to them is no better (and no worse) than in the past. The frequency with which exports are socially efficient appears to have increased slightly, however, over the last 12 months from roughly 43 percent to 50 percent. This is consistent with the findings in Chapter 2 section 4.2, where we have observed that there has been a convergence between the Richview reference price (and thus the Beck Ebus nodal price) and HOEP over this same period.

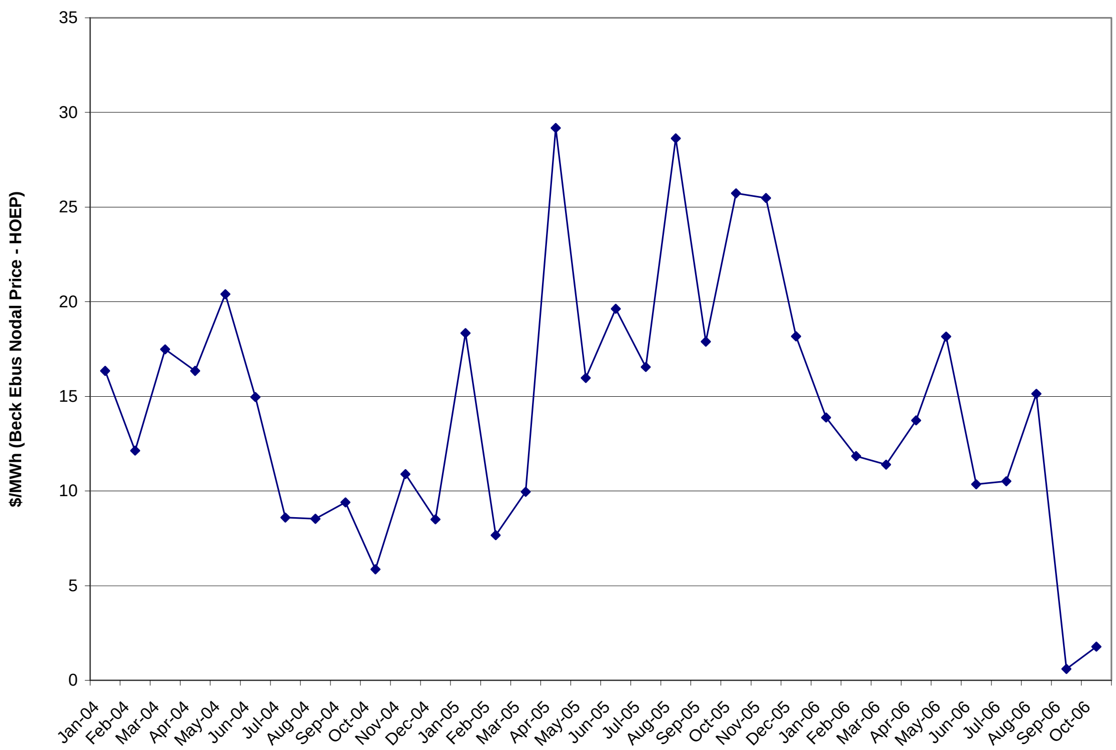
Figure 3-2: Percentage of Export Energy to New York Privately Efficient and Socially Efficient January 2004 – October 2006



What is of interest is that there still remains a large wedge, about 20 percent, between the respective percentages of exports that are privately efficient and socially efficient. That is, about 20 percent of exports are privately efficient but socially inefficient. The continued gap provides strong evidence that there is room for an improvement in the market design in Ontario.

As noted in our June 2006 report, the export inefficiency comes from the discrepancy between the price that exporters pay and the production cost of their purchase. Figure 3-3 illustrates the monthly average difference between the Beck Ebus nodal price and the HOEP. Although the price difference fluctuated from month to month, it decreased in past 12 months and this decrease contributed to the convergence between social efficiency and private efficiency.

Figure 3-3: Monthly Average Difference Between Beck Ebus Nodal Price and HOEP January 2004 – October 2006



As explained in Chapter 2, the factors leading to the convergence of the Beck nodal price and HOEP include

- *increasing constrained-off exports*: Due to increased Lake Erie circulation, the transmission capability for power to flow from Ontario to New York has been reduced. Since this reduced capability is not fully recognized in the market schedule, there are more exports in the market schedule than the constrained schedule. This tends to increase the HOEP (in the market schedule) relative to the nodal prices (in the constrained schedule).
- *under-forecast of demand*: The nodal price is calculated based on the ten minute ahead forecast, while the HOEP is based on the actual demand. When demand is under-forecast, this pushes the nodal price down relative to the HOEP. Since February 2005, there has been an increasing tendency to under-forecast (ten minutes ahead) as shown in Figure 2-6, Chapter 2.
- *minimum loading point (MLP)*: Due to technical characteristics of generating units, a unit is deemed non-dispatchable when it produces below its minimum loading point. As a result, the portion of a generator's output below its MLP is placed at the bottom of the supply curve and not allowed to set the nodal price. This portion, however, is allowed to set the market clearing price in the unconstrained schedule. Consequently, there could be more inframarginal supply in the constrained schedule than in the unconstrained schedule. This could push the nodal price down relative to the HOEP. As shown in Figure 2-7 (in Chapter 2), the total MWh that are constrained on in the constrained schedule has been increasing.

The volume of socially efficient exports has come closer to the volume of privately efficient exports during the past 12 months. The Panel believes that this convergence is mainly a result of nodal prices being closer to the HOEP. This price convergence is a consequence of the developments described above. That is, the observed increase in the incidence of socially efficient exports is an accidental consequence of other changes that have occurred in the market rather than a result of improvement in the market design or information exchange. As more and more exports are constrained off on the New York interface and as fossil generators in the Northwest zone, typically constrained off, are phased out, the HOEP might eventually be roughly the same as or perhaps greater than the nodal price at Beck Ebus. In that case, the proportion of exports that is socially efficient should be the same as the proportion that is privately efficient (in terms of energy exported). To the extent that the HOEP exceeds the nodal price, however, this could attract socially inefficient imports and would also make socially efficient exports privately inefficient. This would also be undesirable.

The Panel remains of the view that discrepancies between the Beck Ebus nodal price and the HOEP will continue to result in significant volumes of socially inefficient exports and imports. The ultimate solution to this problem is to adopt Locational Marginal Pricing. A regime, such as the present one, in which we sell energy at one price while producing it at another price is bound to be problematic.

The adoption of LMP and the improvement of the information content of the pre-dispatch price, while desirable, will not completely eliminate inefficient export or import transactions. There will always be some inefficiencies caused by unanticipated events and some inefficiencies are a consequence of the actions of system operators in adjacent markets. The Panel continues to urge the IESO to address coordination mechanisms between markets, particularly seams issues.

3. *New Matters to Report*

3.1 Intertie Transaction Limits with NYISO

In Chapter 1, section 9 we noted that export congestion at the intertie with New York increased substantially in August 2006 as a result of a reduction in the export limit by the IESO. Upon reviewing some of the history of the limits with New York, it was recognized that not only have the limits dropped, but the IESO and the NYISO were using different limits and this contributed to intertie failures with New York. It was also established that the reduced limits were not a result of reduced capability of the actual interties, but internal limits that affected the ability of the NYISO to import and export over the tie. It is our understanding that these factors have not been fully explained to the IESO.

There are several separate lines linking Ontario and New York but one notional intertie. There is a component of the intertie and limit for Niagara flows (with multiple lines) and another component for the phase shifters connected to New York east of Lake Ontario. These are treated as an aggregate limit, in both the constrained and unconstrained schedules, but individual tie-lines, flows and limits are also modeled in the constrained run.

Since market opening, exports to NYISO have been scheduled in the dispatch scheduling optimizer (DSO) pre-dispatch with net export limits up to about 2,400 MW and net imports with limits as much as 2,000 MW or more.[36] On August 11, 2006, the IESO limits were changed to 2,000 MW for net exports and 1,590 MW for net imports. This change was initiated to be more consistent with the corresponding limits being used by the NYISO.

In discussions with the IESO about these limits, it was learned that the NYISO had been using lower limits since mid-January 2006. As of January 18, 2006, NYISO has applied a limit of 2,000 MW on imports from Ontario and 1,650 MW for exports. Prior to this, the limits were 2,200 MW for each. The IESO was not aware of the New York changes. It is unclear why the NYISO reduced its intertie limits and there have been discussions between the NYISO and the IESO in order to clarify the matter.

The upshot of all this is that, for a period of roughly seven months, from mid-January 2006 until mid-August 2006, the IESO and New York ISO had different scheduling limits. Specifically, the IESO was using a higher export limit in the DSO so that pre-dispatch net exports to NYISO would, at times, have been higher than NYISO was willing to accept. Thus, in the checkout between NYISO and the IESO, it would be seen

[36] Actual hourly quantities have varied across the day or across a month as conditions across the interface, such as line outages, changed.

that New York would not have scheduled as much, and these exports from the IESO would fail for reasons judged to be outside the control of the market participant involved.

Table 3-2 reports estimates of export failures attributable to the difference in scheduling limits between Ontario and New York. It shows that the failures associated with the difference in the limits have represented as much as 24 percent of all export failures to New York on a monthly basis. The IESO's August 11 reduction of its limit to be more consistent with the NYISO limit eliminated this source of export failures.

Table 3-2: Exports above NYISO Limit vs. Failures January–October 2006

	Export Failures to NYISO		
	Actual Failures (1,000 MWh)	**Estimated Failures for Exports above NY Limit (1,000 MWh)**	**Estimated Failures (% Actual)**
January	105.5	9.9	9.4
February	137.1	22	16.0
March	121.5	12.8	10.5
April	141.8	11.9	8.4
May	160.3	12.7	7.9
June	48.6	4.5	9.3
July	50.8	12	23.6
August	65.3	7.8	11.9
September	74.4	0.0	0.0
October	67.2	0.0	0.0
Total	972.5	93.6	9.6

In previous reports, we have discussed the issue of transactions failures and the inefficiencies created by these failures. The inefficiency takes the form of purchasing imports or starting a generator in order to satisfy export demand that is not going to materialize. In turn when the exports fail there is a tendency for the real-time HOEP to be suppressed as unnecessary imports may have been purchased. This may also lead to higher IOG payments for those imports. Present modeling capabilities do not allow us to accurately determine the price effects of these failures.

In sum, during the period January–August 2006, the IESO was scheduling exports that New York with its lower limits was unwilling to accept, leading to transaction failures. The outcome in many hours would have been a suppression of the HOEP and an increase in IOG payments and thus in uplift.

While the IESO's reduction of its export limits to New York on August 11 was appropriate, we would have expected this measure to have been taken much sooner. It appears that procedures for monitoring and/or responding to changes in the NYISO's intertie limits may have been deficient in some respects. The Panel is encouraged to learn that a joint review of them is underway. Since the intertie capability itself has not changed with New York, we recommend that the system operators work together to maximize the scheduling capability of the intertie.

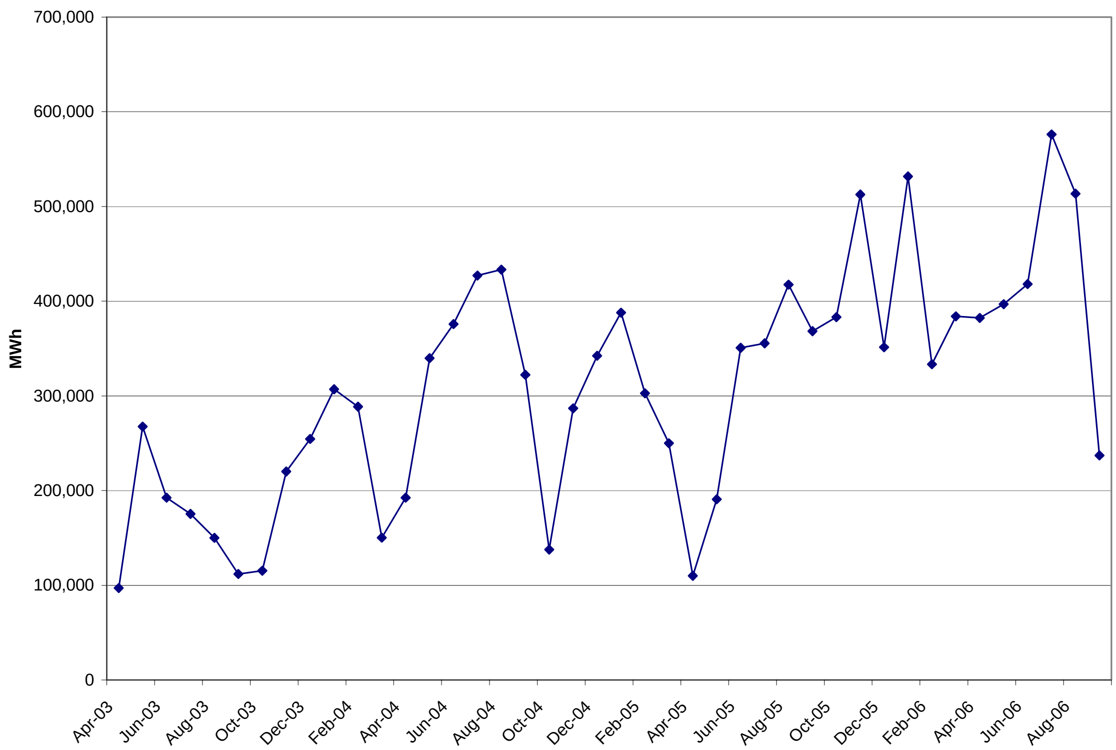
3.2 Increased Lake Erie Circulation Loop Flows

In past reports we have occasionally made reference to loop flows or Lake Erie circulation (LEC) in order to explain some of the events that have occurred in the Ontario market. In this section we look at the increasing magnitude of loop flows and discuss the impact that these are having on the IESO markets.

Loop flows are a naturally occurring phenomenon resulting from power flowing on parallel paths. Power can flow along paths through Ontario and around Lake Erie. Power entering at the New York intertie and flowing out at the Michigan intertie is called counter-clockwise circulation and is designated as positive LEC. Loop flow can occur as the result of generation dispatched in Ontario or as the result of transactions between areas in the US. Loop flow appears across the interties as well as across transmission interfaces within Ontario, reducing the transmission available for intertie scheduling and efficient dispatching of Ontario generation. The data below indicate that counter-clockwise circulation has been increasing.

Figure 3-4 shows the pre-dispatch estimates of LEC for those hours where the flow is positive (counter-clockwise). In recent years flows have typically been counter-clockwise, and as the figure indicates are increasing in magnitude.

Figure 3-4: Positive Lake Erie Circulation
Pre-dispatch Projection
April 2003 - August 2006

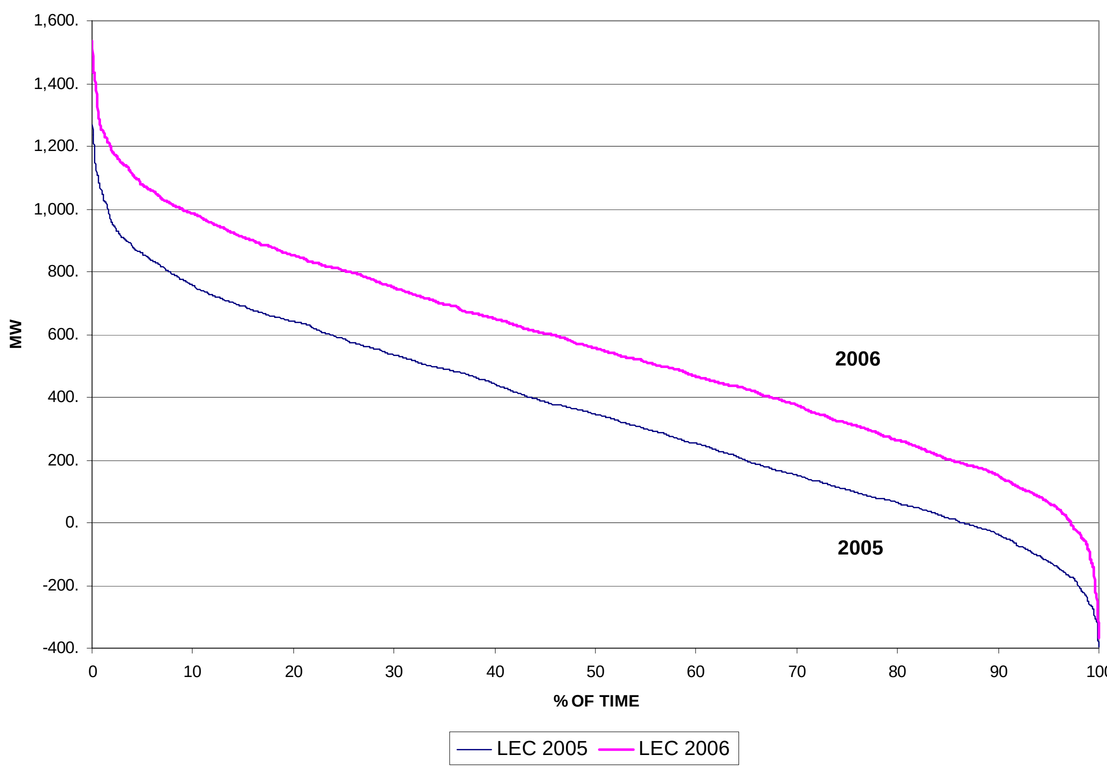


For 12 months starting in April 2003 counter-clockwise circulation totalled about 100,000 to 300,000 MWh each month (on a pre-dispatch forecast basis), averaging about 200,000 MWh. In the 12 months ending September 2006, the monthly values average about twice that amount and have ranged from about 240,000 MWh to about 580,000 MWh.

In pre-dispatch the projected loop flow value is used directly only in the constrained scheduling process, thereby influencing the schedules for constrained imports and exports. Loop flow may be used indirectly by the unconstrained run if loop flow is assessed as affecting the import or export scheduling limits with NYISO or MISO.

