Executive Summary

Overall Assessment

Ontario's IESO-administered wholesale electricity market once again performed reasonably well according to its design over the six-month period November 2007 to April 2008. Spot market prices generally reflected demand and supply conditions. The Market Surveillance Panel (MSP) found no evidence of gaming, abuse of market power or other inappropriate conduct by market participants or the system operator, the Independent Electricity System Operator (IESO). However, as in previous reports, the MSP identified several potential opportunities to improve the efficiency of the market which are reflected in the 11 recommendations summarized below.

Market Prices and Uplift

For just over two years now, energy prices have being been relatively stable, as downward pressure from the modest amount of new supply has been accompanied by an upward pressure on prices induced by higher fuel costs. The average Hourly Ontario Energy Price (HOEP) for the period November 2007 through April 2008 was $49.16/MWh, 0.5 percent higher than the same period a year ago, with on peak HOEP being 1.8 percent higher and off peak HOEP 1.0 percent lower. The effective load-weighted HOEP, which provides a more accurate reflection of what Ontario load pays for energy after accounting for the Global Adjustment and the OPG Rebate, increased by $1.95/MWh or 3.7 percent this winter compared to the previous winter period. Total hourly uplift payments charged to market participants increased by $30 million or 18 percent during the current period compared to the same period the previous winter. This was primarily due to higher congestion management payments associated with bottled energy in the Northwest and more transmission or energy supply limitations in southern Ontario which led to constraining on imports or constraining off exports.

In terms of the distribution of the HOEP, there was some shifting of energy prices from the $20 to $40/MWh range to the $40 to $60/MWh range, corresponding to higher fuel prices. The period also saw a greater incidence of prices below $20/MWh, 261 hours this year versus 189 hour last year. There were 2 hours when the HOEP was above $200/MWh, compared with 1 hour during the period a year ago.

Demand and Supply Conditions

Ontario total energy demand was almost unchanged this winter compared with last, due to colder temperatures and higher demand early in the period being offset by lower demand later in the period. The major component, demand from local distribution companies (LDCs), has been fairly constant year-over-year, but we observe a continuing decline in wholesale load consumption. Total market demand (Ontario demand plus exports) increased by 3.1 TWh. It was driven by a substantial rise in exports, to 8.5 TWh this year representing an increase of more than 60 percent. Total net exports (exports minus imports) increased by 1.8 TWh or 80 percent during the winter 2007/2008 months relative to 2006/2007, with about half the increase in each of the on-peak and off-peak hours.

The above export amounts exclude 1.8 TWh of exports which were part of 'linked wheels' (simultaneous import and export by a market participant for the purpose of moving power between two other markets through Ontario). Since the import offsets the export in a linked wheel there is no net effect on HOEP. Such transactions had been uncommon, but during this winter period grew by a factor of approximately 150 times relative to last year. This phenomenon appears to have arisen in response to features in certain U.S. markets that are being reviewed by the relevant authorities.

Planned outage rates over the recent winter period were generally in line with historical rates and seasonality, although the planned outage rate in April 2008 was lower than any other April since 2003. Forced outage rates during this winter period were comparable to monthly rates seen since the end of 2005. The exception was again April 2008, when nuclear units spiked to a monthly outage rate of almost 22 percent and drove the overall outage rate to 16 percent.

High and Low HOEP

We assessed the two hours during the November 2007 through April 2008 period when the HOEP was greater than $200/MWh and five hours when the HOEP was negative. The highest priced hour occurred on February 1, 2008 in Hour Ending (HE) 11 when the HOEP reached $563.62/MWh. The lowest priced hour this period occurred on February 18, 2008 in HE 3 when the HOEP dropped to minus $2.72/MWh, with the lowest interval price since market opening, minus $31.00/MWh, occurring two hours later in HE 5. While these outcomes are mostly explainable by reference to supply and demand conditions existing at the particular time, some of these outcomes were also influenced by elements of the market design that the Panel recommends be re-examined.

Operational Issues & Recommendations

The Panel has made several suggestions for potential changes to the present IESO-administered markets based on its analysis of observed market outcomes over the past six months.

Recommendation 2-1 (Chapter 2, Section 2.2.1)

The Net Interchange Scheduling Limit (NISL) is a conservative proxy for the ability of domestic generation to ramp up or down in response to abrupt import or export changes at the start of an hour. The upper limit was initially set at 700 MW after IESO discussions with participants prior to market opening. This approximated the ability of slower moving fossil generators to ramp, as it was presumed these would be the typical marginal resources. However, fossil generation may not be at the margin, for example in extremely high demand periods when peaking hydroelectric could be marginal, or in low demand periods when baseload hydroelectric could be marginal.

