

Memorandum

To: Market Pricing Working Group
Date: May 13, 2008
Re: MPWG Issue #9: Peak versus Average Demand Forecast in Pre-Dispatch

The attached report describes the methods and results of work to evaluate the costs and benefits of using an average demand forecast in pre-dispatch, including estimates of the pricing impacts and wealth transfer effects.

The purpose of this initiative is to assess the economic efficiency impacts and reliability impacts of using an average demand forecast in pre-dispatch. The IESO uses a cost-benefit analysis (CBA) to review changes that impact economic efficiencies. As noted in the attached report, using an average demand forecast would improve economic efficiencies but also result in wealth transfers.

We welcome feedback on the analysis methodology and results and would appreciate written feedback by May 27, 2008, for discussion at the June 5th MPWG meeting. Please send written comments to: IESOMarketPricingWorkingGroup@ieso.ca

With respect to a recommendation on whether or not to use an average demand forecast, the IESO is committed to making a decision by the end of 2008. Prior to making that decision, the IESO is proposing to consult with stakeholders on a broader public policy issue, i.e. the appropriate criteria for trading off efficiency gains and wealth transfers. These discussions would involve the Market Pricing Working Group (MPWG) and the Stakeholder Advisory Committee (SAC).

The following is a proposed schedule for stakeholder review of the analysis and to address the broader public policy issue, mindful of the IESO's commitment to making a recommendation by the end of 2008:

May 13	Publish results of analysis
May 16	Discuss analysis methodology and results with MPWG; solicit written comments
May 27	Closing date for comments on the analysis methodology and results
Jun 5	Follow-up with MPWG on any written comments regarding the analysis
Aug 19, 20	Discussions with MPWG and SAC about the broader public policy issue; solicit written comments
Q4 2008	IESO recommendation and decision

Yours truly,

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Attach.



Peak versus Average in Pre-Dispatch: Results of Analyses

May 13, 2008

Public

Table of Contents

1.	PURPOSE	1
2.	BACKGROUND.....	1
3.	EFFICIENCY ANALYSIS	2
3.1	Simulations	2
3.2	Accounting for Export Response and Its Impact on Imports.....	3
3.3	Calculating Efficiency Changes.....	3
3.4	Efficiency Analysis Results.....	4
4.	RELIABILITY ASSESSMENT	5
4.1	Historical Data Review	5
4.2	Assessing Reliability Impacts in the Sample Data Set	5
5.	COST BENEFIT ANALYSIS.....	7
5.1	Potential Benefits.....	7
5.2	Potential Costs	8
5.3	Comparison of Benefits and Costs.....	8
6.	PRICE IMPACTS AND WEALTH TRANSFER EFFECTS	9
6.1	Price Impacts	9
6.2	Wealth Transfer Effects.....	9
7.	CONCLUSIONS AND NEXT STEPS	10
	APPENDIX A – CALCULATING EQUILIBRIUM VALUES	12
	APPENDIX B – CALCULATING CHANGES IN EFFICIENCY.....	14

**APPENDIX C – MARKET SURVEILLANCE PANEL SUPPLY CUSHION
METHODOLOGY 17**

**APPENDIX D – CATALOGUE OF MPWG MATERIALS ON ISSUE #9: USE OF
PEAK DEMAND LOAD FORECAST IN PRE-DISPATCH 20**

1. Purpose

The purpose of this initiative is to assess the economic efficiency impacts and reliability impacts of using an average demand forecast in pre-dispatch compared to the current use of a peak demand forecast. The IESO uses a cost-benefit analysis (CBA) to review changes that impact economic efficiencies.

Addressing the use of peak versus average hourly demand forecast in pre-dispatch is also one of the IESO's corporate performance measures for 2008¹. Note that "addressing" an issue does not necessarily mean a change to the status quo. Retaining the status quo is a possible outcome of the consideration of an issue.

This paper provides:

- A description of the analyses used to assess the efficiency and reliability impacts of using an average demand forecast instead of a peak demand forecast in pre-dispatch;
- The results of the efficiency and reliability analyses;
- Cost-benefit analysis of the proposed change, including price and wealth transfer impacts; and
- Conclusions and next steps.

2. Background

The pre-dispatch run of the unconstrained algorithm determines hourly schedules (quantities) for domestic generation, imports and exports based on a single forecast demand value for a given hour. There will always be economic inefficiencies associated with the use of a single forecast value across a one-hour period because that forecast value is only likely to be correct for one 5-minute interval out of twelve in real-time.

The IESO currently uses a peak demand forecast in pre-dispatch so that sufficient resources are scheduled to meet the highest expected real-time demand in the upcoming hour.

Some stakeholders have expressed concern that using a peak demand forecast in pre-dispatch may be resulting in an over-commitment of supply resources in pre-dispatch due to the difference between the way imports and exports are scheduled compared to domestic supply. Domestic resources are scheduled and dispatched on the basis of forecast actual demand for the next five minutes whereas imports and exports are scheduled one-hour ahead of real-time and are scheduled for an entire hour².