Loop flows also have an impact on the real-time dispatch of energy. In pre-dispatch although imports and exports may have been scheduled differently because of loop flows, some generation may also have been scheduled to deal with the constraints created by the loop flow. Given that imports and exports are fixed in real-time, actual loop flows would require a similar sub-optimal dispatching of generation, in order to prevent interties or internal interfaces from being over-loaded. More than the forecast amount of loop flows would mean an even larger departure for generation from the optimal dispatch. Less than the forecast amount means that imports and exports were unnecessarily constrained and trade opportunities were lost. Figure 3-5 shows the distributions of actual hourly loop flows (positive and negative) for the 3 summer months, June to August, in 2005 and 2006.

Figure 3-5: Real-time Distribution of Hourly Positive and Negative Lake Erie Circulation June 1-August 31, 2005 and 2006 (MW)



The 2006 flows are higher than 2005 by about 200 to 225 MW for most of the distribution. The 50 percentile flow has increased from 345 MW in 2005 to about 555 MW in 2006. Maximum loop flow has grown by a similar amount, from just under 1,300 MW to just over 1,500 MW. The frequency of negative loop flow has also decreased correspondingly from about 13 percent in 2005 to about 3 percent of the time in 2006.

Increased loop flows have several consequences for efficiency and reliability. With counter-clockwise loop flows net imports from New York may be reduced because there is less room available on the intertie with New York or because flows from the Niagara area towards Hamilton reach their limits. The loop flow might, at the same time, reduce net exports from Ontario to Michigan or New York.[37] In addition to the lost opportunity for efficient trade, CMSC must be paid to the constrained on or off transactions.[38] Similarly in real-time, the reduced available intertie and transmission capability is also likely to lead to re-dispatching internal generation and additional CMSC. IESO reliability can also be affected if loop flows reduce import capability during shortage conditions.

Hydro One has just finished repairs to the intertie line B3N to Michigan, which has been out-of-service for an extended period of time. As explained in our December 2005 report, this creates an opportunity for the parties involved (International Transmission Company, MISO, Hydro One, IESO) to develop an agreement regarding the operation of the phase shifters across the Michigan intertie. If this were to occur, a large portion of the observed loop flows could be controlled and total loop flows reduced substantially. With loop flow exceeding 555 MW 50 percent of the time, controlling flows with phase shifters at the Michigan interties should result in significant benefits to our market in most hours.

[37] Exports from Ontario will also flow on parallel paths across the New York intertie as well as the Michigan interties. For example, about 40 percent of exports to New York flow out at the Michigan intertie.

[38] We might observe this as increased constrained off CMSC for imports, or increased constrained on CMSC elsewhere if potentially lower cost constrained on imports were replaced by higher cost constrained on generation further east.

We encourage Hydro One and the IESO to pursue an agreement for the operation of these phase shifters. We encourage the IESO to review their procedures for modifying intertie limits when there are loop flows.

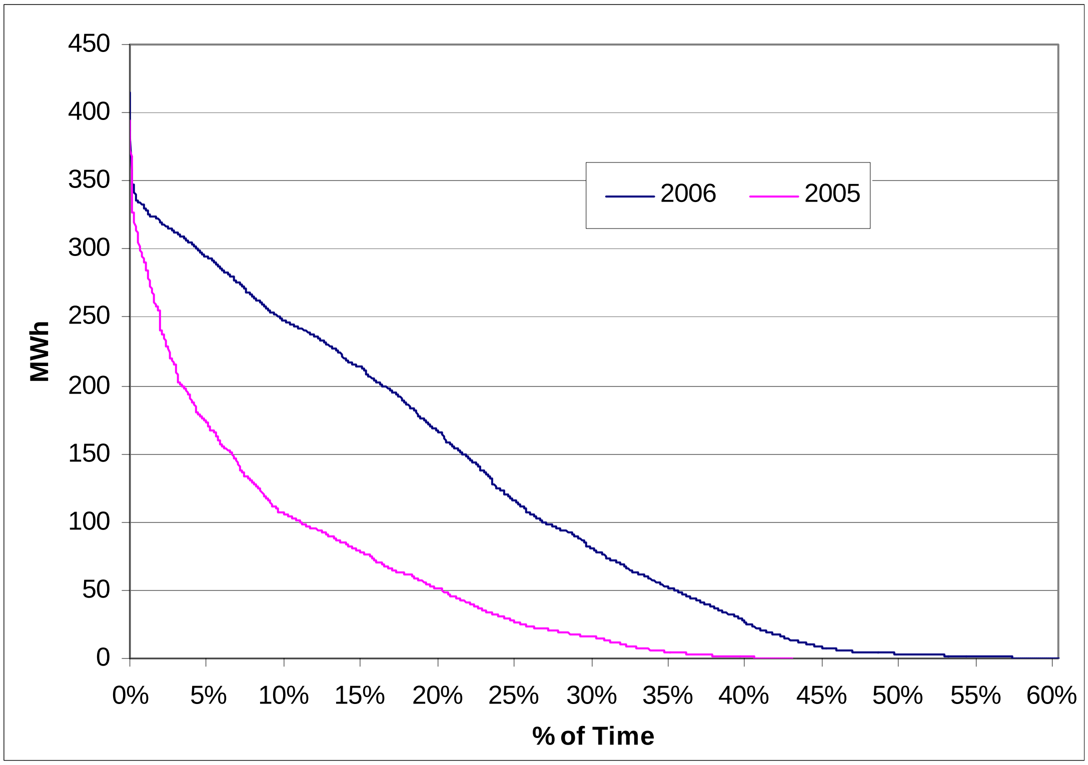
3.3 Automatic Generation Control and Available OR Resources

On May 1 2006, the IESO modified its requirement for Automatic Generation Control (AGC or regulation service), reducing it from +/- 150 MW to +/- 100 MW. Regulation service is required to respond to short term fluctuations in demand or generation output, allowing selected generation to change its production automatically in order to balance total demand and supply. Sources of AGC are procured under ancillary service contracts but selected each day or hour depending on the resources available. The actual cost of this ancillary service contract is spread over all loads as an uplift. Hydroelectric generation is selected to provide the majority of AGC each hour.

In order to be able to respond, a generator on AGC must have a ‘base point’ (nominal scheduled output) which allows it the flexibility to decrease or increase its output, when there is otherwise too much or too little generation. This means that AGC generation is scheduled above its minimum production level (so it can decrease output) or below its maximum capacity (so it can increase its output). Moreover, when providing AGC in a given hour, the generation facility cannot be scheduled to provide OR.

With the reduced AGC requirement in May 2006, the cost of AGC procurement has fallen, estimated by the IESO to be roughly a reduction of $1 million per month. This will tend to reduce overall uplift payments. In addition, it appears that more OR has been available from the station providing the majority of AGC. This can be seen from Figure 3-6, which compares total OR scheduled at that facility between May and October this year and in the previous period in 2005.

Figure 3-6: OR Scheduled at the AGC Station
May–October, 2005 and 2006
(MWh)



The figure shows roughly twice the level of OR being scheduled at this facility in 2006. Across all hours in the period, the average hourly schedule was 69 MW in 2006 and 30 MW in the corresponding period for 2005. OR was scheduled in 60 percent of the hours in 2006 with an average of 114 MW in those hours while it was scheduled for only 43 percent of the time in 2005, for an average of 70 MW.

Assuming the increased schedules are the result of greater availability of capacity for OR scheduling, the data suggest that as the result of the lower AGC requirement about 40 MW more OR resources have been available. This would have caused a small reduction in HOEP. By comparison, in our previous report on the market, we noted that the 50 MW decreased OR requirements due to Regional Reserve Sharing may have reduced HOEP in that 6 month period by about $0.25/MWh, everything else being equal.

4. *Day Ahead Commitment Process and the Real-Time Penalty Charge*

As noted in the Panel's report of June 2006, concern over reliability had been expressed by the IESO after the summer of 2005. It was felt that reliability was jeopardised as a result of:

- import failures caused by the inability of imports to schedule to Ontario day ahead and receive a higher level of transmission access in neighbouring markets;
- no pre-commitment of internal generation resources that would allow both a better scheduling of natural gas supplies as well as better co-ordination of internal generators; and
- real-time import transaction failures.

The IESO, in co-operation with market participants, developed several programs prior to the summer of 2006 with the specific purpose of enhancing reliability. These programs included:

- the launch of an Emergency Load Response Program (ELRP - commented on later in section 5.1);
- addressing dispatch issues to enhance the reliability of generators (already discussed in section 2.1);
- the Day Ahead Commitment Process (DACP); and
- the Real-Time Failure Charge for interties.

It should be pointed out that while both the ELRP and failure charge are permanent features, the DACP was extended by the IESO Board at it's November 17, 2006 meeting until such time as another program is implemented that provides at least equivalent reliability benefits. The program will be reported on annually. It is also our understanding that market participants have agreed with the IESO's recommendation to the IESO Board to continue the program on these terms. The MSP has reviewed what little evidence exists on the consequences of this program for the efficiency of the

Ontario market. Given that the DACP has been in operation only since June 1, 2006 and that its use to date has been limited, we may be better placed to comment on its efficiency implications in a later report. The next section describes the basic features of the program.

4.1 The DACP

To enhance reliability, the DACP economically schedules both imports and generation day ahead. The tool used by the IESO for scheduling is simply the constrained pre-dispatch algorithm. No financial commitment is made for the MW provided by either importers or generators; rather a guarantee is provided to keep the importer or generator whole if they are committed via the DACP. The intent is to ensure sufficient resources have been committed day ahead to meet Ontario's forecast demand.

The MW scheduled by importers receive a Day Ahead Inter-tie Offer Guarantee (DAIOG). The DAIOG keeps the importer whole to its offer price if the real-time price drops below the importer's day ahead offer price. Importers receiving the DAIOG are subject to a financial penalty for not delivering the chosen MW day at hand. The penalty is the difference between their day ahead offer price and the market clearing price.

The IESO's reliability concern leading to the program was that fossil-fired generating units have lengthy start-up times and substantial commitment costs. Their owners must decide whether to commit well in advance of real-time before they can be certain that the unit will be economic. The DACP provides these suppliers with a way of deciding to commit only when it is economic to do so. A subtle but important point is that exports are not part of this process; the program is exclusively designed to commit sufficient resources to meet Ontario demand.

Domestic generators wishing to be dispatched the next day are obligated to offer in the DACP by 11 a.m. day ahead. In turn, the MW from these generators scheduled in the DACP that have significant start-up costs receive an equivalent to the real-time spare generation on line (SGOL) program to hold them whole for their costs at their minimum output. As a ‘sweetener’ for internal generators, those with significant start-up costs (coal and natural gas fired units) are able to claim variable operating and maintenance costs. These are not available to be claimed in the real-time SGOL program which is specifically directed at the repayment of fuel costs.

Market participants’ concerns prior to implementation of the DACP focussed on the potential of an over-commitment of resources day ahead leading to real-time price suppression and inefficiencies. This over-commitment would be caused by an IESO over-forecast of demand and in turn an over-commitment of imports or internal resources. If DACP were to result in excessive imports scheduled, this would depress the HOEP relative to prices in neighbouring markets. We expect, however, there would be a compensatory increase in exports that would push the HOEP back up relative to prices in adjacent markets.

We have not been able to uncover any evidence that the DACP has altered trade flows or the relationship between Ontario and New York prices. We have asked the MAU to continue to monitor the DACP program and report back as more data becomes available.

4.2 Real-Time Transaction Failure Charges

Beginning on June 1, 2006, real-time transaction failure charges have been imposed on market participants for failures to deliver imports or exports chosen in pre-dispatch when the failure involved is under the control of the participant. Delivery failures outside a market participant’s control are not subject to a settlement charge. The belief of both the IESO and some market participants was that a simple settlement charge for an economic failure was more efficient than the compliance mechanisms used prior to June 1 which did not appear to be solving the transaction failure problem.

As the Panel has stated both in previous reports and in Chapter 1 of this report, intertie transaction failures have been a major source of differences between the pre-dispatch price and the HOEP. Import transaction failures also threaten system reliability in situations when supply is tight. An export failure is equivalent to a sudden drop in demand. It reduces the HOEP and thus increases the price difference between pre-dispatch and real time. An import failure is equivalent to a sudden loss of a generator. It pushes up the HOEP and may threaten the power system. The real-time failure charge is imposed on importers and exporters when they fail their transaction for non 'bona fide and legitimate' reasons.[39]

The new measure fundamentally changed the treatment of intertie transaction failures. In the old rules, transaction failures were potentially subject to a compliance investigation with a violation resulting in a formula-based penalty and other sanctions. In the new rules, however, transaction failures are treated as a settlement issue and a market participant has to compensate the market for failures that are considered to be under the participant's control.

An importer with a transaction failure pays an import failure charge equal to the failed amount (MW) times the price difference between HOEP (plus an adjustment factor for the hour) and the one-hour ahead pre-dispatch price. The export failure charge is equal to the failed amount times the price difference between the one-hour ahead pre-dispatch price and the HOEP (plus an adjustment factor for the hour). The adjustment factor for the hour is intended to eliminate systemic and seasonal differences between the pre-dispatch price and the HOEP, leaving a residual difference that is more reasonably attributable to transaction failures in the hour.

Since the implementation of the intertie transaction failure charges, the IESO has collected $757,122 for export failures and $211,258 for import failures. Twenty-six out of a total of thirty-one intertie traders have paid either an export failure charge or an import failure charge. The transaction failure charges are highly concentrated, with five

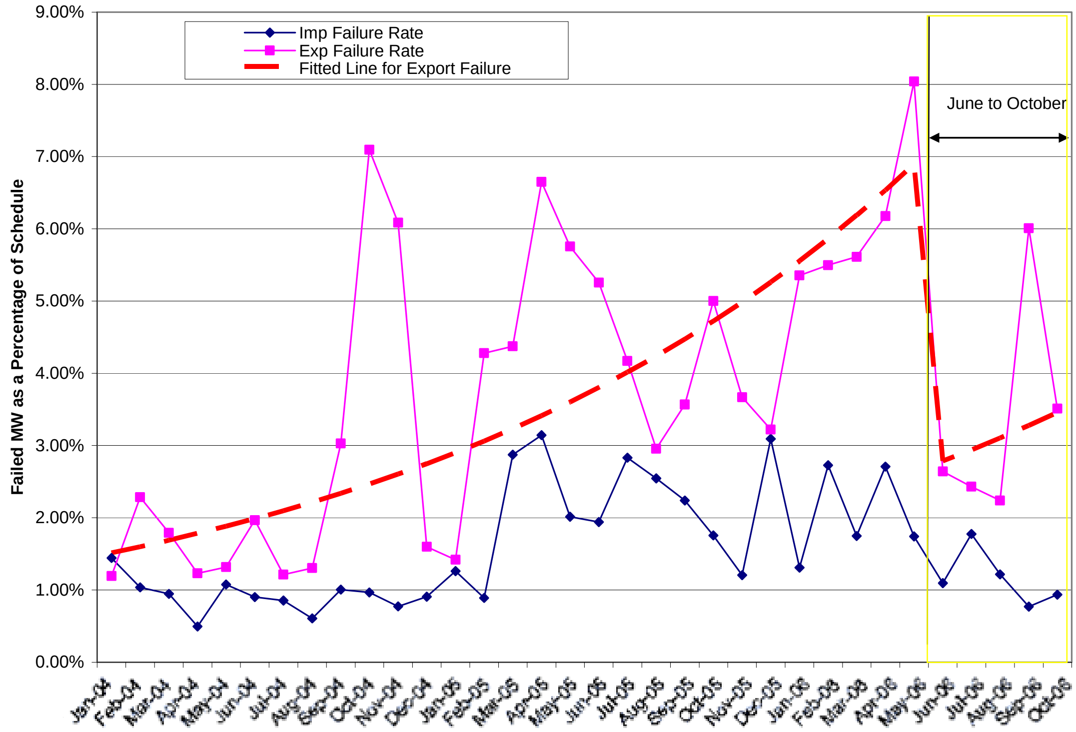
[39] The 'bona fide and legitimate' reasons include failures caused by actions and circumstances beyond the control of the market participant or due to the IESO or external scheduling entity error or action. The new procedures are specified in Market Manual 5.5, section 1.8.12.

companies accounting for 60 percent of export failure charges and five companies accounting for 66 percent of import failure charges.

The rate of transaction failures under participants' control, especially the export failure rate, appears to have decreased significantly. Figure 3-7 plots the monthly import and export failure rates since January 2004. The export failure rate for a month is the ratio of total failed MWh due to factors under market participants' control to the total MWh of exports dispatched in the pre-dispatch run in the month. A trend line of export failures is also plotted. Since January 2004, the export failure rate increased up to May 2006, then dropped abruptly in June 2006. This drop supports the inference that the failure charge changed exporters' trading behaviour. The failure rate for September and October 2006 bounced back up. This might be the result of:

- a smaller price difference between pre-dispatch and real time in Ontario which reduces the penalty for non-delivery relative to the loss in actually delivering to New York thus making failing a transaction less unattractive for a trader; or
- significantly higher adjustment factors which also reduced if not eliminated the penalty for non-delivery for some hours in September and October. This also reduced the cost to a trader of failing a transaction relative to facing a loss from delivering to New York.

Figure 3-7: Monthly Export and Import Failure Rate (Failures Under Participants' Control)[40] January 2004 - October 2006



Although the import failure rate has also declined, it is not clear whether the decline was a result of the implementation of the intertie transaction failure charge or simply a trend over time as a result of other factors. The import failure rate suddenly increased in early 2005, coincident with the opening of MISO's market, but has gradually returned to its earlier level. This may indicate that there was a temporary increase in import transaction failures with MISO at the time its market opened.

Figure 3-7 also shows that the import failure rate was lower than the export failure rate. The main reason for this is that Ontario typically imports from MISO, Quebec, and Manitoba. On the MISO interface, an importer typically bids high in the MISO to purchase power, which tends to reduce the likelihood that an import is scheduled in

[40] This failure rate is different from what is reported in Tables 1-22 and 1-23 because those tables include transaction failures for all reasons, including reasons outside the control of market participants.

