

# Status Report on the progress towards High-Level Cost-Benefit Analysis of the Proposed DAM Options



## Background:

In a discussion paper published on August 10, 2007, the IESO indicated its intention to conduct a “high-level” cost-benefit analysis (CBA) of the DAM options by the end of the year. The high-level CBA would aim to identify and quantify where possible the net efficiency improvements that could be realized from having a DAM. The findings of the high-level CBA would then be shared with the Stakeholder Advisory Committee and the IESO Board and would serve as input for assessing the merits of proceeding with more detailed study of specific day-ahead options.

At the September stakeholder sessions, the IESO outlined its methodology for conducting the high-level CBA. The IESO proposed the following.

- The focus of the high-level CBA would be on the net efficiency gains or losses to the province as a whole. The high-level CBA would not include consideration of wealth transfers. Precise evaluation of the impacts of the options on individual participants’ welfare is dependent on the detailed design. The IESO indicated that it would complete a more detailed CBA prior to seeking final approval for implementing any particular DAM option. Estimation of the wealth transfer effects of the recommended option, if any, would be provided with the more detailed CBA.
- The IESO would focus its study on five main areas in which day-ahead market mechanisms have been purported to provide benefits to either suppliers or consumers of electricity in the province and hence contribute towards improved industry efficiency. These areas included (i) improved opportunities for demand response; (ii) enhanced efficiency through improved use of embedded generation; (iii) enhanced unit commitment efficiency; (iv) reduced transaction costs through improved coordination of natural gas/electricity operations; and (v) reduced cost of forward contracting. Additional benefits such as the role of a DAM in enabling the development of load-serving entities, while not quantifiable, would be given some consideration.
- The IESO proposed to focus its study on the cost required to implement a DAM (particularly the cost for the IESO) and the on-going maintenance costs that are incremental to a DAM - relying on participants for an understanding of any additional implementation costs that they would incur. Additionally the IESO indicated that it would look to identify whether the integration of a DAM into the current uniform-pricing regime and hybrid market would be likely to create perverse incentives for consumers/generators that would undermine the current level of efficiency in dispatch.
- The high-level CBA would then provide a comparison of the costs and benefits to determine the net benefits attributable to a DAM. The comparison would include quantitative estimates of costs and benefits when available, as well as qualitative costs and benefits.

The August discussion paper also indicated that the IESO would rely heavily on stakeholders for information, data and analysis of how a DAM would affect their operations. To this end, in September, the IESO established a technical support group to assist in the development of the cost/benefit analysis – gathering input and advice from stakeholders on their expected responses to, and the costs and benefits of, their participation in a DAM. The technical support group consists of seven industry representatives covering various participant classes.

## **Status Report**

Over the last several months, the IESO, with the assistance of stakeholders and consultants, has progressed its understanding of the specific types of efficiency improvements realizable under a DAM. However, work on quantification of these efficiencies has been more challenging than originally anticipated. As a result, the IESO is unable to provide a high-level CBA that is developed to the extent that was initially intended or hoped. Instead, this memo provides an update of the IESO's work and findings to date.

## **Areas of Potential Efficiency Gains**

The IESO has made progress in three of the five main areas outlined above: (i) enhanced unit commitment efficiency, (ii) improved opportunities for demand response, and (iii) reduced transaction costs through improved coordination of natural gas/electricity operations.

### *(i) Enhanced Unit Commitment Efficiency*

The IESO's preliminary review indicates that there are material efficiency gains that could be realized from moving to a DAM with three-part offers and 24-hour optimization of all operating costs.

Currently, generators with minimum loading points greater than 0 MW and minimum run-times greater than one hour are eligible for a commitment guarantee in the Day-Ahead Commitment Process (DACP). The Generation Cost Guarantee (GCG) removes the financial risk associated with the day-ahead commitment by compensating generators who do not recover their commitment costs (i.e., start-up costs, speed-no-load costs and O&M) through real-time market revenues. Generators are eligible for the GCG if they are scheduled in the DACP for the length of their minimum run-time. The GCG applies only to the minimum loading point quantity. Furthermore, a second unit commitment program called the Spare Generation On-line program (SGOL) offers non-quick start generators with a second opportunity to minimize their commitment risk. If these generators are scheduled in any of the three hour to one hour ahead pre-dispatch runs, they are eligible to receive a cost recovery payment for start-up cost and speed-no-load costs for the minimum run time. Unlike the DACP, the unit does not have to be scheduled in pre-dispatch for the entire period of its minimum run time or even its minimum loading point.

