
Monthly Market Report
August 2006
ieso
Power to Ontario.
On Demand.

Table of Contents

List of Figures

This report provides a summary of key market data from the IESO-administered markets. It is intended to provide a quick reference for all market stakeholders. In all cases, the data used to produce all graphs in this report, are available for download from the Market Summaries page of the IESO Web site. Any data used in this report is provided for information purposes only, and should not be used for settlement purposes.

1. Market Prices

1.1 Introduction

This section provides information on several of the key prices in the Ontario wholesale electricity market. A brief description of each displayed price item is included. For more information on any of the price items, please refer to appropriate market rules, market manuals and IESO Marketplace Training materials, or contact the IESO Customer Relations.

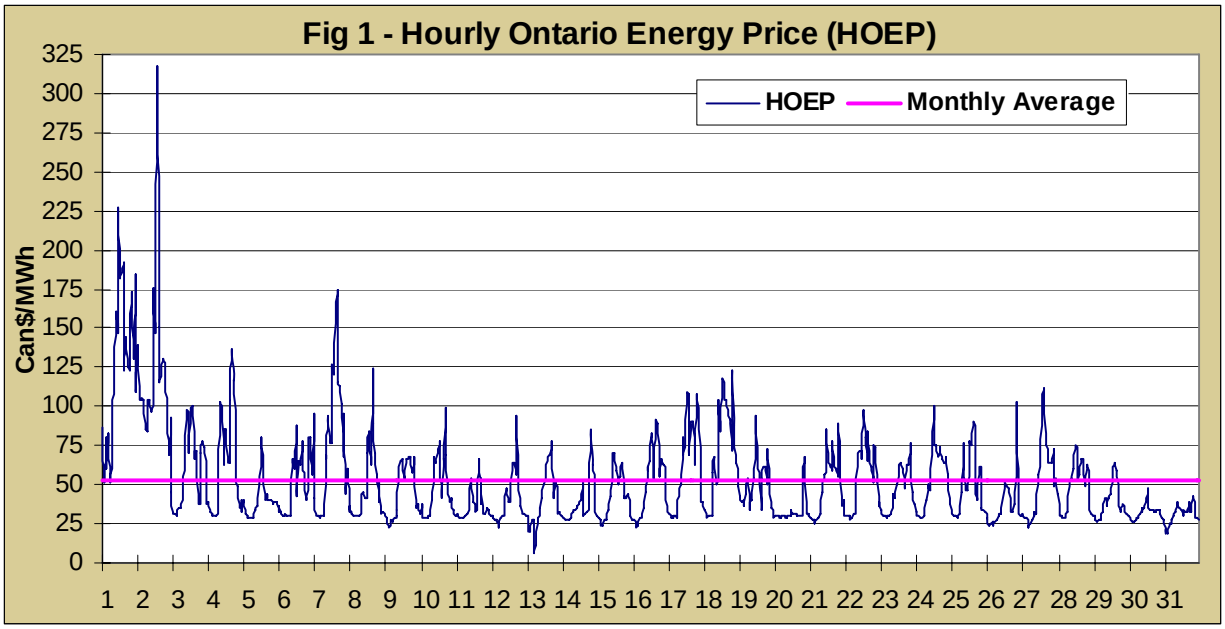
1.2 Hourly Ontario Energy Price (HOEP)

HOEP is the hourly price that is charged to Local Distributing Companies and other non-dispatchable loads. HOEP is also paid to self-scheduling generators. HOEP becomes the basis of the commodity charges in the Retail electricity market if customers receive their electricity from their Local Distributing Company. Customers who have arranged contracts with licensed Retailers are not affected by HOEP, but instead are charged their particular contract rate for the commodity.

Note: The IESO provides a convenient graph of HOEP prices for the current and previous day on the Today's Market page on the IESO Web site. These graphs also provide an estimate of future HOEP prices for the remainder of the day, and by afternoon, estimates for the next day. The estimates for future Hourly Ontario Energy Prices are extracted from an IESO report referred to as the pre-dispatch. Pre-dispatch data is updated every hour. All future prices are derived by simulating a supply/demand balance, using prices offered by suppliers in the market, prices bid by price-sensitive consumers in the market, and the IESO's forecast of the total demand for electricity in the province. The actual supply/demand balance can vary from these projections for a number of reasons:

- The actual demand for electricity can fluctuate as factors such as weather, (temperature, amount of cloud cover, wind etc.), affect the amount of electricity required by consumers.
- At the same time, operational difficulties or delays in a generation unit returning from an outage can result in higher priced generation being called on to fill the gap.
- Finally, any changes in price resulting from such variations can cause some price-sensitive loads to make alternative consumption decisions, or cause importers and exporters to revise their plans.

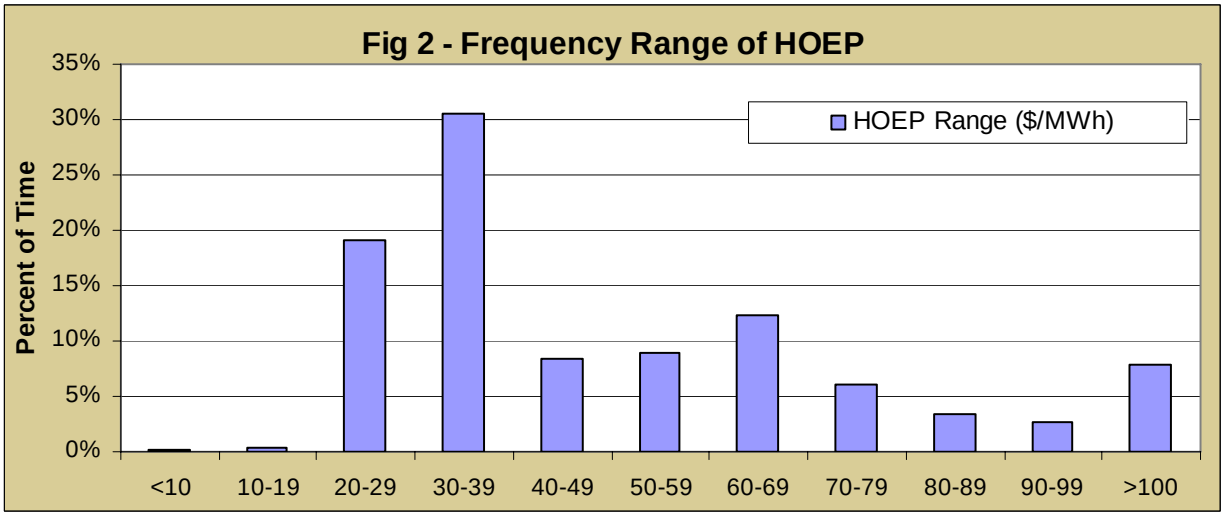
In this report, two graphs of HOEP are provided; the first shows a chronological graph of hourly HOEP prices for the month. The second graph shows the frequency at which the HOEP fell within specific price bands.



Hourly Ontario Energy Price $/MWh			
	For the month	On-Peak	Off-Peak
Average	52.72	65.05	41.64
Maximum	317.76	317.76	173.48
Minimum	6.43	28.97	6.43

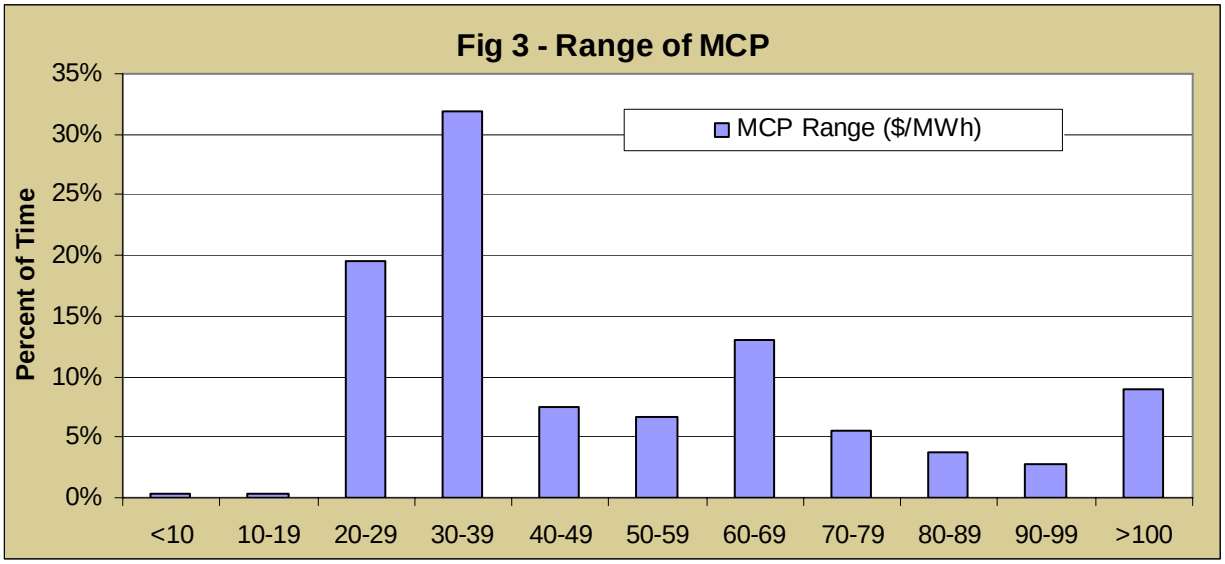
Monthly Weighted Average based on Ontario Demand = $56.67 / MWh or 5.67 ¢/kWh.
This weighted average is provided as information, and may be of use to customers whose consumption pattern, or that of their local distributing company, approximates that of the total Ontario system.