Ontario while not in the MISO.[41] Quebec and Manitoba are currently not open markets, so that exporters from these control areas have little reason to fail transactions because their purchasing price is not subject to market uncertainty and because they lack resale opportunities. Most exports from Ontario go to New York, where a trader is allowed to change its offers/bids after the offer/bid window in Ontario is closed. An exporter may deliberately fail a transaction when it expects an unfavourable price in New York. It is therefore reasonable to expect that the intertie transaction failure charge would be most effective in reducing export transaction failures to New York.

4.3 Impact on the Export Volume with New York

The concern has been expressed that penalizing failed intertie transactions might reduce importing and exporting activity with a commensurate loss of benefits both to the Ontario market and to the markets with which it trades. The New York market is the major export market for Ontario traders. In this section we analyse the impact of the intertie transaction failure charge (IFC) on the volume of export trades to the New York market.

In this analysis we estimate a reduced form model (the same one that was used in section 9.1 in Chapter 1) for variation in export volumes on the New York-Ontario intertie. The complexities of the electricity market and the non-storability of the electricity product mean that often the intended volume of export trades deviates from the finalised actual trade volume. There are several reasons for these deviations. Transmission limitations on the IESO grid are a prime cause of changes to export transactions. System operators have administrative tools at their disposal to manage flows on the grid. The MAU controls for the effect of one relevant administrative variable, TLRe (external Transmission Loading Relief), in the analysis.

When the New York system operator anticipates that transmission or security issues would cause problems in New York market, it can limit the proposed volume of exports

[41] Thus to fail an import to Ontario from MISO, an importer has to send a wrong e-tag to the MISO market or does not bid at all.

from Ontario. When it does so, the Ontario system operator applies a TLRe code to the Ontario system algorithm and the volume of exports to New York is subsequently reduced to reflect the situation in the New York market. This means the TLRe code can act to lower the export volume in the Ontario market schedule.

As has been explained in section 3.2 of this chapter, loop flow also influences export quantities in the constrained schedule. For this reason, a loop flow variable is included as an explanatory variable in the analysis.

Then to test for the effect of the intertie failure charge on exports, we include in the analysis a binary explanatory variable which takes a value of one beginning in June 2006 and a value of zero prior to that.

Our simple model therefore expresses the monthly export volume as a function of the monthly average New York price, the TLRe variable and the loop flow variable as well as exogenous factors in the Ontario market. We perform the analysis for peak and off-peak hours for the period August 2003 to October 2006. Results are reported in Table 3-3.

Table 3-3: Reduced Form Econometric Model Export Volume Variations New York-Ontario Intertie Estimation Results August 2003 - October 2006

	PEAK		**OFF-PEAK**	
Variable	Coefficient	Prob.	Coefficient	Prob.
C	524.37	0.01	209.91	0.68
ONLOAD	-0.04	0.10	-0.05	0.16
NUCLEAR	0.08	0.00	0.15	0.00
NYPRICE	-0.77	0.52	3.91	0.13
TLRe	-0.70	0.21	0.42	0.78
LOOP	-0.42	0.05	-0.34	0.29
SELF	-0.11	0.42	-0.23	0.39
HYDRO	0.08	0.48	0.10	0.50
JAN	235.44	0.00	201.40	0.04
FEB	-71.41	0.49	104.65	0.36
MAY	41.89	0.31	136.85	0.04
JUNE	-14.08	0.80	75.31	0.33
JUL	-101.40	0.11	-98.80	0.17
AUG	-46.25	0.24	113.13	0.22
SEP	-89.50	0.19	-92.87	0.50
OCT	-25.12	0.64	-38.53	0.60
NOV	8.04	0.93	89.06	0.53
IFC	**-27.88**	**0.69**	**-90.89**	**0.38**
Model Diagnostics				
R-squared	0.89		0.86	
Adjusted R-Sq	0.81		0.75	
LM Serial Correlation Test	Absent		Absent	
JB test of normality residuals	Normal		Normal	
Number of observations	39		39	

During peak and off-peak hours the volume of exports is increasing in the nuclear output and decreasing in the Ontario load. (These results are consistent with our analysis of trade flows in Chapter 1). The key hypothesis centers on the intertie failure charge (IFC) variable. This analysis indicates that during both peak and off-peak hours, the IFC has no impact on export volumes.[42]

[42] We use a two-tailed hypothesis test where the null states that the IFC variable has no influence on export trades. The probability that we make an error in rejecting the null is indicated in the "Prob" column. In this case this probability is large - 69 percent and 38 percent respectively. So we make a large error if we reject the null. As a result we do not reject the null that the IFC variable is insignificant. Hence we conclude the failure charge has no impact on export trades.

Based on this preliminary analysis, the Panel finds no evidence that the intertie failure charge has led to a reduction in export trading activity between Ontario and New York. The Panel has instructed the MAU to continue the monitoring of the impact of the intertie failure charge on trading activities.

The Panel welcomes the actions taken by the IESO to address intertie failures. The implementation of the intertie transaction failure charge appears to have reduced the failure rate for export transactions, although the ultimate magnitude of this reduction remains to be seen. In addition, the export failure charge does not appear to have discouraged export activity.

Any reduction in import and export failures brings the HOEP and the pre-dispatch price closer together. This increase in price fidelity can improve market efficiency by inducing more efficient consumption and production decisions.

5. *Demand Response Programs in Ontario*

In our first Market Monitoring Report, the Panel stated that ensuring that energy users receive accurate and timely information about prices, and have the incentive to modify their demands in response to such information, is important for the short-term and long-term efficient operation of the Ontario electricity sector. The Panel also stated that interval meters and pricing plans that permit consumers to take advantage of load management by paying at hourly rates rather than average rates offer substantial potential benefits. The Panel believes that allowing loads to be price-responsive remains important for both the short-term and long-term efficient operation of the Ontario market and more broadly the energy sector insofar as it allows more accurate capacity investment decisions.

Recently, several demand side management or demand response programs have been implemented. Over the next few years, these programs may be expanded or new demand response programs may be designed in order to meet the conservation targets put forth by the Ontario Government in its June 2006 Supply Mix Directive to the Ontario Power Authority.[43] In this section, the Panel provides a review of the various demand response programs implemented in Ontario since market opening and offers its comments on their consequences for market efficiency.

5.1 A Review of Ontario Demand Response Programs[44]

A program aimed at facilitating demand response promotes short-term dispatch efficiency if it enables customers to: (i) curtail their consumption of a service (or have it curtailed on their behalf) when the value the customer derives from the service is less than the incremental cost of providing it and (ii) consume when the value they derive from the service exceeds the incremental cost of providing it. Incentive programs that induce customers to curtail consumption at times when the value they derive from the service is greater than the incremental cost of providing it foreclose opportunities for mutually beneficial exchange and result in the inefficient use of resources.

A demand response program promotes long-term efficiency if the investment costs (for equipment or other infrastructure) incurred to enable consumers to respond to time-of use prices, are less than the flow of benefits derived by these consumers from managing their consumption. Consumers derive benefits from managing their consumption when they are able to reduce consumption of MW on which they place a relatively low value and increase the consumption of MW that they value relatively highly. It is this efficiency criterion that the Panel applies when evaluating the various demand response programmes implemented since market opening.

[43] The Government Supply Mix Directive called for a doubling of the conservation efforts suggested in the OPA's initial report, to reduce electricity demand by 6,300 megawatts by 2025.

[44] The U.S Department of Energy defines demand response as:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.* (U.S. Department of Energy, *Benefit of Demand Response in Electricity Markets and Recommendations for Achieving Them*, A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, Page 6.)

There are several demand response programs currently available to Ontario consumers, both at the wholesale and retail levels. These include:

- 5-minute dispatchable loads;
- Hour Ahead Dispatchable Load Program (HADL);
- Transitional Demand Response Program (TDRP);
- Emergency Load Response Program (ELRP);
- the OPA Demand Response Program (DRP) Phase I; and
- the Toronto Hydro Peaksaver Program.

5.2 5-Minute Dispatchable Loads

The dispatchable load program has been in place since the opening of the market. Dispatchable loads are generally large industrial customers that are capable of adjusting their electricity consumption in response to a five-minute dispatch instruction from the IESO. These customers participate directly in the wholesale market by making hourly bids to buy electricity. These bids reflect the value that these loads place on consumption.

The IESO can send dispatch instructions to the dispatchable loads every 5 minutes to consume or curtail their consumption based on their bids. The dispatchable loads are instructed to curtail their energy consumption if the cost of supplying the energy (based on the supply offers) is higher than their bid (i.e., the incremental cost of supplying energy is higher than the value the customer derives from consuming it). Furthermore, dispatch instructions are generated from the constrained schedule and as a result, the instruction to curtail a dispatchable load is based on the relevant nodal price for the load rather than the HOEP. These nodal prices reflect the incremental cost of supply (or demand curtailment) at the meter point of the consumer. In this regard, the 5-minute dispatchable load program promotes dispatch efficiency.

Furthermore, the 5-minute dispatchable load program creates an additional source of operating reserve supply. This provides the potential for improved overall efficiency in that it taps into a previously unutilized resource. Dispatchable loads are able to offer the

IESO the option of curtailing their consumption in response to a contingency on the grid, i.e., operating reserve. This represents a source of operating reserve supply that would not exist absent the dispatchable load program (NPCC and NERC standards require operating reserve to be provided from dispatchable sources). When dispatchable loads are carried for operating reserve, it frees up other supply sources to be used to produce electricity. The impact is that the combined energy and OR demand in Ontario is met at a lower overall production cost. This increased efficiency generally translates into a lower HOEP and lower operating reserve prices.

The investment costs of becoming a dispatchable load are borne entirely by the load involved. The load will incur this cost only if it expects that the benefits of the program (value of avoiding high prices and the revenues earned from providing operating reserve in the wholesale market) outweigh the cost. In a market where the prices reflect the incremental cost of supply, a large customer will become a dispatchable load only if it is also efficient to do so.[45]

At the opening of the market in 2002, there were only two large industrial consumers that were registered in the dispatchable load program. These loads bid roughly 200 MW of consumption. Neither of these dispatchable loads offered operating reserve at the time. Currently there are 9 large industrial consumers that are registered as dispatchable loads for a total of roughly 709 MW of consumption. These loads also offer operating reserve.

5.3 HADL

The economic and operating characteristics of many large industrial customers prevent them from participating in the wholesale market on a 5-minute dispatchable basis. However, many of these consumers are price responsive and can make consumption

[45] Many large consumers are price responsive. Some of these consumers may be located in areas where the locational price (the incremental cost of supplying their consumption) is higher than the HOEP, the price that they pay. Some of these customers may decide that it is not in their private interest to invest in the infrastructure to become a dispatchable load because the benefits of avoiding the HOEP are not sufficient to overcome the cost of the investment. However, if these customers had to pay the relevant nodal price, they may have made the investment. This is an example of a situation in which the uniform HOEP would not induce the long-term efficient investment by a consumer.

decisions over a longer period of time such as one or two hours. The IESO introduced the Hour Ahead Dispatchable Load Program (HADL) in July of 2003 in order to integrate these price responsive loads into the wholesale market. Prior to the HADL, some non-dispatchable loads would attempt to respond to high pre-dispatch prices by reducing their energy consumption. However, their reduction in consumption would not be captured in the IESO's pre-dispatch demand forecast. This reduction in consumption, along with other factors, caused the real-time price of energy to fall below the pre-dispatch forecast. With the lower real-time price, it often would have been more economic for these large industrial customers to have continued consuming at their previous level. Furthermore, the IESO's inability to forecast the curtailment of demand often resulted in the IESO scheduling additional imports unnecessarily to supply these loads. Given that imports are scheduled an hour in advance of real-time and cannot be dispatched down if it is determined in real-time that they are not needed (or economic), this further reduced dispatch efficiency. The HADL program promised to integrate these consumers' price responsiveness into the pre-dispatch forecast so as to achieve a better forecast signal. It also provided the large industrial customers a guarantee that they would be compensated if they reduced consumption only to find that their reduction in consumption was unwarranted in the light of the lower real-time price.

The HADL program works as follows. The load submits a bid to the IESO indicating the amount of energy it will reduce in real-time if the pre-dispatch energy price (the uniform Ontario price) exceeds a certain level. The bid is submitted at least three hours prior to the real-time dispatch hour. If the three-hour ahead pre-dispatch price is higher than the load's bid price, the IESO sends dispatch instructions to the load to reduce its consumption. The HADL uses the three-hour ahead pre-dispatch to allow the loads sufficient time to respond. If the HOEP turns out to be lower than the bid price, the load is compensated with a payment equal to the difference between their bid price and the HOEP for the amount of actual consumption curtailed. This payment represents the value of the load's lost consumption opportunity from responding to the IESO's three-hour ahead-dispatch instruction. In this sense, it is analogous to a constrained-off payment. If the HOEP is higher than the bid price, and the load accurately reduced its consumption, there is no compensation – the HADL facilitated the requisite level of load curtailment.

As we concluded in our December 2005 report, the effectiveness of this program for inducing efficient demand response depends on the accuracy of the three hour ahead pre-dispatch price. Our analysis at the time indicated a slight gain in efficiency as a result of the HADL implementation. Most of the efficiency gain has been a result of the integration of consumers' demand responses into the IESO's dispatch decisions. With the HADL, the IESO can now foresee the load curtailment of these customers in response to high prices three-hours in advance of real-time. The IESO was not successful at forecasting this curtailment in the past. As a result, the IESO avoids unnecessarily dispatching imports that due to the hour-ahead scheduling, must run in real-time even when the load curtailment meant that they were not needed. Additional efficiencies would be gained if the HADL program were based on locational prices rather than HOEP. That being said, improvements in the IESO's demand forecasting tools to capture the price responsiveness of these consumers would make this program unnecessary or of little value to either consumers or the IESO.

5.4 TDRP

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

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

The key difference between the HADL and the TDRP is that the TDRP pays consumers not to consume. The HADL provided a guarantee for lost consumption value in the event of a three-hour ahead forecast error while the TDRP pays consumers the three-hour ahead price. The TDRP, by paying consumers the three-hour ahead price for their curtailment will at times, induce these consumers to curtail consumption when the value they derive from the energy involved is greater than the incremental cost of supplying it to them. This is an inefficient outcome. As we noted in our June 2006 report, the TDRP has led to short-term dispatch inefficiencies in the past. Furthermore, whether it has induced loads to become more responsive to market signals (outside the program) and whether the efficiency gains from any increased price-responsiveness would be sufficient to cover the cost of the requisite infrastructure remains to be determined. In this regard, an assessment of the extent and nature of any changes in price responsiveness by TDRP participants would be useful.

5.5 ELRP

The ELRP is a voluntary program administered by the IESO and is available to all loads and organizations that have emergency back-up generation. Currently there are fourteen participants and 316.8MW registered capacity.[46] When the IESO projects tight supply/demand conditions, the ELRP process is initiated. It can be initiated either in the day-ahead time frame or early on in the dispatch day. The process starts with a notification to participants, followed by a voluntary submission of bids by participants, and then activation of those bids by the IESO if needed. If selected in the ELRP, the IESO pays the participant a stand-by payment of $15/MW until the participant is activated. When a participant is activated, it will be paid an amount equal to the verified curtailment quantity times the greater of HOEP, or $400/MW for two hours of consecutive reduction, or $500/MW for three hours of consecutive reduction, or $600/MW for four hours of consecutive reduction. The ELRP has yet to be activated.

The ELRP is not viewed by the IESO as a substitute for market mechanisms and is only instituted when the market itself cannot solve the reliability issue. This should not excuse it from economic analysis. The Panel is not able to say at this point that the ELRP is the most efficient solution to the reliability problem perceived by the IESO or that the market could not have addressed it, given the opportunity.

5.6 OPA Demand Response Program Phase I

The Ontario Power Authority (OPA) implemented a Demand Response Program (DRP) Phase I on June 23, 2006, targeting 250 MW of registered capacity.

The key components of the program are as follows.

1. The program requires eligible participants to have a demand response capability between 0.5 MW and 100 MW.

[46] 226.5MW of registered capacity is located in Northern areas, and 90.3MW in Toronto and its surrounding areas.

2. Each month, participants submit a strike price at which they are willing to curtail consumption. The strike price must be equal to or exceed the floor price provided by the OPA for the contract period. The floor price is currently \$90/MWh.[47]
3. If the three-hour ahead price hits the strike price, a program participant indicates to the OPA that it will reduce its consumption for that hour and up to two hours after the event.
4. The OPA will pay the participant an amount equal to the verified demand reduction times the strike price for each eligible hour. The verified demand reduction for an hour is measured against a baseline demand. The baseline demand is measured on an hourly basis as the average of the ten highest consumption levels for the given delivery hour in the past eleven days or through an alternative approach proposed by market participants and approved by the OPA.

The structure of the DRP is similar to that of the IESO's existing TDRP. As such, the Panel shares the same concerns towards the DRP as it does with the TDRP – in many instances, it will pay consumers not to consume even when it is efficient for them to do so.

That being said, there are three key differences between the DRP and the TDRP that are worth further discussion. First, the DRP allows participants to choose their own strike price. The Panel sees this as a potential improvement from the TDRP program. The OPA's DRP pays a load an amount equal to the amount of the load curtailment times the accepted strike price, while the IESO's TDRP pays an amount equal to the amount of the load curtailment times the three-hour ahead price (to a maximum of \$500/MWh), as long as the three-hour ahead price exceeds \$120. The DRP allows a participant to reveal the value it places on foregone consumption by setting its own strike price and thus provides a better opportunity than the TDRP for consumers' decisions to reflect their evaluation of

[47] The OPA updates the floor price monthly on its website: www.powerauthority.on.ca

foregone consumption. The DRP will still induce inefficient choices since the avoided cost of the curtailed consumption is roughly half the load's evaluation of it.

Second, unlike the TDRP, the DRP is not integrated into the IESO's dispatch decisions. As a result, the IESO will not reflect the consumers' load curtailments in its load forecasting. This will result in additional inefficiencies if the IESO then schedules unnecessary imports or starts fossil units unnecessarily. This represents an additional efficiency loss beyond the inefficiencies induced by the TDRP.