The IESO has an explicit control action allowing it to increase NISL during high demand periods to maximise net imports, but not during low load periods to maximise net exports. A higher NISL could have avoided the situation observed this winter where exports were failing during a low load period, which limited net exports the next hour and induced more imports to be scheduled. These additional imports were more costly than the Ontario generation they replaced.

The MSP reiterates the recommendation in its June 2007 report that the IESO should review the 700 MW Net Interchange Scheduling Limit (NISL). This review should take into account the effects on potential efficient exports from Ontario in addition to the import issues raised in the MSP's prior report.

Recommendation 2-2 (Chapter 2, Section 2.2.4)

Following the forced outage of two nuclear units and the loss of 1,700 MW of generation, the IESO took a series of control actions needed to sustain reliability. These control actions included the Shared Activation of Reserve (SAR), the activation of Regional Reserve Sharing (RRS), the curtailment of exports for adequacy and Operating Reserve Activation (ORA). IESO procedures with respect to the first three treat these as a reduction in energy demand and ORA is accompanied by an equivalent reduction in operating reserve demand. Such reductions in the demand levels used in the unconstrained sequence do not correspond to any actual decrease in economic demand in the market. As a result, the HOEP was significantly and artificially lower.

The MSP reiterates the recommendations in its December 2006 and June 2007 reports, respectively, regarding Shared Activation of Reserve (SAR), and prompt replenishment of the Operating Reserve requirement levels. In addition, the MSP recommends the IESO review the application of Regional Reserve Sharing (RRS) because the current treatment of RRS in the unconstrained sequence also induces counter-intuitive prices.

Recommendation 3-1 (Chapter 3, Section 2.2.4)

In recent years, an increasing fraction of real-time IOG payments have been paid during periods of excess domestic supply, implying that these payments may not be buying much in the way of additional reliability for the Ontario market. In fact, during the period May 2006 to April 2008, the majority of IOG payments in on-peak hours were paid in hours when the Ontario was a net exporter, and even more so in off-peak hours. The high IOG payments in such hours warrant a more detailed study on whether IOG payments continue to bring corresponding reliability benefits to Ontario.

As market supply conditions have improved, an increasing fraction of Intertie Offer Guarantee (IOG) payments is being paid in hours when there appear to be negligible reliability concerns. The MSP recommends the IESO review the real-time IOG program and determine if it is providing commensurate improvements in reliability.

Recommendation 3-2 (Chapter 3, Section 3.1)

Competitive wholesale energy markets utilize offers and bids to match electricity supply with demand. Unlike other markets reviewed, the IESO does not publish any form of offer or bid data. In general, publication of market information enhances market efficiency by equipping market participants to respond effectively. The traditional concern with the release of offer and bid data, in particular, is that it may facilitate implicit or overt collusion. However, the Panel believes that a multi-month lag is an adequate safeguard to prevent coordinated changes to offer/bid behaviour by market participants and still produce a favourable impact. The primary benefits from releasing bid/offer data with a lag relate to longer term decision-making by market participants (e.g. investment decisions) as well as opportunities for increased external scrutiny of the market.

The MSP recommends that the IESO publish masked bid and offer data on a four-month time lag.

<u>Recommendation 3-3 (Chapter 3, Section 3.1)</u>

When the market opened in 2002, some generators were concerned that releasing production information by unit could lead to inappropriate market behaviour. The Panel recommended that unit production data be released, but with a two hour time lag due to concerns by a participant that more timely release of this information could lead to withholding by other generators. To date, the MAU has not observed any inappropriate behaviour resulting from publication of output data. In fact, one major Generator in the province releases its own production information by fuel type on a 15-minute basis.

The MSP recommends that the IESO publish generating unit output using a one-hour lag rather than the current two-hour lag.

<u>Recommendation 3-4 (Chapter 3, Section 3.1)</u>

Forced outages of generating units are an inevitable occurrence from time to time. The impact on the market can be dramatic when large units are suddenly taken out of service. Information on the generation type is important because it suggests the probable duration of an outage to knowledgeable observers. Releasing information on the type of generating unit experiencing an outage in the IESO's System Status Reports (SSR) will facilitate a more widespread understanding of its implications for future market prices in Ontario and allow market participants to respond in an effective manner. It would also mitigate the present asymmetry of information with the largest generator having a much greater knowledge of the type and the extent of outages indicated.

The MSP recommends that when the System Status Reports indicate that a generating unit of greater than 250 MW has been forced from service, the IESO should also disclose the fuel type of the unit in order to increase the information available to all market participants regarding future market conditions.