¹ IESO 2008 Corporate Performance Measures can be found at:

<http://www.ieso.ca/imoweb/corp/corppperformance.asp>

² The scheduling of imports and exports is based on scheduling protocols between Ontario and neighbouring jurisdictions; changes to those protocols would require agreement amongst all parties.

From an economic efficiency perspective, the commitment of supply resources on the basis of the forecast of peak demand may be exaggerating the inefficiencies associated with the use of single demand forecast value in pre-dispatch. The use of peak forecast value may be resulting in:

- Higher priced committed imports instead of lower priced available domestic supply; and
- The advanced start or delayed shut-down of fossil generating units causing unnecessary fuel costs and speed-no load costs.

It has been suggested that using an average demand forecast, rather than a peak demand forecast value, may improve economic efficiencies.

More details about this initiative can be found on the stakeholder engagement web page at:

http://www.ieso.ca/imoweb/consult/consult_se54.asp

3. Efficiency Analysis

3.1 SIMULATIONS

In order to determine the economic efficiency impacts of using an average demand forecast, simulations were performed to replicate the dispatch scheduling optimizer (DSO). The DSO determines the most efficient solution by maximizing the economic gain from trade. By definition, this solution will be the lowest cost solution to satisfy a given level of demand based on the offers/bids submitted.

Using 12 weeks of actual data from 2006, two sets of simulations of pre-dispatch and real-time were performed in order to generate two values for the total cost of satisfying real-time demand³. The first set of simulations generated pre-dispatch and real-time schedules based on a peak demand forecast in pre-dispatch while the second set of simulations generated different pre-dispatch and real-time schedules based on an average demand forecast in pre-dispatch. The economic efficiency impacts of using an average forecast were determined by comparing the difference between the two sets of simulations in the total costs of meeting real-time demand.

In order to estimate the true market efficiency impact of the proposed change, simulations of the constrained run of the DSO would be necessary. However, the IESO simulation tools only simulate the pre-dispatch and real-time unconstrained run of the DSO.

With respect to the pricing impacts of moving from a peak to average demand forecast in pre-dispatch, a 3x ramp rate multiplier would provide the best estimates of those price impacts since real-time price is determined in the unconstrained sequence using a 3x ramp rate multiplier. For the purpose of this study, a 3x ramp rate multiplier was used in the simulations to provide the most reasonable estimates of the pricing impacts.

Other assumptions of the simulations include:

- No change in Ontario demand
- Generator offers are representative of production costs

³ The sample data consists of one week of data from each month in 2006. The data from January and August contain the winter and summer peak demands, respectively.

- Import offers are representative of the opportunity cost of providing energy to Ontario
- Dispatchable load bids are representative of the value of consumption
- No change in offers/bids of generators, imports, dispatchable loads
- Export response to price based on elasticity estimates from a previous IESO study – see section 3.2.

Using an average demand forecast instead of a peak demand forecast in pre-dispatch would put downward pressure on the pre-dispatch price. In real-time, it's expected there would be upward pressure on price because scheduling fewer import transactions in pre-dispatch means there would be fewer import transactions included in the real-time supply stack. Since scheduled imports are assigned a -\$2000/MWh offer price in real-time, reducing the level of imports in real-time would cause upward pressure on real-time price.

3.2 ACCOUNTING FOR EXPORT RESPONSE AND ITS IMPACT ON IMPORTS

The potential export response resulting from the expected upward pressure on price needs to be incorporated into the analysis. The expected increase in real-time price would likely lead to fewer exports. This would result in a lower pre-dispatch demand so fewer imports would be scheduled.

To incorporate these effects into the analysis, the simulation data was modified to capture the relationship between exports and real-time prices based on export elasticity estimates from a previous IESO study⁴. In that study, it was estimated that a 1% increase in the real time price reduces the volume of real-time exports by 5.6% in on-peak hours and by 2.8% in off-peak hours.

Finally, the estimated decrease in exports (and market demand) would likely result in even fewer imports being scheduled. This likely response was also modelled by modifying the simulation data through the use of mathematical formulas. Refer to Appendix A for more details about the method used to calculate the equilibrium values that account for export response and its impact on imports.

3.3 CALCULATING EFFICIENCY CHANGES

The change in efficiency is equivalent to the change in total surplus. Since the change in total surplus is equal to the change in the cost of satisfying demand, the change in efficiency is dependent on three components:

- Change in avoided cost of imports;
- Change in export surplus, i.e. lost surplus to exports due to reduced exports; and
- Change in domestic production costs.

By using an average demand forecast instead of a peak demand forecast in pre-dispatch, it's expected that fewer import transactions would be scheduled and, therefore, the cost of imports would decrease, i.e. avoided cost of imports increases.

⁴ Refer to http://www.ieso.ca/imoweb/pubs/consult/mep2/MP_WG-20070509-Export-Elasticity-Estimate.pdf

Given that scheduling fewer import transactions in pre-dispatch would put upward pressure on real-time price, it's expected that fewer export transactions would be scheduled thereby reducing export surplus.

Finally, the change in domestic production costs are likely to increase since more internal generation would be scheduled in place of imports.