Third, the DRP is offered to all market participants, including those that are currently registered as dispatchable loads. The Panel is concerned that by paying loads their strike price to curtail their consumption, the DRP represents a more lucrative option for some customers that are currently five-minute dispatchable loads or who were otherwise planning to become five-minute dispatchable loads. The Panel is aware of one large industrial consumer that has chosen to migrate from the IESO's dispatchable load program to the DRP and at least one large customer that had intended to register in the IESO's dispatchable load program but has since decided to participate in the DRP instead. The migration of consumers from the IESO's dispatchable load program to the DRP would result in dispatch inefficiency. Instead of dispatchable loads curtailing consumption because the value they derive from it is less than the HOEP, DRP participants, being paid to go away, curtail consumption even though the value they derive from it is twice the HOEP.

Programs that pay consumers not to consume when it would otherwise have been efficient to do so have at times been justified by their proponents on the basis that they provide benefits to the other consumers in the market (at the expense of generators) since their consumption reduction generally results in lower overall prices. The Panel rejects this justification on the grounds that it confuses a transfer of resources among market participants with more efficient use of resources. Moreover, as politically desirable as price suppression might be in some quarters, the DRP may not even do this. For example, the effect of the migration of one large industrial customer from the dispatchable load program to the DRP on the HOEP and on the price of OR in May 2006 was simulated by the MAU. In the past, this consumer had typically offered 80 MW of ten-minute reserve which it could no longer offer once it ceased to be a dispatchable load. The elimination of the 80 MW of OR formerly supplied by this dispatchable load in May 2006 would have raised the monthly average HOEP by $0.47/MWh and the monthly average 10-minute non-spinning reserve price by $0.88/MWh (assuming all other variables remained unchanged).[48]

5.7 Toronto Hydro's Peaksaver Program

Toronto Hydro, a local distribution company, also implemented a program in the summer of 2006 in order to encourage conservation. The program is called the *Peaksaver AC* program. Under this program Toronto Hydro installed a peaksaver switch on the central air conditioners and water heaters of enrolled residential and commercial consumers. During peak hours, when electricity prices reach a specified level, Toronto Hydro sends a signal to the peaksaver switches to interrupt the power supply to these appliances for a short time. In this sense, the peaksaver technology facilitates demand response in that it allows consumers to reduce their electricity consumption when they are away from the house or when they are unable to see the prices of electricity. Toronto Hydro activated the *Peaksaver* program on two occasions during the summer, once for a two-hour period and once for a three-hour period. The hourly consumption reduction was 9 MWh in the first instance and 14MWh in the second instance.

The MAU simulated the price impact of *Peaksaver* for the three hours when *Peaksaver* AC was activated on August 1. Table 3-4 summarizes the results of the simulation. The HOEP could have been $0.83 to $4.45 higher than the actual price although demand was curtailed only by 11.8 to 14 MWh.

[48] This particular dispatchable load is located in a congested area of the province (Northwestern Ontario) where locational prices are lower than the HOEP, the price at which the load's strike price for the DRP is based on. This implies that this load will be dispatched off by the DRP in many hours when it was more efficient to consume.

The *Peaksaver* program increases market efficiency in the sense that participants choose a limited, perhaps barely noticeable, curtailment of their consumption during periods when incremental generation costs are very high. On the second efficiency question of whether the present and probable future economic gains (the avoided cost of generation less the value of consumption foregone) resulting from the curtailment of consumption involved are sufficient to cover the cost of the peaksaver switch, its installation and related costs, the Panel has seen no evidence.

Table 3-4: Price Impact of Peaksaver AC
August 1, 2006

Hour	Load Reduction (MWh)	HOEP ($/MWh)	Simulated HOEP ($/MWh)	HOEP Difference ($/MWh)	Demand (MWh)
14	11.8	187.44	188.27	0.83	26,891
15	14	191.64	192.47	0.83	26,874
16	13.8	124.59	129.05	4.45	26,962

5.8 Time-of Use Pricing, Smart Meters and Price Responsive Loads

As we reported in several of our previous reports, there are many large metered consumers who do not participate in any of the demand response programs, but do respond to price signals.[49] This demand response was induced simply by implementing time of use prices through the wholesale market. The Government's Smart Meter initiative will provide many more Ontario consumers with interval meters. The Smart Meters, along with the OEB's implementation of a time-of-use pricing plan for the customers currently under the Regulated Pricing Plan (RPP), could provide additional demand response potential. From a long-term efficiency perspective, however, the Panel would have preferred an environment in which individual consumers could choose to invest or not to invest in interval meters in the light of a cost-based time of use pricing schedule and their own consumption preferences, patterns and ability to shift consumption to off-peak periods. Given a centralized decision to require that interval

[49] In our second Market Monitoring Report, we estimated the price responsiveness of 18 large industrial consumers that were not dispatchable loads. When we compared their consumption patterns prior and post market opening and the introduction of time-of-use pricing, we found that several of these customers shifted their consumption from high priced peak demand periods to lower price off peak periods after market opening.

meters be installed, their contribution to market efficiency depends on the dissemination of accurate and timely information about prices to consumers.

5.9 The Panel's Comments on Demand Response Programs

In the Panel's view, conservation should not mean simply using less electrical energy. Conservation is properly defined, in the Panel's view, as efficient use and stewardship of resources in general. Insofar as the role of demand response programs or initiatives in meeting the government's conservation goals is concerned, the Panel's efficiency perspective leads it to offer the following comments:

1. Before turning to demand response programs such as the ones discussed above to meet the province's conservation goals, make the most of the Smart Meter initiative by implementing appropriate time-of-use pricing programs and ensuring that interval metered energy users receive accurate and timely information about prices.

2. If demand response programs are deemed to be required they should be designed so as to enable customers to: (i) curtail their consumption of a service (or have it curtailed on their behalf) when the value customers derive from the service is less than the incremental cost of providing it and; (ii) consume when the value they derive from the service exceeds the incremental cost of providing it. Incentive programmes that induce customers to curtail consumption at times when the value they derive from the service is greater than the incremental cost of providing do not conserve resources in the true sense of the word.

3. If implemented, demand response programs should be integrated into the IESO's dispatch decision process either directly through a bid program like the one used for the HADL, or through recognition of the curtailment in the IESO's demand forecast. This will avoid the types of import scheduling inefficiencies that have occurred in the past.

4. Future planning and procuring of generation sources should as much as possible recognize the price responsiveness of demand in order to avoid over-investment.

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Chapter 4: The State of the IESO-Administered Markets

1. *Introduction*

This is our 9th report on the performance of the IESO-administered market. Consistent with our previous reports, we have examined participant behaviour, market operations and market outcomes from the perspective of economic efficiency. We conclude that the market once again functioned reasonably well according to its design over the six-month period May – October 2006. Spot market prices generally reflected demand and supply conditions. We found no evidence of gaming, abuse of market power or other inappropriate conduct by market participants or the market and system operator, the Independent Electricity System Operator (IESO).

Our review of the six-month period of May 2006 through October 2006 revealed that the average HOEP was about $30/MWh lower than the same period in 2005. The lower average HOEP was attributable to an increase in supply in Ontario and more moderate weather causing lower demand for electricity. For much of the period Ontario's HOEP was on average the lowest price among the neighbouring markets of New York, New England, PJM and the Midwest Independent System Operator.

A principal cause of the lower HOEP was weaker demand in Ontario over the period; it declined by 2.9 TWh or 3.7 percent compared to the previous year. That being said, despite the lower average demand, during a heat wave on August 1, 2006 a new summer peak record of 27,005 MW was set. The lower HOEP experienced in 2006 also reflected the availability of additional nuclear units and a reduction in outages. Forced outages have declined continuously since May 2003.

Our review for this period also indicated a decline in hourly uplift charges. The combined hourly charges for the Import Offer Guarantee, Congestion Management Settlement Credit, Operating Reserve and transmission losses payments were 60 percent lower than in 2005. Since market opening in May 2002 the trend in total market-related uplift payments has been downward and uplift payments per MWh of load have fallen even faster.

Over the period May – October 2006 the large differences between the zonal prices in the Northwest and Northeast compared to the rest of the province remained, but in southern Ontario zonal prices were closer to each other than in previous periods. On average zonal prices everywhere were considerably lower than six months and a year ago as a result of increased supply and weaker demand. Zonal prices in southern Ontario are also closer to the HOEP but this convergence does not imply that the HOEP is more reflective of underlying market realities. The convergence of zonal prices and the HOEP is not a result of a better matching of the unconstrained dispatch with the constrained dispatch due, for example, to less transmission congestion. There has been continued bottling of supply in the Northwest, and some reduction in congestion within southern Ontario, but, congestion has increased on many interties. The net effect of this intertie congestion was to reduce actual exports (in the constrained schedule) relative to notional exports (in the unconstrained schedule) thereby reducing zonal prices relative to the HOEP. While the convergence of the HOEP with zonal prices during the period May – October, 2006 had the effect of reducing the inefficiencies associated with the uniform price regime, this trend could easily reverse itself. There is nothing in recent events to change the basic case for replacing the uniform price regime with some form of locational pricing.

Finally, our study of the trend in Ontario energy prices highlights a growing effect of government regulations and OPA contracts on the bill ultimately paid by consumers. While the average HOEP declined by 40 percent in the period May – October, 2006 when compared to the corresponding period a year ago, if one adjusts the HOEP to account for the OPG rebate and the Global Adjustment credits or obligations to provide a reflection of the all-in charge to a typical consumer, this adjusted HOEP declined by only 17 percent. An increasing percentage of the province's consumption is becoming 'backstopped' by these arrangements.[50] These fixed price contracts are effectively

[50] Recent estimates by both the IESO and Navigant Consulting suggest that roughly 80 percent of the provinces annual consumption is currently covered by some form of fixed price arrangement.

shielding the overall impact of month to month changes in the HOEP on both consumers' bills and by extension, generators' revenues. This trend raises questions about the relevance of the real-time market and market prices in what many in the industry have called a 'hybrid market'.

In the rest of this chapter we address the role of the real-time spot market in the new hybrid market and offer our observations on how this hybrid market might still realize some of the efficiencies that would be derived from a competitive marketplace.

2. *Realizing Efficiencies in the New Hybrid Market*

2.1 Role of the real-time wholesale market and the continued importance of efficient price signals

In each of its market monitoring reports, the Panel has consistently emphasized the importance of efficient price signals. By efficient price signals, we mean real-time prices that accurately reflect either the incremental cost of supplying another MW of electricity at a given location or the incremental value of consuming another MW at that location.[51] In a market context, efficient price signals direct the decisions of diverse sets of suppliers and buyers so as to ensure that in the short-term output is produced by the lowest cost suppliers and is consumed only when its value to the user is at least as great as its incremental cost of production. In the long-term, efficient price signals guide the decisions of the diverse set of suppliers and buyers toward efficient technology choices and timely and efficient capacity investment decisions.

With the creation of the new hybrid market, the province will, at least for the near term, rely on central planning and government directives rather than efficient price signals to guide technology choice, capacity investment as well as many energy conservation decisions. The OPA, either in response to a government directive or in conjunction with the OEB approved Integrated Power System Plan (IPSP), will procure these investments through long-term contracts with various privately and publicly owned interests.

[51] Pre-dispatch should reflect best available forecasts of these incremental costs and benefits.

In the hybrid market, compensation for the day-to-day production and conservation decisions will depend on the terms and conditions of OPA contracts. In many cases, the contracts reference hourly wholesale prices such as the HOEP, as a basis for establishing compensation. The Clean Energy Supply (CES) contracts and early mover contracts are two such examples. In other cases however, compensation does not depend on wholesale prices and production and consumption of the market participants involved will be insulated from hourly prices and the industry conditions influencing these prices.

Under the new hybrid market, commitments made under these long-term contracts must ultimately be covered by the province's rate-payers and/or taxpayers.[52] Currently, any financial obligation on consumers resulting from these contracts is included in the Global Adjustment.[53] As we discussed in Chapter 1, the Global Adjustment shows up either as a charge or rebate on the monthly bills of Ontario wholesale customers; it is a rebate when the average HOEP is high relative to the prices paid under the long-term contracts and it is a charge when the HOEP is relatively low. Retail customers pay a regulated rate that is revised periodically by the OEB. The Global Adjustment is one of the factors the OEB would take into account when it revises the regulated rate. As we note in Chapter 1, the Global Adjustment, in conjunction with the OPG rebate, has dampened the redistributive effects of monthly changes in the HOEP thereby shielding many of the province's consumers from the month to month volatility in wholesale energy prices.

With the OPA now guiding the long-term investment decisions of the province and the Global Adjustment shielding typical consumers from the month to month volatility of wholesale energy prices, some may ask if there still is a role for the IESO wholesale market itself. It is the Panel's position that, as a source of guidance for planners and regulators as well as producers and consumers in the new hybrid market, there is no good

[52] The assignment of this form of risk was one of the factors that precipitated electricity market restructuring in Ontario, where it was believed that suppliers were better able to manage these risks.
[53] In addition to the cost of the new investments which are covered under the Global Adjustment, consumers continue to pay for the cost associated with the investments made by the old Ontario Hydro. These are (in part) being paid through the 0.07 cents/kWh Debt Retirement Charge.

substitute for real-time price signals generated by an efficient wholesale market. Moreover, with the Global Adjustment dampening the redistributive effects of changes in HOEP and mitigating any harm that might be said to be visited upon consumers from potentially higher HOEP, the Panel contends that there may be no better time than now to address the remaining sources of inefficiency in the design of the Ontario spot market. Artificially reducing the HOEP, as is the outcome under the current market design, simply means that consumers pay more (or receive a smaller rebate) through the Global Adjustment, all the while inducing market inefficiencies from which all Ontarians lose.

The real-time price signals generated by an efficient wholesale market are central to the economic success of the new hybrid market for several reasons:

- First, the real-time production and consumption decisions of many wholesale participants will continue to be guided by real-time prices.[54] If these price signals continue to ignore certain system realities such as transmission constraints or the actual ramping capabilities of generation facilities, they will at times induce these participants to make decisions that reduce the short-term dispatch efficiency. As we have indicated in Chapter 3, factors such as the uniform pricing system and the 12 times ramp rate assumption create a wedge between the HOEP and local shadow prices. This can result in inefficient production and consumption decisions such as the inefficient exports from Ontario to New York that we began documenting in our last report. Prices that understate the incremental cost in a particular region of the province may also induce inefficient consumption decisions from wholesale customers that have the means and would otherwise have the incentive to shift consumption from high priced periods to low price periods or to avoid consuming all

[54] Under the new hybrid market, several classes of market participants will continue to be affected by the HOEP and the related congestion management payments that are derived from a uniform pricing system. These participants include: (i) exporters who directly pay the HOEP; (ii) metered customers that pay HOEP and seek opportunities to shift consumption from high-price, peak periods to low-price, off-peak periods or simply to stop consuming when they feel prices are too high (see Chapter 2 subsection 4.1); (iii) importers who are paid the higher of the HOEP or their accepted offer price; (iv) generators that do not have an OPA contract and derive revenues from the real-time prices; and (v) generators that have signed OPA contracts such as the CES contracts which impute revenues based on the HOEP.

together. These inefficiencies ultimately result in higher costs to all consumers in the province.

- Second, even though long-term investment will be guided through central planning in the near term, price signals from an efficient wholesale market can and should play an important role in guiding this planning process. Efficient real-time pricing can provide the OPA and the OEB with a measure of the expected value of new investment that reflects the economic reality of the province's overall supply and demand situation. These signals are bound to be more accurate than the notional engineering costs that might have been used prior to market opening for central planning purposes. These signals may also help the OPA and OEB avoid or minimize the potential for the overinvestment that can occur in a centrally planned regulatory regime. The cost of this over-investment is ultimately borne by the province's rate-payers through the Global Adjustment. Furthermore, as we have argued above, attempts to subsidize consumers by suppressing real-time prices leads to over-consumption and could ultimately lead to over-investment by the planners at OPA.
- Third, the future success of programs such as the Smart Meter program will depend on the extent to which metered customers are able to base their consumption decisions on efficient real-time prices. We understand that the government is committed to the policy of requiring all consumers to own a smart meter by 2010. The principle behind the move to smart metering is that consumers will be able to shift demand from high-price times to lower price times, or perhaps even avoid consumption in the high-price periods entirely. For this program to be effective (and to help defray the investment costs of the program), efficient real-time prices must be available to guide the OEB in its time-of-use rate setting. Ideally, these time-of-use rates would be based on hourly real-time prices. As we noted in Chapter 1, the presence of the Global Adjustment and the OPG rebate does not reduce the benefits consumers can derive from shifting their consumption from high price periods to low price periods.

In short, in the Panel's view, the wholesale market has a vital role to play in the new Ontario hybrid market. In order for it to play this role properly, certain deficiencies in the design of the market should be corrected. The first step towards moving to a more efficient pricing regime is to adopt a locational pricing system in the province. This will offer a better opportunity for efficient pricing across the province and will remove some of the subsidization inherent in the one-price fits all approach of the uniform price system. A locational pricing system would also remove or at least limit the need for congestion management payments and the associated uplift fees. The Panel has spoken in favour of locational pricing in other reports and it formally recommended the adoption of locational pricing in its last report. In this report we wish merely to add that the efficiency case for locational pricing and other improvements remains strong.

2.2 OPA procurement contracts and the transition to an efficient and competitive electricity industry

The OPA has publicly stated that its long-term objective is to evolve the hybrid market into a more "robust" competitive market-based system.[55] This involves a transition of the risk inherent in the long-term procurement contracts from consumers back towards investors. It will come as no surprise that we encourage the idea of the eventual full restoration of the energy market and market based mechanisms as the means for encouraging new investment. We encourage the OPA in its efforts to manage this transition. The OPA is the organization that is in the best position to achieve this transition through careful attention to its procurement process. We offer the following observations in this regard.

