IESO Commentary on 12 Times Ramp Rate Solution Options

Background:

There are three primary goals of all electricity industry structures; reliable supply, allocative (dispatch) efficiency and dynamic (investment) efficiency. An electricity market attempts to achieve all three of these goals through economic signals that generate rational responses by all participants. The degree of success or failure in achieving this objective is therefore very dependent on the quality of those signals.

An effective price signal is one that permits decisions to be made with reasonable knowledge of the economic impacts of those decisions. An effective real-time price is normally considered to provide the necessary signals to make such decisions if it reflects the costs of supplying one more or one less increment of demand for electricity. This is the philosophy embedded in the IESO's dispatch algorithms.

Currently, Ontario's real-time price signal is calculated using a sequence of the dispatch algorithm which is separate from the one used to dispatch the system. This is a relatively unique feature of the Ontario market compared to other jurisdictions. The separate pricing sequence was conceived in the late 1990s by the Market Design Committee as a way to calculate a single price for energy in Ontario, and became known as the "unconstrained sequence"[1].

As discussed further in this report, in the testing phases leading up to market opening in 2002 the prices calculated by the unconstrained sequence showed large and rapid fluctuations. This was especially true during load pick-up hours. These sorts of price outcomes led to a common concern among the majority of stakeholders about the practicality of opening the market. At the same time, the existence of a separate pricing sequence provided the IMO staff, stakeholders and the IMO Board with an opportunity to

[1] The Unconstrained sequence does not respect transmission constraints while determining price, all Ontario load and generation is considered to exist at a single point

"adjust" the pricing calculation without affecting the reliable dispatch of resources in real time. Hence, on April 18, 2002 the IMO Board approved the use of the 12x ramp rate multiplier in the unconstrained sequence, as a temporary measure[2].

As illogical as it sounds to start the market with a real-time pricing sequence that is told that generators can ramp 12 times faster than they are physically capable of, some comfort came from the fact that this was a temporary measure. Participants anticipated that the question of how best to address the ramp rate multiplier would be addressed within the first 18 months of the market, as the IMO was planning to address how the costs of congestion should be addressed in Ontario's market in that time. Most stakeholders believed that in addressing the substantive issue of aligning real-time pricing with the realities of the transmission system capabilities, the question of how to deal with the generators' actual ramping capabilities would by necessity be addressed at the same time.

The IMO started to discuss a day-ahead market, (DAM), with stakeholders in 2003[3]. Initial work on a DAM was based on the use of nodal prices and the analysis from this effort was building toward a locational pricing basis for congestion pricing. Significant analysis was done on various locational pricing models, ranging from straight nodal pricing, to zonal pricing, to supply-side nodal with a single Ontario energy price based on an average of the nodal prices. As the day-ahead market analysis of locational pricing progressed, it became clear that a change to nodal pricing was going to raise the average price paid by consumers. This increase in price was in part due to accounting for the effects of congestion in prices (rather than making side payments), and also in part due to the fact that the existing price was calculated using the 12x ramp rate multiplier. Nodal prices on the other hand, were the outcome of the dispatch sequence which used actual ramp rates. The IMO concluded, based on views from many stakeholders in both the generation and consumer communities, and from the government that locational

[2] The IESO board approved an amendment to Market Rule appendix 7.5 section 4.13.1 to enable 12X RR pricing

[3] For materials produced by the DAM design group please refer to this link: http://www.ieso.ca/imoweb/consult/mep_dam.asp

pricing was unlikely to have broad support in the foreseeable future. From that point on, the day-ahead market development work concentrated on creating a market that incorporated the unconstrained sequence and focus shifted away from real-time pricing concerns, including how to address the temporary 12x ramp rate factor.

On June 23, 2004, the IMO incorporated the multi-interval optimization methodology into the physical dispatch algorithm, (the constrained sequence), as discussed in greater detail later in this report. At that time, there was discussion about incorporating the same logic into the unconstrained pricing sequence, but it was not implemented. Stakeholders had little experience with this new and more complicated MIO algorithm, and in the circumstances did not have the comfort required to support implementation

There are several reasons why the 12 times ramp rate multiplier issue is being addressed at this time. First, in December 2005, the IESO Board, as part of its approval of the high-level design of the Day Ahead Commitment Process, (DACP), directed the IESO management to address the 12x ramp rate multiplier. They did so in response to the concern expressed by the generation stakeholder community about the potential price impacts of the DACP, and about the possibility the DACP would limit further market evolution. Second, replacing the 12x ramp rate assumption in the pricing algorithm with something that would better signal the cost or price effects of the actual ramping capabilities of generators should improve both the allocative and dynamic efficiency of the market; efficiencies that would benefit all market participants. Thirdly, the OPG rebate, and the various components of the Global Adjustment limit participants' exposure to any potential price change that could emerge under an alternative pricing measure. Currently, these contracts essentially fix the price for roughly 70 percent of energy transacted in the market – significantly mitigating the potential impacts of changes in pricing.