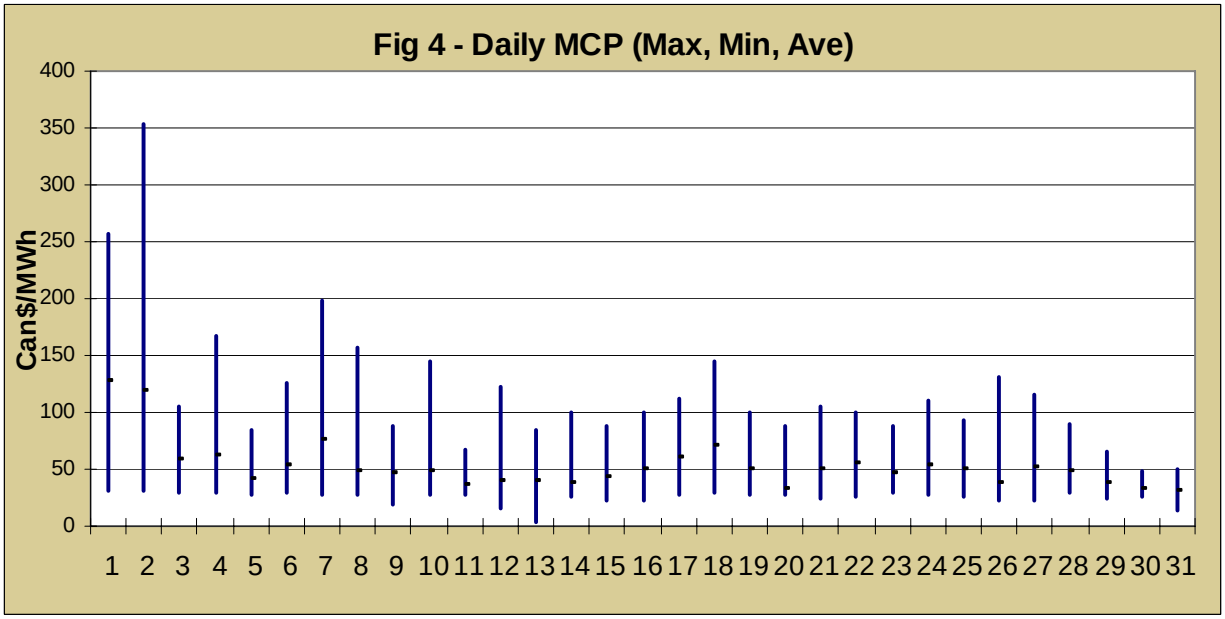
Note: On Peak average price is the straight arithmetic average of HOEP in hours 8 to 23 (EST), Monday to Friday (5 x 16). Off Peak average price is the straight arithmetic average of HOEP for all remaining hours in the week. August 7 was considered as 24 off-peak hours, in recognition of the Civic Holiday statutory holiday. The wholesale market does not use a formal definition of on and off-peak hours. The IESO is providing this calculation purely for information purposes, and will continue to use this definition throughout the year.



1.3 Ontario 5-Minute Market Clearing Price (MCP)

The Ontario 5-minute MCP is the price paid to dispatchable generators and charged to dispatchable loads. All other participants are charged or paid using hourly prices. The 5-minute price is calculated immediately after the fact for every 5-minute interval, using the unconstrained dispatch algorithm. The algorithm takes generator offers to sell and price-sensitive loads' bids to buy and dispatches these resources to achieve a supply-demand balance, and resulting price. The price is posted on the Market Data page on the IESO Web site, within 5-minutes of the conclusion of an interval. The 5-minute price, by its nature, will fluctuate more than the HOEP (an arithmetic average of the 12 MCPs for any particular hour), as it more directly reflects the short-term supply/demand variations caused by unexpected fluctuations in the demand for electricity or by equipment breakdowns.



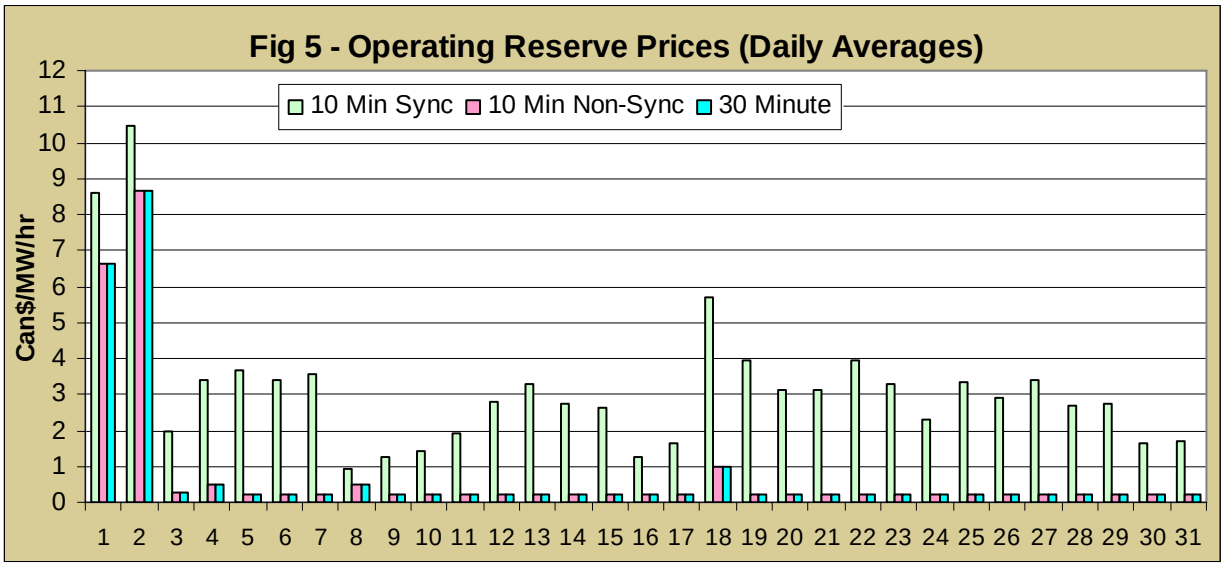


1.4 Operating Reserve Prices

Operating Reserve is generation capacity or load reduction capacity that the IESO can call upon on short notice. Operating Reserve is purchased by the IESO in amounts needed to meet the reliability rules established by the North American Electricity Reliability Council (NERC), and the Northeast Power Coordinating Council (NPCC). The IESO recovers the required funds to pay for the purchased operating reserve from all customers in the wholesale market, via the Hourly Uplift Settlement Charges. These Charges are discussed further and presented in Section 1.5 of this report.

The IESO purchases defined amounts of Operating Reserve from Participants via three real-time markets; a 10 minute synchronized reserve market, a 10 minute non-synchronized reserve market, and a 30-minute reserve market.

The operating reserve is like a buffer - a shock absorber to maintain the reliability of the system by allowing for sudden unexpected surges in demand or unanticipated reductions in supply - that is, in available generation. Like energy dispatch instructions, Operating Reserve schedules are determined every 5 minutes, with a resultant price for each type of operating reserve for every 5-minute interval. The IESO's decisions, on who will provide the market with operating reserve, and who will supply the market with energy, are integrated to arrive at the optimum market outcome. This creates a strong correlation between the energy price fluctuations and the fluctuations in reserve prices.



Average Operating Reserve Prices for this month were:

10 minute synchronized reserve:	$3.19/MW/hr
10 minute non-synchronized reserve:	$0.73/MW/hr
30 minute reserve:	$0.73/MW/hr

1.5 Hourly Uplift Settlement Charges

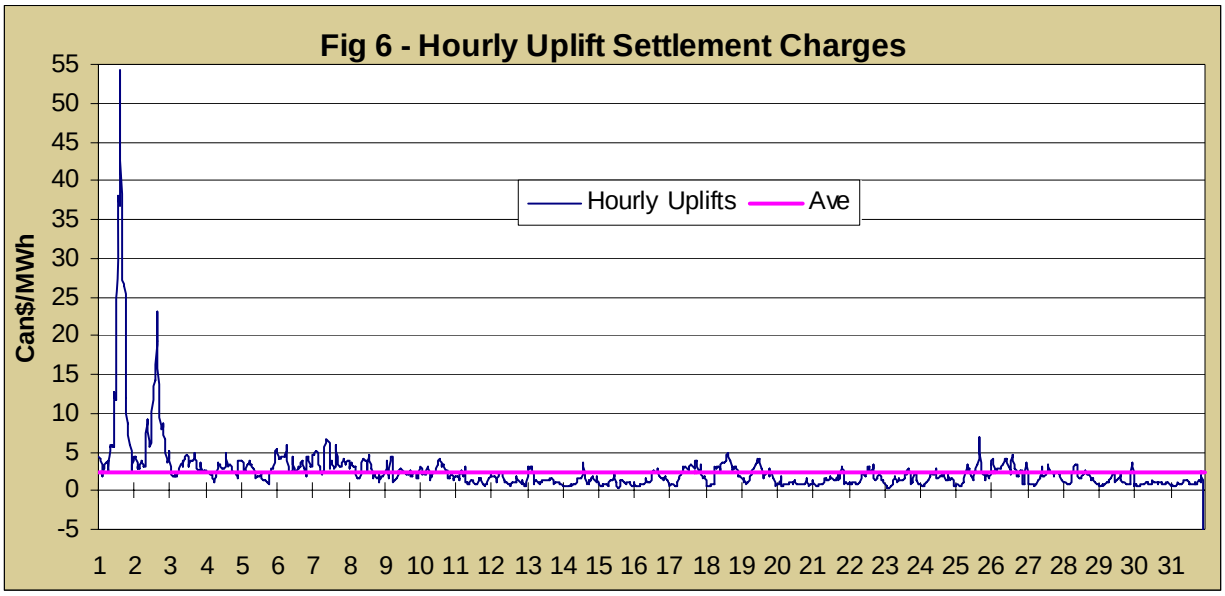
Hourly Uplift Settlement Charges are applied to all customers in the wholesale market. The IESO uses funds collected under these charges to pay for such items as the three types of Operating Reserve, any Congestion Management Settlement Credits owed to dispatchable resources, Intertie Offer Guarantee payments and other incurred hourly costs such as energy losses on the IESO-controlled grid.

For a description of Operating Reserve, and information on Operating Reserve prices, please see Section 1.4 above.

Congestion Management Settlement Credits are payments made by the IESO to all dispatchable resources, such as generators or large consumers, who responded to instructions from the IESO to take specific actions to avoid possible overloads of the transmission system, or to maintain the balance between supply and demand.

Energy losses occur when electricity flows across transmission lines. The resistance in the lines causes them to heat up, consuming power in the same way, as does the filament in a toaster. This is referred to as line losses. Since the IESO pays generators using the same price as it uses to charges customers, and since the presence of line losses requires generators to produce more than what is consumed by customers, the IESO must recoup the additional money required to pay all generators in full, and does so via the Hourly Uplift Settlement Charge.

The information on Hourly Uplift Settlement Charges graph shown below is collected from Market Participant Settlement Statements.



Average Hourly Uplift Settlement Charges to wholesale customers for this month = $2.33 / MWh or 0.23 ¢/kWh
Average Hourly Uplift Settlement Charges to wholesale customers since May 1, 2006 = $2.25 / MWh or 0.23 ¢/kWh
Weighted Average Hourly Uplift Settlement Charges to wholesale customers for this month = $2.57 / MWh or 0.26 ¢/kWh
Weighted Average Hourly Uplift Settlement Charges to wholesale customers since May 1, 2006 = $2.41 / MWh or 0.24 ¢/kWh

Note: The above averages exclude the Local Market Power Rebates.

1.6 Monthly Uplift Charges

The IESO incurs some monthly costs in purchasing services required to ensure the reliability of the Ontario power network, and to meet commitments to other system operators throughout North America. Specifically, there are three services that the IESO must purchase under contract from suppliers; Black Start Capability, Voltage Support, and Regulation Service. The monthly costs incurred by the IESO under these contracts are shared among all wholesale customers on a pro rata basis. This month, the payments made by the IESO for these services resulted in charges to wholesale customers totalling $0.41/MWh, or 0.041 ¢/kWh. In addition, there are a few more monthly uplift charges, which occur occasionally (i.e. Emergency Energy purchase and EDRP costs, Hour Ahead Dispatchable Load Offer Guarantee, etc.). This monthly total is contained in Section 8.