For a more detailed discussion about the efficiency calculations, refer to Appendix B.

3.4 EFFICIENCY ANALYSIS RESULTS

The total change in efficiency can be expressed as:

$$\text{change in avoided cost of imports} + \text{change in export surplus} - \text{change in domestic production costs}$$

(positive value) (negative value) (positive value)

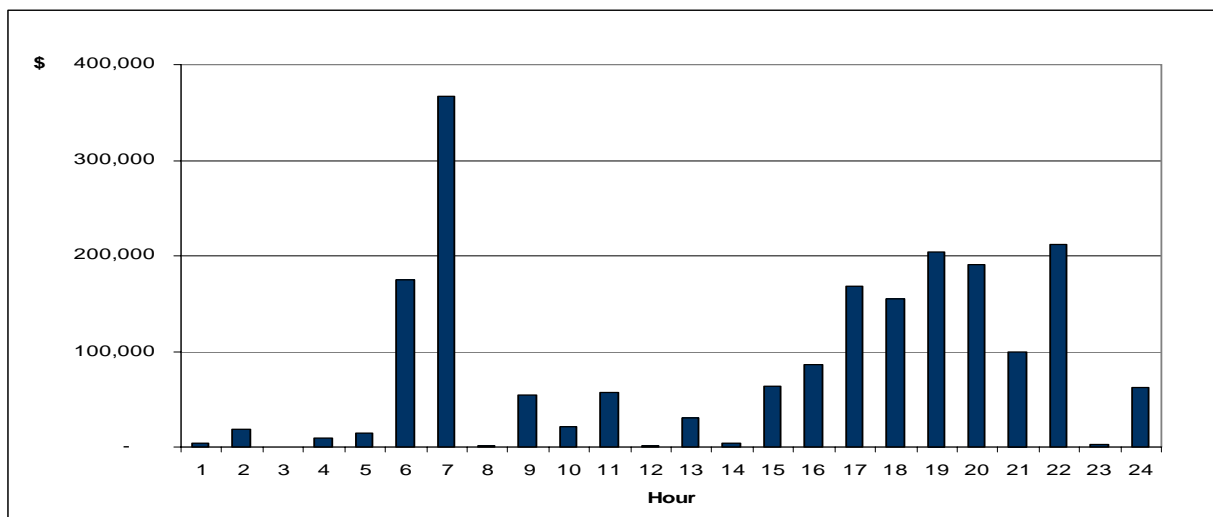
The change in efficiency will be positive if the change in avoided cost of imports exceeds the reduction in export surplus and the increase in domestic production costs. Table 1 shows the results of the efficiency analysis for the 12 weeks in the sample.

Table 1: Efficiency Analysis Results (\$ million)

Period	Δ avoided cost of import	Δ export surplus	Δ domestic production costs	Δ total efficiency (for the sample)	Δ total efficiency (annualized)
All hours	17.6	-10.8	4.8	2.0	8.7
On-peak	14.1	- 8.7	3.7	1.7	7.4
Off-peak	3.5	- 2.1	1.1	0.3	1.3

The sample estimates of total changes in efficiency, by hour, are shown in Figure 1. Efficiency gains are positive in all hours and are generally larger in those hours where demand is ramping up/down.

Figure 1: Total Efficiency Changes for the Sample, by Hour



4. Reliability Assessment

The IESO currently uses the peak demand forecast in pre-dispatch so that sufficient resources are scheduled to meet the highest expected real-time demand in the upcoming hour.

In order to estimate the reliability impacts of using an average demand forecast instead of a peak demand forecast, the increased probability of the use of control actions was used as a proxy for the increased reliability risk of moving from peak to average.

A review of the historical relationship between the use of control actions for global adequacy and the Market Surveillance Panel (MSP) real-time supply cushion measure⁵ provided a benchmark for establishing a supply cushion “threshold”. For supply cushion levels below this threshold, the probability of having to use control actions increases.

4.1 HISTORICAL DATA REVIEW

The historical review considered hourly supply cushion data and control actions taken from January 2005 to October 2007. A control action occurred in any hour where at least one of the following actions occurred: implemented voltage reductions, implemented environmental variances, issued NERC Emergency Energy Alert 3, operated to emergency condition limits, purchased emergency assistance, and implemented EDRP.

Control actions were used in the historical data set in 0.17% of all hours. For each event when control actions were used, the supply cushion dropped below 5% in at least one of the hours leading up to or during the event. Although there were many hours where the supply cushion dropped below 5% and control actions were not taken, the historical data provides some evidence that a supply cushion of less than 5% combined with other events increases the likelihood of having to use control actions.

4.2 ASSESSING RELIABILITY IMPACTS IN THE SAMPLE DATA SET

The first step in assessing the reliability impact of using an average demand forecast instead of a peak demand forecast was to determine the number of hours in the 12-week sample where the real-time supply cushion dropped below 5%. The next step was to calculate, for all hours in the 12-week sample, the real-time supply cushion based on the use of an average demand forecast in pre-dispatch.

