ieso
Power to Ontario.
On Demand.

Day-ahead Market Evolution Preliminary Assessment Summary

May 8, 2008

Table of Contents

1. Executive Summary

Changes in Ontario's electricity sector are on the horizon. Ontario's generation fleet is shifting away from coal through reduction and ultimate retirement in 2014 towards more natural gas, renewable and embedded generation. Growing focus on the environment, and the shift to greener solutions to meet Ontario's increasing electricity demand, has amplified the need to facilitate opportunities for demand response and utilization of Smart Meter technology.

In 2007, the IESO initiated a study to assess how our day-ahead planning mechanisms might be amended to support anticipated changes in Ontario's electricity sector. The assessment addressed both current and future challenges including how to most efficiently integrate and optimize Ontario's changing generation fleet (reduction and retirement of coal, more natural gas, renewable and embedded generation) and how to provide accurate price signals in advance of real-time to enable opportunities to better manage demand response and utilize Smart Meter technology. The merits of various possible day-ahead mechanisms have been studied and assessed under Stakeholder Engagement Plan 21 (SE-21). The goals[1] on entering into the study and assessment were threefold:

- **Enhanced unit commitment[2] efficiency-** Establish if there are more efficient ways, in light of the changing supply mix, to commit resources to meet Ontario's energy needs in the day-ahead planning timeframe.

- **Provide more accurate day-ahead price signals and examine opportunities from day-ahead financial commitments -** Support the market but specifically demand response and embedded or distributed generation with more accurate day-ahead price signals. Present participants with an opportunity to manage real-time price and quantity risk by providing financial commitments day-ahead. Day-ahead financial commitment allows participants to lock in price and quantity day-ahead, reducing exposure to real-time volatility and provides hedging and risk mitigation opportunities. Both of these endeavors could create opportunities to facilitate operational efficiency for customers and suppliers.

- **Ensuring continued reliable system operations -** To ensure that the IESO day ahead planning mechanisms continue to support reliable operation of the grid with the changing supply mix expected to emerge in the next few years.

As the study progressed over the last year, the IESO reduced the range of options for consideration in its analysis of potential improvements to day-ahead market mechanisms to three options plus a baseline scenario. The baseline scenario provided the starting point against which the options were evaluated:

---

[1] Outlined at first stakeholder meeting April 11, 2007: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20070411-DAM-Evolution.pdf and further detailed in August 2007 in Appendix A, Attachment A of the IESO publication A Discussion Paper on Day-Ahead Mechanisms: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20070810_IESO_Staff_Report.pdf

[2] Unit commitment refers to the ability of a generator or a consumer to make a commitment to produce or consumer energy for a given period.

- **Baseline Scenario –** Carrying on with the current wholesale market and Day-Ahead Commitment Process (DACP) design, along with the continued publishing of the IESO day-ahead price forecast of real-time Hourly Ontario Energy Price (HOEP) and a review of reliability cost guarantees

Options 1 and 2 focus on enhancing the current DACP, as follows:

- **Option 1:** An enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees, along with the continued publishing of the IESO day-ahead price forecast of real-time HOEP[3]

- **Option 2:** An enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees and an Energy Forward Market (EFM)

Option 3 would establish a new day-ahead market under which participants would assume, and be financially responsible for, prices and quantities established day-ahead. It is anticipated that this new market would then establish the reference price for Ontario, with the current real-time market assuming a balancing role, while maintaining its dispatch function.

- **Option 3:** An unconstrained day-ahead market (UDAM). Like Options 1 and 2, the UDAM would incorporate an enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees. Financial day-ahead positions would be derived from the IESO unconstrained algorithm.

The IESO used cost benefit analysis (CBA) techniques and consideration of additional non-quantifiable impacts to assess the relative merits of the options. The cost-benefit analysis included IESO and stakeholder costs and benefits measured through overall market efficiency impacts. The additional non-quantifiable factors analysis discusses impacts on relevant aspects of market and physical operation. Net effects on consumer bills were also considered.
The overall objective of the various analyses was to help identify day-ahead mechanism improvements that would result in net benefits to the province as a whole relative to the existing DACP. The outcome of our analyses is summarized in the table below.

