Stakeholder Engagement SE-54 - IESO decision on the use of a peak vs. average demand forecast

Over the past year, the IESO has actively consulted with members of the Market Pricing Working Group (MPWG) on the merits of using an average demand forecast in pre-dispatch compared to the current use of a peak demand forecast. In considering this change, the IESO conducted a cost-benefit analysis (CBA) to assess the impacts on economic efficiency, reliability and stakeholders, including on consumers' electricity bills.

In addressing this matter, we also endorsed a structured approach to decision-making aimed at encouraging a general understanding within the industry as to how we would resolve the tensions that can exist between efficiency improvements and impacts on participants, providing more transparency and predictability of decision making, accelerating the decision making process, and resulting in "better" overall decisions. Drawing on expert advice in cost-benefit analysis and public policy decision making, four possible decision criteria were identified and presented for consideration to the members of the Stakeholder Advisory Committee (SAC).

The IESO analysis indicates that changing to the use of an average forecast would produce overall market efficiencies of some $3.4 million per annum, with gains to generators of $23 million but at a cost to consumers of $17 million. Additional qualitative costs and benefits were also identified.

Given the current economic conditions, and the relatively small efficiency gains, the IESO has concluded that in the circumstances we should not make the change to use of an average forecast. With this decision taken, the IESO will continue to work with participants and Stakeholder Advisory Committee members to advance other market evolution initiatives that will produce efficiency gains to the benefit of the province.

A synopsis of the matters considered in addressing the issue of "peak vs average" is appended. Additional background Material can be found at http://www.ieso.ca/imoweb/consult/consult_se54.asp and http://www.ieso.ca/imoweb/consult/consult_se77.asp.

APPENDIX A

Background

- The IESO introduced the use of an hourly peak demand forecast for pre-dispatch scheduling prior to the opening of the market. Based on pre-market testing, it was decided that the hourly peak demand forecast was needed for reliability; the peak demand forecast was chosen to ensure that in the pre-dispatch scheduling process the IESO plans to commit enough resources to satisfy the highest expected demand within each delivery hour.

What is the identified problem?

- The use of a peak demand forecast in pre-dispatch was first identified as an issue in the Market Surveillance Panel's (MSP) inaugural report on Oct 07, 2002. The MSP identified the use of peak demand as a problem for two reasons:
    - *Inefficiency:* the use of peak demand in the hourly pre-dispatch forecast can lead to an over-scheduling of imports. Imports must be committed an hour in advance. If in real time the volume of electricity actually consumed during each five-minute interval is lower than the pre-dispatch peak forecast, the commitment made to imports remains, often at higher cost than would be the case if the demand served by those imports could have been met by Ontario generation;
    - *Inaccurate price signals and transparency:* it contributes to a persistent positive difference between the pre-dispatch price and the HOEP – sending participants an inaccurate signal to plan their operations both in the short-term and over the long-term.

How does the use of peak demand result in inefficiencies?

- The source of the problem is that imports and exports for a particular hour are scheduled and "locked down" one hour in advance based on pre-dispatch prices using the IESO's forecast of load. In contrast, internal generators (and dispatchable consumers) are scheduled in real-time on the basis of five-minute prices and actual demand.
- Ideally, for any volume of demand, the (real-time) market mechanism would ensure that only the lowest-cost producers actually produce. One can think of producers being ranked from lowest cost to highest cost. If price increases, the next highest-cost producer goes on stream. If price decreases, the highest-cost producer of those actually producing goes off stream. The highest cost producer is always at the margin.
- That export and import volumes are determined and fixed at a different time and for a different duration than when other production and consumption decisions are made can result in inefficiencies given the low probability that each hour's demand forecast will be perfectly accurate. That is, the volume of electricity actually

consumed per time period will typically not have been produced at least cost. There are three potential outcomes.