1.7 Transmission Rights Auction

The Transmission Rights Market is a financial market that is based on the import and export of electricity on the interconnection lines between Ontario and its surrounding markets in Manitoba, Quebec, New York, Michigan and Minnesota. The transmission capacity of these interconnections is limited. When the interconnection lines reach their limits, energy prices can differ between Ontario and its surrounding markets. The Transmission Rights Market allows participants to buy financial protection ahead of time, to hedge against the possible price differences. These transmission rights are financial only. They do not give the holder of these rights any scheduling priority and do not limit other participants' access to physical transmission across the interconnection lines.

The Transmission Rights contracts are auctioned off by the IESO. Successful bidders pay the market clearing price for the particular Transmission Right, in return for the right to receive revenues from the IESO in amounts proportional to the financial congestion which may occur over that interface for the duration of the contract.

This month, the IESO conducted one transmission rights auction. The market clearing prices in the auction are listed in the table below. The prices have been rounded to the nearest dollar.

Intertie Zone	1st Long Term Auction October, 2006 to September, 2007 $/MW/Year		2nd Long Term Auction October, 2006 to September, 2007 $/MW/Year		Short Term Auction September, 2006 $/MW/Month	
	Import to Ontario	Export from Ontario	Import to Ontario	Export from Ontario	Import to Ontario	Export from Ontario
New York	522	8514	471	8848	40	1015
Michigan	8444	844	2800	665	367	225
Minnesota	28837	719	31100	804	n/a	n/a
Manitoba	4205	n/a	4310	n/a	1100	n/a
Quebec - D5A	105	101	105	101	40	n/a
Quebec - D4Z	1051	n/a	150	n/a	n/a	n/a
Quebec - P33C	109	n/a	125	n/a	n/a	n/a
Quebec - X2Y	105	n/a	105	n/a	n/a	n/a
Quebec - H4Z	n/a	17520	n/a	7008	n/a	n/a
Quebec - B5D/B31L	119	n/a	119	n/a	20	n/a

1.8 Transmission Rights Payments

The holders of Transmission Rights Contracts own the right to receive congestion payments from the IESO whenever congestion results in differences between the Ontario price and the relevant external zone price. The table in this section shows the payments that a holder of a 1 MW Transmission Rights Contract received from the IESO in this month. These payments would be made to holders of either Long - Term Transmission Rights Contracts that encompass this month, or Short -Term Transmission Rights contracts for this month.

Intertie Zone	Import to Ontario ($ per 1 MW contract)	Export from Ontario ($ per 1 MW Contract)
Manitoba	202.8	0.0
Minnesota	908.10	84.62
Michigan	0.0	59.4
New York	25.02	2075.91
Quebec - B5D/B31L	234.0	0.0
Quebec - D4Z	0.0	0.0
Quebec - D5A	0.0	0.0
Quebec - H4Z	0.0	0.0
Quebec - P33C	4.1	0.0
Quebec - X2Y	0.0	0.0

2. Market Demand

2.1 Market Demand Definitions and Graphs

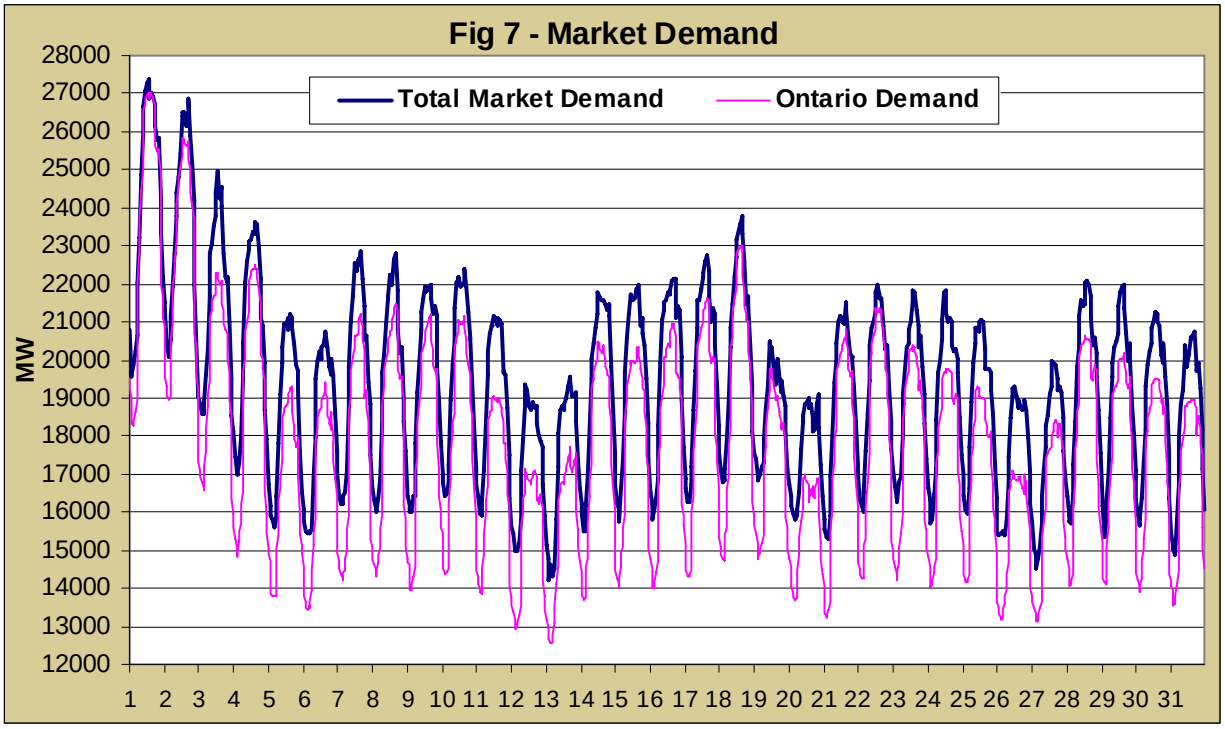
The graph below plots values for both Total Market Demand and Ontario Demand.

Total Market Demand represents the total energy that was supplied from the IESO-Administered Market.

The IESO calculates Total Market Demand by summing all output from generators registered in the Market plus all scheduled imports to the province. It is also equal to the sum of all load supplied from the Market plus exports from the province, plus all line losses incurred on the IESO-controlled grid.

Ontario Demand represents the total energy that was supplied from the IESO-Administered Market for the sake of supplying load within Ontario.

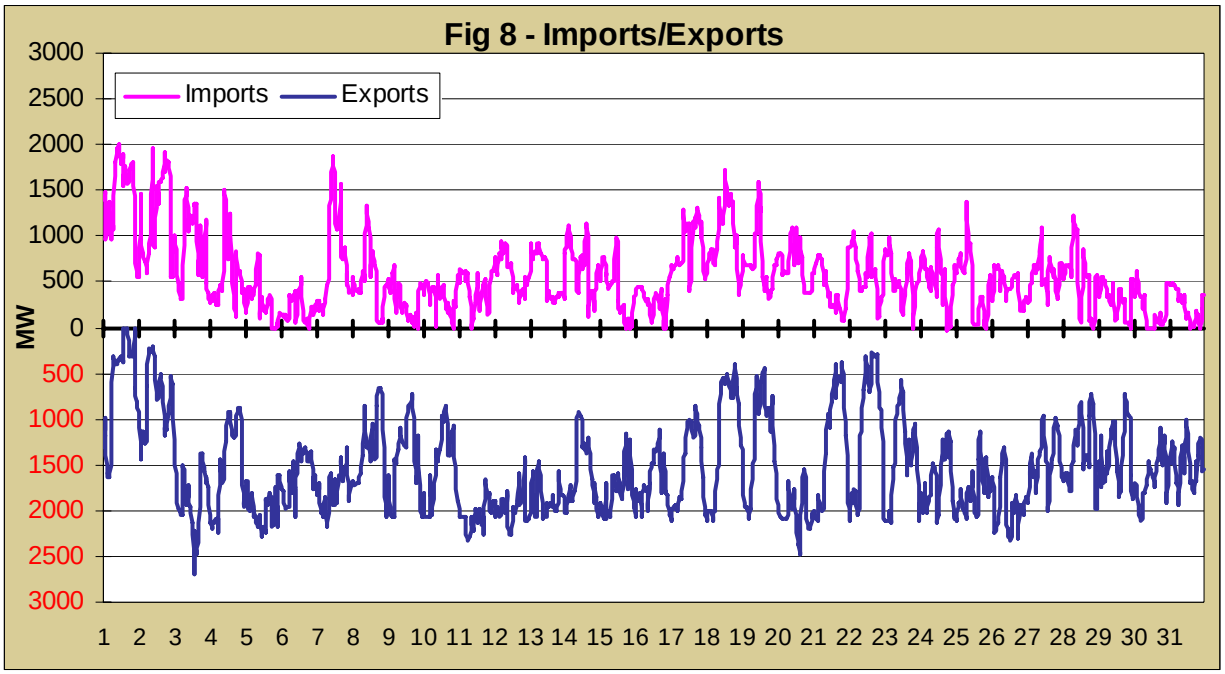
The IESO calculates Ontario Demand by subtracting exports from the Total Market Demand quantity. It is also equal to the sum of all load within Ontario which is supplied from the Market, plus all line losses incurred on the IESO-controlled grid.



	Total Market Demand	Ontario Demand
Average hourly values for the month:	19,423 MW	17,887 MW
Maximum hourly values for the month:	27,375 MW	27,005 MW
Minimum hourly values for the month:	14,218 MW	12,545 MW
Total Demand for the month:	14,450,962 MWh	13,308,130 MWh

2.2 Imports & Exports

The graph below plots both imports to Ontario and exports from Ontario during the month. Economic **imports** and **exports** are scheduled into/out of Ontario on an hourly basis, up to the physical capabilities of the Grid and the interconnections between the systems.