[3] For an explanation of 24-hour optimization and 3 part bids/offers see Appendix 2 of the November 5, 2007 Status Paper on Day-Ahead Mechanisms - http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20071105-DAM_Status_report.pdf

CBA Analysis Outcome	Option 1	Option 2	Option 3
Net Present Value (NPV((over 15 years)	$88.4M	$88.24M	$60.93M
Pay-back Post Implementation (# years)	2	2	3
Impact of Non-quantified	+ (shorter pay-back period)	++ (shorter pay-back period)	± (not likely to shorten pay-back)
Stakeholder Impact Analysis Outcome			
Year Post Implementation Bill Savings Realized	1	1	2
Rank	**2**	**1**	**3**

Following receipt and consideration of stakeholder comments, the IESO study team responsible for this assessment will propose proceeding with one of the options or continuing with the Baseline Scenario. As set out in the final section of this report, the preliminary view of the study team is that Option 2 appears to offer a better overall set of amendments for addressing the efficiency, pricing and reliability goals on which this work has focused.

However stakeholder considerations are central to this assessment and before making any recommendation the IESO study team welcomes the opportunity to consider stakeholder views, and in particular to understand any stakeholder concerns with the study results.

2. Cost Benefit Analysis

Baseline Scenario

When conducting our analysis of the impact of each of the day-ahead options, we conceptualize two scenarios: one that does not include the option (i.e., the baseline scenario) and one that does include the option (i.e., the "with options" scenario). The incremental costs and benefits of the option are measured relative to the baseline scenario.

For its analysis, the IESO makes the following assumptions for defining a baseline scenario:

- The wholesale market continues as today. In particular, resources are dispatched based on offers and bids submitted to the IESO;
- The uniform "unconstrained" pricing model remains in place;
- The future generation and demand profile is consistent with the one that is projected by the OPA's Integrated Power System Plan (IPSP).
- Regulations governing Ontario Power Generation's assets (Prescribed Assets and Non-Prescribed Assets) will continue;
- OPA contracts for new gas-fired generation assets will continue to use contracts similar to the Clean Energy Supply contracts;
- IESO cost guarantees, such as the DACP "Generator Cost Guarantee" or "Spare Generation on-line" guarantee are improved.[4]

2.1 Cost Analysis

The IESO identified two categories of cost for inclusion in the day-ahead mechanism CBA:

(1) IESO implementation and Operation Maintenance & Administration (OM&A) costs; and

(2) Participants' implementation and OM&A costs.

2.1.1 IESO Costs

The IESO has conducted a review of the cost to implement and maintain each of the day-ahead mechanism options.

The cost estimates summarized below have been determined by reviewing and adjusting the detailed cost estimates prepared for the 2004 Day-Ahead Market (DAM) project. For those estimates, a detailed DAM design was made available to vendors, and the IESO received several vendor DAM cost estimates.

[4] The improvements contemplated would be to address concerns related to excess of use of the programs as more and more non-quick start generation comes on-line.

The accuracy of these estimates is subject to a ± 30% error band due to unknown issues related to either design or implementation that can not be identified nor estimated until project completion.

Table 1: Estimated Implementation Costs

	Labour & Associated Costs	System Procurement & Development	Interest	Contingency	System Upgrades – 7 year Refresh of IT systems	Total
Option 1	$3.8 M	$17 M	$1.1M	$4.6 M	$8.1 M	$35.1M
Option 2	$3.8 M	$17 M	$1.1M	$4.6 M	$8.25 M	$35.75M
Option 3	$7M	$24M	$1.5M	$6.5M	$11.7M	$50.7M
Status Quo	$.5M	$.5M				$1M

Table 2: Expected OM&A costs for Each Option

	Staff Required	Rate	Total Annual Cost
Option 1	2 1/3 Full Time	$150,000	$350,000
Option 2	2 Full Time	$150,000	$300,000
Option 3	4 Full Time	$150,000	$600,000
Status Quo	1/3 Full Time	$150,000	$ 50,000

2.1.2 Participants' Cost

In March 2008, the IESO issued a survey to all dispatchable market participants and marketers requesting estimates of the implementation and on-going OM&A costs that they would incur for participation in either Option 1 or Option 3 (see http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080318-cost_survey.pdf for cost survey issued). We expect participant costs for Options 2 to be similar to those for Option 1.

The overall estimated costs to participants in the industry are summarized in Table 3.