- *Actual demand is equal to forecasted demand* in which case the pre-dispatch price should equal the real-time price and the electricity consumed during the hour will likely have been produced by the set of lowest-cost producers, be they in- or out-of-province;
- *Actual demand exceeds forecasted demand* in which case the real-time prices should be higher than the pre-dispatch price and internal generators respond by expanding output. Note, however, that importers and exporters cannot respond because their ability to contract terminated at least an hour before the real-time activity. The economic problem is that the cost of the internal-generators expanded output may be greater than that of additional importers had the forecast been closer to the mark;
- *Actual demand is less than forecasted demand* in which case the real-time prices should be less than the pre-dispatch price and internal generators respond by reducing their output. The economic problem is that the cost of continuing to use the scheduled imports could be higher than what it would have cost to use internal generators had the forecast been closer to the mark.

- The preferred or ideal outcome is the first outcome - forecasted demand equals actual demand. But the IESO's use of a peak demand forecast means that for the most part, the outcome is that forecasted demand exceeds actual demand. The issue in question before the Market Pricing Working Group was whether the use of an average demand forecast would lead to outcomes that on balance are more efficient or more reflective of the desired first outcome but at the same time, pose no material risk to reliability.

IESO Analysis:

In considering this change, the IESO conducted a cost-benefit analysis (CBA) to assess the impacts on economic efficiency, reliability and stakeholders, including on consumers' electricity bills. The IESO analysis indicates that:

Reliability:

- There is a potential risk to reliability of using an average demand forecast in hours where demand is increasing significantly (generally the ramp hours of 6 to 9 and 16 to 19). The IESO is of the view that in these hours, this potential risk is too significant to adopt the use of an average demand.
- However, in all remaining hours, the IESO believes that the risks to reliability of using an average demand forecast would be manageable.

Efficiency Benefits:

- Using an average demand forecast in all hours except ramp-up periods would increase economic efficiencies (result in a lower overall cost of meeting demand)

by approximately $3.4 million annually.[1] This represents a net benefit or economic gain for the province as a whole. These efficiencies would be achieved by scheduling fewer imports and more internal generation when the imports were more costly than the internal generation.

Stakeholder Impacts:

- By scheduling fewer imports which don't set price in real-time and more internal generators which do set price, the change to average demand would have an impact on the HOEP. The proposed change would result in an average annual increase in HOEP of approximately $0.72/MWh. At the same, time, scheduling fewer imports would lead to a reduction in IOG payments estimated to be roughly $4.3 million annually. After accounting for the affect of the global adjustment and the OPG rebate, the change to average demand in the non-ramping hours would result in a net increase in consumers' bills of roughly $17 million annually (C = - $17 million). With an annual Ontario demand of roughly 152 TWh, this change would represent an increase on an average consumer's bill of roughly 0.01cents/kWh; an approximate increase of 0.14% on the total electricity bill. Some consumers, particularly those that consume proportionately more of their total load in off-peak hours, will experience slightly higher overall bill impacts. Using the load shape of one large industrial customer that consumes more off peak than on peak, the IESO estimated the bill increase would be 0.015cents/kWh on average, for an increased annual cost of $317,000.
- Taken as a group, importers and exporters would be made worse off by the change; the IESO estimates a decline in importers' and exporters' combined surplus to be $2.6 million (I/E = - $2.6 million).
- Internal generators would be scheduled more often. The higher HOEP and increased output for internal generators would mean that they would be made better off by the change. The IESO analysis indicates that post global adjustment and OPG rebates, combined generator net revenues would increase by a total of $23 million (G = $23 million).

Implementation Costs:

- The cost to implement this change is insignificant. There are no tool costs. There are no market rule changes required as this is simply a change in IESO procedures. There may be labour costs incurred each year to conduct analysis to determine the hours in which peak demand will continue to be used; it is expected that the IESO would want to adjust the definition of ramp hours on a seasonal basis.