Providing Incentives for Efficient Dispatch

[55] "I consider the OPA to be a transitional entity … My view is that the OPA should probably do itself out of a job sometime between 10 and 20 years from now. The transition that the OPA needs to manage is to progressively shift the risk from customers to investors as electricity moves from a monopoly, command-control structure to a mature, competitive market model.…I think the OPA's success should be measured by the degree to which it is able to shift risk away from customers and toward investors. This will be evidenced by an increasing robustness of the competitive market and a shrinking role of regulation and of the OPA itself." Jan Carr, CEO, OPA: "The Ontario Power Authority – What It Is and Where It is Going" Speech presented to the Toronto Board of Trade (January 26, 2005).

Over the next several years, the OPA will enter supply arrangements with a diverse set of publicly and privately owned generators. The IESO will continue to require some approach to coordinate the operating decisions of these diversely owned assets to ensure that the grid is operated reliably and efficiently (generation is selected in merit order within transmission constraints).[56] As we indicate above, we believe that the wholesale market is the best vehicle for achieving this coordination. To realize all of the benefits of the wholesale market, however, future supply contracts should include terms and conditions that induce new generation to offer into the wholesale market at prices that reflect their incremental cost of production. This will help to ensure efficient dispatch.

As we stated in our last report, to the best of our knowledge, the CES contracts and early mover contracts entered into by OPA are designed so as to maintain dispatch efficiency. Under these contracts, the asset owners are expected to make hourly offers into the wholesale market. The owners of these facilities receive revenues based on their actual production in the market and the prices computed in the market. However, under these contracts, the generators are provided a monthly net revenue guarantee to ensure that they can recoup any costs that are not covered by the market. If the net revenue deemed to have been received by the generators from the market is less than or exceeds the agreed-upon monthly net revenue requirement, generators will either receive whatever support payments are needed to achieve the guaranteed net revenue, or will be required to pay back 95 percent of excess revenue. In our view, these contracts provide the generators involved with the appropriate incentive to offer at incremental cost and are therefore consistent with dispatch efficiency. This is in contrast to fixed price supply agreements such as the old Power Purchase Agreements (NUG contracts). Fixed price contracts pay the asset owner a fixed price per unit of output produced. Under these contracts, the asset owner has the incentive to operate whenever the fixed price is higher than the incremental

[56] This would be true even if we had a regulated centralized dispatch. With diverse ownership of generation assets, all with different unit operating costs and characteristics, the regulated centralized dispatch would have to have some mechanism that would provide the incentives for all owners to operate when and only when it was efficient relative to the other generation facilities that were available.

cost of production. The owner's decision to operate is not driven by the prevailing supply and demand conditions and as a result, the asset is often operated out of merit.[57]

Promoting Competition

The original design of the Ontario market provided for the divestiture of generation assets by OPG in order to increase the number and size of independent competitors in the market. While OPG is no longer required to divest any generation, it remains important for planners and regulators in the hybrid market to take the effect of their policies on competition into account. For example, other things being equal, it would make sense from the perspective of promoting competition for OPA to contract with suppliers other than OPG for future supply.

Promoting Forward Contracting Liquidity

One of the potential shortcomings of a centralized procurement process is that it can stifle the development of a private forward contract market in which suppliers and buyers mange their production and consumption risks.

Most of the province's existing generation is currently under some form of regulated or OPA contract. The terms of these arrangements are generally five years or more. Recent estimates by both the IESO and Navigant Consulting indicate that roughly 80 percent of the provinces annual consumption is currently covered by such contracts. Furthermore, in the near future, all of the province's new generation investments will be under long-term procurement arrangements with the OPA. These contracts provide long-term revenue guarantees to the owners of the assets thereby mitigating their price risk. This means that the owners of these assets have no incentives to sell their output in a forward market. With most of the province's assets under contract, very little supply remains

[57] As an extreme example, there are times, in low demand periods, when baseload generation assets must spill water or when nuclear assets must lower production while higher cost NUG generators continue to operate.

available for longer term contracting with wholesale buyers or retailers who might sell contracts to smaller commercial and residential consumers.

Despite the fact that residential consumers are protected by the Regulated Price Plan (RPP) under which they pay a fixed rate reviewed and adjusted periodically by the OEB, there appears to be a modest but growing interest in contracts with retailers.[58] The incentive to enter these contracts appears to be that they promise a price advantage relative to the RPP over the longer term. Given that most of the province's generation assets are already 'sold-forward' through OPA contract or government regulation, it is our understanding that the retailers that are offering these contracts are finding it difficult to strike counter contracts with generators to back the risk of any future contracts sold to retail consumers. It may be that current OPA contracts and other regulatory arrangements are impeding the development of private contracting between retailers and individual customers.

It would be unfortunate, from the Panel's perspective, if the current arrangements in the hybrid market were preventing both market-based hedging and the growth of an organized demand side in the market as well as many of the innovative solutions that come from market-based contracting. If this pre-emption extended to the types of agreements between generators and consumers or their agents that could induce new investment, the hybrid market might well entrench the need for government or OPA backing for all future investments. This would be contrary to the OPA's stated objective to transition towards a competitive market system.

We encourage the OPA to consider ways to transform their long-term contracts into forward exchanges to increase the potential for private bilateral contracts. We offer the following thought of how this may be accomplished. First, whenever possible, the OPA should act as the facilitator between generators and buyers rather than itself being the counterparty to a contract. This may be achieved through the establishment of

[58] According to the OEB, approximately 206,000 residential customers have signed retail contracts since retail rates were fixed by the government. Much of this has happened in the last six months.

competitive auctions between potential new investors and large wholesale buyers or retailers. Alternatively, within the OPA contracts, new investors could be provided incentives to sell their output on private forward markets when it would be efficient to do so. Finally, the OPA could continue to use its forward auction process to release some of its current contractual obligations.

The Role of Demand Management

Demand side management or demand response programs appear to be increasingly prominent in the hybrid market. Programs are likely to be expanded in order to meet the conservation targets put forth by the Ontario Government in its June 2006 Supply Mix Directive to the Ontario Power Authority.[59] The Panel is of the view that the goal of conservation should be to eliminate instances in which the value of energy to its users is less than its cost of production rather than simply to reduce energy use. For this reason, we have consistently opposed measures to suppress the HOEP in order to subsidize consumers whether residential or industrial. The Panel has frequently expressed the view that the best way to ensure that energy is not used for purposes in which its value is less than its cost of production is for customers to face prices that accurately reflect the incremental cost of production. For the Panel, the best course of action is to make the most of existing and planned interval metering programs by implementing appropriate time-of-use pricing programs and ensuring that energy users receive accurate and timely information about prices. Insofar as demand response programs are concerned, the Panel’s views can be found in Chapter 3 of this report. Incentive programmes that pay customers to reduce consumption often induce them to curtail it even though the value they derive from it is greater than the incremental cost of providing it and, in the Panel’s view, do not conserve resources in the true sense of the term.

3. *Summary*

[59] The Government Supply Mix Directive called for a doubling of the conservation efforts suggested in the OPA's initial report, to reduce electricity demand by 6,300 megawatts by 2025.

The oversight activities of the Panel focus on the consumption, investment and dispatch efficiency of IESO-administered markets. In this report, we recognize that the analysis and commentary in which we have been engaged since market opening must be placed in the context of Ontario's new hybrid market in which centralized planning and regulation have a much more important role.

In the new hybrid market, dispatch decisions continue to be made in the spot market but decisions affecting consumption efficiency and investment efficiency have been largely subsumed by the government's policy initiatives. The government has set targets for conservation and demand management and has asked the OPA to achieve these targets through various incentive programs. The OEB also has a role in the efforts to encourage conservation through its development of time-of-use pricing. Similarly, the direct contracting for new sources of Ontario-based generation has supplanted the market as the vehicle to attract new investment, at least for a transitional period.

In the Panel's opinion, the spot market has a central role to play in ensuring that consumption, investment and dispatch decisions in Ontario's new hybrid market are efficient. The Panel believes strongly that both hybrid and spot market design should be such as to allow spot market prices to provide an accurate reflection of underlying supply and demand conditions. The Panel further believes that there are changes in the design of the spot market which would increase the quality of the signals it can provide to planners and regulators as well as to producers and consumers and that now is a good time to make these changes. Finally, the Panel believes that to the extent that the cost of OPA contracts and demand management decisions can be reflected in real-time prices rather than eventually showing up as a non-market uplift cost to consumers, the efficiency of the hybrid market would also be served.

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

Ontario

Market Surveillance Panel

Statistical Appendix

Monitoring Report on the IESO-Administered Electricity Markets

for the period from
May 2006 – October 2006

PUBLIC

December 2006

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

List of Tables

Table A-50: Average One Hour Ahead Forecast Error
Table A-51: Low Price Hours

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

	Ontario Demand		Total Market Demand		Exports	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	11.77	11.99	12.76	13.18	0.99	1.20
Jun	13.51	12.59	14.26	13.51	0.75	0.91
Jul	14.10	13.89	14.83	14.92	0.73	1.03
Aug	14.06	13.32	14.89	14.53	0.83	1.21
Sep	12.61	11.58	13.52	12.41	0.91	0.83
Oct	12.25	11.99	13.17	12.97	0.93	0.98
Nov	12.48	N/A	13.59	N/A	1.12	N/A
Dec	13.77	N/A	14.80	N/A	1.04	N/A
Jan	13.62	N/A	14.81	N/A	1.20	N/A
Feb	12.57	N/A	13.66	N/A	1.09	N/A
Mar	13.22	N/A	14.45	N/A	1.23	N/A
Apr	11.53	N/A	12.85	N/A	1.32	N/A

* This data has been revised to include dispatchable loads.

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

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

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

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

* Temperature is calculated at Toronto Pearson International Airport

*Table A-4: Outages (TWh), May 2005-October 2006**

	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	N/A	2.23	N/A	2.76	N/A
Dec	4.26	N/A	1.46	N/A	2.80	N/A
Jan	3.03	N/A	1.38	N/A	1.65	N/A
Feb	2.47	N/A	1.10	N/A	1.37	N/A
Mar	4.05	N/A	2.60	N/A	1.45	N/A
Apr	4.89	N/A	3.36	N/A	1.52	N/A

* 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 ($/MWh), On and Off-Peak, May 2005-October 2006

	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	N/A	74.11	N/A	44.39	N/A
Dec	79.77	N/A	101.29	N/A	63.52	N/A
Jan	55.54	N/A	64.95	N/A	47.79	N/A
Feb	48.12	N/A	53.98	N/A	42.80	N/A
Mar	49.01	N/A	57.62	N/A	40.59	N/A
Apr	43.52	N/A	55.96	N/A	35.23	N/A

Table A-6: Average Richview Slack Bus Price ($/MWh), On and Off-Peak May 2005-October 2006

	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	N/A	102.68	N/A	56.87	N/A
Dec	94.85	N/A	124.83	N/A	72.22	N/A
Jan	67.37	N/A	83.80	N/A	53.84	N/A
Feb	57.23	N/A	67.15	N/A	48.22	N/A
Mar	57.44	N/A	69.01	N/A	46.12	N/A
Apr	53.12	N/A	68.33	N/A	42.98	N/A

Table A-7: Ontario Demand (GWh) by Market Segmentation, May 2005-October 2006

	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	9,409	9,626	1,880	1,657	175	177	11,465	11,460	280	467	11,745	11,927
Jun	11,235	10,130	1,750	1,662	170	193	13,155	11,986	344	555	13,499	12,541
Jul	11,662	11,477	1,726	1,610	193	187	13,581	13,274	514	580	14,095	13,854
Aug	11,412	10,990	1,895	1,670	208	161	13,515	12,822	517	486	14,032	13,308
Sep	10,041	9,425	1,854	1,534	197	159	12,092	11,118	461	403	12,553	11,521
Oct	9,828	9,768	1,766	1,504	177	149	11,771	11,421	416	541	12,187	11,962
Nov	10,233	N/A	1,709	N/A	165	N/A	12,107	N/A	334	N/A	12,441	N/A
Dec	11,497	N/A	1,728	N/A	197	N/A	13,422	N/A	324	N/A	13,746	N/A
Jan	11,185	N/A	1,752	N/A	188	N/A	13,124	N/A	473	N/A	13,597	N/A
Feb	10,425	N/A	1,555	N/A	164	N/A	12,145	N/A	423	N/A	12,568	N/A
Mar	10,787	N/A	1,756	N/A	174	N/A	12,717	N/A	483	N/A	13,200	N/A
Apr	9,247	N/A	1,659	N/A	154	N/A	11,059	N/A	454	N/A	11,513	N/A

Table A-8: Frequency Distribution of HOEP, May 2005-October 2006
(Percentage of Hours within Defined Range)

	HOEP Price Range ($/MWh)																			
	< 10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	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	N/A	0.56	N/A	2.64	N/A	20.56	N/A	**28.75**	N/A	17.08	N/A	8.19	N/A	12.64	N/A	9.58	N/A	0.00	N/A
Dec	0.00	N/A	0.27	N/A	0.81	N/A	10.89	N/A	22.98	N/A	14.52	N/A	9.27	N/A	12.90	N/A	**28.09**	N/A	0.27	N/A
Jan	0.00	N/A	0.40	N/A	1.34	N/A	11.02	N/A	**33.20**	N/A	29.44	N/A	11.96	N/A	7.80	N/A	4.84	N/A	0.00	N/A
Feb	0.00	N/A	0.89	N/A	1.79	N/A	17.41	N/A	**47.62**	N/A	18.45	N/A	9.38	N/A	3.72	N/A	0.74	N/A	0.00	N/A
Mar	0.00	N/A	0.13	N/A	2.55	N/A	30.65	N/A	**31.85**	N/A	15.86	N/A	10.08	N/A	6.85	N/A	2.02	N/A	0.00	N/A
Apr	5.97	N/A	7.22	N/A	9.72	N/A	**26.81**	N/A	20.69	N/A	12.64	N/A	9.31	N/A	5.97	N/A	1.11	N/A	0.56	N/A
May-05 Apr-06	0.54	N/A	1.34	N/A	3.25	N/A	18.14	N/A	**24.55**	N/A	14.44	N/A	8.79	N/A	12.34	N/A	15.74	N/A	0.87	N/A
May-06 Oct-06	N/A	1.01	N/A	2.39	N/A	17.28	N/A	**35.58**	N/A	13.72	N/A	10.23	N/A	8.00	N/A	9.32	N/A	2.36	N/A	0.13

* Bolded values show highest percentage within month.

Table A-9: Frequency Distribution of HOEP plus Hourly Uplift, May 2005-October 2006
(Percentage of Hours within Defined Range)

	HOEP plus Hourly Uplift Price Range ($/MWh)																			
	<10.00		10.01 - 20.00		20.01 - 30.00		30.01 - 40.00		40.01 - 50.00		50.01 - 60.00		60.01 - 70.00		70.01 - 100.00		100.01 - 200.00		> 200.01	
	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	N/A	0.56	N/A	2.22	N/A	18.19	N/A	**24.44**	N/A	19.03	N/A	10.56	N/A	13.47	N/A	11.39	N/A	0.00	N/A
Dec	0.13	N/A	0.27	N/A	0.54	N/A	10.35	N/A	19.22	N/A	14.11	N/A	11.16	N/A	14.38	N/A	**28.90**	N/A	0.94	N/A
Jan	0.13	N/A	0.40	N/A	0.40	N/A	10.62	N/A	23.52	N/A	**33.87**	N/A	15.99	N/A	9.14	N/A	5.91	N/A	0.00	N/A
Feb	0.15	N/A	0.60	N/A	0.89	N/A	13.39	N/A	**46.43**	N/A	22.02	N/A	9.97	N/A	5.65	N/A	0.89	N/A	0.00	N/A
Mar	0.13	N/A	0.13	N/A	1.61	N/A	24.46	N/A	**34.54**	N/A	16.53	N/A	11.16	N/A	9.14	N/A	2.15	N/A	0.13	N/A
Apr	5.97	N/A	6.53	N/A	8.19	N/A	19.86	N/A	**26.11**	N/A	10.56	N/A	10.83	N/A	9.72	N/A	1.67	N/A	0.56	N/A
May-05 Apr-06	0.63	N/A	1.13	N/A	2.47	N/A	14.35	N/A	**24.24**	N/A	15.25	N/A	9.88	N/A	13.63	N/A	17.32	N/A	1.10	N/A
May-06 Oct-06	N/A	1.01	N/A	2.03	N/A	12.16	N/A	**36.71**	N/A	15.50	N/A	10.28	N/A	8.66	N/A	10.31	N/A	3.10	N/A	0.25

* 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-October 2006

	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	N/A	5.82	N/A	3.90	N/A
Dec	4.32	N/A	4.93	N/A	3.86	N/A
Jan	4.09	N/A	4.40	N/A	3.83	N/A
Feb	3.90	N/A	3.99	N/A	3.81	N/A
Mar	3.93	N/A	4.49	N/A	3.39	N/A
Apr	7.00	N/A	7.59	N/A	6.61	N/A

Table A-11: Total Hourly Uplift Charge ($ Millions), May 2005-October 2006

	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	1.76	3.85	N/A	N/A	10.75	14.93	3.27	3.03	15.87	13.71
Jun	53.07	28.23	1.43	2.03	N/A	0.35	21.46	12.53	1.37	0.51	24.93	12.82
Jul	86.93	31.69	1.16	1.85	N/A	0.55	43.26	11.65	1.31	0.84	30.56	16.81
Aug	110.14	36.83	0.93	2.91	N/A	0.72	54.96	16.20	1.41	1.05	33.48	15.95
Sep	62.35	15.22	1.22	0.59	N/A	0.16	23.50	5.27	1.33	0.81	30.10	8.40
Oct	56.07	18.88	1.53	1.65	N/A	0.16	22.50	5.72	3.53	0.96	21.96	10.39
Nov	40.24	N/A	6.90	N/A	N/A	N/A	11.26	N/A	3.91	N/A	17.60	N/A
Dec	51.92	N/A	4.00	N/A	N/A	N/A	13.31	N/A	4.21	N/A	25.88	N/A
Jan	34.07	N/A	4.79	N/A	N/A	N/A	11.43	N/A	2.00	N/A	18.00	N/A
Feb	25.29	N/A	1.95	N/A	N/A	N/A	8.40	N/A	1.43	N/A	13.68	N/A
Mar	28.28	N/A	3.33	N/A	N/A	N/A	8.20	N/A	1.76	N/A	14.66	N/A
Apr	35.91	N/A	5.28	N/A	N/A	N/A	15.22	N/A	6.07	N/A	13.25	N/A

* The IOG numbers are not adjusted for IOG offsets, which was implemented in July 2002. IOG offsets are reported in Table A-15. All IOG Reversals have been applied to RT IOG.
** Numbers are adjusted for Negative Price CMSC Revision and Self-Induced CMSC Revisions for Dispatchable Loads, but not for Local Market Power adjustments. Local Market Power Adjustments are reported in Table A-19.