Table 3: Total Participant Costs

Option	Cost	Expected Cost	High Estimate	Low Estimate
Option 1 or Option 2	Implementation	$2.4M	$4.6M	$2.1M
	Annual OM&A	$0	$0	$0
Option 3	Implementation	$6.2M	$11.7M	$5.3M
	Annual OM&A	$1.4M	$2.5M	$1.2M

2.2 Benefit Analysis

Each of the proposed options is expected to produce benefits in the form of improved efficiencies. The IESO has attempted to identify all potential efficiency impacts that could be attributable to the implementation of each of the options. Some of these efficiencies have been quantified and monetized. Other impacts were more difficult to monetize or even quantify either due to the nature of the impact or the lack of data available to the IESO. The other impacts considered included embedded generation, hydro-electric risk, import/export trade, impact on real-time dispatch, reliability, forward contracting, alignment of constrained and unconstrained algorithms and integration of regulated and OPA contracts. These impacts were not expected to be material and hence were dealt with qualitatively as unquantified in the net present value tables.

Monetized Benefits
Unit Commitment Efficiencies

The IESO estimates that the introduction of three-part offers and 24-hour optimization of all operating costs would provide between $4 million and $5 million annually in improved efficiencies for the province.

Estimated Efficiency Gains:
The IESO estimated the cost savings (efficiencies gains) that could have been realized via a day-ahead mechanism with three-part offers and 24-hour optimization of all operating cost during in 2007 period to be in excess of $6 million dollars.

Table 4: Efficiency Gains from Improved Unit Commitment

Year	2010	2011	2012	2013	2014	2015	2016 to 2020
Estimate	$5.0M	$4.9M	$4.5M	$4.5M	$4.5M	$4.3M	$4.3M
High Estimate	$5.3M	$5.2M	$4.9M	$4.9M	$4.9M	$4.8M	$4.8M
Low Estimate	$4.8M	$4.6M	$4.1M	$4.1M	$4.1M	$3.9M	$3.9M

The above benefits could be potentially higher due to two factors. First, the analysis uses only internal generation and available cheaper import offers as the basis for identifying output to replace the over-committed units and ignores the potential avoidance of exports as replacement. Second, the analysis does not capture the potential for improved start times for committed generation.

Reduced Cost for Gas-Fired Generators

Analysis conducted for the IESO by Baden Energy Consulting Limited (BECL) indicates that 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.

Estimated Efficiency Gains:
The BECL analysis produced the following conclusions.

- The results of the baseline scenario were consistent with the operating experience of existing combined-cycle gas-fired generation in Ontario; predicted load factors were close to the actual load factors for these generators.
- Scenario analysis resulted in annual efficiency gains for the province as a whole. The annual efficiency gains for DAM1 (earlier closing time) ranged from $7.5 million to $14 million over the projected time period. The annual efficiency gains for DAM2 (later closing time), were slightly less; they ranged from $7 million to $11 million over the projected time period. The implication is that Option 3 with an earlier closing time is likely to reduce the hedge cost risk and lead to larger efficiency gains.
- Both Proxy Price Scenarios also resulted in annual efficiency gains. The annual efficiency gains for DAM1 ranged from $8.5 million to $17 million over the projected time period. The annual efficiency gains for DAM2, were slightly less; they ranged from $8.5 million to $14 million over the projected time period.

Day Ahead Demand Response Efficiencies

The IESO retained the services of Dr. Dean Mountain and Dr. Ken Deal to estimate the potential efficiency gains of having a day-ahead market in Ontario. The results of their study suggest that the introduction of a day-ahead market in Ontario would generate annual efficiency gains ranging greater than what was previously considered achievable.

The key findings are;

1. The more inaccurate the day-ahead price forecast, the more likely consumers would lock-in their consumption day-ahead.
2. The more inaccurate the day-ahead price forecast, the more consumers would respond to day-ahead prices. In other words the elasticities are higher when day-ahead price forecasts are poor.

3. The day-ahead elasticity of substitution between peak and off-peak consumption ranges between 0.307 and 0.388.
4. The day-ahead own-price peak elasticity ranges from -0.12 to -0.151
5. The day-ahead total impact own-price peak elasticity ranges from -0.20 to -0.23

Estimated Efficiency Gains:
Overall, the authors conclude that these elasticities, along with the other findings from this research, support the notion that a day-ahead market with improved day-ahead prices could have real efficiency benefits for large industrial, commercial and institutional customers in Ontario.

As part of Day-ahead Forecast of Real-time Price initiative, the IESO conducted a numerical study to assess the potential efficiency gains from providing an improved day-ahead price forecast. [20] This analysis estimated annual efficiency gains in the range of $200,000 to $2 million, depending on the assumed level of elasticity. The DM elasticity estimates suggest a level of price responsiveness of large Ontario consumers that is larger than the level assumed by the IESO in its SE-58 analysis, implying that the efficiency gains are likely to be on the upper range of the initial estimates.