Average export schedule for the month = 1,536 MW
Average import schedule for the month = 569 MW
Average net intertie schedule = 967 MW net export

3. Unavailable Capacity

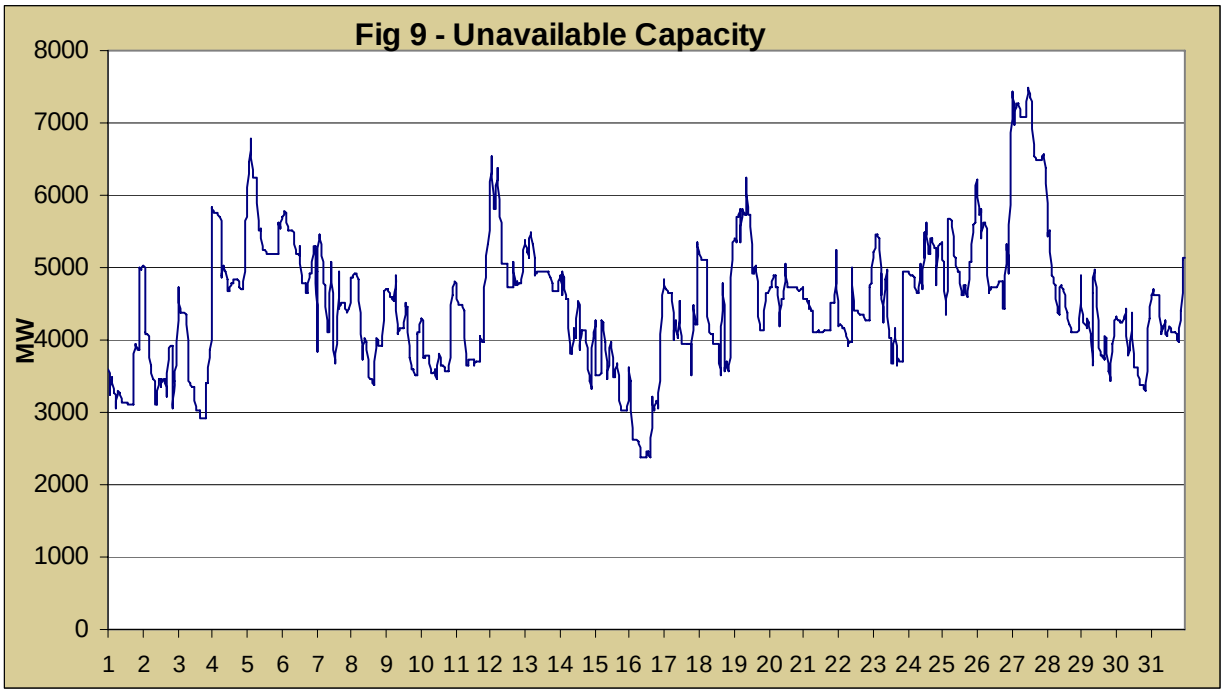
3.1 Unavailable Capacity

It is clear from the various graphs in this report that the demand for electricity varies greatly; from hour to hour, from day to day, and from season to season. The amount of generation available for operation also varies greatly over these same timeframes. The graph in this section shows the total capability of generation within Ontario that is unavailable for operation. These quantities are published by the IESO several times per day in the System Status Reports (SSR). The values in this graph are calculated by summing the following quantities (all in MW):

- capacity of generators on planned and forced outages
- capacity of planned and forced deratings
- unscheduled capacity from Intermittent, Self Scheduling , and Transitional Scheduling Generators
- constrained capacity due to operating security limits

and plotting the highest value for each day. The values are taken from the most up-to-date SSR at any point in time.

In addition, in accordance with the Market Rules, the IESO is publishing the Generator Disclosure Report on a monthly basis, six months after the fact. This report provides generating station capability and actual energy production factors of all stations with output greater than 20 MW. The report is located on the Market Data page of the IESO Web site.



4. Compliance

4.1 Compliance and Sanctions

Ensuring compliance with the market rules is key to the operation of a competitive and reliable electricity market. The Market Assessment and Compliance Division (MACD) of the IESO monitors, assesses and enforces compliance by reviewing breaches of the market rules. Market participants who breach market rules may be subject to sanctions if the IESO considers it appropriate. The sanctions cover a range of possible actions from a simple directive instructing a market participant to rectify a market breach or undertake more stringent record keeping, to financial penalties or termination from the market, depending on the nature of the breach. The process for compliance enforcement and sanctions for breaches of market rules is described in Chapter 3, section 6 of the market rules. Described below is a summary of reviews and investigations, for the past 12-month period.

CATEGORIES	August 2006					Year to Date 2006			
	Preliminary Reviews	Formal Investigations	Concluded	Letter Sanctions	Financial Sanctions	Preliminary Reviews	Formal Investigations	Concluded	Letter Sanctions
Operations:									
Communication	2		4			26	1	36	
Dispatch Data and Deviations	10	1	19	1		46	11	64	1
Failed Intertie Transactions						129	109	318	
Operating Reserve	2		3			11	1	16	
Outages			1			8		9	
Reliability Standards	3	1				3	1	1	
Other						1		2	
Finance	2		2			23	3	34	
Information Confidentiality								1	1
Metering & Settlements		1	1			1	1	10	
Miscellaneous			1	1		1	2	3	1

Please note that beginning January 2006, the Compliance categories have been expanded and the information given is for the month and calendar Year-to-Date.

The Compliance page on the IESO Web site provides more information about the Compliance functions of the IESO.

The Sanctions page on the IESO Web site provides more information on sanctions issued by MACD.

The Compliance Activities page on the IESO Web site provides information on other MACD activities.

To assist market participants, MACD has prepared an Overview of Intertie Transaction Failures which is available on the IESO Web site.

4.2 Dispute Resolution

Dispute Resolution is a process to resolve disputes involving the application and interpretation of the Market Rules by the IESO, and disputes that arise between market participants, including the IESO participant. The process is designed to resolve disputes in the most expeditious and least expensive way. The process most often includes three stages - good faith negotiations, mediation and arbitration. Disputes are confidential until they reach the arbitration stage, at which time the process becomes public. The Dispute Resolution process is described in Chapter 3, section 2 of the market rules. Described below is a summary of the disputes that have been commenced since Market Opening.

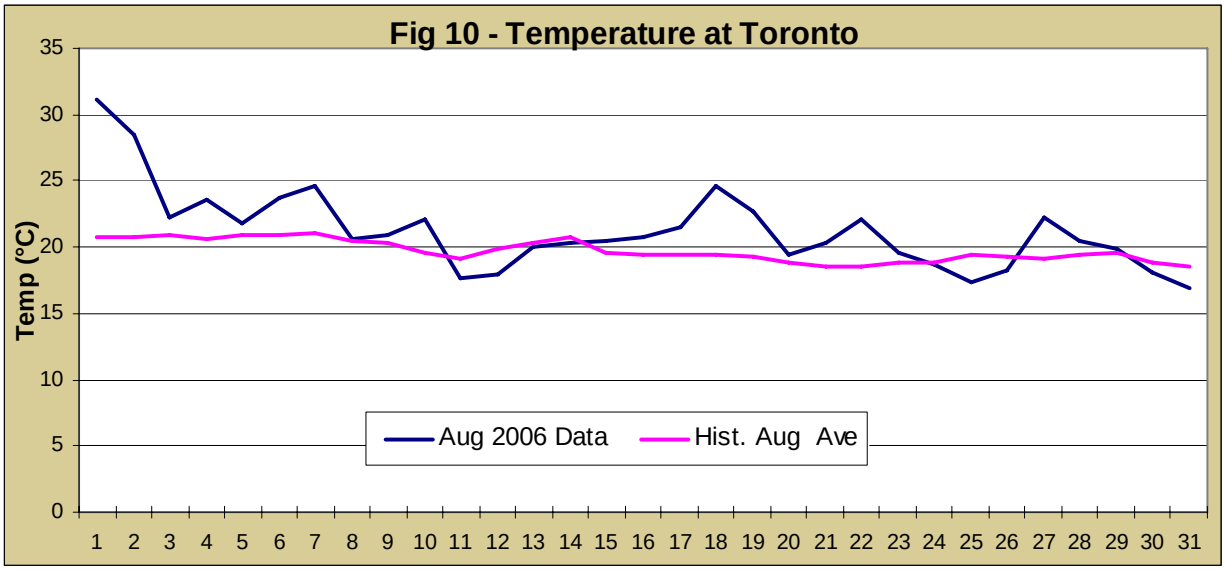
The Dispute Resolution page on the IESO Web site provides more information on the Dispute Resolution process.

Notices of Disputes Served		Number Ongoing	Number Resolved
Current Month	Since May 1, 2002		
0	24	0	24

5. Weather

5.1 Temperature

Demand for electricity is affected by weather in many ways. By far the most significant factor is temperature, with warm summer-like temperatures causing an increase in load due to air conditioning use, and cold winter temperatures resulting in additional heating load. The graph below shows the average daily temperature in Toronto throughout this month, and compares it to historic average temperatures for the corresponding days. This graph displays Toronto temperatures. However, the IESO monitors weather conditions (temperature, humidity, wind speed, illumination, storm activities) across the entire province and factors these conditions into our demand forecasting and our operational decisions.