For both of these programs, generators do not submit three-part offers including offers for their variable energy cost, start-up cost, speed-no-load costs. Therefore, the DACP does not minimize the total cost of meeting load including these fixed operating costs. Instead, the program selects the units for commitment based on energy offers only, where energy offers are reflective of incremental or marginal cost. This process can at times results in an over commitment of generation and lost efficiencies. In particular, the total cost of meeting the load, including start-up and speed-no-load costs is higher than it would be if there were three part bids and optimization over all operating cost parameters. These higher costs appear in the market as higher uplift costs. Furthermore, since generators' start-up cost, speed-no-load costs and minimum run times are not included in the optimization and hence do not influence generators' scheduling, generators are not influenced by competitive forces to minimize these costs when possible.

It is anticipated that a DAM with three-part offers and optimization of all operating costs would improve the efficiency of dispatch and lower the total cost of dispatch. It would also provide additional competitive discipline with respect to ensuring that most economic units are committed.

In an effort to better understand the potential efficiency gains that could be achieved with the implementation of a DAM with three-part offers and optimization of all operating costs, the IESO conducted a preliminary analysis for the period June 2006 (the start of DACP) to May 2007. The methodology and preliminary findings of this analysis were presented to the CBA technical support group for their review. Attachment A provides a brief summary of this methodology. The following is a summary of the preliminary findings of this analysis.

- For the one year period of June 2006 to March 2007 there were a total of 100 days in which the current DACP process over-committed a non-quick start unit. Over-commitment occurred most often in the fall (September, October, and November) and in the spring months (March and May).
- For the 100 days when there was an over-commitment, the average amount of generation over-committed was about 1000 MWh per day.
- The IESO estimated the cost savings (efficiencies gains) that could have been realized via a DAM with three-part offers and 24-hour optimization of all operating cost during the June 2006 to May 2007 period to be in excess of \$5 million dollars. The cost savings were computed as the difference between the total cost of the unit that was over-committed and the total cost of replacing the output of this unit with output from generation that was unused but available (i.e., either quick start units or non-quick start units that were on-line in real-time, and units that were not bottled due to transmission).

The IESO expects that this is an underestimate of the potential efficiency gains that could be achieved for several reasons. First, the analysis uses only internal generation as the basis for identifying output (and the cost of this output) to replace the over-committed units and ignores the potential use of cheaper imports or the avoidance of exports as replacement. In a DAM, the

optimization engine would have the option of scheduling more imports or not scheduling exports instead of committing a unit with fixed start-up costs and minimum run-times. Second, the analysis does not capture the potential for improved start times for committed generation. There is some preliminary evidence that the current GCG and SGOL guarantees provide incentives for generators to be prematurely committed and run longer in a day than would otherwise be economic.

The IESO will continue to further its analysis of the potential efficiency gains attributable to three-part offers and 24-hour optimization. Future study will include an estimate of the potential price and uplift implications of moving to three-part offers and 24-hour optimization of all operating costs. This analysis will account for the mitigating impacts of exports and imports in the process. Furthermore, the IESO will expand its analysis to project the future impacts attributable to the changing supply mix and fleet characterization. The changing supply mix includes an increase in supply from gas fired generation. This generation will largely replace the current coal fired generation. The future gas fired generation units will have higher minimum output levels than the current coal fired units. The higher minimum makes the decision to commit a gas unit much more significant. The IESO expects that as the size of the gas fleet grows so would the cost of continuing with the current inefficient commitment process.