For any given hour, the real-time supply cushion based on an average demand forecast will be smaller than the real-time supply cushion using a peak demand forecast because fewer resources will be selected in pre-dispatch.

Table 2 shows the number of hours in the 12-week sample where the supply cushion was below 5% in the sample using a peak and average demand forecast in pre-dispatch, respectively. Table 3 shows the hourly breakdown for all hours where the supply cushion was less than 5%.

⁵ Refer to Appendix D for a more detailed description of the MSP real-time supply cushion measure.

Table 2: Sample statistics for supply cushion below 5%

Supply cushion below 5%	Peak Forecast	Average Forecast	Delta
# hours	370	399	29
% of all hours in sample	19.3%	20.8%	1.5%
average supply cushion during those hours	2.9%	2.7%	-0.2%

Table 3: Number of hours where supply cushion was below 5%

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Peak	0	0	0	0	0	0	8	22	26	33	34	29	25	17	15	16	18	37	39	31	17	2	1	0
Avg	0	0	0	0	0	0	8	24	27	34	36	30	27	18	15	16	20	42	43	33	20	5	1	0
Delta	0	0	0	0	0	0	0	2	1	1	2	1	2	1	0	0	2	5	4	2	3	3	0	0

As shown in Table 3, there are no instances in hours 1-6, and 24 where the supply cushion drops below 5%, in either scenario. In hours 7, 15 and 16, the use of an average demand forecast does not increase the number of times the supply cushion drops below 5%. For the remaining hours, the use of an average demand forecast results in a small increase in the number of times the supply cushion drops below 5%.

Based on IESO experience, and considering the supply cushion data for the 12-week sample, the IESO has concluded that there would be unacceptable risk of adverse reliability impacts of using an average demand forecast in hours where demand is increasing significantly (roughly hours 6-9 and hours 16-19). In all remaining hours, the IESO believes that the risk of adverse reliability impacts of using an average demand forecast would be manageable.

In advance of implementing any proposed change, the IESO would define and publish the “ramp-up periods”, i.e. those hours where demand is increasing significantly. A peak demand pre-dispatch forecast would continue to be used for those hours. For any given day, there are likely to be 5-8 hours that would be considered ramp-up hours, depending on the season and other conditions. Also, the IESO would use a peak demand forecast in any hour if:

- the supply cushion for that hour falls below 5% in the day-ahead commitment run; or
- the IESO identifies any reliability concerns with using average for that hour.

If, for the reasons noted above, the IESO decided to use a peak forecast in any hour other than the pre-defined ramp-up hours, the IESO would notify the market to that effect by issuing a system status report.

While quantifying the costs and benefits assists the decision makers in understanding the magnitude of the effects of the different options, it may not be possible or practicable to monetize some costs and benefits because of their nature or lack of data. With respect to monetizing the reliability impacts, the sample data set does not provide sufficient data for a quantitative assessment.

5. Cost Benefit Analysis

5.1 POTENTIAL BENEFITS

Efficiency Improvements

The efficiency analysis described in section III tested the hypothesis that using an average demand forecast in pre-dispatch, rather than a peak demand forecast, would improve economic efficiencies.

Based on the results of the efficiency analysis, it's estimated that using an average demand forecast would improve efficiency in all hours. Estimates of the annual efficiency improvements range from approximately \$1.3 million for off-peak hours to \$8.7 million for all hours. Given that the IESO has determined, for reliability reasons, that a peak forecast will continue to be used for ramp-up hours, its estimated that the efficiency improvements of using a average forecast in the remaining hours would be in the range of \$3.4 million annually⁶.

Other Non-Quantified Benefits

- Convergence between pre-dispatch and real-time price

As identified by the Market Surveillance Panel, the use of a peak demand forecast in pre-dispatch contributes to a persistent positive difference between the pre-dispatch price and the real-time price. This provides market participants with an inaccurate market signal from which to plan their operations. By using an average demand forecast instead of a peak demand forecast in pre-dispatch, it's expected that fewer import transactions would be scheduled and fewer domestic resources would receive a pre-dispatch schedule. This would result in a lower pre-dispatch price. In real-time, it's expected there would be upward pressure on price because scheduling fewer import transactions in pre-dispatch means there would be fewer import transactions included in the real-time supply stack. Therefore, the use of an average demand forecast would be expected to improve the convergence between pre-dispatch and real-time price, providing a better price signal to the market in pre-dispatch.

- Reduction in excess baseload generation (EBG)

Excess baseload generation occurs when baseload generation exceeds demand. EBG occurs during low demand periods and can result in significant financial costs to baseload generators. Using an average demand forecast in the off-peak hours could reduce the occurrences of EBG because fewer non-baseload resources would be scheduled.

- Reduction in the volatility of dispatch instructions

One of the reasons market demand and market supply exhibit abrupt changes at the top of the hour is the coordinated change in exports and imports made at that time. By using an average demand forecast instead of a peak demand forecast, fewer import and export transactions would be scheduled in both pre-

⁶ This estimate is based on the assumption that an average forecast is used in all hours except hours 6-9 and 16-19.

dispatch and real-time. This could alleviate some of the volatility in the dispatch instructions received by domestic generators.