Summary of Non Quantified Impacts and Incorporation into CBA

Table 5 provides a summary of the non-quantified impacts for each of the three options.

A plus sign indicates that there are benefits to this option that the baseline scenario does not have. A minus sign indicates that there are drawbacks to this option that the baseline does not have. An 'NA' implies that there are no incremental impacts relative to the Baseline Scenario.

Table 5 Summary of Non Quantified Impacts

Impact	Option 1	Option 2	Option 3
Embedded Generation	+	+	+
Reliability	+	+	+
Impact of Financial Commitment on Real-time Dispatch	-	-	-
Alignment of Constrained and Unconstrained Algorithms	NA	NA	-
Integration of Regulated Contracts	NA	NA	-
Price/Scheduling Accuracy	+	+	+
Financial Commitment	NA	+	+

Overall, the IESO believes that while not quantified, there are additional positive efficiency gains that would be realized from the implementation of Option 1 or Option 2 relative to the baseline scenario. The only possible negative impact attributable to these options relates to the potential impact of financial commitments on real-time dispatch. As mentioned above, the IESO does not expect this to be material. It also expects that the positive impacts of the other factors would outweigh this impact.

Furthermore, the IESO believes that the non-quantified benefits of Option 2 are likely larger than those of Option 1, since Option 2 offers the potential for additional financial commitments not afforded under Option 1.

Overall, the IESO believes that there may be additional efficiency gains that could be realized from the implementation of Option 3. However, because of the concerns related to the alignment of the constrained and unconstrained algorithms and the concerns regarding the integration of the regulated contracts it is less certain of this outcome.

2.3 Net Present Value

The following tables illustrate cumulative net present value of each option under consideration over a 15 year period. The table includes monetized benefits and costs for both the quantified aspects of each option.

Table 6: Net Present Value, Option 1, 7 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
BENEFITS																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.00
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	12.38
Cumulative PV Benefits	0.00	0.00	12.18	23.32	33.48	43.93	53.74	64.04	74.05	83.55	92.53	101.10	108.61	115.75	122.10	17.38
COST																
IESO																
Implementation Cost	4.65	20.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.36
O&M Cost	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.33
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.72
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	5.13	25.85	26.11	26.36	26.59	26.80	27.00	32.68	32.85	33.02	33.17	33.31	33.44	33.57	33.69	4.80
Cumulative NPV	**(5.13)**	**(25.85)**	**(13.93)**	**(3.03)**	**6.90**	**17.13**	**26.74**	**31.36**	**41.20**	**50.54**	**59.37**	**67.79**	**75.16**	**82.18**	**88.41**	**12.59**

Table 7: Net Present Value, Option 2, 7 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
BENEFITS																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.00
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	12.38
Cumulative PV Benefits	0.00	0.00	12.18	23.32	33.48	43.93	53.74	64.04	74.05	83.55	92.53	101.10	108.61	115.75	122.10	17.38
COST																
IESO																
Implementation Cost	4.75	20.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.42
O&M Cost	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.28
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.73
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	5.23	26.32	26.54	26.75	26.94	27.11	27.28	33.02	33.17	33.30	33.43	33.55	33.66	33.77	33.86	4.82
Cumulative NPV	**(5.23)**	**(26.32)**	**(14.36)**	**(3.42)**	**6.55**	**16.82**	**26.46**	**31.01**	**40.88**	**50.25**	**59.10**	**67.55**	**74.95**	**81.98**	**88.24**	**12.56**

Table 8: Net Present Value, Option 3, 7 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
BENEFITS																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.00
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	12.38
Cumulative PV Benefits	0.00	0.00	12.18	23.32	33.48	43.93	53.74	64.04	74.05	83.55	92.53	101.10	108.61	115.75	122.10	17.38
COST																
IESO																
Implementation Cost	6.90	26.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.50
O&M Cost	0.00	0.00	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.61
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04
Participant																
Implementation Cost	1.24	4.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84
O&M Cost	0.00	0.00	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.56
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16
Cumulative PV Cost	8.14	37.50	39.20	40.79	42.28	43.67	44.97	54.63	55.76	56.82	57.81	58.74	59.61	60.41	61.17	8.71
Cumulative NPV	**(8.14)**	**(37.50)**	**(27.02)**	**(17.47)**	**(8.79)**	**0.26**	**8.77**	**9.41**	**18.29**	**26.73**	**34.72**	**42.36**	**49.00**	**55.33**	**60.93**	**8.67**

3. Assessment of Stakeholder Impacts

In addition to the CBA, the IESO's overall assessment of the merits of each option includes an analysis of the distribution of the impacts of each option on various stakeholders (wealth transfer impacts). Stakeholder analysis attempts to allocate the net benefits or losses generated by each option. The output of the stakeholder analysis contains critical information for decision makers, as it indicates which groups would be the net beneficiaries and which groups would be the net losers and by how much.