Table A-12: Operating Reserve MCP ($/MWh), May 2005-October 2006

	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	N/A	4.92	N/A	3.16	N/A
Dec	4.25	N/A	5.88	N/A	4.13	N/A
Jan	1.88	N/A	3.40	N/A	1.87	N/A
Feb	1.54	N/A	2.61	N/A	1.52	N/A
Mar	1.79	N/A	2.63	N/A	1.79	N/A
Apr	6.90	N/A	8.87	N/A	6.68	N/A

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

	Nuclear (Average Hourly MW)		Base-load Hydroelectric (Average Hourly MW)		Self-Scheduling (Average Hourly MW)		Lakeview (Average Hourly MW)		Ontario Demand (NDL) (Average Hourly MW)		Average HOEP ($/MWh)	
	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	7,640	8,857	1,997	1,725	783	688	0	0	13,440	13,565	40.20	33.04
Jun	8,938	9,403	1,823	1,642	806	803	0	0	15,381	14,522	42.88	33.52
Jul	9,391	10,169	1,788	1,768	760	751	0	0	15,723	15,298	48.60	35.09
Aug	9,813	10,823	1,628	1,699	747	750	0	0	15,647	14,979	51.17	36.28
Sep	9,690	9,582	1,644	1,812	594	799	0	0	14,567	13,570	57.67	25.79
Oct	8,700	8,852	1,573	1,821	684	887	0	0	13,997	13,571	47.21	30.35
Nov	9,180	N/A	1,738	N/A	734	N/A	0	N/A	14,835	N/A	42.68	N/A
Dec	9,448	N/A	1,743	N/A	683	N/A	0	N/A	16,160	N/A	66.50	N/A
Jan	9,950	N/A	1,759	N/A	679	N/A	0	N/A	15,871	N/A	46.06	N/A
Feb	10,369	N/A	1,789	N/A	755	N/A	0	N/A	16,363	N/A	41.94	N/A
Mar	10,040	N/A	1,951	N/A	848	N/A	0	N/A	15,549	N/A	40.69	N/A
Apr	9,432	N/A	1,911	N/A	667	N/A	0	N/A	13,741	N/A	28.01	N/A

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

*Table A-14: Exogenous Factors, On-Peak**

	Nuclear (Average Hourly MW)		Base-load Hydroelectric (Average Hourly MW)		Self-Scheduling (Average Hourly MW)		Lakeview (Average Hourly MW)		Ontario Demand (NDL) (Average Hourly MW)		Average HOEP ($/MWh)	
	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	7,643	8,843	2,456	2,212	918	822	0	0	16,478	16,963	62.23	55.80
Jun	8,938	9,412	2,389	2,103	920	936	0	0	20,043	18,264	82.51	55.05
Jul	9,395	10,169	2,375	2,314	869	875	0	0	20,271	20,038	95.67	61.54
Aug	9,794	10,826	2,261	2,236	895	900	0	0	20,106	19,125	114.72	64.45
Sep	9,662	9,538	2,109	2,205	748	932	0	0	18,529	16,964	119.43	42.29
Oct	8,708	8,830	1,960	2,270	833	993	0	0	17,356	16,996	96.42	47.24
Nov	9,167	N/A	2,301	N/A	915	N/A	0	N/A	18,173	N/A	69.38	N/A
Dec	9,448	N/A	2,359	N/A	837	N/A	0	N/A	19,266	N/A	89.25	N/A
Jan	9,950	N/A	2,169	N/A	843	N/A	0	N/A	19,070	N/A	62.30	N/A
Feb	10,627	N/A	2,329	N/A	900	N/A	0	N/A	19,364	N/A	52.54	N/A
Mar	10,051	N/A	2,440	N/A	987	N/A	0	N/A	18,337	N/A	54.96	N/A
Apr	9,403	N/A	2,279	N/A	798	N/A	0	N/A	16,580	N/A	54.60	N/A

* 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, May 2006-October 2006**

Delivery Date	Guaranteed Imports for Day (MWh)	IOG Payments ($ Millions)	Average IOG Payment ($/MWh)	Peak Demand in 5-minute Interval (MW)
2006/05/30	13,582	1.17	84.53	25,062
2006/08/02	9,728	0.87	89.48	27,097
2006/06/18	17,363	0.45	23.39	23,836
2006/08/01	9,940	0.36	36.17	27,288
2006/05/31	18,987	0.34	18.09	23,861
2006/08/03	12,199	0.33	27.12	24,933
2006/06/19	15,633	0.28	17.70	23,995
2006/08/07	10,689	0.27	25.57	22,954
2006/10/30	15,480	0.27	17.45	20.710
2006/06/17	15,560	0.25	15.95	21,800
	Total Top 10 days	4.59		
	Total for Period	12.98		
	% of Total Payments	35.36		

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

Table A-16: IOG Offsets due to Implied Wheeling

	IOG Offset ($'000)		IOG Offset (%)	
	2005/2006	2006/2007	2005/2006	2006/2007
May	259	39	10.14	1.01
Jun	477	158	8.97	7.66
Jul	652	63	5.52	3.39
Aug	1,118	106	5.51	3.64
Sep	844	24	11.37	4.06
Oct	716	79	8.86	4.70
Nov	836	N/A	11.20	N/A
Dec	642	N/A	7.54	N/A
Jan	258	N/A	9.74	N/A
Feb	59	N/A	3.34	N/A
Mar	68	N/A	1.85	N/A
Apr	55	N/A	3.98	N/A

Table A-17: CMSC Payments, Energy and Operating Reserve ($ Millions), May 2005-October 2006

	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	N/A	3.53	N/A	12.53	N/A	0.94	N/A	13.48	N/A
Dec	7.46	N/A	4.77	N/A	13.46	N/A	0.92	N/A	14.38	N/A
Jan	7.26	N/A	3.10	N/A	11.94	N/A	0.45	N/A	12.39	N/A
Feb	5.98	N/A	2.56	N/A	9.36	N/A	0.35	N/A	9.72	N/A
Mar	6.11	N/A	2.15	N/A	8.86	N/A	0.45	N/A	9.31	N/A
Apr	11.23	N/A	2.15	N/A	14.78	N/A	1.19	N/A	15.96	N/A
May 05 - Apr 06	163.31	N/A	82.16	N/A	260.58	N/A	6.88	N/A	267.48	N/A
May 06 - Oct 06	N/A	41.09	N/A	24.08	N/A	70.32	N/A	4.00	N/A	74.32

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

Table A-18: Share of Constrained On Payments by Import and Domestic Suppliers (%)

	Domestic		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	N/A	45	N/A
Dec	62	N/A	38	N/A
Jan	52	N/A	48	N/A
Feb	46	N/A	54	N/A
Mar	42	N/A	58	N/A
Apr	36	N/A	64	N/A

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

	Share of Total Payments Received by Top 10 Facilities		Share of Total Payments Received by Top 5 Facilities	
	Constrained Off	**Constrained On**	**Constrained Off**	**Constrained On**
May 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
May 2005 – Apr 2006	60.09	55.63	46.25	39.47
May 2006 – Oct 2006	53.46	54.08	38.82	39.27

*Table A-20: Local Market Power Investigation Statistics**

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

* Data for March, 2006 to October 2006 are presently unavailable and will be included online as part of the Errata.

Table A-21: Share of Real-time MCP Set by Resource (%), May 2005-October 2006

	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	N/A	0	N/A	12	N/A	16	N/A
Dec	61	N/A	0	N/A	23	N/A	16	N/A
Jan	84	N/A	0	N/A	6	N/A	11	N/A
Feb	85	N/A	0	N/A	4	N/A	11	N/A
Mar	73	N/A	0	N/A	9	N/A	18	N/A
Apr	65	N/A	0	N/A	8	N/A	27	N/A

Table A-22: Share of Real-time MCP Set by Resource (%), Off-Peak, May 2005-October 2006

	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	N/A	0	N/A	2	N/A	14	N/A
Dec	72	N/A	0	N/A	10	N/A	18	N/A
Jan	88	N/A	0	N/A	2	N/A	10	N/A
Feb	89	N/A	0	N/A	1	N/A	9	N/A
Mar	86	N/A	0	N/A	3	N/A	11	N/A
Apr	63	N/A	0	N/A	2	N/A	35	N/A

Table A-23: Share of Real-time MCP Set by Resource (%), On-Peak, May 2005-October 2006

	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	N/A	0	N/A	24	N/A	19	N/A
Dec	45	N/A	0	N/A	41	N/A	14	N/A
Jan	79	N/A	0	N/A	10	N/A	11	N/A
Feb	81	N/A	0	N/A	6	N/A	13	N/A
Mar	59	N/A	0	N/A	16	N/A	25	N/A
Apr	67	N/A	0	N/A	17	N/A	15	N/A

Table A-24: Resources Selected in Real-time Market Schedule (%), May 2005-October 2006

	Injections		Offtakes		Fossil-Coal		Fossil-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	N/A	9	N/A	17	N/A	6	N/A	24	N/A	52	N/A
Dec	6	N/A	7	N/A	20	N/A	6	N/A	23	N/A	51	N/A
Jan	6	N/A	9	N/A	20	N/A	5	N/A	22	N/A	53	N/A
Feb	3	N/A	8	N/A	18	N/A	5	N/A	22	N/A	54	N/A
Mar	4	N/A	9	N/A	16	N/A	6	N/A	24	N/A	54	N/A
Apr	2	N/A	11	N/A	11	N/A	6	N/A	29	N/A	54	N/A

Table A-25: Resources Selected in the Real-time Market Schedule (TWh), May 2005-October 2006

	Injections		Offtakes		Fossil-Coal		Fossil-Oil/Gas		Hydroelectric		Nuclear		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	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	N/A	1.12	N/A	2.19	N/A	0.81	N/A	3.01	N/A	6.60	N/A	12.61	N/A
Dec	0.85	N/A	1.04	N/A	2.74	N/A	0.88	N/A	3.27	N/A	7.03	N/A	13.92	N/A
Jan	0.78	N/A	1.20	N/A	2.78	N/A	0.75	N/A	3.08	N/A	7.40	N/A	14.01	N/A
Feb	0.44	N/A	1.09	N/A	2.38	N/A	0.70	N/A	2.96	N/A	7.14	N/A	13.18	N/A
Mar	0.55	N/A	1.23	N/A	2.21	N/A	0.86	N/A	3.28	N/A	7.47	N/A	13.83	N/A
Apr	0.28	N/A	1.32	N/A	1.36	N/A	0.70	N/A	3.68	N/A	6.78	N/A	12.52	N/A

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

*Table A-26: Offtakes by Intertie Zone, On-peak and Off-peak (MWh), May 2005-October 2006**

		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	16,353	32,020	280	1,217	511,177	625,542	59,461	52,405
	On-Peak	128	0	31,000	53,998	139	674	334,474	404,776	34,248	26,366
Jun	Off-peak	0	0	4,933	9,401	147	1,572	406,800	513,275	41,918	46,919
	On-Peak	184	68	36,405	45,704	610	144	229,136	274,574	27,417	22,417
Jul	Off-peak	0	628	20,219	47,172	409	7,898	505,227	606,468	41,977	47,799
	On-Peak	13	522	45,079	75,307	203	8,374	100,715	218,667	12,143	15,560
Aug	Off-peak	0	139	17,397	36,520	1,474	2,582	510,880	668,712	42,732	34,307
	On-Peak	0	147	43,185	95,408	970	1,536	183,081	355,071	28,678	15,547
Sep	Off-peak	0	1,976	4,152	14,754	1,146	1,890	602,683	441,741	54,665	48,387
	On-Peak	0	130	5,868	16,491	820	2,680	202,956	282,686	37,526	22,321
Oct	Off-peak	0	18,282	18,497	25,355	303	4,830	515,081	480,649	59,617	54,425
	On-Peak	0	7,617	19,215	38,010	187	4,816	279,983	320,902	33,938	24,960
Nov	Off-peak	0	N/A	8,845	N/A	617	N/A	583,318	N/A	58,291	N/A
	On-Peak	0	N/A	23,455	N/A	300	N/A	395,340	N/A	46,773	N/A
Dec	Off-peak	472	N/A	34,355	N/A	1,038	N/A	592,952	N/A	58,652	N/A
	On-Peak	8,543	N/A	60,676	N/A	1,100	N/A	240,503	N/A	38,591	N/A
Jan	Off-peak	0	N/A	5,791	N/A	157	N/A	596,785	N/A	54,543	N/A
	On-Peak	250	N/A	16,002	N/A	410	N/A	488,721	N/A	34,612	N/A
Feb	Off-peak	0	N/A	24,471	N/A	0	N/A	549,983	N/A	51,078	N/A
	On-Peak	74	N/A	58,541	N/A	217	N/A	366,894	N/A	34,060	N/A
Mar	Off-peak	0	N/A	19,166	N/A	118	N/A	639,453	N/A	47,787	N/A
	On-Peak	0	N/A	58,314	N/A	1,169	N/A	439,656	N/A	26,955	N/A
Apr	Off-peak	0	N/A	121,123	N/A	951	N/A	684,203	N/A	43,527	N/A
	On-Peak	26	N/A	109,300	N/A	529	N/A	347,253	N/A	12,208	N/A

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

*Table A-27: Injections by Intertie Zone, On-peak and Off-peak (MWh), May 2005-October 2006**

		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	104,990	58,600	378,392	177,291	32,738	1,217	7,500	5,681	1,237	1,375
	On-Peak	81,372	49,983	258,089	125,559	22,503	13,319	16,112	23,734	22,452	41,684
Jun	Off-peak	88,762	69,744	334,001	242,964	26,446	13,806	27,795	11,702	18,512	4,955
	On-Peak	78,517	62,192	260,234	117,616	23,022	16,031	88,336	25,129	103,591	32,336
Jul	Off-peak	106,182	98,885	307,890	139,757	27,902	23,401	27,891	21,971	48,628	41,537
	On-Peak	72,496	41,865	200,680	60,781	24,375	12,810	126,258	31,609	119,781	100,717
Aug	Off-peak	101,796	78,314	271,676	105,290	29,387	17,099	31,557	7,634	29,174	12,235
	On-Peak	84,284	34,862	227,519	41,548	28,958	11,758	96,054	27,217	41,497	69,860
Sep	Off-peak	88,172	63,741	344,228	115,209	25,782	10,561	20,300	14,375	71	286
	On-Peak	67,792	46,974	293,601	88,376	21,075	9,497	78,148	6,527	15,385	8,086
Oct	Off-peak	83,580	27,167	432,958	158,365	13,959	15,068	12,896	8,538	312	3,485
	On-Peak	60,445	5,939	329,739	92,763	11,317	7,408	33,726	10,105	14,443	28,391
Nov	Off-peak	85,779	N/A	380,087	N/A	21,538	N/A	13,853	N/A	1,721	N/A
	On-Peak	61,058	N/A	308,131	N/A	17,551	N/A	28,585	N/A	25,036	N/A
Dec	Off-peak	82,790	N/A	333,200	N/A	22,031	N/A	32,480	N/A	16,254	N/A
	On-Peak	42,343	N/A	218,732	N/A	13,178	N/A	40,094	N/A	48,801	N/A
Jan	Off-peak	82,046	N/A	356,141	N/A	20,355	N/A	4,693	N/A	1,638	N/A
	On-Peak	61,843	N/A	201,464	N/A	15,902	N/A	12,877	N/A	19,139	N/A
Feb	Off-peak	57,494	N/A	174,417	N/A	15,522	N/A	3,593	N/A	1,221	N/A
	On-Peak	46,981	N/A	104,802	N/A	12,084	N/A	11,543	N/A	15,290	N/A
Mar	Off-peak	54,587	N/A	185,629	N/A	18,839	N/A	2,472	N/A	11,333	N/A
	On-Peak	49,823	N/A	130,077	N/A	20,378	N/A	16,033	N/A	63,621	N/A
Apr	Off-peak	65,462	N/A	91,920	N/A	5,807	N/A	9,691	N/A	5,679	N/A
	On-Peak	41,490	N/A	27,208	N/A	4,713	N/A	4,524	N/A	18,658	N/A

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

Table A-28: Net Exports (MWh)

Year	Month	On-Peak	Off-Peak	Total
2003	Nov	(142,459)	(222,416)	(364,875)
	Dec	(249,784)	(97,079)	(346,863)
2004	Jan	(174,322)	(32,596)	(206,918)
	Feb	(239,477)	(66,647)	(306,124)
	Mar	(67,594)	(12,846)	(80,440)
	Apr	156,329	223,503	379,832
	May	350,620	455,317	805,937
	Jun	233,037	236,563	469,601
	Jul	276,589	266,961	543,549
	Aug	333,185	256,730	589,915
	Sep	(295,232)	(253,139)	(548,370)
	Oct	(175,493)	(221,560)	(397,053)
	Nov	(329,824)	(267,649)	(597,473)
	Dec	(139,370)	(8,289)	(147,660)
2005	Jan	25,133	45,765	70,898
	Feb	176,943	91,037	267,980
	Mar	138,751	180,724	319,475
	Apr	(207,975)	(187,057)	(395,031)
	May	(539)	62,414	61,875
	Jun	(259,946)	(41,718)	(301,664)
	Jul	(385,437)	49,339	(336,099)
	Aug	(222,398)	108,893	(113,506)
	Sep	(228,831)	184,093	(44,738)
	Oct	(116,347)	49,794	(66,553)
	Nov	25,506	148,094	173,600
	Dec	(13,734)	200,714	186,980
2006	Jan	228,771	192,403	421,174
	Feb	269,666	373,287	642,953
	Mar	246,164	433,664	679,828
	Apr	372,724	671,245	1,043,969
	May	231,286	454,918	686,204
	Jun	89,601	227,996	317,597
	Jul	70,645	384,413	455,058
	Aug	282,463	521,687	804,150
	Sep	164,847	304,576	469,423
	Oct	251,698	370,919	622,617