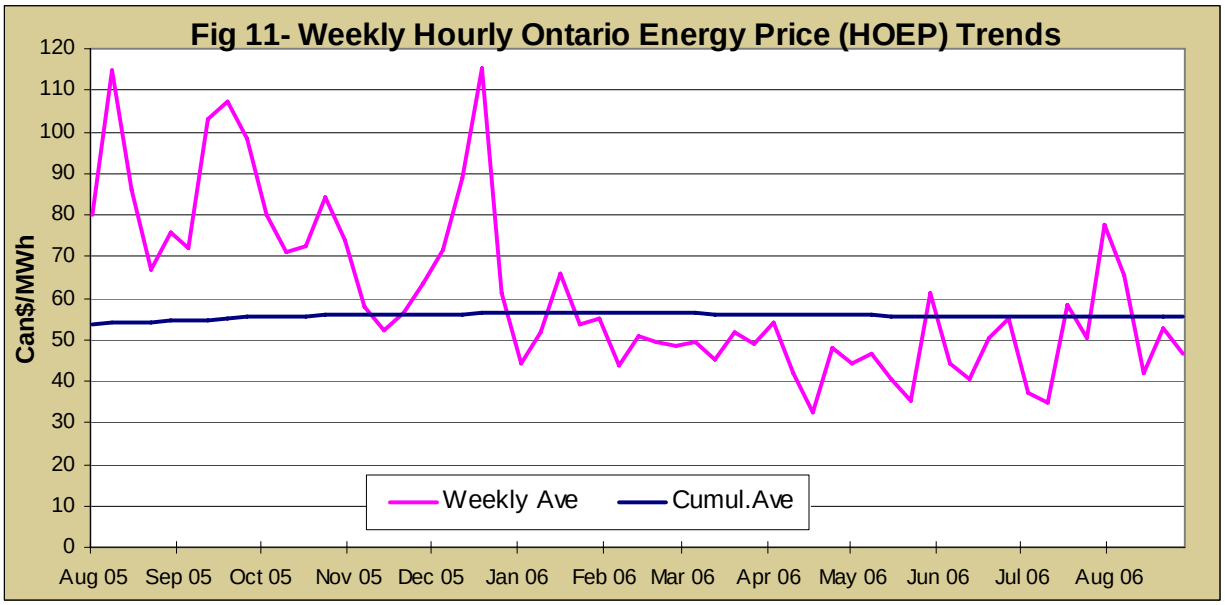


6. Longer-Term Trends

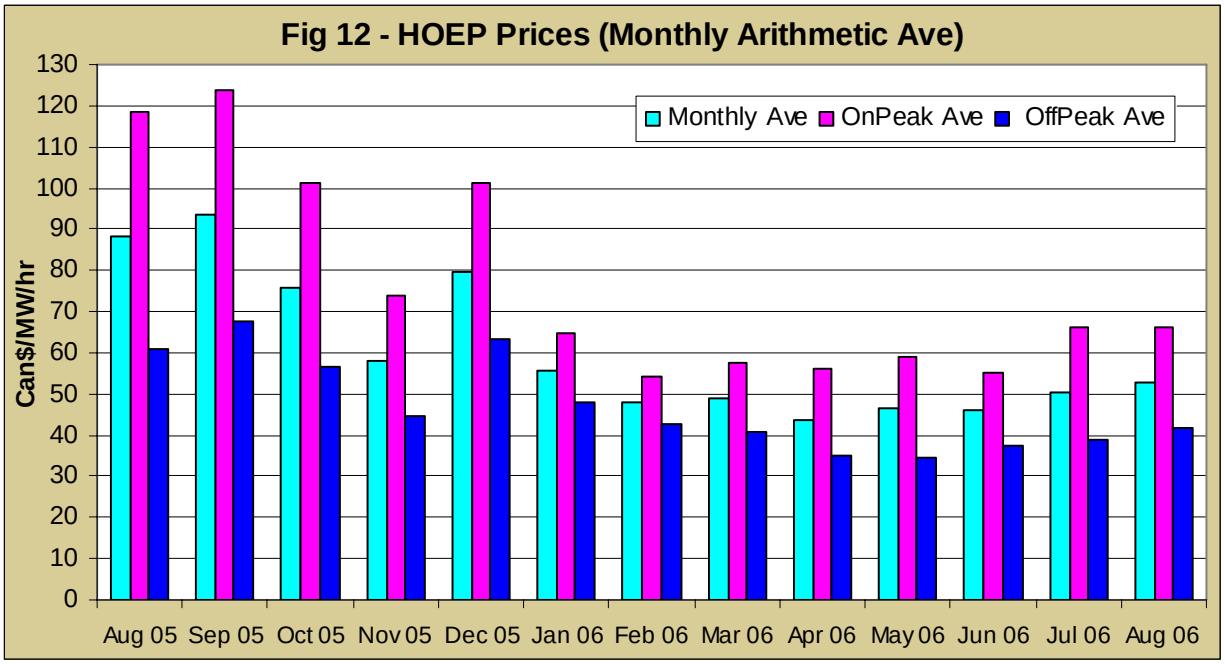
This section provides graphs that display average quantities over longer periods of time than what is available in either the Monthly graphs or in the IESO's Weekly Market Reports. This longer-term perspective will allow seasonal variations to be observed. For additional background on the particular information being graphed, please refer to the relevant monthly graph and write-up presented earlier in this report.

Starting in January, 2004, the Monthly Market Report incorporated nine new graphs. All of these graphs have been produced based on data previously included in the Market Surveillance Panel Reports, and depict a small subset of the tabular data from these reports. In the January 2004 Monthly Market Report these graphs showed information from market opening to January 2004. Starting with the February 2004 Monthly Market Report, the graphs show the most recent month plus one year of history.

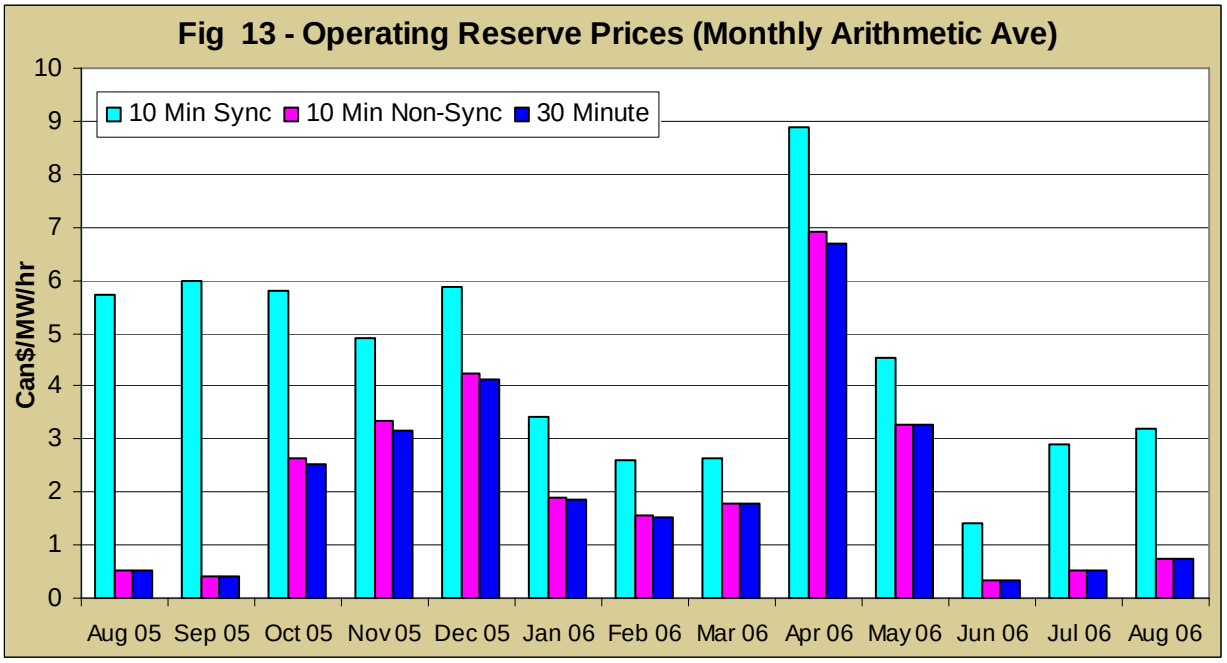
6.1 Weekly Hourly Ontario Energy Price (HOEP) Trends



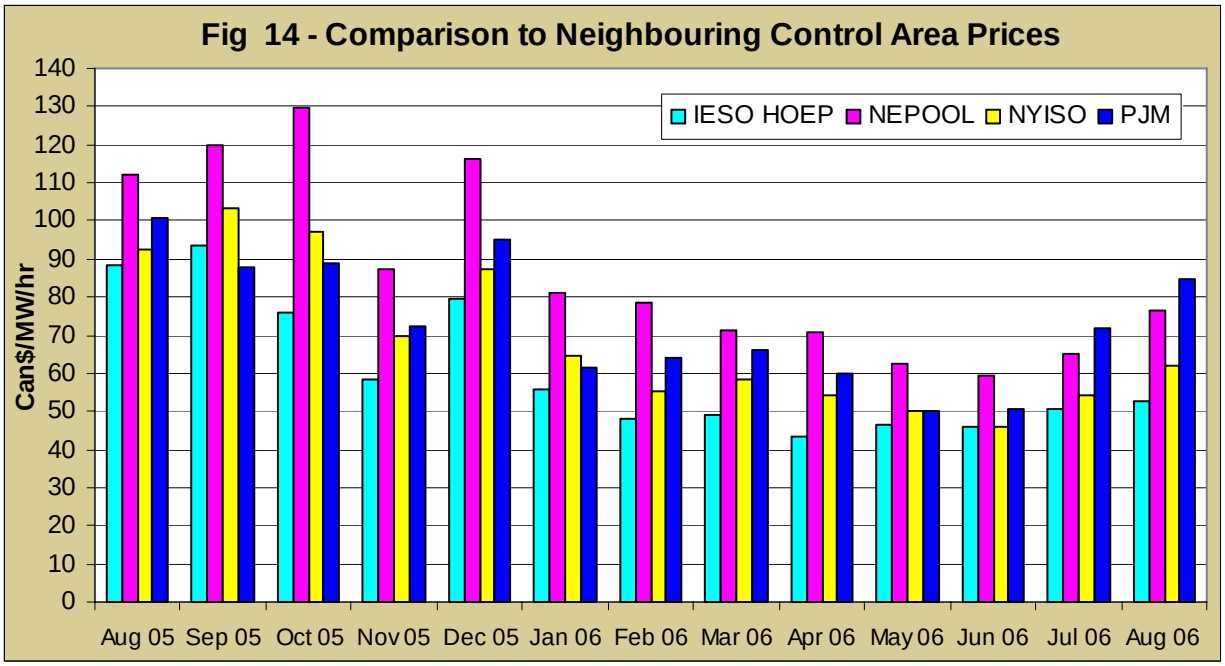
6.2 HOEP Prices (Monthly Arithmetic Ave)



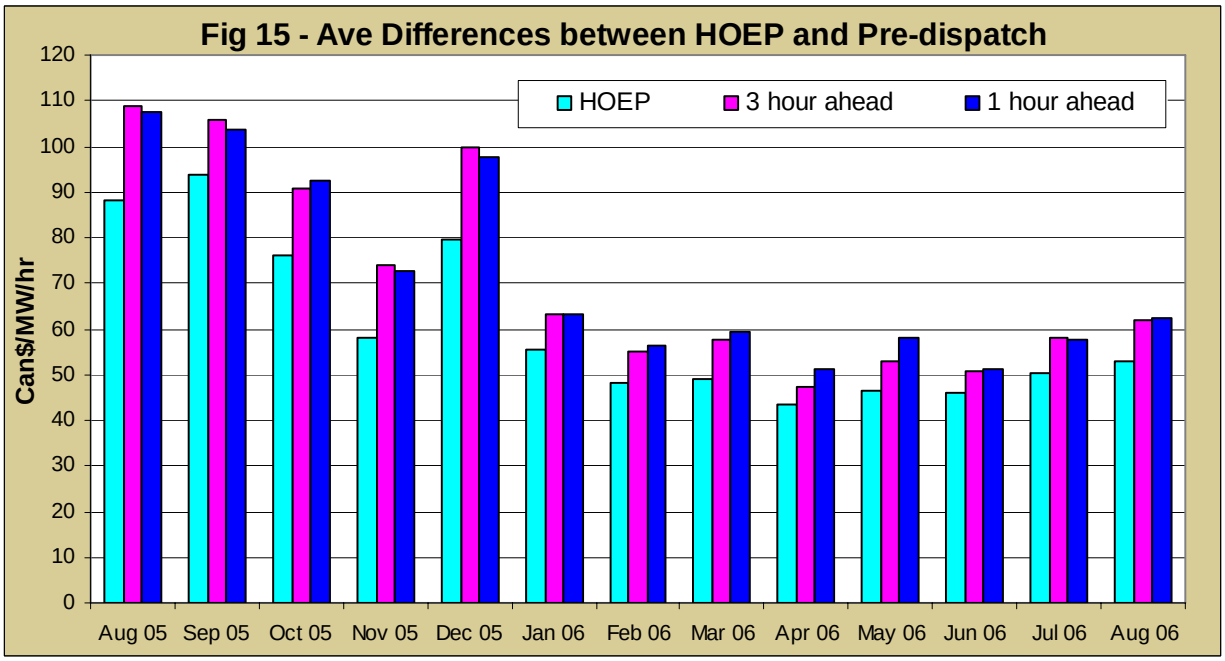
6.3 Operating Reserve Prices (Monthly Arithmetic Ave)