- Reducing the global adjustment

Using an average demand forecast instead of peak demand forecast is expected to put upward pressure on real-time price. This would reduce the global adjustment thereby increasing the transparency of electricity costs on consumers' bills.

5.2 POTENTIAL COSTS

Reliability Impacts

While the reliability costs are not quantified, based on the reliability assessment described in section 4, the IESO does not believe that there would be a material impact on reliability by moving from a peak to average demand forecast in pre-dispatch for those hours where demand is not significantly increasing. However, if a decision is made to use an average demand forecast in certain hours, the IESO would retain the right to use a peak demand forecast if the IESO identifies any reliability concerns associated with the change.

Implementation Costs

- There are no IESO implementation costs associated with this change.
- This change should be seamless to participants so it's not expected that participants' will incur any implementation costs associated with this change.

5.3 COMPARISON OF BENEFITS AND COSTS

Typically, a cost-benefit analysis would consider the net present value of the costs and benefits of the proposed change. Since there are positive benefits associated with using an average demand forecast instead of a peak demand forecast and there are no material costs, it is not necessary to specify the timeframes and discount rates associated with this proposed change.

Therefore, the net benefit of the proposed change is equivalent to the estimated efficiency improvements. On an annual basis, the net benefits are estimated to be approximately \$3.4 million if an average demand forecast was used in hours where demand is not increasing significantly.

6. Price Impacts and Wealth Transfer Effects

6.1 PRICE IMPACTS

Using an average demand forecast in pre-dispatch is expected to put upward pressure on real-time price because fewer import transactions (priced at -\$2000/MWh in real-time) would be included in the real-time supply stack.

Based on the simulation results and accounting for export response, the average increase in the hourly Ontario energy price (HOEP) is estimated to be \$1.08/MWh for those hours in which an average demand forecast is used⁷. This translates into an average annual increase in HOEP of approximately \$0.72/MWh.

The degree to which Ontario consumers are exposed to changes in the hourly Ontario energy price (HOEP) depends on the amount of Ontario production under fixed price contracts. Much of the generation in Ontario is associated with some fixed pricing mechanism, either regulated or contracted prices. Each month, wholesale consumers receive an adjustment amount to account for the difference between the market price for energy and the prices paid to certain regulated and contracted generators. This adjustment is called the “global adjustment.” It has been estimated that the effective hedge provided by the global adjustment is approximately 80%⁸. That is, a \$1/MWh increase in HOEP would translate into an effective price increase of \$0.20/MWh. Therefore, the estimated average annual increase in HOEP of approximately \$0.72/MWh translates into an effective price increase of \$0.14/MWh.

6.2 WEALTH TRANSFER EFFECTS

Although the total net benefit of the proposed change is positive, there are wealth transfer implications associated with using an average demand forecast in pre-dispatch instead of a peak demand forecast. Use of an average demand forecast in pre-dispatch would put upward pressure on price. Therefore, there would be a wealth transfer from Ontario consumers, those paying the increased price, to domestic generators, those receiving revenues based on higher prices.

Other wealth transfer considerations include:

- Intertie Offer Guarantee Impacts

Import offers that are scheduled in pre-dispatch receive an intertie offer guarantee (IOG) which pays importers based on the higher of their offer price and the real-time price. IOGs are intended to help ensure adequate supply in Ontario by attracting sufficient imports.

By using an average demand forecast in non ramp-up hours in pre-dispatch, fewer imports would be scheduled thereby reducing the amount of IOG payments. For those hours in the sample where an average demand forecast is used, it's estimated that total IOG payments in these hours would fall by \$1.0 million. On an annualized basis, this represents a reduction in IOG payments of approximately \$4.3 million.

⁷ This estimate is based on the assumption that an average forecast is used in all hours except hours 6-9 and 16-19.

⁸ Refer to IESO discussion paper, “The Role of Fixed Price Contracts and the Global Adjustments in Mitigating Price Changes to Consumers”, <http://www.ieso.ca/imoweb/pubs/consult/se17/se17-20061019-Fixed-Prices-and-Hedging.pdf>

- Congestion Management Settlement Credits

The IESO does not expect a material change in the level of congestion management settlement credits (CMSC) payments. The DSO minimizes the cost of meeting a certain level of demand and since one of the assumptions of the analysis is that Ontario demand does not change, total CMSC payment are not expected to change significantly.

Table 4 provides a summary of the estimated total wealth transfer effects on Ontario consumers.

Table 4: Wealth Transfer Effect on Ontario Consumers

Option	Change in Annual Average HOEP (\$/MWh)	Change in Average Effective ⁹ HOEP (\$/MWh)	Change in Effective HOEP times MW Consumed (\$ million)	Change in IOG Payments (\$ million)	Net Wealth Transfer from consumers to suppliers (\$ million)
Use avg in all hours except ramp-up hours	0.72	0.14	21.6	-4.3	17.3

7. Conclusions and Next Steps

The results of the cost-benefit analysis suggest that using an average demand forecast in pre-dispatch in all hours would improve economic efficiencies. The IESO has determined that the potential risk to reliability of using an average demand forecast in hours where demand is increasing significantly, outweigh any potential efficiency gains in those hours. In all remaining hours, the IESO believes that the risks to reliability of using an average demand forecast would be manageable.