3.1 IESO Stakeholder Impact Analysis

The IESO stakeholder impact analysis involves consideration of the effect of each option on (i) the Hourly Ontario Energy Price (HOEP), (ii) IESO uplifts and (iii) assignment of the IESO's implementation costs. The IESO has conducted an analysis of the likely impact on HOEP and uplifts under the same assumptions applied in the CBA.

While the stakeholder analysis considers the impacts on all stakeholders, we also determined the overall impact to the electricity bills of Ontario consumers. By combining the potential changes to HOEP and uplifts, and the assignment of IESO implementation costs, we estimated the consumers' electricity bill impacts for each of the options. Consumers could see a slight increase to their bill of less than 1 cent / MWh with Options 1 and 2 in the first year post implementation and an increase of about 1 cent / MWh for Option 3 for the first two years post implementation. Beyond the first few years post implementation for all options, consumers could then see a decrease of their electricity bill of up to 3 cents / MWh. The NPV of savings for consumers over the 15-year analysis period for Options 1 and 2 is $23 million dollars. For Option 3, the NPV savings is $13 million dollars.

4. Assessment of options against the additional considerations outside the cost/benefit analysis

4.1 Re-contracting of Non-Utility Generation Contracts

The implementation of a UDAM (Option 3) could act as the catalyst to affect further positive change within the industry. For example, the introduction of UDAM could create opportunities to achieve a more efficient utilization of the provinces Non-Utility Generation (NUG) plants. To the extent that the UDAM enables positive change that may not otherwise occur should be factored into any final decision regarding the merits of the different day-ahead options.

Using data of the resource operating and cost characteristics provided by NUG owners, the IESO made assumptions regarding the likely "offer strategy" for each of the plants after a UDAM implementation and then ran a simulation of the real-time market, incorporating these offers for the NUG resources. The simulations were conducted for the year 2007. Depending on the level of flexibility achievable from these resources, the efficiency gains could range from $3.8 million to upwards of $10 million per year. These efficiency gains would come in the form of reduced fuel cost for the province as a whole for meeting its energy demand. That being said, the reduced operation of these NUGs would put upward pressure on the HOEP. For the period simulated, the average HOEP would have been between $3.00/MWh to $5.00/MWh higher.

4.2 Enabling Other Market Evolution Issues

At the outset of our study, we indicated changes to the market design must meet the needs of today, but should not impede future market initiatives. Therefore, as part of our assessment is it essential to consider the extent to which each day-ahead option either encourages or inhibits evolution of the market. As a means to provide option comparison for impacts on future market development, the IESO limited their analysis against to the following broad-based market initiatives:

- implementation of locational marginal pricing (LMP)
- possible development of load serving entities (LSE)
- promotion of long-term resource adequacy mechanism (RAM)
- encourage environmental goals
- real-time market improvements/changes

Table 9: Enabling Market Evolutions

Options	Option 1	Option 2	Option 3	Baseline Scenario
LMP	Positive influence – introduction of multi-pass constrained	Positive influence – introduction of multi-pass constrained	Less positive influence - introduction of multi-pass constrained offset by impact of avoidable capital cost of financial commitment	Neutral
LSE	Neutral	Positive influence only if EFM clears	Positive influence	Neutral
RAM	Neutral	Neutral	Neutral	Neutral
Environmental	Positive influence	Positive influence	Positive influence	Neutral
Real time market	Positive influence	Positive influence	Positive influence	Positive influence

5.0 Summary of Findings and Direction of Assessment

As the IESO approaches a decision in respect of day-ahead mechanisms, the focus of the IESO study team has been to pull together and document the various analyses that will provide the basis for our recommendation. From the outset of the study, the cost benefit analysis has been as central to that work. The aim of the CBA was to quantify and monetize the incremental benefits and costs of the options against the Baseline Scenario to the greatest practicable extent. Other aspects relevant to a decision but not amenable to quantification because of their nature or lack of available data, have been evaluated on a qualitative basis as to how they would influence the ranking of each of the options. These considerations, and other factors such as differences in customer costs between options, are also important in reaching a recommendation.