1 Based on a review of the year 2006, as described later.

Other Non-Quantified Benefits:

- Improved convergence of the real-time and pre-dispatch prices. This would lead to improved efficiencies if the convergence allows participants (consumers and producers) to better plan their operations.
- Reduction in hours with surplus baseload generation (SBG), although the IESO does not expect a reduction in the number of hours prior to the removal of coal nor does it expect there to be a large number of hours reduced post coal removal.
- Reduced global adjustment – higher HOEP means more of the overall cost of electricity is reflected in the hourly energy price (which can be hedged) and less in the uplift (global adjustment and IOG) which is more difficult to hedge.

Other Non-Quantified Costs:

- Added complexity for bidders – some have stated that using average demand in some hours and peak in other hours may create some added uncertainty and complexity for dispatchable participants (largely importers and exporters). This could create some risk and affect offer/bid incentives.

Measurement Risks and Uncertainties:

- The interaction of pre-dispatch import/export schedules and real-time outcomes is difficult to model using standard industry models such as production cost models. The IESO has developed simulation tools that use historic data to replicate the interaction between pre-dispatch scheduling and real-time outcomes. The IESO analysis in this matter used historic data (2006) and a combination of econometric modeling and these simulation techniques to estimate the likely impacts of using an average demand forecast in pre-dispatch. This analysis provides a fairly accurate estimate of what the impacts would have been in 2006.
- However, there are several significant changes planned for the industry over the next few years. These include the planned change in the generation fleet and the government's off-coal program.
- The IESO pre-dispatch and real-time simulation models are not readily adaptable for these changes. As a result, the IESO had to conduct a qualitative analysis using the planned fleet change articulated in the IPSP and the emission targets for the coal plants as described under government directive. This qualitative analysis focused on the likely impact on the future offer curve from these changes over the next several years. The focus of the analysis was to determine if there would likely be a significant change in the slope (elasticity) of the offer curve to change the predicted results of the IESO's simulation results.
- Using this approach, the IESO was unable to find any evidence that the impact calculations conducted using 2006 data would be appreciably different post-implementation of "off-coal" and the IPSP fleet change.

- Since conducting this analysis there have been several additional changes to the industry plan and the economic environment.
    - The Minister has asked the OPA to revisit the IPSP and find ways to incorporate more renewable generation within the plan.
    - The economic downturn has affected electricity demand. There is increased uncertainty regarding future electricity demand.
    - There is increased uncertainty regarding fuel prices and other factors that may affect generator costs and plant availabilities.
- As a result, there remains uncertainty regarding the likely impacts of using average demand forecast in pre-dispatch and the "plus or minus" error bands around the IESO's impacts are difficult to quantify until more certainty around these conditions is gained.

Discussions with SAC Re: Decision Criteria

- Since the spring, the IESO has consulted with stakeholders and SAC members on the appropriate decision criterion to use for approving or rejecting changes to the market rules, and market design.
- In general, a tension arises when a change to the market promises to result in improved efficiencies but at the same time, results in higher electricity prices and hence higher electricity bills for consumers. When making a decision on these issues, the IESO, in effect, must balance what could be seen to be competing objectives of the *Electricity Act*:
    - to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; and
    - to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
- The IESO has argued that coming to a general understanding within the industry of how these objectives are balanced when they appear to be in tension, would provide more transparency and predictability of decision making, accelerate the decision making process, and result in "better" overall decisions.
- The IESO engaged an expert (Dr. Peter Townley from the University of Windsor) in cost-benefit analysis and public policy decision making to discuss possible decision criteria for the industry.
- There were four possible decision criteria identified:
    - *Kaldor-Hicks* which approves a change if it results in a net benefit to the population as a whole (i.e., if the gains to those made better off exceeds the losses of those made worse off) but does not consider how the net benefits are distributed amongst the population.
    - The *Price Standard* which approves a change that produces efficiencies so long as it does not lead to higher prices (or in other words, does not make consumers worse off).