It's estimated that the proposed change, i.e. using an average demand forecast in all hours except ramp-up periods, would increase economic efficiencies by approximately \$3.4 million annually. It's also estimated that the propose change would result in an average annual increase in HOEP of approximately \$0.72/MWh. Considering the impact of the global adjustment and the OPG rebate, the effective HOEP would increase by \$0.14/MWh. This would result in a wealth transfer from consumers to suppliers in the range of \$17 million dollars annually.

A standard CBA recommends changes that are economically efficient, while ignoring the effects of the change on wealth distribution¹⁰. However, efficiency is typically not the sole criterion for public policy decision; analysis of who gains and who loses can be critical to the final decision. In the IESO-administered markets, stakeholder impacts, particularly the impact on the province's consumers would be considered and factored into the IESO's final recommendation to the Board¹¹.

⁹ Effective HOEP includes the impact of global adjustment and OPG rebate.

¹⁰ This is the outcome of the Kaldor-Hicks criterion. See "[Overview of Cost-Benefit Analysis and its Applications in Public Policy Decisions](#)," by Michael Trebilcock, Adonis Yatchew, and Andy Baziliauskas

¹¹ Along with promoting economic efficiency for the sector, a key objective defined by the Electricity Restructuring Act, 2004 is "to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service." The IESO must be mindful of this objective when reviewing market evolution initiatives.

Prior to making a recommendation to the IESO Board, the IESO will consult with stakeholders on the appropriate criteria for trading off efficiency gains and wealth transfers. These discussions would involve the Market Pricing Working Group and the Stakeholder Advisory Committee.

Appendix A – Calculating Equilibrium Values

Equilibrium Conditions:

- 1) $\Delta H = k_1 \cdot (\Delta E - \Delta I)$
- 2) $\epsilon = \Delta E / \Delta H \cdot H/E \Rightarrow \Delta H = (H/E \cdot 1/\epsilon) \cdot \Delta E \Rightarrow \Delta H = k_2 \cdot \Delta E$
- 3) $\Delta D + \Delta E = k_3 \cdot \Delta I + (1 - k_3) \cdot \Delta G, k_3 \leq 0.5$

where:

ΔH = change in HOEP;

ΔE = change in exports;

ΔI = change in imports;

ϵ = export elasticity, i.e. % change in export volume resulting from a 1% change in HOEP;

ΔD = change in Ontario demand; and

ΔG = change in Ontario generation;

Solve for k_1, k_2, k_3

- a) k_1 represents the slope of the real-time supply curve;

$k_1^* = \Delta H_s / (\Delta E_s - \Delta I_s)$, where:

ΔH_s = simulated real-time HOEP based on average demand forecast in pre-dispatch minus simulated real-time HOEP based on peak demand forecast in pre-dispatch

ΔE_s = simulated real-time exports based on average demand forecast in pre-dispatch minus simulated real-time exports based on peak demand forecast in pre-dispatch

ΔI_s = simulated real-time imports based on average demand forecast in pre-dispatch minus simulated real-time imports based on peak demand forecast in pre-dispatch

- b) k_2 represents the slope of the export demand curve;

$k_2^* = H_p / E_p \cdot 1/\epsilon$, where:

H_p = simulated real-time HOEP based on peak demand forecast in pre-dispatch

E_p = simulated real-time exports based on peak demand forecast in pre-dispatch

ϵ = export elasticity measure: -5.6 for on-peak hours, -2.8 for off-peak hours¹²

- c) k_3 represents the proportion of market demand change met by imports

Mathematically, large price changes in the data set can result in final export and import values that are negative because of the assumption of a single export elasticity values, -5.6 and -2.8, for all peak and off-peak hours,

¹² These elasticity estimates were obtained from a previous IESO study. For more information on the analytical approach used to derive the elasticity estimates, refer to http://www.ieso.ca/imoweb/pubs/consult/mep2/MP_WG-20070509-Export-Elasticity-Estimate.pdf

respectively. Capping k_3 at 0.5 ensures that the calculated final export and import values in the sample are non-negative.