6.4 Comparison to Neighbouring Control Area Prices

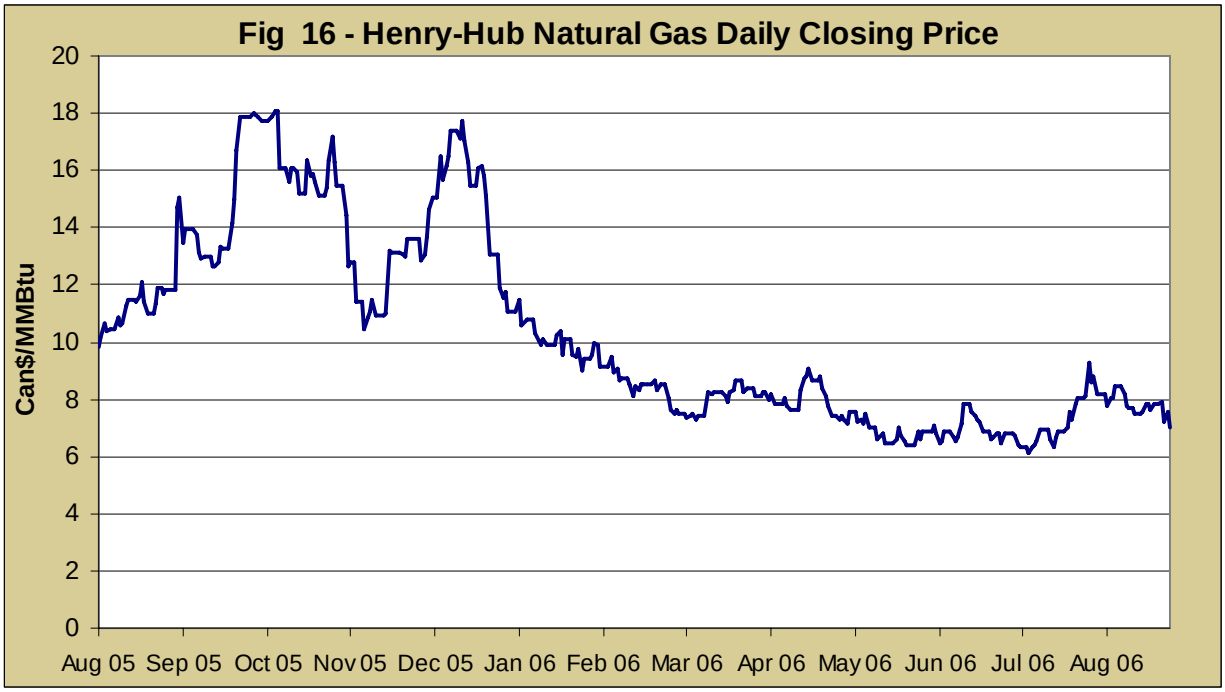


6.5 Ave Differences between HOEP and Pre-dispatch

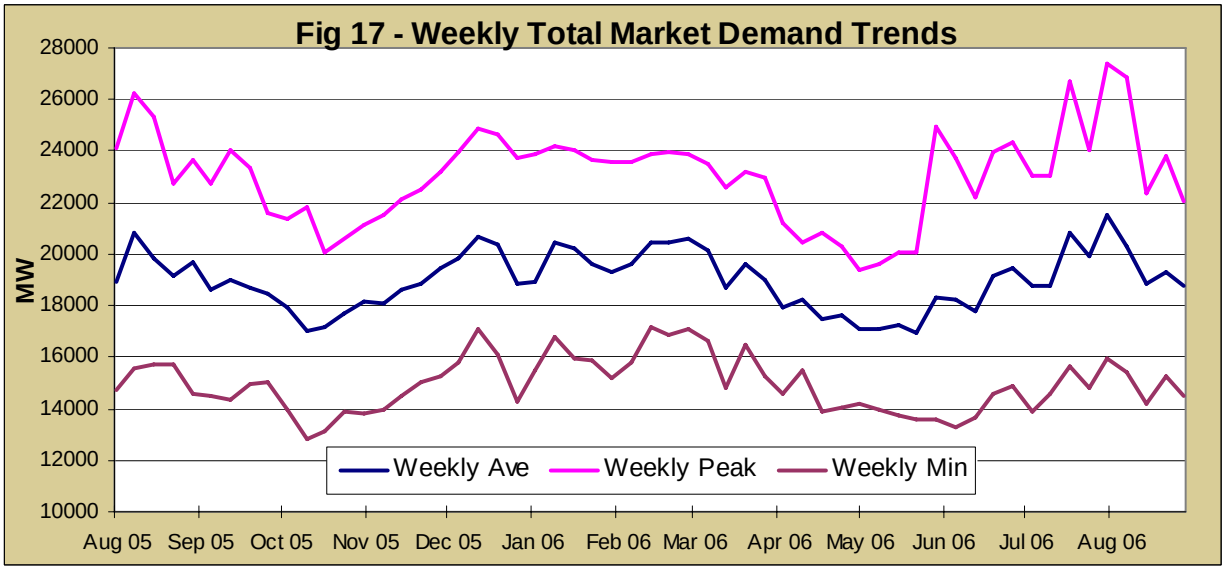


6.6 Henry-Hub Natural Gas Closing Price

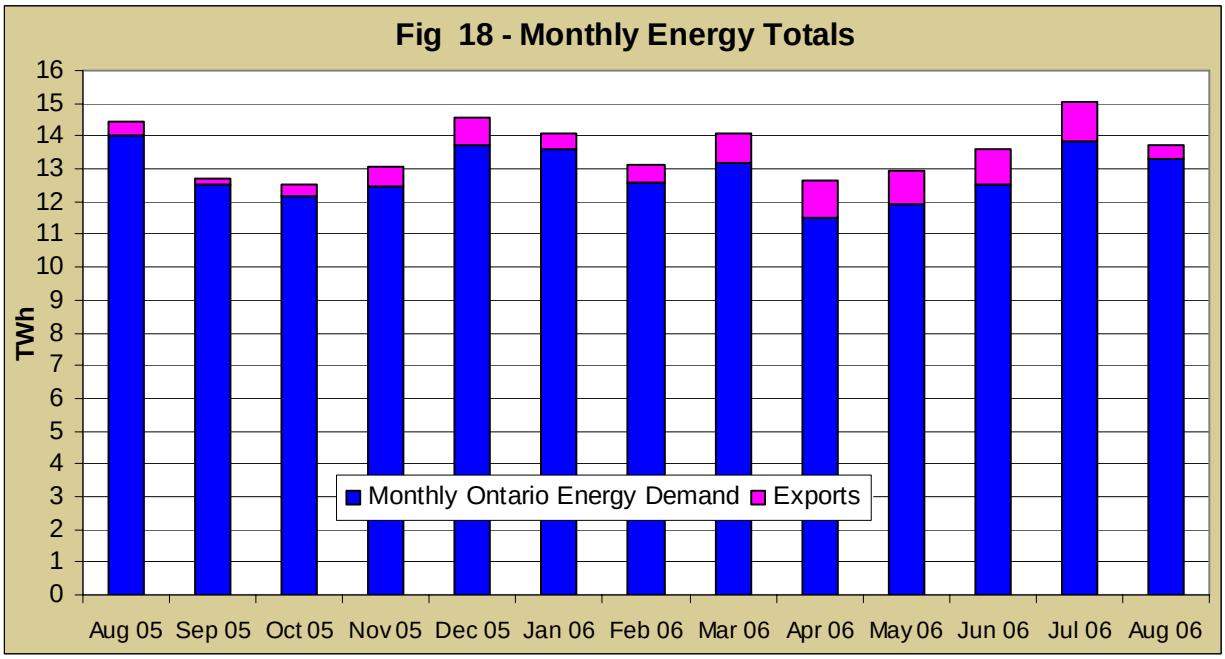
Natural gas is a fuel for some Ontario-based generation, and when dispatched, is often the marginal source of electricity in Ontario. In addition, gas prices influence import offers into Ontario and export bids out of the province.