- The *Balancing Weights Approach* - this is Dr. Townley's preferred approach. This is the approach that he recommended to, and was accepted by, both the Canadian Competition Tribunal and the Federal Court of Appeal in their review of the Superior Propane merger. The Balancing Weights Approach is simply one way to focus on the relevant efficiency versus equity trade-off. Assume, for example, that a proposed market change would lead to an efficiency increase of $1 million but cause suppliers to gain $2 million and consumers to lose $1 million. In order to reject the market change, the IESO would have to conclude, for good and sufficient reasons, that the consumer's interest in prices had at least twice the weight of the suppliers interest. More generally, if a change is expected to make consumers worse off, the Balancing Weights Approach simply calculates the critical weight required to be assigned to the consumers' impact such that the decision maker would be just indifferent between approving or rejecting the change. There may be circumstances in which the IESO may feel quite comfortable rejecting the market change on this basis. However, in the absence of evidence of "egregious" distributional impacts, the market change should proceed. It is not enough to treat any adverse distributional impact as a policy veto; some assessment of its importance relative to efficiency gains is necessary. The IESO stakeholder processes provide an opportunity for market participants to bring forth this evidence. This could include evidence from some industrial or commercial consumers that the change (the price or bill increase) would directly result in plant closings or significant job loss that could severely affect some individuals or a community.
- The *Ross-Winter Proposal which* draws on a methodology described by the Canadian Competition Tribunal in the Superior Propane merger hearings to prescribe a weight to be applied to consumers' impact. The underlying principle of the Tribunal's methodology was that "government intervention in mergers should not be relied upon more strongly to implement a redistribution of income than the policy instruments designed specifically for that purpose." Using evidence with respect to the Canadian tax code and various social assistance programs the Tribunal essentially "justified welfare weights that are higher than the weight on profits only for consumers who are "poor or needy." Tom Ross and Ralph Winter used this evidence to prescribe a rate to overall consumers' impact of roughly 1.08. That is, in computing the net benefit of a change, a 1 dollar loss to consumers is treated as being 1.08 more important than a 1 dollar gain to producers (and importers/exporters).

- At the last meeting of the SAC, it was clear that there was little support for purely "formulaic" decision making. Members generally agreed that all four perspectives were informative.
- While the Balancing Weights approach appeared to best capture the element of judgment involved in making market decisions, there was no consensus on the relative weights to be given to producer vs. consumer interests. They also noted that the bulk of the effort in these analyses was in the cost benefit work – all four criteria applied the

outcome of that work. It was also noted that the types of benefits realized in the peak vs. average issue are relatively small and that they would prefer that the IESO use its staff and time to further changes with more material benefits.

Application of the decision criterion to Peak vs. Average

- Using the quantified stakeholder impacts estimated above, an application of each of decision criteria indicates the following:
    - The *Kaldor-Hicks approach* simply adds up the impacts on each of the stakeholder groups and if the net amount is positive it would approve the proposal to use average demand *in non-ramp hours*. That is:
        - G + I/E + C = $23M - $2.6M - $17M = $3.4 >0 so approve proposal.
    - The *Price Standard* would consider the net impact on Ontario consumer's only. Since the net impact on Ontario Consumers is a negative $17M, it would reject the proposal to use average demand in non-ramp hours.
    - The *Balancing Weights approach* would compute the critical weight on consumers' impact as follows:
        - Solve W such that G + I/E + WxC =0
        - That is $23M - $2.6M - Wx$17M =0 or W= 1.2

      Under the Balancing Weights Approach, the IESO would have to evaluate the evidence to determine if the change would lead to adverse distributional impacts on Ontario consumers such that it should weight the impact on consumers 20 percent higher than the impacts on other stakeholders.
    - The *Ross-Winter approach*, derives a weight of 1.08 to be applied to Ontario consumers and a weight of 1 to be applied to all other stakeholder impacts. This approach then simply adds up the weighted impacts on each of the stakeholder groups and if the net amount is positive it would approve the proposal to use average demand in non-ramp hours. That is:
        - 1xG + 1xI/E + 1.083xC = $23M - $2.6M – 1.08x$17M = $2M >0 so approve proposal.