Each of the options considered result in a positive quantified NPV relative to the Baseline Scenario over a 15 year period. In fact, within three to four years post implementation, the NPV to that point (the annualized NPV) becomes positive for each option. With implementation in year 2, Option 1 and Option 2 achieve the break-even point sometime in Year 5, while Option 3 achieves the break-even point in Year 6.

Based on the CBA, the quantified NPV estimate for Option 1 ranks the highest with a NPV of $88.4 million (or $12.59M/yr). The NPV of Option 2 is marginally lower than Option 1 at $88.24 million (or $12.56M/yr). Option 3 provides for the lowest NPV of the three options at $60.93 million (or $8.67M/yr).

Moving to consideration of the qualitative analysis, the IESO study team believes that there are additional positive benefits for each option not realized in the NPV. But by using the results of the quantified NPV analysis, we can identify what value non quantified benefits must be worth to change the overall outcome of the CBA. For instance, the IESO calculates that non quantified benefits attributed to the UDAM would have to be valued at over $27.5 million dollars over the 15 year period (or $4 M/yr) to rank it higher than the other options. The IESO study team is not confident that the non-quantified benefits attributed to the UDAM would be material enough to meet this test. When comparing Option 2 with Option 1, the difference in the NPVs between the options is small – calculated at $0.17 million over the 15 year life of the Option (or $30,000M/yr). It seems reasonable that the introduction of the EFM for hedging and risk management purposes provides enough of a material positive benefit to exceed the required $30,000/yr so as to rank Option 2 higher than Option 1.

In its assessment of the merits of each of the day-ahead options, the IESO study team also considered stakeholder impacts, particularly the impact on the overall electricity bills of Ontario consumers. In the initial year post implementation (year 3), essentially no change- less than one cent per megawatt hour – is anticipated for Options 1 and 2, with savings in all subsequent years. For Option 3, the increase in the initial year post implementation has been calculated at one cent per megawatt hour, with savings in all years commencing 2 years after implementation. Bill impacts reflect both anticipated HOEP changes and the effect of the Global Adjustment. Overall, the NPV of savings for consumers over the 15 year analysis period for the implementation of Options 1 and 2 is $23M. For Option 3, the NPV of the savings is $13M.

The IESO considers all of the options robust enough to meet the needs of today without inhibiting future market evolution initiatives. But the preliminary view of the IESO study team is that Option 2: an enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees and an EFM offers a better overall set of amendments to our day-ahead planning mechanisms in support of anticipated changes in Ontario's electricity sector.

The IESO study team welcomes stakeholder views – and especially the rationale for those views - on both the overall assessment and the quantified and qualitative analyses.

6.0 Next Steps

- May 15, 2008 - Stakeholder meeting to present all of the results of the analysis and IESO conclusions – receive stakeholder feedback on IESO conclusions in advance of IESO recommendation
- Late May, 2008 - IESO publishes a day- ahead recommendation
- June 4, 2008 - Stakeholder Advisory Committee meeting to gather input and advice for the IESO Board of Directors regarding the recommendation
- June 19, 2008 - IESO Recommendation to Board of Directors for decision

List of Acronyms

Acronym	Title	For more information can be found at the following links:
DACP	Day-Ahead Commitment Process	http://www.ieso.ca/imoweb/dacp/dacp-index.asp
HOEP	Hourly Ontario Energy Price	http://www.ieso.ca/imoweb/mktOverview/mktOverview.asp
DAM	Day-Ahead Market	http://www.ieso.ca/imoweb/consult/consult_se21.asp
CBA	Cost Benefit Analysis	http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080505_DAM_Assessment_Report.pdf
NPV	Net Present Value	
IPSP	Integrated Power System Plan	http://www.powerauthority.on.ca/electron/Page.asp?PageID=1193&SiteNodeID=144&BL_ExpandID=244
OM&A	Operation Maintenance & Administration	
NUG	Non-Utility Generation	
LMP	Locational Marginal Pricing	http://www.ieso.ca/imoweb/consult/consult_se25.asp
LSE	load serving entities	http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6466&SiteNodeID=131
RAM	Resource Adequacy Mechanism	http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080505_DAM_Assessment_Report.pdf
EFM	Energy Forward Market	http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080505_DAM_Assessment_Report.pdf