(ii) *Improved Opportunities for Demand Response*

Currently in Ontario most large customers are paying real-time prices with little or no prior notice. Insufficient advance notice of prices is a major customer complaint in Ontario and in many other electricity jurisdictions without a day-ahead market. Nonetheless, the question remains whether Ontario consumers would be more or less responsive with a day-ahead notice of prices than without such notice. In short, the IESO is still working to answer this question, but offers the following up-date on the work conducted to this point.

In October, the IESO engaged two academics from McMaster University, Dr. Ken Deal and Dr. Dean Mountain, to assist them in studying the potential for more demand responsiveness from providing customers with “firm” prices a day in advance. Dr. Deal and Dr. Mountain have considerable experience conducting elasticity studies in energy markets and have worked for other ISOs in the evaluation of their demand response programs.

The challenge in answering the outstanding question of course is that there are no direct objective measurements of the likely responsiveness of Ontario consumers to day-ahead market prices, since a DAM has yet to be implemented in the province. As a result, Dr. Deal and Dr. Mountain were asked to survey information from studies conducted in other jurisdictions to identify evidence of the impact of a DAM (firm day-ahead prices) on consumer responsiveness in these jurisdictions. Additionally, they were asked to use this information and their professional expertise to draw inference of the potential for enhanced consumer responsiveness

in Ontario. Dr. Deal and Dr. Mountain provided the IESO with a preliminary report just prior to the writing of this memo. While their report is still in draft form, the following findings are available:

- In general, while there is little direct evidence available of the potential value to demand response of a DAM in Ontario, there is some evidence that demand is more elastic for certain customer segments in jurisdictions with a DAM or with firm day-ahead prices than in jurisdictions without a DAM.
- There are no studies that the authors surveyed that estimated customer elasticities before and after the implementation of a DAM.
- The available literature includes studies with estimates of both (i) the elasticity of substitution which provides a measure of the degree to which consumers are willing to switch the ratio of peak to off-peak electricity consumption across hours in a day or across a couple of days in response to hourly price changes and (ii) own-price elasticity, which provides a measure of the degree to which consumers are willing to reduce consumption in a given hour in response to a price change.
- Based on their survey of these studies, the authors offer what in their professional opinion are plausible ranges of elasticities in Ontario following the implementation of a DAM that offers firm day-ahead prices. Drs. Deal and Mountain project that several customer classes, particularly large commercial customers (government and education), and large industrial customers would be more price responsive (both the elasticity of substitution and own-price elasticities would be more elastic). They cite evidence suggesting that customers with embedded generation would be the most impacted by the firm day-ahead prices.
- Drs. Deal and Mountain compare the projected elasticities for these customer classes to the most recent elasticity estimates produced by the Frasier Institute, and suggest that the elasticities of some customer classes could be in the order of a half a percentage to a percentage more elastic. This would represent a doubling of elasticities. While the authors are not at this time in a position to quantify any efficiency gains attributable to this degree of change, they do go on to cite a recent unpublished paper of Holland and Mansur (2005) that suggest that the efficiency benefits as a percentage of the energy bills doubles when the elasticity doubles.

The initial findings of Dr. Deal and Dr. Mountain regarding demand elasticities offer promise for potential improved efficiencies through demand response following the implementation of a DAM. The IESO will continue to work with Dr. Deal and Dr. Mountain to explore ways to quantify the potential benefits from enhanced demand response. For future work, the authors suggest that these ranges of elasticity estimates would be useful inputs for conducting simulations to measure potential benefits to Ontario customers and to the Ontario electricity system. The IESO does recognize the limitations of applying elasticity estimates from other jurisdictions and is mindful of the significant differences between Ontario's electricity sector and the situation in other jurisdictions and will consider how these differences could be accounted for in future analyses.

(iii) *Reduced Transaction Costs for Gas-Fired Generators through Improved Coordination of Natural Gas/Electricity Operations*

It is expected that by providing greater certainty of dispatch a day-ahead for the electricity market, will reduce the uncertainties and risks associated with natural gas procurement for gas-fired generation facilities.