- The non-quantified benefits suggest additional efficiency gains – improved pre-dispatch price signals which would lead to more efficient operational decisions for consumers and producers as well as fewer SBG hours which could avoid nuclear shutdowns and potential higher prices (due to the loss of the nuclear output) to consumers.

Stakeholder Views

Industrial Consumers (AMPCO)

- AMPCO is opposed to the use of average demand in non-ramping hours
    - There is sufficient uncertainty regarding the off-coal program and the IPSP and the IESO analysis does not effectively account for this uncertainty.

- AMPCO argues that the change to average demand will largely affect off-peak prices while leaving on-peak prices unaffected. They argue that this would undermine the government's goal of conservation as it would discourage shifting consumption from peak periods to off-peak periods.
- All other jurisdictions use a peak demand forecast in pre-dispatch.

Ontario Generators

- Ontario Generators are in favour of the use of average demand in non-ramping hours
  - Ontario Generators believe the IESO is responsible for promoting the reliable and efficient operation of the grid – the IESO should not concern itself with income distribution concerns as this is the role of the OEB or the government. As a result, they recommend that the IESO apply the Kaldor-Hicks decision criterion when evaluating changes.
  - The reason for adopting the use of a peak demand forecast in pre-dispatch was originally stated as being for reliability reasons. In the fuller analysis conducted as part of this review, the IESO has since determined that it would be acceptable from a reliability perspective and more efficient to use average demand in those hours of the day in which demand is not ramping up.
  - Use of average forecast demand, particularly in hours of relatively low demand would make it somewhat easier to manage Surplus Baseload Generation.

Inter-jurisdictional Traders

- Some have argued that using average demand in some hours and peak demand in other hours will create uncertainty for traders when projecting the merits of scheduling imports or exports between jurisdictions. At least one stakeholder indicated a preference for "all-or-nothing"- use either average in all hours or peak in all hours to avoid confusion.

Additional Considerations

- The use of peak or average demand is an issue simply because the IESO must schedule imports and exports on an hourly basis, one hour in advance of real-time. If imports and exports were able to adjust to 5-minute price signals, then it would not matter if the IESO used a peak demand or average demand forecast. SE-61 Exploration of Enhancements to Dispatch Methodology and Process will explore the possibility of having imports/exports scheduled more frequently, such as every 15 minutes, as is done in some other jurisdictions. This would reduce the impacts of the use of peak demand in pre-dispatch scheduling and is likely to be a superior solution to the one proposed here. That being said, it is unlikely that any change in this regard could be achieved in the immediate future, as it would also require co-ordinated market changes among our interconnected jurisdictions.

IESO Decision and Reasons

The IESO Management concluded the following:

1. The decision criteria, specifically the "balancing weights approach" and the "Ross-Winter" implementation of this approach provide substantial insight and guidance for IESO decisions and will be used in future decision-making.

2. Under more normal economic circumstances, the efficiency gains available by moving to an average demand forecast should be captured consistent with obligations under the *Electricity Act* to "promote economic efficiency", and those gains would not be out-weighed by the additional *Electricity Act* obligation "to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".

3. However, the timing of and circumstances surrounding a decision are also important factors for consideration, and in this case support not proceeding with this change. In particular:
   - There is substantial uncertainty as to the economic environment in which we would be making this change. The current economic conditions make any cost increase to consumers more sensitive.
   - Overall, the estimated efficiency gains are modest.
   - As part of SE-61: "Exploration of Enhancements to Dispatch Methodology and Process" the IESO is embarking on a study of the possibility of having imports/exports scheduled more frequently, such as every 15 minutes, as is done in some other jurisdictions. This change should produce efficiencies gains; the types of efficiencies projected from switching to an average demand could be achieved through alternative means.

As a result, the IESO has decided to continue to use a peak demand in pre-dispatch scheduling.