Recommendation 3-5 (Chapter 3, Section 3.1)

The supply cushion is an important market and reliability measure that represents the amount of excess supply available for dispatch in a given hour. In the Panel's view it is a simple yet powerful indicator of supply and demand conditions in the province and its publication would be beneficial to market participants. If published in advance of the hour using forecast demand and expected available supply, this indicator could increase the ability of market participants and others to understand price movements and to make more efficient production/import and consumption/export decisions. The Panel understands that the IESO intends to begin publishing a supply cushion. However, the way in which this statistic is currently calculated by the IESO does not accurately reflect actual supply availability.

The IESO is planning to publish the supply cushion on a hourly basis. Its current calculation, however, does not represent actual supply capability. The MSP recommends that the IESO refine its formula to take into account forced outages, deratings, and import capabilities at the interties.

Recommendation 3-6 (Chapter 3, Section 3.3)

In Chapter 2, the Panel discussed some anomalous outcomes of intertie failures that resulted from the use of different reason codes by the IESO. In particular:

- a failed import in the constrained sequence can increase imports in the unconstrained sequence and thus decrease the real-time price; and
- a failed export in the constrained sequence can increase exports in the unconstrained sequence and thus increase the real-time price.

The anomalous outcomes are a result of the two-sequence dispatch algorithm and the way the IESO assigns a reason code to a failed transaction.

We understand that it is important for the IESO to separate transaction failures by reasons as this process can help the IESO to find the exact causes and improve system operation in the future. However, the modification of the unconstrained schedule that occurs when some of these reason codes are applied interferes with the operation of the market, and can lead to both distorted price signals and reduced market efficiency.

1. ***For interjurisdictional transactions that fail because of market participants' ('OTH') or external system operators' actions ('TLRe' and 'MrNh'), the MSP recommends the IESO revise its procedures to avoid distorting the unconstrained schedule. This would prevent counter-intuitive pricing results (and would allow traders in those instances to receive the Congestion Management Settlement Credit payment consistent with other situations where such payments are currently available).***

2. ***The MSP restates the recommendation in its December 2007 report that curtailed exports (or imports) for internal resource adequacy ('ADQh') should not be removed from the unconstrained schedule in order to ensure that actual market demand (or supply) is not distorted.***

<u>Recommendation 3-7 (Chapter 3, Section 4.1)</u>

Between August and October 2003 in an effort to reduce the instances of counter-intuitive prices, 400 MW of out-of-market Operating Reserve was introduced into the market as Control Action Operating Reserve (CAOR).[1] When scheduled in pre-dispatch, this CAOR is backed by the IESO designating an equivalent amount of exports as recallable. This measure (along with others) appears to have lessened counter-intuitive effects of control actions on market prices. We now observe, however, that CAOR scheduled in pre-dispatch has itself become associated with counter-intuitive prices following a change in procedure by the New York Independent System Operator and

[1] The IESO's market rule amendment MR-00235-R00-R05, was effective on August 6, 2003. Another 400 MW of CAOR was introduced in November 2005.

more recently by the Midwest Independent Transmission System Operator which will no longer accept recallable exports.

The MSP recommends that the IESO explore a solution to the emerging problem posed by recallable exports that are designated for Control Action Operating Reserve (CAOR), which induce counter-intuitive prices when rejected by the New York Independent System Operator and the Midwest Independent Transmission System Operator.

Recommendation 3-8 (Chapter 3, Section 4.2)

As shown in our December 2007 report and in Chapter 1 of this report, both the frequency and the magnitude of operating reserve activations (ORA) have been increasing. An operating reserve activation is: "selected based on an 'unoptimized' simple stacking of the lowest to highest energy costs (offers) for the facilities with an operating reserve schedule".[2] The major purposes of an ORA are to:

- deal with a sudden loss of a large generator or a main transmission line;
- restore Area Control Error (ACE)[3] from a large negative (above 200 MW) to zero;[4] and
- rarely, to activate OR for Shared Activation of Reserve or Regional Reserve Sharing at the request of external markets or jurisdictions.

The Panel has explored reasons for the increase in both frequency and magnitude of operating reserve activations, most of which can be attributed to restoring ACE. There were two major changes in May 2006 that appear to have led to increases in ACE deviations:

[2] See IESO's discussion paper titled: "Operating Reserve Activations (ORA) vs. One Time Energy Dispatch (OTD)", April 4, 2007.
[3] ACE is a function of generation output deviation from their schedule, frequency deviation, and a small term adjusted for operational metering error. ACE is mainly affected by internal generation off-dispatch and forced outages, as well as ACE deviation in adjacent markets.
[4] See "Market and System Operations Part 2.4: Real-Time Operating Procedures, Section 2: Assess Impact on Routine Operations". When ACE is positive by a large number, the IESO will manually dispatch down generators, based on generators' preference when the IESO verbally communicates with the generators.