Table A-29: Measures of Difference between 3-Hour Ahead Pre-dispatch Prices and HOEP

	3-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	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	N/A	133.49	N/A	(107.11)	N/A	28.53	N/A	31.25	N/A
Dec	19.94	N/A	128.93	N/A	(139.24)	N/A	32.23	N/A	32.25	N/A
Jan	7.83	N/A	95.15	N/A	(55.84)	N/A	16.72	N/A	15.52	N/A
Feb	7.10	N/A	91.97	N/A	(63.38)	N/A	13.21	N/A	16.31	N/A
Mar	8.58	N/A	98.99	N/A	(76.97)	N/A	16.97	N/A	20.14	N/A
Apr	3.71	N/A	223.01	N/A	(651.03)	N/A	31.42	N/A	30.78	N/A

Table A-30: Measures of Difference between 1-Hour Ahead Pre-dispatch Prices and HOEP

	1-Hour Ahead Pre-Dispatch Price Minus HOEP ($/MWh)									
	Average Difference		Maximum Difference		Minimum Difference		Standard Deviation		Average Difference as a % of the HOEP	
	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	N/A	109.26	N/A	(95.91)	N/A	24.08	N/A	30.18	N/A
Dec	17.99	N/A	115.79	N/A	(170.48)	N/A	29.64	N/A	31.06	N/A
Jan	7.76	N/A	98.88	N/A	(54.91)	N/A	15.46	N/A	15.99	N/A
Feb	8.33	N/A	85.36	N/A	(58.70)	N/A	12.23	N/A	18.82	N/A
Mar	10.25	N/A	92.99	N/A	(89.21)	N/A	15.45	N/A	24.13	N/A
Apr	7.74	N/A	107.75	N/A	(621.55)	N/A	29.19	N/A	40.88	N/A

Table A-31: Measures of Difference between Pre-dispatch Prices and Hourly Peak MCP

	1-Hour Ahead Pre-dispatch Price Minus Hourly Peak MCP			
	Average Difference ($/MWh)		Average Difference* (% of Hourly Peak MCP)	
	2005 / 2006	2006 / 2007	2005 / 2006	2006 / 2007
May	(3.64)	4.34	3.83	15.19
Jun	(1.20)	(0.82)	7.96	2.16
Jul	(4.21)	(0.36)	8.53	4.37
Aug	(3.54)	1.08	8.87	5.10
Sep	(10.75)	(0.60)	0.59	6.41
Oct	(4.81)	0.51	8.42	8.25
Nov	1.79	N/A	10.93	N/A
Dec	(0.47)	N/A	9.53	N/A
Jan	0.29	N/A	5.24	N/A
Feb	2.98	N/A	9.29	N/A
Mar	2.31	N/A	10.98	N/A
Apr	(1.50)	N/A	20.88	N/A

* 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 ($/MWh)

	HOEP		Hourly Peak MCP		Peak minus HOEP	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	53.05	46.32	61.66	53.92	8.62	7.61
Jun	65.99	46.08	76.86	52.02	10.87	5.95
Jul	76.05	50.52	92.84	57.79	16.78	7.26
Aug	88.24	52.72	111.25	61.37	23.01	8.65
Sep	93.70	35.42	114.44	39.84	20.74	4.42
Oct	75.92	40.17	97.45	45.91	21.53	5.74
Nov	58.25	N/A	71.09	N/A	12.84	N/A
Dec	79.77	N/A	98.20	N/A	18.43	N/A
Jan	55.54	N/A	63.01	N/A	7.47	N/A
Feb	48.09	N/A	53.44	N/A	5.35	N/A
Mar	49.01	N/A	57.15	N/A	8.14	N/A
Apr	43.52	N/A	52.77	N/A	9.25	N/A

*Table A-33: Frequency Distribution of Difference Between 1-Hour Pre-dispatch and HOEP, May 2005-October 2006**

	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	1.34	**0.81**	3.23	1.21	2.55	1.21	11.69	6.18	52.82	49.33	16.94	**22.98**	11.29	**17.47**	0.13	0.81
Jun	0.42	0.14	1.53	1.94	2.50	3.06	10.83	**15.69**	42.08	53.61	22.92	16.11	19.17	9.44	0.56	0.00
Jul	2.55	0.27	3.36	1.21	2.96	2.69	12.37	13.58	32.66	51.61	13.58	17.88	**25.67**	12.37	6.85	0.40
Aug	2.55	0.54	4.44	**3.23**	4.44	**3.90**	11.69	13.17	30.91	44.49	13.17	16.26	20.97	15.32	11.83	**3.09**
Sep	**4.17**	0.28	**7.08**	1.11	**4.72**	1.81	**14.44**	12.64	26.67	**67.50**	10.69	12.78	22.50	3.89	9.72	0.00
Oct	1.75	0.00	5.91	0.94	3.76	2.83	9.41	12.26	33.74	54.72	10.08	19.27	20.56	9.84	**14.78**	0.13
Nov	1.25	N/A	2.08	N/A	2.64	N/A	9.72	N/A	37.92	N/A	15.56	N/A	23.06	N/A	7.78	N/A
Dec	2.02	N/A	2.69	N/A	3.23	N/A	8.60	N/A	33.06	N/A	13.84	N/A	22.45	N/A	14.11	N/A
Jan	0.13	N/A	1.88	N/A	3.09	N/A	12.90	N/A	54.17	N/A	15.32	N/A	9.41	N/A	3.09	N/A
Feb	0.30	N/A	1.04	N/A	0.89	N/A	6.71	N/A	**59.17**	N/A	20.12	N/A	10.73	N/A	1.04	N/A
Mar	0.40	N/A	1.88	N/A	2.28	N/A	6.05	N/A	46.37	N/A	21.24	N/A	20.03	N/A	1.75	N/A
Apr	0.97	N/A	2.50	N/A	1.67	N/A	7.22	N/A	43.06	N/A	**27.64**	N/A	16.81	N/A	0.14	N/A

* Bolded values show highest percentage within price range.

Table A-34: Difference between 1-Hour Pre-dispatch and HOEP within Defined Ranges

	1-Hour Ahead Pre-Dispatch Price Minus HOEP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	81.18	90.05	0.00	0.54	18.82	9.41
Jun	84.72	78.61	0.00	0.56	15.28	20.83
Jul	78.76	82.12	0.00	0.13	21.24	17.74
Aug	76.88	79.03	0.00	0.13	23.12	20.83
Sep	69.58	83.47	0.00	0.69	30.42	15.83
Oct	79.17	83.96	0.00	0.00	20.83	16.04
Nov	83.89	N/A	0.42	N/A	15.69	N/A
Dec	83.47	N/A	0.00	N/A	16.53	N/A
Jan	81.85	N/A	0.13	N/A	18.01	N/A
Feb	91.06	N/A	0.00	N/A	8.94	N/A
Mar	89.25	N/A	0.13	N/A	10.62	N/A
Apr	87.50	N/A	0.14	N/A	12.36	N/A

Table A-35: Difference between 1-Hour Pre-dispatch and Hourly Peak MCP within Defined Ranges

	1-Hour Ahead Pre-Dispatch Price Minus Hourly Peak MCP (% of time within range)					
	Greater than $0		Equal to $0		Less than $0	
	2005/2006	2006/2007	2005/2006	2006/2007	2005/2006	2006/2007
May	59.41	73.66	4.30	2.28	36.29	24.06
Jun	64.31	51.39	2.08	4.17	33.61	44.44
Jul	53.23	57.93	1.88	2.15	45.89	39.92
Aug	52.28	51.75	2.15	3.76	45.56	44.49
Sep	43.61	56.53	3.47	7.22	52.92	36.25
Oct	51.34	59.70	2.69	3.91	45.97	36.39
Nov	63.19	N/A	2.50	N/A	34.31	N/A
Dec	58.60	N/A	2.42	N/A	38.98	N/A
Jan	62.10	N/A	2.42	N/A	35.48	N/A
Feb	75.56	N/A	2.09	N/A	22.35	N/A
Mar	70.83	N/A	2.96	N/A	26.21	N/A
Apr	71.81	N/A	2.08	N/A	26.11	N/A

Table A-36: Percentage Intervals with Operating Reserve Reductions Due to Shortage (Market Schedule), May 2005-October 2006

	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	98.44	100.00	0.48	0.00	0.65	0.00	0.43	0.00	0.00	0.00
Jun	98.70	100.00	0.09	0.00	0.47	0.00	0.65	0.00	0.08	0.00
Jul	98.97	100.00	0.60	0.00	0.12	0.00	0.30	0.00	0.00	0.00
Aug	99.81	100.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sep	100.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oct	98.81	100.00	0.02	0.00	0.63	0.00	0.41	0.00	0.12	0.00
Nov	98.97	N/A	0.42	N/A	0.50	N/A	0.13	N/A	0.00	N/A
Dec	99.87	N/A	0.00	N/A	0.13	N/A	0.00	N/A	0.00	N/A
Jan	100.00	N/A	0.00	N/A	0.00	N/A	0.00	N/A	0.00	N/A
Feb	100.00	N/A	0.00	N/A	0.00	N/A	0.00	N/A	0.00	N/A
Mar	100.00	N/A	0.00	N/A	0.00	N/A	0.00	N/A	0.00	N/A
Apr	99.98	N/A	0.00	N/A	0.02	N/A	0.00	N/A	0.00	N/A
AVG	99.46	100.00	0.15	0.00	0.21	0.21	0.16	0.00	0.02	0.00

Table A-37: Demand Forecast Error

	Mean absolute forecast difference: pre-dispatch minus average demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus peak demand in the hour (MW)				Mean absolute forecast difference: pre-dispatch minus average demand divided by the average demand (%)				Mean absolute forecast difference: pre-dispatch minus peak demand divided by the peak demand (%)			
	3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead		3-Hour Ahead		1-Hour Ahead	
	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	2.01	2.03	1.77	1.90	1.44	1.19	1.07	0.96
Jun	530	379	466	335	363	244	259	185	2.92	2.19	2.55	1.95	1.93	1.36	1.36	1.03
Jul	573	485	466	413	424	344	288	251	3.11	2.62	2.54	2.26	2.25	1.80	1.53	1.32
Aug	418	420	368	353	315	301	224	210	2.22	2.35	1.96	2.00	1.64	1.64	1.16	1.15
Sep	325	297	280	265	248	182	190	144	1.89	1.86	1.63	1.67	1.40	1.12	1.08	0.89
Oct	270	309	245	282	203	190	156	152	1.67	1.94	1.51	1.78	1.22	1.16	0.94	0.93
Nov	347	N/A	314	N/A	209	N/A	167	N/A	2.03	N/A	1.84	N/A	1.21	N/A	0.97	N/A
Dec	360	N/A	327	N/A	224	N/A	175	N/A	1.97	N/A	1.79	N/A	1.22	N/A	0.95	N/A
Jan	381	N/A	329	N/A	256	N/A	202	N/A	2.09	N/A	1.81	N/A	1.39	N/A	1.09	N/A
Feb	352	N/A	315	N/A	222	N/A	175	N/A	1.88	N/A	1.68	N/A	1.18	N/A	0.92	N/A
Mar	315	N/A	285	N/A	189	N/A	155	N/A	1.78	N/A	1.61	N/A	1.06	N/A	0.86	N/A
Apr	296	N/A	265	N/A	187	N/A	152	N/A	1.87	N/A	1.67	N/A	1.16	N/A	0.94	N/A
AVG	373	369	328	325	256	243	193	183	2.12	2.17	1.86	1.93	1.43	1.38	1.07	1.05

*Table A-38: Percentage of Time that Mean Forecast Error (Forecast to Hourly Peak) within Defined MW Ranges (%)**

	> 500 MW		200 to 500 MW		100 to 200 MW		0 to 100 MW		0 to -100 MW		-100 to -200 MW		-200 to -500 MW		<-500 MW		>0 MW		< 0 MW	
	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	N/A	15	N/A	15	N/A	18	N/A	20	N/A	16	N/A	14	N/A	1	N/A	50	N/A	50	N/A
Dec	2	N/A	18	N/A	15	N/A	17	N/A	20	N/A	13	N/A	15	N/A	0	N/A	52	N/A	48	N/A
Jan	3	N/A	18	N/A	12	N/A	18	N/A	15	N/A	14	N/A	17	N/A	3	N/A	51	N/A	49	N/A
Feb	2	N/A	17	N/A	14	N/A	19	N/A	17	N/A	14	N/A	14	N/A	1	N/A	54	N/A	46	N/A
Mar	2	N/A	14	N/A	16	N/A	20	N/A	21	N/A	14	N/A	12	N/A	0	N/A	52	N/A	48	N/A
Apr	1	N/A	14	N/A	15	N/A	20	N/A	22	N/A	16	N/A	13	N/A	0	N/A	49	N/A	51	N/A

* This data has been revised to include dispatchable loads.

*Table A-39: Discrepancy between Self-Scheduled Generators' Offered and Delivered Quantities**

	Pre-Dispatch (MW)		Maximum Difference (MW)		Minimum Difference (MW)		Average Difference (MW)		Fail Rate (Difference/MW Pre-dispatch) (%)	
	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	187.12	292.03	(61.18)	(68.46)	20.11	30.84	2.18	3.08
Jun	724,804	737,975	242.51	188.82	(43.18)	(99.27)	49.68	41.24	4.67	4.44
Jul	701,810	722,572	244.28	239.22	(70.56)	(100.69)	55.18	59.15	6.06	6.43
Aug	667,215	709,496	200.67	206.10	(167.25)	(55.05)	15.43	46.28	1.37	5.56
Sep	543,183	727,818	258.62	250.61	(62.01)	(136.35)	22.42	41.04	3.22	4.82
Oct	629,537	827,835	170.60	164.67	(275.80)	(136.82)	(1.27)	21.46	(0.12)	2.05
Nov	670,401	N/A	184.95	N/A	(164.43)	N/A	1.83	N/A	(0.26)	N/A
Dec	638,461	N/A	233.19	N/A	(108.64)	N/A	1.98	N/A	0.43	N/A
Jan	645,993	N/A	141.63	N/A	(81.23)	N/A	11.80	N/A	1.66	N/A
Feb	618,271	N/A	134.26	N/A	(89.06)	N/A	8.24	N/A	1.08	N/A
Mar	767,993	N/A	131.56	N/A	(102.08)	N/A	(2.59)	N/A	(0.22)	N/A
Apr	636,415	N/A	175.08	N/A	(126.48)	N/A	15.39	N/A	2.66	N/A
AVG	663,856	735,745	192.04	223.58	(112.66)	(99.44)	16.52	40.00	1.89	4.40

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

Table A-40: Discrepancy between Wind Generators' Offered and Delivered Quantities

	Pre-Dispatch (MW)	Maximum Difference (MW)	Minimum Difference (MW)	Average Difference (MW)	Fail Rate (Difference/MW Pre-dispatch) (%)
	2006	2006	2006	2006	2006
Feb	1,762	10.80	0.76	6.57	92.62
Mar	22,169	52.67	(45.54)	5.94	24.78
Apr	20,577	69.75	(58.15)	1.92	0.27
May	19,781	76.33	(62.72)	1.79	2.30
Jun	24,730	93.48	(124.68)	3.52	8.44
Jul	28,632	75.63	(97.79)	3.32	8.28
Aug	27,434	89.88	(91.48)	7.94	25.77
Sep	53.686	130.13	(115.10)	9.79	19.54
Oct	83,010	96.06	(116.20)	9.53	12.24
AVG	25,350	77.19	(78.99)	5.59	21.58

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

	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	6.07	3.10
Jun	348	187	916	848	190	153	5.94	4.58
Jul	349	207	1,110	1,020	192	123	5.95	4.25
Aug	301	171	1,025	405	188	113	5.70	4.53
Sep	316	54	885	300	173	76	5.43	1.12
Oct	335	109	810	240	134	69	4.33	2.08
Nov	273	N/A	539	N/A	112	N/A	3.15	N/A
Dec	293	N/A	667	N/A	141	N/A	4.64	N/A
Jan	212	N/A	910	N/A	126	N/A	3.32	N/A
Feb	211	N/A	525	N/A	107	N/A	4.85	N/A
Mar	174	N/A	405	N/A	102	N/A	3.13	N/A
Apr	84	N/A	421	N/A	104	N/A	3.10	N/A

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

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

	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	4.78	3.10
Jun	184	78	916	490	177	132	5.57	3.91
Jul	171	115	1,110	587	219	107	6.47	4.75
Aug	161	72	1,025	405	202	91	6.42	3.43
Sep	164	20	885	300	162	99	5.29	1.22
Oct	138	60	466	240	129	74	3.83	3.01
Nov	134	N/A	539	N/A	110	N/A	3.25	N/A
Dec	139	N/A	550	N/A	124	N/A	4.54	N/A
Jan	71	N/A	910	N/A	143	N/A	3.16	N/A
Feb	90	N/A	525	N/A	99	N/A	4.47	N/A
Mar	69	N/A	300	N/A	86	N/A	2.07	N/A
Apr	30	N/A	223	N/A	68	N/A	2.08	N/A

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

Table A-43: Incidents and Average Magnitude of Failed Imports into Ontario, Off-Peak*

	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	7.03	3.10
Jun	164	109	672	848	205	168	6.35	5.07
Jul	178	92	771	1,020	166	143	5.40	3.87
Aug	140	99	777	385	172	128	4.95	5.43
Sep	152	34	700	200	185	63	5.56	1. 04
Oct	197	49	810	191	137	63	4.74	1.44
Nov	139	N/A	422	N/A	114	N/A	3.06	N/A
Dec	154	N/A	667	N/A	156	N/A	4.72	N/A
Jan	141	N/A	492	N/A	117	N/A	3.43	N/A
Feb	121	N/A	505	N/A	113	N/A	5.13	N/A
Mar	105	N/A	405	N/A	113	N/A	4.18	N/A
Apr	54	N/A	421	N/A	125	N/A	3.64	N/A