The natural gas consumption patterns for most industrial natural gas consumers are predictable, and for the most part, self-controllable. As a result, these consumers can order the appropriate amount of natural gas a day-ahead of actual consumption, with the hourly variation in actual consumption volumes and scheduled volumes being very minor. The predictability of their gas consumption patterns allows these customers considerable flexibility to schedule their next day gas needs at what they believe to be the best available price trading in the market that day. It also means that they can make appropriate arrangement with upstream pipelines, storage operators and distribution utilities to plan for the delivery and receipt of the required gas so as to minimize these additional costs. Finally, any minor variation between actual consumption and scheduled volumes can be managed with existing services and minimal cost.

In contrast, the hourly consumption patterns of gas-fired generators are less predictable. This is a product of the unpredictability of the electricity market and the electricity output of the gas-fired generation more specifically. Gas-fired generation is often the marginal generation unit in the electricity market which means that its electricity output can vary widely within an hour. Furthermore, variations in electricity demand or the unpredictable performance of other types of generation make it difficult for the gas-fired generator to predict a day in advance what will be its gas consumption requirements for the next day.

As a result, hourly and daily variations in actual consumption versus volumes scheduled on the gas-transmission systems for generators can be significant and may require supplemental pipeline services to manage the imbalances. For instance gas generators run the risk of purchasing and scheduling gas supply a day ahead and then not being dispatched in real time, which would result in the generator's gas supply packing the pipeline. This can result in substantial penalties being assessed against the generator by the pipeline operator unless alternate markets for the gas can be found (such as storage), which could in turn lead to increased balancing costs for the generator. Conversely, if the generator does not nominate its gas supply ahead of time, (to avoid the risk of having too much gas), the generator runs the risk that the physical supply and pipeline transmission capacity may not be available when it is dispatched. Further if the gas is available and can be transported, the price could be at a significant premium versus normal day-ahead index pricing. These risks are heightened in the winter, especially on a cold winter day, and seasonally when storage levels are low.

The enhanced pipeline services, introduced following the Natural Gas Electricity Interface Review (NGEIR) undertaken by the Ontario Energy Board, do provide a generator with tools to better manage imbalances that will occur as the result the unpredictability of the gas-fired generators' next day's consumption pattern but the enhanced services do not eliminate the underlying uncertainties. The unpredictability of the next day consumption pattern creates commodity cost risk, and requires the gas generator to incur additional transactions cost; it must purchase additional storage capacity and incur additional injection/withdrawal costs to manage the variability or forgo the opportunities to re-optimize its gas incremental/detrimental gas needs within the electricity trading day.

The implementation of a DAM would offer these gas generators more predictability and a financial guarantee of their next day's gas needs. It could lead to efficiency gains in the form of reduced commodity costs, and reduced transaction cost for storage and injection/withdrawal services.

In September, 2007 the IESO contracted with Baden Energy Consulting Ltd. (BECL) to analyze the implications of a DAM for gas-fired generation facilities. In particular, BECL were asked to identify how the costs and risks associated with purchasing and scheduling natural gas to meet a dispatch schedule under the current market design would change with the implementation of a DAM as described under Option 3. Their focus is on quantifying the potential efficiencies achieved through reduced commodity cost and reduced transactions cost (storage costs and injection/withdrawal costs). Their analysis will also explore how the location of the generator – within the Union Gas Zone or outside of the Union Gas Zone – could affect the potential efficiencies.

BECL first met with affected stakeholders in early October to elicit feedback on the key factors to consider in this analysis. Following this meeting, BECL drafted a proposal of the methodology that they would employ to quantify the change in costs and risks; the draft was posted on the web at [http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20071112-BECL Methodology for CBA.pdf](http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20071112-BECL_Methodology_for_CBA.pdf). BECL again met with affected stakeholders on November 15, 2007, this time to get feedback on the proposed methodology. Several constructive comments were offered for which BECL agreed to incorporate into the analysis.

While there are no quantitative estimates available at this time, the initial indication is that there will be annual efficiency savings in the form of reduced commodity costs, reduced storage costs and reduced injection/withdrawal costs, and that these efficiencies will be material.