- On May 4, 2006, the IESO lowered the minimum Automatic Generation Control requirement from 150 MW to 100 MW, in an effort to reduce the AGC cost. The 50 MW reduction in AGC capacity had some effect of increasing the use of ORA as well as One-Time Dispatches (OTD).[5]

- On May 8, 2006, the IESO increased the compliance deadband from 10 MW to 15 MW (i.e., the actual output of a unit is allowed to deviate by 15 MW from its received dispatch instruction without any compliance consequences). However, at times an OTD or ORA may be needed when many units deviate in the same direction. This is especially true in periods of increasing or decreasing load where typically fossil generators, which have a limited ramp capability, are moving in the same direction.

In response to increases in ACE deviation and the IESO exceeding the NERC Control Performance Standard (CPS) by lesser margins, the IESO changed its operating policy regarding the monitoring of CPS obligations in late September 2006. The Panel does not question the IESO's objective of recovering ACE deviations as required by NERC. However, it is not clear that the IESO's goal of having a higher performance standard than required by NERC is bringing benefits to the Ontario market that are greater than the costs involved in achieving it. The Panel believes, however, that the IESO can achieve its objectives in a way that is more compatible with market efficiency.

1. ***To avoid distorting market prices, the MSP recommends that the IESO maintain the Operating Reserve requirement when Operating Reserve is activated in response to Area Control Error (ACE);***

2. ***If the IESO believes that it must maintain a higher standard than the NERC Control Performance Standard, the MSP recommends that the IESO conduct a cost-benefit analysis comparing alternatives for responding to Area Control Error***

[5] See the IESO's study "DIWG – AGC Requirement", December 12, 2006 and "Proposal for Minimum Scheduling of AGC", February 16, 2007.

(ACE) deviations, that is: providing more Automatic Generation Control (AGC); using One-Time Dispatch (OTD); using Operating Reserve Activation (ORA); and establishing a capability to re-run the dispatch algorithm on demand.

3. ***In the interim, until a cost-benefit study of the alternatives for handling ACE deviations is completed, in accordance with Recommendation 3-8(2), and assuming the IESO adopts Recommendation 3-8(1) regarding the maintenance of the Operating Reserve requirement level when Operating Reserve is activated for ACE, the MSP recommends that the IESO should use ORA instead of One-Time Dispatch to deal with negative ACE whenever possible.***

Recommendation 3-9 (Chapter 3, Section 5)

The Panel has long questioned what benefits the market receives from constrained-off payments. One of the major explanations for this market design feature was that, in a uniform-priced market, providing constrained-off payments encouraged market participants to follow their dispatch instructions. It has been argued that without these payments generators might continue to supply above their dispatch in order to avoid losing profit associated with production at higher prices.

We are now observing that there are fairly regular large dispatch deviations by generators which result in the need for the IESO to activate operating reserve or use one-time dispatches to correct for shortfalls in generation (see Chapter 3). There have been more than $550 million in constrained off CMSC payments since the market opened, on average about $7.6 million per month.

The Panel continues to hold the view that constrained off CMSC payments cannot be justified by the assumption that these encourage resources to comply with dispatch instructions. In spite of these payments, we have seen an increase in deviations from dispatch, and have seen deviations induce CMSC payments. Also, about one-quarter of the constrained off CMSC payments are to imports and exports for which there is no possibility of deviations, because of scheduling protocols between markets.

The MSP recommends that the IESO review the benefits of constrained off payments with a view to their discontinuation.

In response to a suggestion of the IESO's Stakeholder Advisory Committee, we have identified relative priorities among these recommendations. We have grouped the recommendations under four categories – price fidelity, dispatch, transparency, and hourly uplift payments – and ranked them as follows:

PRICE FIDELITY	DISPATCH	TRANSPARENCY	HOURLY UPLIFT PAYMENTS
3-7	2-1	3-5	3-9
3-6(2)	3-8(2)	3-3	3-1
3-8(1)	3-8(3)	3-4	
3-6(1)		3-2	
2-2			

The Panel regards each recommendation as important to improving the operation of the market. In particular, changes that may individually not be regarded as large can have a substantial cumulative effect, as well as spillover benefits in improving the confidence that market participants have in the operation of the Ontario market. Many of the recommendations do not appear to involve significant implementation costs; however, it remains the task of the IESO and stakeholders to identify costs and benefits from a broader perspective and establish final priorities and implementation schedules.