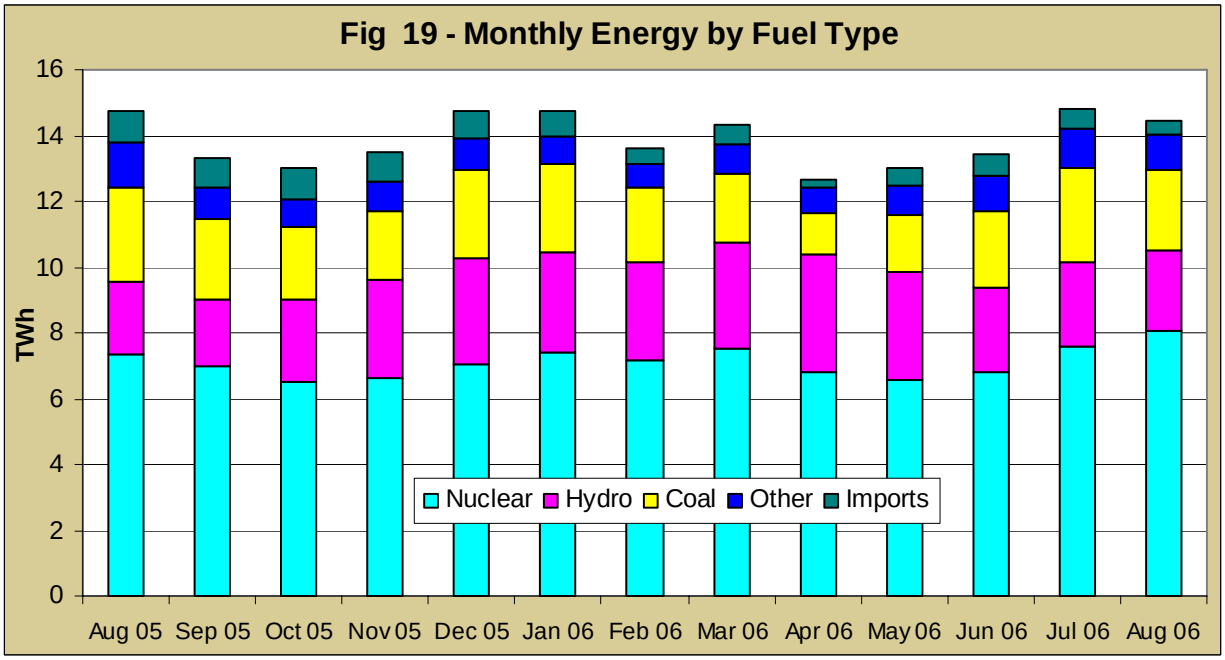
6.7 Weekly Market Demand Trends



6.8 Monthly Energy Totals

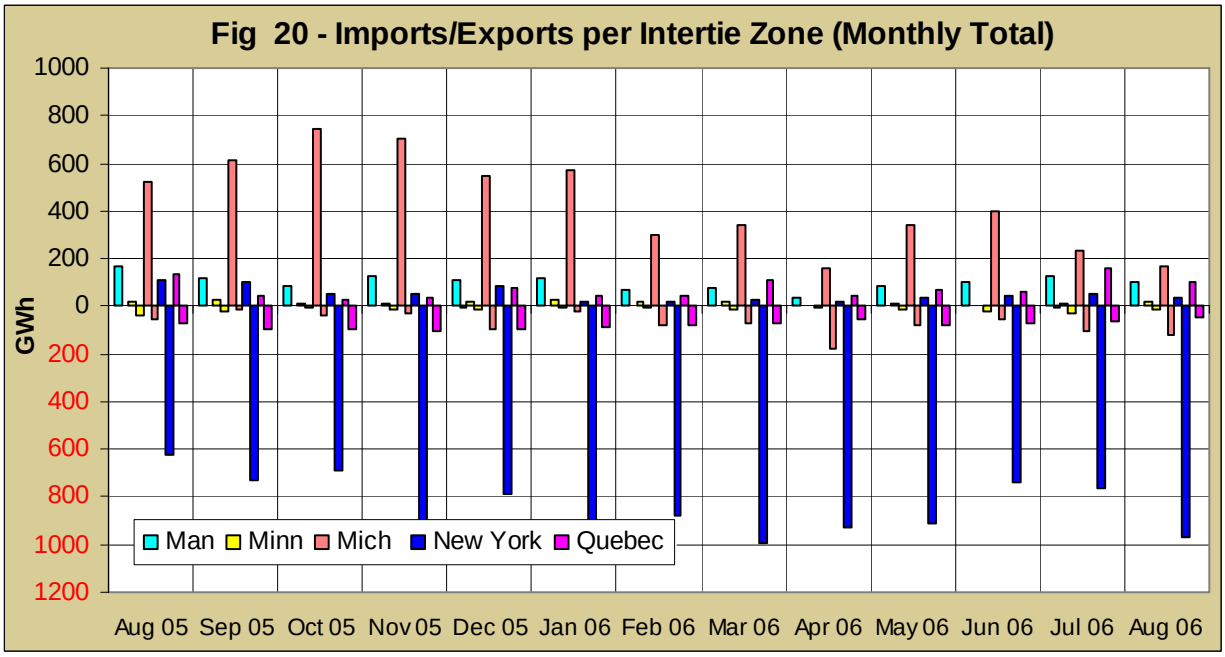


6.9 Monthly Energy by Fuel Type

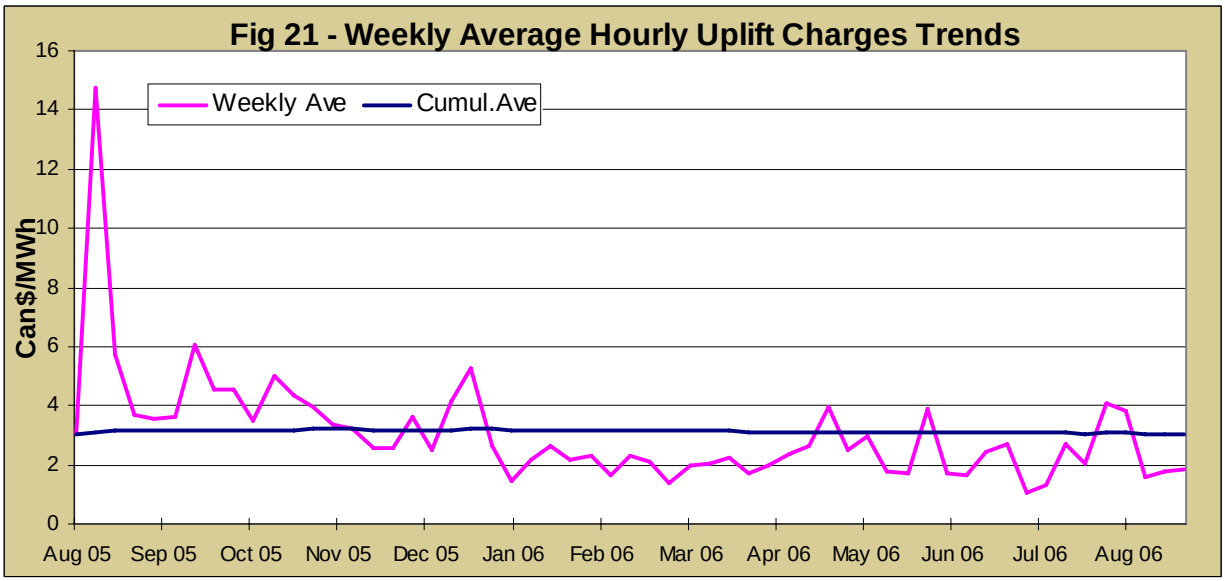


6.10 Imports/Exports per Intertie Zone (Monthly Total)

Note: Imports are depicted as above zero, whereas Exports are depicted as below zero



6.11 Weekly Average Hourly Uplift Charges Trends



6.12 Hourly Uplifts (Monthly Total)

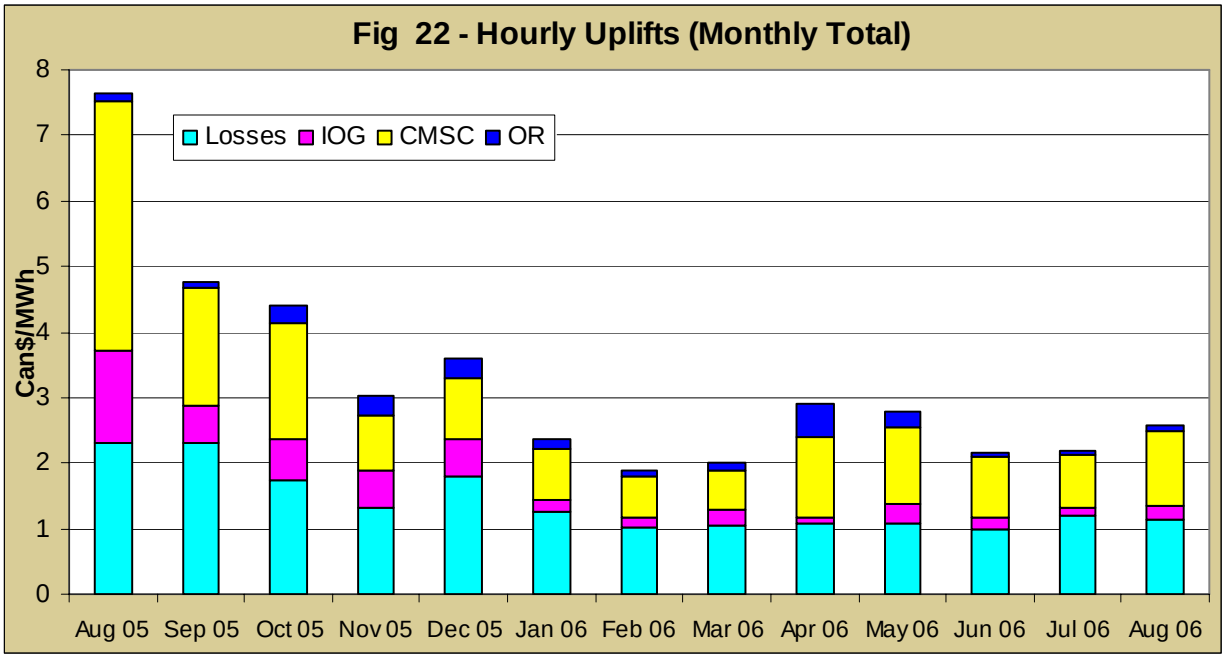


Fig 22 - Hourly Uplifts (Monthly Total)

6.13 Weekly Maximum Unavailable Capacity Trends

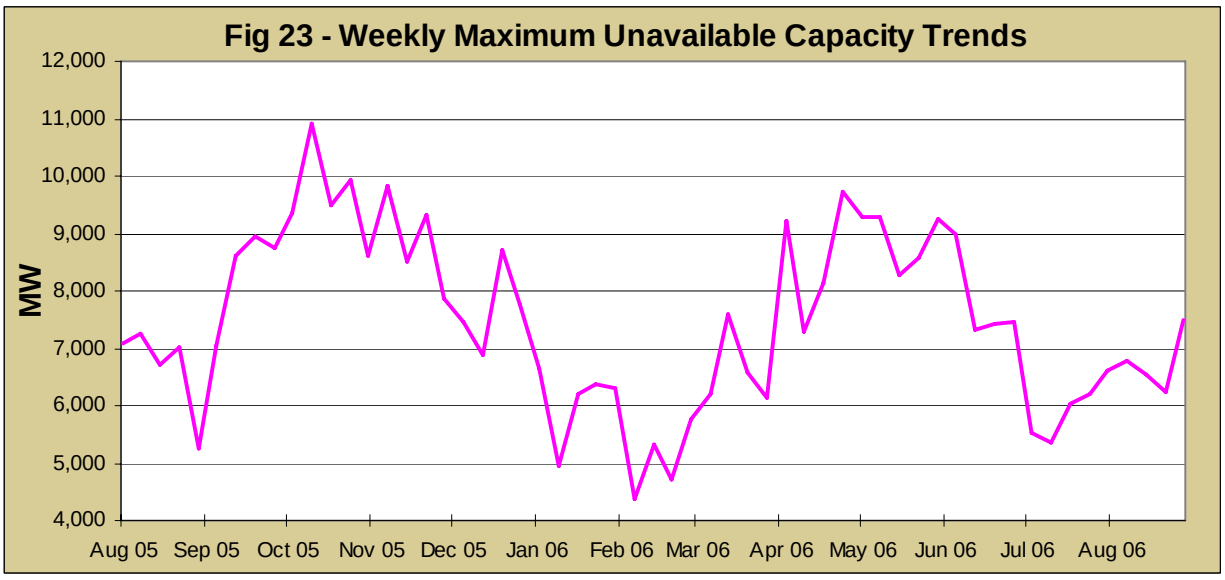
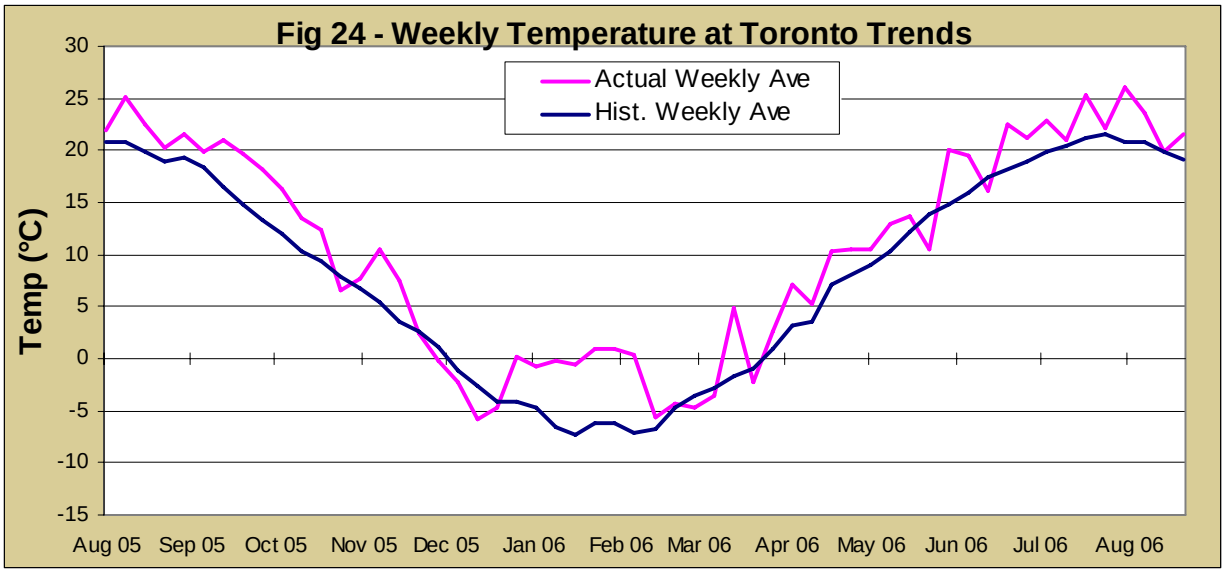


Fig 23 - Weekly Maximum Unavailable Capacity Trends

6.14 Weekly Temperature at Toronto Trends



7. Market Rebates

7.1 Business Protection Plan Rebate (BPPR)

The Market Design Committee (MDC) was created in 1998 to establish the basic structure of Ontario's competitive electricity markets. Drawing on experience from other jurisdictions, the MDC determined that the relative ability of different players to exercise market power could present a major challenge.