$k_3^* = \Delta I_s / (\Delta D_s + \Delta E_s)$, where:

ΔD_s = change in Ontario demand \rightarrow difference between average and peak demand forecast, and change in exports

Solve Equilibrium Values

Solve for final values which incorporate export and import responses to price changes

• Three equations with three unknowns: ΔH_f , ΔE_f , ΔI_f

1) $\Delta H_f = k_1^* \cdot (\Delta E_f - \Delta I_f)$

2) $\Delta H_f = k_2^* \cdot \Delta E_f$

3) $\Delta I_f = k_3^* \cdot (\Delta D_s + \Delta E_f)$

Substitute 3) into 1)

(1') $\Delta H_f = k_1^* \cdot [\Delta E_f - k_3^* \cdot (\Delta D_s + \Delta E_f)]$

Solve for ΔE_f^* by setting (2) equal to (1')

$$k_2^* \cdot \Delta E_f^* = k_1^* \cdot [\Delta E_f^* - k_3^* \cdot (\Delta D_s + \Delta E_f^*)]$$

$$k_2^* \cdot \Delta E_f^* = k_1^* \cdot \Delta E_f^* - k_1^* \cdot k_3^* \cdot \Delta D_s - k_1^* \cdot k_3^* \cdot \Delta E_f^*$$

$$k_2^* \cdot \Delta E_f^* = \Delta E_f^* (k_1^* - k_1^* \cdot k_3^*) - k_1^* \cdot k_3^* \cdot \Delta D_s$$

$$\Delta E_f^* = (-k_1^* \cdot k_3^* \cdot \Delta D_s) / [k_2^* - (k_1^* (1 - k_3^*))]$$

Solve for ΔH_f^* using equation (2)

Solve for ΔI_f^* using equation (3)

Solve for ΔG_f^* :

$\Delta G_f^* = \Delta D_f + \Delta E_f^* - \Delta I_f^*$, where $\Delta D_f = 0$ since assume no change in real-time Ontario demand

Appendix B – Calculating Changes in Efficiency

Change in total surplus = change in avoided cost of imports plus change in export surplus minus increase in domestic production costs

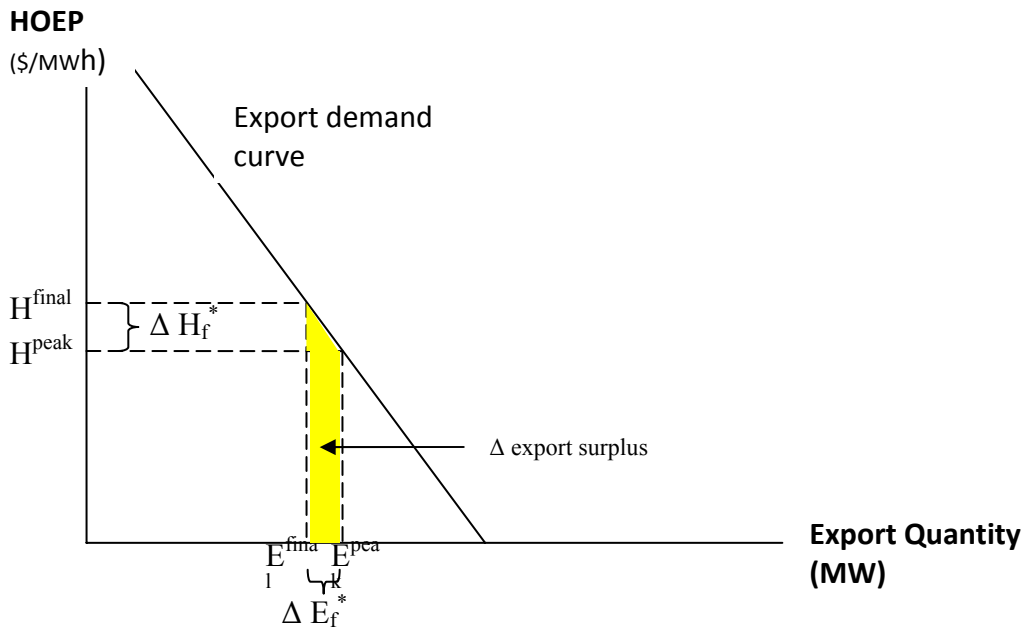
1) Δ Avoided cost of imports

- From the initial pre-dispatch and real-time simulations, know the total hourly change in import levels and the change in total import cost. From this information, can compute an hourly average avoided import cost (\$/MWh).
- Apply this hourly average avoided cost value to the final change in imports to arrive at the new total avoided import cost.