### **Implementation Cost Estimates**

The IESO has reviewed cost estimates developed during the 2004 DAM design effort and has concluded that the \$16 million currently allowed for in the Business Plan over 2008 and 2009 is likely on the low end of the range of costs that would be required if Option 3 was to be

implemented. Better definition of the potential range of costs will require consulting with vendors, something that would not be productive without more design details. More definitive implementation costs will be developed for purposes of the cost benefit analysis and the business case.

### **Additional Concerns Identified During the Stakeholder Process**

Over the last several months of stakeholder review, neither the IESO nor stakeholders have identified any obvious issues with any of the remaining option designs that would lead to abandoning further study. A few stakeholders did however raise some concerns of how the DAM could lead to potential inefficiencies in real-time dispatch. These stakeholders asked the IESO to consider these concerns in the future as part of the CBA. These included a concern that (i) a DAM with financial commitments might reduce the incentives for load following in real-time; and (ii) a DAM with an early closing time (for example earlier than 3:00 pm) and financial commitments could lead to inefficiencies in the use of hydro-electric resources. The IESO will work with these stakeholders to better understand these concerns and address them through further study as needed.

### **Summary and Concluding Remarks**

The IESO is continuing the work to quantify the potential efficiency gains attributable to the different DAM options, taking into account concerns raised by stakeholders of the potential for off-setting inefficiencies. The IESO will also continue to tighten its estimates of the implementation costs for the different DAM options and will be seeking stakeholder input regarding the materiality of the stakeholders' implementation costs.

The findings to date indicate that there are potential efficiencies to be realized through the adoption of one of the DAM options. The preliminary estimates of the annual efficiencies that would be achieved through three-part offers and 24-optimization of all operating costs are material. Furthermore, while the efficiencies attributable to enhanced demand response and improved coordination of natural gas/electricity production are yet to be quantified, there is evidence that efficiencies will be achieved. In the case of the gas coordination, efficiency opportunities are also expected to be material.

Finally, while considerable additional analysis is required to quantify both benefits and costs, based on the information and evidence available at this time, it is reasonable to expect that the implementation of one of the remaining DAM options would result in a positive net benefit to the province; the present value of the future stream of net efficiency gains would exceed the costs of implementation. Hence, further examination of the remaining options is warranted.

**Appendix A:**  
**Methodology to estimate efficiency gains attributable to a DAM with three-part offers and 24-hour optimization of all operating costs**

**Objective:**

- Estimate the efficiency gains from three-part offers and 24-hour optimization of all operating costs by identifying days when the Day-Ahead Commitment Process (DACP) over-committed a generator and therefore inefficiently scheduled a resource.
- Quantify the possible daily efficiency gains attributable to a DAM with three-part offers and 24-hour optimization of all operating costs by computing the difference between the total daily cost incurred to commit the unit and the total daily cost that would be incurred to replace the output of the unit.

**Methodology:**

- The methodology employed is illustrated in **Figure 1: Methodology Process Diagram**. The following describes the process depicted in Figure 1.
- To determine whether any generators were over-committed by DACP. Compared the daily average cost per MW of each committed generator to its daily weighted average shadow price. Note, the average cost per MW was computed using the generator's cost information as submitted as in the DACP process and the energy offers for output beyond the unit's minimum generation levels. The cost information submitted in the DACP is presumed to capture the costs of start-up, speed-no-load costs, O&M costs and variable costs incurred from operating at minimum output levels.
  - A committed generator with a daily average cost per MW higher than its daily weighted average shadow price would be a candidate for further review of potential over-commitment.
- Identify other available generators on-line or capable of responding to a real-time dispatch instruction in the hours when the committed unit was operating on the day. Using energy offers from these generators, compute the total cost to replace all the output scheduled for the committed generator for the entire day.
  - Generators that were constrained off did not qualify as replacement resources
  - Any available import offers or export bids were not considered as replacement resources
- Compare the total daily replacement cost of these resources to the total cost of the committed generator on this day.
  - If the replacement resources were less expensive, then the committed generator was overcommitted and the savings from using the replacement resources was calculated
  - If the replacement resources were more expensive, then no over-committed occurred

Figure 1: Methodology Process Diagram