Market Power is the ability of a market participant to profitably influence the market price. The MDC recognized that as the successor to Ontario Hydro's generation assets, Ontario Power Generation (OPG) had the most significant potential among market participants to exercise market power. The MDC and the Ontario government, therefore, negotiated a Market Power Mitigation Agreement (MPMA) with OPG. One key aspect of the MPMA was the imposition of a revenue cap on most of OPG's generation by establishment of the Market Power Mitigation Rebate (MPMR). In general terms, this mechanism rebates money to eligible consumers should the average price of electricity exceed a certain level.

The rebate program is in effect from May 1, 2002 to March 31, 2005. Due to the complexity of the MPMR calculations, the program has changed to the Business Protection Plan Rebate (BPPR) beginning with the Settlement Period starting May 1, 2003. The purpose of the change is to make the rebate calculation more transparent to Market Participants.

The BPPR for a market participant will be determined using the following formula:

BPPR=(WAP – CAP) x 0.5 x AQEW where;

WAP = Weighted Average Price: The average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.
CAP = The Price Cap: $38.00 per MWh.
AQEW = Total Allocated Quantity of Energy Withdrawn by the MP from the IESO-controlled grid for use in Ontario for the applicable portion of the Settlement Period.

The total amount of the BPPR to be distributed for the first 9 months of the settlement period of May 1, 2004 to March 31, 2005 is $984,034,150.59.

The Total Allocated Quantity of Energy Withdrawn (TAQEW) for Ontario is 138,207,043.622 MWh.

The Market Rebates Quick Take on the IESO Web site provides more information on the BPPR.

7.2 OPG Rebate

The Ontario Power Generation (OPG) Rebate is a rebate from OPG on revenues above a set price for its "non-prescribed" or unregulated generation. The OPG Rebate replaces the Market Power Mitigation Rebate.

The OPG Rebate is a payment to market participants based on their pro-rata share of the total Ontario allocated quantity of energy withdrawn (AQEW). Starting in May, 2006 this rebate will be issued quarterly.

LDCs will receive this rebate from the IESO and disperse these funds to customers who pay the wholesale rate (i.e. not on the Regulated Price Plan (RPP)). Some non-RPP customers with a retailer contract may not receive this rebate depending on their contract provisions.

The OPG Rebate to market participants covers three distinct periods, each with a slightly different calculation.

April 1, 2005 to December 31, 2005

This rebate will be determined using the following formula:

Payment = Sum over all hours [(HOEP - $47) x (ONPA(output) x 0.85)] where;

OPG's Non-Prescribed Assets are those Ontario Power Generation assets, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the Ontario Energy Board Act, 1998 as amended by the Electricity Restructuring Act, 2004. (OPG's Prescribed Assets are Beck, Saunders, Decew, Pickering A, Pickering B and Darlington.)

HOEP = The Hourly Ontario Energy Price as determined by the IESO.
ONPA(output) = The generation output from OPG's Non-Prescribed Assets over each hour of the period adjusted to take into account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005.

January 1, 2006 to April 30, 2006

For this period, the Rebate calculation will also incorporate amounts determined in an OPA energy auction for OPG output. This Rebate will be paid out for the four-month period, January 1, 2006 to April 30, 2006.

May 1, 2006 to April 30, 2009

Starting May 1, 2006, the OPG Rebate will be in effect until April 30, 2009. Each 12-month settlement period will contain interim payments paid quarterly to eligible market participants.

A preliminary estimate of the amount of the OPG Rebate for the settlement period (ie. May 1, 2006 to July 31, 2006) is **$58,000,000**. The preliminary total Allocated Quantity of Energy Withdrawn (AQEW) for Ontario for the same period is **38,000 GWh**. This results in an estimated rebate rate of approximately **$1.53/MWh**.

A preliminary estimate of the amount of the OPG Rebate for the settlement period (ie. August 1, 2006 to October 31, 2006) is **$36,000,000**. The preliminary total Allocated Quantity of Energy Withdrawn (AQEW) for Ontario for the same period is **13,000 GWh**. This results in an estimated rebate rate of approximately **$2.77/MWh**.

Note: This section has been updated to accommodate the changes as per the recent announcement by the Government of Ontario dated February 9, 2006.

7.3 Global Adjustment

The global adjustment is the difference between the total payments made to certain contracted or regulated generators/demand management projects, and any offsetting market revenues. The adjustment may be positive or negative.

The global adjustment includes the following:

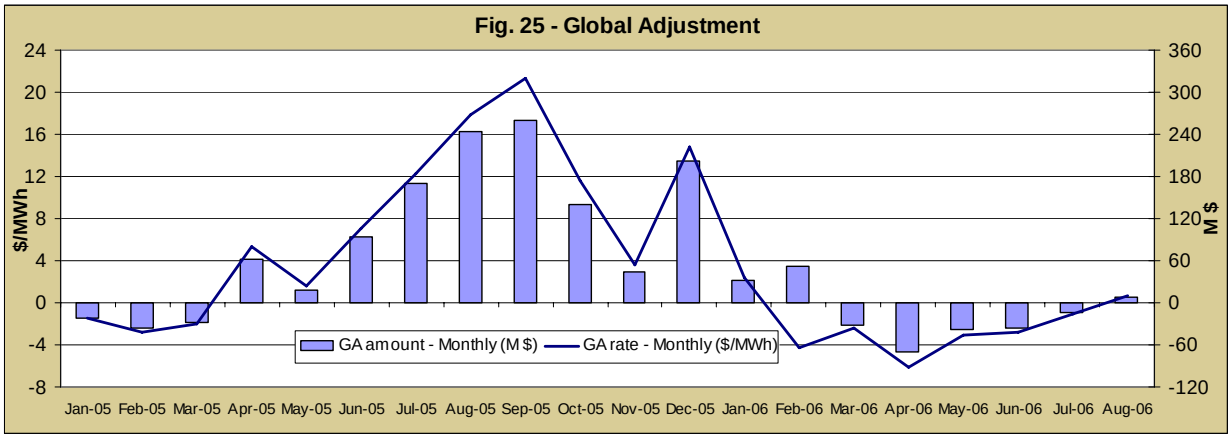
- OPG's regulated baseload generation
- Non-utility generators (NUGs)
- Future generation/load reduction to be provided through the current government requests for proposals (RFPs) for new supply and demand management

The global adjustment amount is calculated each month by taking into account the amount of each type of regulated or contracted generation injected into the IESO-controlled grid, the regulated price or contract costs for that generation, and any offsetting market revenues.

The total global adjustment for the month is then applied to the settlement statement for the last trade day of the month for all market participants who have withdrawn energy from the grid during the month (except exporters). For distributors, the global adjustment is allocated based on the volume of electricity withdrawn from the grid plus the volume of electricity supplied by embedded generators.

Distributors will have some customers on the Regulated Price Plan, some paying the market price, and some with retail contracts. The distributors will have the global adjustment applied to the prices they pay for electricity, and will, in turn, pass the global adjustment on to their non-regulated customers. Distributor's customers paying a regulated price will not be affected by the global adjustment.

Fig. 25 - Global Adjustment



8. Summary of Wholesale Market Electricity Charges in Ontario's Competitive Marketplace

In early August 2002, the IESO released "A Guide to Electricity Charges in Ontario's Competitive Marketplace". That guide shows how market charges flow from the wholesale market to the retail market, and how these charges may appear on a typical consumer's utility bill. The bar chart contained in this section is taken directly from that Guide. Also shown here, is a summary of this month's market results that correspond with the charge items indicated in the chart.

IESO Wholesale Market	Arithmetic Average		Weighted Average	
	Current Month	Year-to-Date	Current Month	Year-to-Date
Commodity Charge (varies)	\$52.72/MWh or 5.27 ¢/kWh	\$48.93/MWh or 4.89 ¢/kWh	\$56.67/MWh or 5.67 ¢/kWh	\$52.34/MWh or 5.23 ¢/kWh
Wholesale Market Service Charges				
CMSC	\$1.03	\$0.91	\$1.14	\$1.01
IOG	\$0.22	\$0.17	\$0.26	\$0.22
Other Hourly	\$1.13	\$1.13	\$1.24	\$0.91
Monthly	\$0.85	\$1.09	\$0.85	\$1.09
IESO Administration	\$0.91	\$0.91	\$0.91	\$0.91
Rural/Remote Settlement	\$1.00	\$1.00	\$1.00	\$1.00
Total	\$5.14/MWh or 0.51 ¢/kWh	\$5.21/MWh or 0.52 ¢/kWh	\$5.40/MWh or 0.54 ¢/kWh	\$5.14/MWh or 0.51 ¢/kWh
Wholesale Transmission Charge	\$9.15/MWh or 0.92 ¢/kWh	\$8.93/MWh or 0.89 ¢/kWh	\$9.15/MWh or 0.92 ¢/kWh	\$8.93/MWh or 0.89 ¢/kWh
Debt Retirement Charge	\$7.00/MWh or 0.70 ¢/kWh	\$7.00/MWh or 0.70 ¢/kWh	\$7.00/MWh or 0.70 ¢/kWh	\$7.00/MWh or 0.70 ¢/kWh
Totals	\$74.01/MWh or 7.40 ¢/kWh	\$70.07/MWh or 7.01 ¢/kWh	\$78.22/MWh or 7.82 ¢/kWh	\$73.41/MWh or 7.34 ¢/kWh

Note: Year-to-Date is since May 1, 2005

There are two commodity charges quoted above. The arithmetic average price would be representative of the average commodity charge for a customer whose electrical demand is relatively consistent throughout the day, the night and the weekends. The weighted average price would be applicable to a customer whose consumption mirrored that of the total system. The actual average commodity price paid by a wholesale customer will be very sensitive to their consumption pattern.

The Wholesale Transmission Charge listed above has been calculated by summing all transmission-related fees paid by all loads in the province, and dividing that sum by the total energy delivered to those loads. As such, this number is not representative of the fee paid by any particular customer. Rather, each customer's actual fee for transmission service will depend on many factors such as peak consumption pattern and the types of transmission services applicable to the customer.

Questions on any information contained in this report should be directed to:

IESO Customer Relations
1-888-448-7777
customer.relations@ieso.ca