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

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

	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	11.55	13.03
Jun	457	324	1,128	817	238	176	12.71	5.87
Jul	337	354	1,350	850	275	201	11.34	6.47
Aug	368	399	1,478	914	226	187	9.16	5.80
Sep	341	422	1,000	788	241	192	8.28	8.88
Oct	477	412	1,188	874	231	185	10.63	7.25
Nov	503	N/A	850	N/A	224	N/A	9.17	N/A
Dec	461	N/A	1,098	N/A	221	N/A	8.95	N/A
Jan	543	N/A	1,132	N/A	216	N/A	8.92	N/A
Feb	541	N/A	1,190	N/A	282	N/A	12.33	N/A
Mar	527	N/A	975	N/A	260	N/A	10.02	N/A
Apr	543	N/A	1,000	N/A	291	N/A	10.68	N/A

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

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

	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	8.85	11.18
Jun	187	123	800	785	198	153	11.20	5.19
Jul	102	126	1,180	850	224	193	12.64	7.09
Aug	143	161	815	914	191	215	9.65	6.89
Sep	125	148	716	644	164	163	7.65	6.92
Oct	180	144	600	874	144	162	7.23	5.56
Nov	185	N/A	619	N/A	160	N/A	5.97	N/A
Dec	165	N/A	1,057	N/A	173	N/A	7.54	N/A
Jan	242	N/A	805	N/A	169	N/A	7.06	N/A
Feb	261	N/A	1,190	N/A	258	N/A	12.75	N/A
Mar	225	N/A	775	N/A	209	N/A	8.19	N/A
Apr	201	N/A	836	N/A	245	N/A	9.50	N/A

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

*Table A-46: Incidents and Average Magnitude of Failed Exports from Ontario, Off-Peak**

	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	13.30	14.26
Jun	270	201	1,128	817	266	190	13.66	6.27
Jul	235	228	1,350	749	298	205	10.97	6.19
Aug	225	238	1,478	709	249	167	8.94	5.09
Sep	216	274	1,000	788	285	208	8.51	10.08
Oct	297	268	1,188	710	284	198	12.43	8.36
Nov	318	N/A	850	N/A	262	N/A	11.33	N/A
Dec	296	N/A	1,098	N/A	248	N/A	9.65	N/A
Jan	301	N/A	1,132	N/A	253	N/A	10.40	N/A
Feb	280	N/A	950	N/A	304	N/A	12.01	N/A
Mar	302	N/A	975	N/A	299	N/A	11.33	N/A
Apr	342	N/A	1,000	N/A	317	N/A	11.32	N/A

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

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

	Dispatchable Load (% of Total Requirement)		Hydroelectric (% of Total Requirement)		CAOR (% of Total Requirement)		Fossil (% of Total Requirement)		Import (% of Total Requirement)		Export (% of Total Requirement)		Total (Average Hourly Value MW)	
	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	30.09	21.51	61.38	68.38	0.26	0.15	7.82	7.84	0.25	0.39	0.20	1.55	1,413	1,487
Jun	32.08	21.56	61.76	67.95	0.01	0.00	5.92	6.43	0.12	0.23	0.10	3.83	1,418	1,435
Jul	25.20	22.29	68.79	65.06	0.00	0.16	5.35	8.40	0.62	0.26	0.05	3.83	1,410	1,368
Aug	18.83	17.42	75.24	71.92	0.00	0.00	5.52	7.11	0.41	0.18	0.00	3.37	1,395	1,370
Sep	18.56	19.45	74.65	70.04	0.00	0.00	6.67	6.74	0.12	0.00	0.00	3.77	1,399	1,367
Oct	15.00	17.65	78.94	69.02	0.02	0.00	4.97	6.89	0.00	0.03	1.07	4.52	1,460	1,368
Nov	20.27	N/A	74.56	N/A	0.00	N/A	4.95	N/A	0.00	N/A	0.21	N/A	1,430	N/A
Dec	18.74	N/A	74.37	N/A	0.31	N/A	4.85	N/A	0.00	N/A	1.62	N/A	1,430	N/A
Jan	22.10	N/A	73.33	N/A	0.00	N/A	4.34	N/A	0.00	N/A	0.10	N/A	1,375	N/A
Feb	23.53	N/A	72.02	N/A	0.06	N/A	4.16	N/A	0.00	N/A	0.06	N/A	1,368	N/A
Mar	23.57	N/A	70.63	N/A	0.11	N/A	5.50	N/A	0.00	N/A	0.00	N/A	1,368	N/A
Apr	25.05	N/A	61.29	N/A	0.73	N/A	11.37	N/A	0.28	N/A	1.19	N/A	1,367	N/A

Table A-48: Shares by Fuel Type of Total Operating Reserve Requirements, On-Peak Periods

	Dispatchable Load (% of Total Requirement)		Hydroelectric (% of Total Requirement)		CAOR (% of Total Requirement)		Fossil (% of Total Requirement)		Import (% of Total Requirement)		Export (% of Total Requirement)		Total (Average Hourly Value MW)	
	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	23.63	23.87	64.31	61.74	0.85	0.86	7.15	6.69	2.14	1.64	1.92	4.81	1,413	1,366
Jun	24.56	22.34	68.66	66.99	0.16	0.00	5.05	5.41	1.01	2.42	0.54	2.83	1,395	1,368
Jul	19.49	24.04	73.47	65.76	0.14	0.04	4.82	6.28	1.65	1.83	0.42	2.05	1,402	1,370
Aug	18.56	17.09	76.07	74.37	0.14	0.31	4.25	5.79	0.30	0.44	0.67	1.99	1,387	1,380
Sep	19.70	20.41	75.11	71.78	0.05	0.00	4.79	4.67	0.10	0.39	0.24	2.75	1,398	1,367
Oct	16.17	18.35	75.90	71.23	0.42	0.02	5.71	5.10	0.17	1.29	1.60	2.85	1,463	1,384
Nov	19.31	N/A	68.53	N/A	0.79	N/A	7.95	N/A	0.06	N/A	3.29	N/A	1,524	N/A
Dec	19.98	N/A	65.23	N/A	1.37	N/A	8.09	N/A	0.62	N/A	4.22	N/A	1,430	N/A
Jan	22.44	N/A	65.61	N/A	0.35	N/A	4.88	N/A	2.65	N/A	3.90	N/A	1,370	N/A
Feb	23.40	N/A	59.40	N/A	0.24	N/A	5.36	N/A	7.02	N/A	4.37	N/A	1,367	N/A
Mar	22.99	N/A	61.94	N/A	0.30	N/A	6.69	N/A	3.09	N/A	4.64	N/A	1,368	N/A
Apr	25.15	N/A	49.61	N/A	1.21	N/A	20.40	N/A	0.84	N/A	2.49	N/A	1,367	N/A

Table A-49: Day Ahead Forecast Error (as of Hour 18)

Year	Month	Average Forecast Error (MW)	Average Absolute Error (% of Peak Demand)	No. of Hours with Forecast Error ≥ 3%	Percentage of Hours with Absolute Error ≥ 3%
2003	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	151.0	20
	Jun	(100)	2.91	279.0	39
	Jul	178	3.02	317.0	43
	Aug	26	2.55	258.0	35
	Sep	101	1.70	127.0	18
	Oct	6	1.60	94.0	13

Table A-50: Average One Hour Ahead Forecast Error

Year	Month	Peak Forecast Error (MW)	Average Absolute Error (% of Peak Demand)	No. of Hours with Forecast Error ≥ 2%	Percentage of Hours with Absolute Error ≥ 2%
2003	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

Table A-51: Low Price Hours

Delivery Date	Delivery Hour	Net Failed Export (MW)	RT Demand (MW)	PD Demand (MW)	HOEP ($/MWh)	PD Price ($/MWh)
2006/05/02	2	650	12,330	12,365	15.41	29.89
2006/05/02	3	526	12,202	12,279	15.39	29.55
2006/05/07	4	500	11,733	11,612	7.88	32.62
2006/05/07	5	550	11,857	11,883	4.70	32.62
2006/05/07	22	705	14,541	15,152	13.51	39.53
2006/05/07	24	150	12,738	13,159	13.68	33.36
2006/05/14	3	516	11,274	11,167	18.24	32.63
2006/05/14	6	350	11,272	11,532	4.52	32.82
2006/05/17	2	1,136	12,583	12,819	10.17	29.04
2006/05/19	3	484	12,248	12,431	5.94	24.31
2006/05/19	4	300	12,360	12,596	19.93	24.92
2006/05/21	7	487	12,316	12,616	19.93	34.00
2006/05/24	4	565	12,604	12,842	7.49	28.05
2006/05/27	7	33	13,149	13,936	15.55	29.60
2006/05/28	7	559	12,344	12,964	15.53	31.31
2006/05/28	8	436	13,463	14,257	19.22	33.48
2006/05/29	4	847	13,101	12,896	13.41	29.39
May 2006	17	517	12,477	12,736	12.97	31.01
2006/06/04	6	236	11,654	11,760	15.25	26.99
2006/06/04	7	495	12,262	12,540	8.12	20.01
2006/06/05	6	0	14,074	15,055	16.04	30.35
2006/06/06	2	300	13,344	13,611	19.90	24.48
2006/06/06	4	25	13,041	13,442	14.46	22.27
2006/06/07	2	460	13,397	13,434	11.68	28.05
2006/06/07	5	0	13,376	13,984	18.85	28.50
2006/06/09	2	240	13,453	13,738	15.63	29.80
2006/06/11	3	300	11,554	11,627	19.34	26.66
2006/06/11	5	260	11,390	11,427	4.57	19.09
2006/06/11	6	46	11,505	11,756	6.32	24.00
2006/06/14	5	233	13,268	13,527	18.65	29.50
2006/06/30	3	110	12,736	13,017	13.80	25.75
2006/06/30	4	510	12,725	12,771	16.67	26.93
Jun 2006	14	230	12,699	12,978	14.23	25.88
2006/07/01	4	25	12,212	12,341	18.42	24.00
2006/07/01	5	1	12,127	12,192	19.84	23.00
2006/07/01	6	(362)	12,176	12,875	12.64	24.92
2006/07/02	2	350	13,526	13,507	19.31	25.25
2006/07/02	4	400	13,078	12,824	17.12	19.99
2006/07/02	5	396	12,854	12,851	10.27	20.00
2006/07/02	6	200	12,898	13,225	8.82	23.72
2006/07/02	7	310	13,778	14,142	19.28	27.72
2006/07/05	6	(210)	14,074	15,288	19.17	29.46
2006/07/06	2	202	12,768	12,956	19.81	22.31
2006/07/06	3	0	12,543	12,498	19.18	19.08
2006/07/06	4	175	12,558	12,474	19.69	20.34
2006/07/06	5	(100)	12,774	13,211	13.86	25.05
2006/07/07	4	350	12,700	12,622	18.57	20.83
2006/07/07	5	325	12,973	13,223	7.54	25.42

2006/07/08	3	400	12,786	12,863	19.54	21.79
2006/07/08	4	200	12,607	12,661	19.97	21.04
2006/07/08	5	125	12,440	12,585	17.61	21.12
2006/07/08	6	672	12,681	13,154	9.69	25.05
2006/07/08	7	185	13,608	14,196	19.76	28.19
2006/07/09	3	0	12,603	12,867	16.28	19.88
2006/07/09	4	150	12,413	12,320	13.42	17.00
2006/07/09	5	136	12,292	12,268	13.09	15.29
2006/07/09	6	275	12,260	12,534	5.63	20.00
2006/07/09	7	(100)	12,986	13,517	15.07	26.53
2006/07/11	2	85	13,271	13,565	17.80	25.33
2006/07/11	3	73	12,935	13,143	15.40	20.44
2006/07/11	5	0	13,269	13,736	12.30	25.34
2006/07/11	6	40	14,255	15,137	11.58	27.20
2006/07/23	6	197	12,076	12,513	16.25	23.05
Jul 2006	30	150	12,851	13,110	15.56	22.94
2006/08/13	6	200	12,033	12,246	6.43	27.00
2006/08/13	7	200	12,526	12,890	11.91	27.99
2006/08/31	1	321	13,642	13,891	19.25	27.16
2006/08/31	3	0	12,961	12,903	19.15	19.41
Aug 2006	4	180	12,790	12,982	14.19	25.39
2006/09/01	1	225	13,583	13,720	18.42	26.80
2006/09/01	2	88	13,078	13,164	6.44	20.85
2006/09/01	3	43	12,866	12,831	14.98	20.59
2006/09/01	4	0	12,863	12,805	4.79	22.00
2006/09/02	1	300	13,067	12,859	19.41	24.25
2006/09/02	2	300	12,665	12,467	16.77	20.63
2006/09/02	3	301	12,424	12,178	10.69	12.35
2006/09/03	2	0	11,959	11,990	9.01	4.00
2006/09/03	3	17	11,717	11,716	3.95	4.30
2006/09/03	4	200	11,684	11,604	2.10	4.20
2006/09/03	5	400	11,691	11,612	(3.10)	4.10
2006/09/03	6	278	11,892	11,876	2.41	4.60
2006/09/03	7	200	12,190	12,689	0.69	23.05
2006/09/03	8	100	13,105	13,473	5.71	18.77
2006/09/03	15	500	14,659	14,895	17.46	26.77
2006/09/03	16	487	14,747	15,087	16.34	26.92
2006/09/03	18	244	14,693	14,729	14.25	24.69
2006/09/03	19	179	14,647	14,841	17.07	25.88
2006/09/03	22	364	14,126	14,625	11.98	28.25
2006/09/03	23	439	13,290	13,906	4.53	27.66
2006/09/03	24	57	12,610	13,022	5.03	15.80
2006/09/04	1	386	12,027	12,267	10.03	27.85
2006/09/04	2	7	11,705	11,940	15.33	24.99
2006/09/04	4	0	11,455	11,409	19.68	17.59
2006/09/04	5	0	11,555	11,676	14.22	13.72
2006/09/04	6	0	11,769	11,857	17.87	20.88
2006/09/05	3	425	12,343	12,392	11.74	20.69
2006/09/05	4	425	12,461	12,691	5.15	20.29
2006/09/05	5	350	13,024	13,575	15.40	22.96
2006/09/09	2	175	13,135	13,301	10.17	24.02
2006/09/09	3	250	12,847	12,894	8.03	22.40

2006/09/09	4	175	12,722	12,663	13.04	13.70
2006/09/09	5	125	12,836	12,853	18.57	24.20
2006/09/09	6	282	13,262	13,512	18.23	26.66
2006/09/10	2	173	11,876	12,011	5.25	25.72
2006/09/10	3	350	11,721	11,759	1.42	23.54
2006/09/10	4	100	11,595	11,650	10.86	25.36
2006/09/10	7	0	12,287	12,735	6.58	26.40
2006/09/17	1	230	12,398	12,372	18.97	22.24
2006/09/17	2	350	11,921	11,957	18.74	22.03
2006/09/17	3	284	11,732	11,711	13.64	20.91
2006/09/17	4	200	11,715	11,573	15.62	10.98
2006/09/17	5	354	11,777	11,586	9.21	15.00
2006/09/17	6	350	12,052	11,851	7.39	22.00
2006/09/17	7	63	12,380	12,332	13.81	10.00
2006/09/20	3	200	12,471	12,794	15.80	26.75
2006/09/25	23	644	14,270	15,203	19.61	30.91
2006/09/26	1	178	12,842	12,881	11.72	24.23
2006/09/26	2	200	12,549	12,362	7.99	4.90
2006/09/26	3	90	12,451	12,386	15.15	5.00
2006/09/26	4	472	12,497	12,686	5.03	12.23
2006/09/26	5	300	13,011	13,633	10.24	26.83
2006/09/26	24	(22)	13,328	13,752	18.06	26.76
2006/09/27	1	70	13,029	12,890	19.78	20.55
2006/09/27	2	(43)	12,642	12,675	18.46	18.27
2006/09/27	3	632	12,419	12,319	5.42	14.00
2006/09/27	4	398	12,524	12,640	5.03	21.00
2006/09/29	3	0	12,542	12,708	8.05	24.76
2006/09/29	24	160	13,191	13,649	18.56	28.21
2006/09/30	3	150	12,144	12,106	17.42	24.96
2006/09/30	4	0	12,146	12,220	14.28	22.28
2006/09/30	5	150	12,290	12,413	6.06	24.69
2006/09/30	24	100	12,588	13,100	10.88	26.45
Sep 2006	63	214	12,620	12,747	11.51	20.21
2006/10/01	1	350	12,091	12,449	2.51	25.2
2006/10/01	2	100	11,794	12,068	4.66	25
2006/10/01	3	173	11,634	11,679	16.1	25
2006/10/02	4	390	12,274	12,479	9.58	26.84
2006/10/02	24	218	13,308	13,827	19.98	27.39
2006/10/03	2	554	12,435	12,654	4.54	25.15
2006/10/03	3	305	12,282	12,166	6.7	15.3
2006/10/03	4	50	12,346	12,168	18.06	12
2006/10/05	2	150	12,563	12,650	17.88	26.32
2006/10/05	3	235	12,425	12,592	10.22	20
2006/10/07	23	710	13,250	13,425	16.19	29.03
2006/10/08	1	200	11,940	12,264	17.23	27.7
2006/10/08	3	502	11,480	11,496	8.83	23
2006/10/08	4	448	11,474	11,413	10.43	22.79
2006/10/08	5	200	11,621	11,848	10.6	23.71
2006/10/08	6	166	11,910	12,219	17.67	28.05
2006/10/08	7	350	12,363	12,919	14.92	29.77
2006/10/09	2	22	11,243	11,405	19.29	26.88
2006/10/09	3	250	11,118	11,285	4.89	25
2006/10/22	3	0	12,273	12,401	17.6	17.7

2006/10/22	4	15	12,088	12,229	13.1	15.5
Oct 2006	21	257	12,091	12,268	12.43	23.68