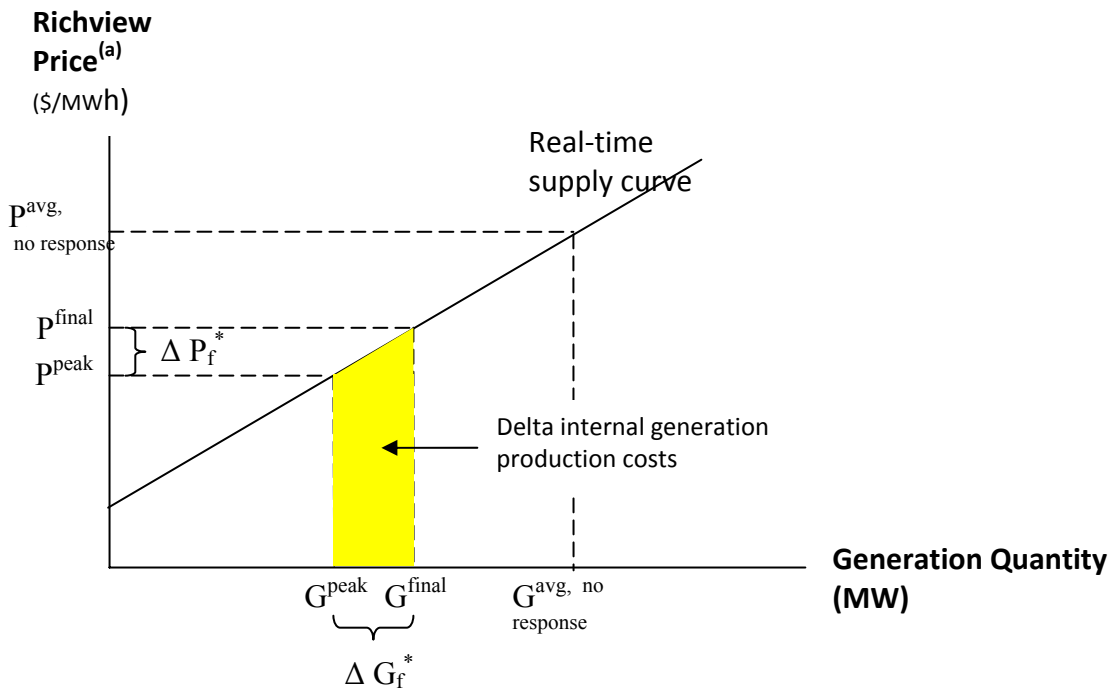
Illustrative Example:

	Delta Imports (MW)	Delta Total Avoided Cost of Imports (\$)	Average Avoided Import Cost (\$/MW)
From Simulations Imports under peak minus Imports under average	100	5,000	= 5000/100 = 50
Imports under peak (from simulation) minus Final Imports (accounting for export response)	118	=118 x 50 = 5,900	Assume same as above

$$2) \Delta \text{ Export Surplus} = \Delta E_f \cdot (H_{\text{peak}} + H_{\text{final}}) / 2$$



$$3) \Delta \text{ Internal generation production costs} = \Delta G_f \cdot (P_{\text{peak}} + P_{\text{final}}) / 2$$



^(a) The increase in domestic generation is priced according to locational marginal price. The nodal price at the Richview bus is representative of the load-weighted average of nodal prices around the province. For this analysis, the "final" Richview price was approximated by multiplying the estimated final HOEP value by the sample

average ratio of Richview price to HOEP. For the 12-week sample from 2006, the average ratio of Richview price to HOEP is approximately 1.09.

Appendix C – Market Surveillance Panel Supply Cushion Methodology

Appendix: A Revised Supply Cushion Methodology

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

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

Where:

EO = total amount of available energy offered

ED = total amount of energy demanded (average in an hour)

OR = total operating reserve requirement (average in an hour)

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

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

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

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

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

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

	Old Approach	New Approach
Import offers	Offers counted in the PD-TSC and actual imports included in the RT-TSC ¹	Scheduled MW in the PD-TSC and actual MW in the RT-TSC.
Ramp capability	Not considered	Considered with 60 minute horizon for pre-dispatch and 5 minute for real-time
Energy demand	Non-dispatchable demand plus both dispatchable demand and exports that bid at \$2,000	Non-dispatchable demand plus dispatchable demand that bid at \$2,000 (exports excluded)
Non price responsive generators, such as nuclear, self-scheduling, and intermittent generators	Offers in all SC	Offers in the PD SC, but actual supply in the RT SC
Definition of an online fossil generator	Online in the delivery hour	Online at the time PD run for the PD-TSC and PD-DSC, or online in interval 12 in previous hour for the RT-TSC and RT-DSC ²⁶

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

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

²⁷ The CAOR resource was removed from supply in our December 2006 report.

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

Appendix D – Catalogue of MPWG Materials on Issue #9: Use of Peak Demand Load Forecast in Pre-Dispatch

Date	Meeting #	Documents
Feb 7, 2008	MPWG 47	Presentation - Preliminary Efficiency Analysis Results (Phase 1 – no export/import response)
Jul 19, 2007	MPWG 43	Presentation: Draft Efficiency Analysis Proposal Discussion Paper: Draft Efficiency Analysis Proposal
May 9, 2007	MPWG 41	Presentation: Pre-Dispatch Demand Forecasting: Refresher \ Information Session and Proposed Work Plan
Dec 6, 2006	MPWG 35	Presentation: Investigating Gross Inefficiencies
Nov 3, 2006	MPWG 34	Presentation - Peak vs Average Pre-Dispatch Demand Forecasting
Sep 1, 2006	MPWG 32	Simulation data – Peak vs. Avg Guide to simulation data – Guide to Peak vs. Average Data
Sep 9, 2005	MPWG 23	Presentation - Possible Changes to PD Demand Forecast and IOG
Aug 5, 2005	MPWG 22	Encore Presentation – Demand Forecast Used by Pre-Dispatch
Jul 8, 2005	MPWG 21	Presentation - Demand Forecast Used by Pre-Dispatch
Jul 9, 2004	MPWG 5	Discussion paper – Use of Peak Demand in Pre-Dispatch Sequence
Oct 7, 2002	n/a	Issue identified in MSP Report for May-Aug 2002 (section 2.5.1)