The implementation of a change to market pricing would in some cases require significant IESO and stakeholder efforts that would in turn delay work on further evolution of the market. This could be seen as the "opportunity cost" of a pricing change and that cost would need to be weighed against the benefits of the new pricing method.

Analysis:

The decision on how to address the current 12 times multiplier in the pricing algorithm must be made with a longer term perspective in mind. The market's real-time price calculation method must be stable and predictable as one looks forward in time. Expectations of real-time price serve as a basis for forward commitments, whether they are bilateral contracts between participants or OPA forward contract auctions. Any change must be seen as either an enduring feature of Ontario's electricity market, or be widely understood to be a transitional measure, consistent in direction with reasonably-anticipated future scenarios, and accompanied by a plan of how future evolution is expected to unfold. It is in this light that the IESO offers the following comments on the options currently being considered to address the pricing question.

1X Myopic

A move to 1x myopic pricing (i.e. pricing which does not look beyond the past 5-minute interval) would represent a return to the original design of Ontario's electricity market. This is the preferred solution by the vast majority, if not all, of the generators in the province. They argue that it provides the right price signals for both short-term allocative efficiency and for longer-term investment.[4] This option is strongly opposed by the power consumers because of concerns about the increases to average prices. Further, they argue that price increases would provide a benefit to all forms of generation – baseload, intermediate and peaking – whether or not such generation was able to respond to shortages by increasing output at the time of the shortage.[5]

[4] Please see the presentation given by APPrO at the market pricing working group (MPWG) on March 24, 2006. Slide 10 discusses APPrO's rationale for supporting 1X Myopic as the preferred solution. APPrO's presentation can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060324-APPrO-Ramp-Rate-Issues.pdf

[5] Please see AMPCO's proposal submitted to the MPWG for the March 3, 2006 meeting, which can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060120-AMPCO-response.pdf.

In June of 2004, Ontario moved away from dispatching the system using a myopic algorithm and introduced a multi-interval optimization algorithm, (MIO), similar in concept to that used by the New York ISO. The change to MIO dispatch was primarily initiated to deal with dispatch issues. The myopic dispatch was routinely creating situations where the IESO system operators had to intervene and manually adjust dispatch instructions to ensure reliability. MIO has significantly addressed this problem, with IESO intervention in dispatch being mainly eliminated. The exception has been reliability concerns that result when high demands for electricity coincide with significant energy constraints on Ontario suppliers over a day; a situation which is being addressed by the Day-Ahead Commitment Process, (DACP).

It can be argued that Ontario had to move to MIO dispatch because the Ontario energy prices were not providing their originally-intended signals to the generators – signals that would permit the generators to strategically adjust their offers on their own to take advantage of high price opportunities. The strategic offers would then mitigate any shortage conditions and effectively achieve the same result as the MIO dispatch. It has been further argued that by moving back to the 1x myopic pricing, these sort of strategic offers from generators would materialize.

The use of an unconstrained price signal injects a very significant and well-documented distortion in the Ontario energy price relative to the costs incurred in dispatch. The Market Surveillance Panel's (MSP) most recent report highlighted the significant differences in incremental costs of production across the province last summer.[6] Accordingly, we do not believe that the simple replacement of the 12x ramp rate multiplier in the unconstrained pricing sequence with a myopic 1x multiplier will

Page 3 of this proposal provides a summary of AMPCO's position, while the remainder of the paper proposes a possible solution.

[6] The MSP compared the prices among the 10 transmission zones in Ontario. These prices indicate the incremental cost of producing a MW in each zone. The MSP found that the zonal prices over the summer of 2005 were relatively consistent in Southern Ontario yet were significantly different in the Northwest. Prices in Southern Ontario were approximately 3X prices in the Northwest. Please see Section 15 Internal Zone Prices of the 2005 MSP report for a detailed discussion of these results. The MSP report can be found here: http://www.oeb.gov.on.ca/documents/msp/msp_report%20final_131205.pdf.

result in pricing signals of sufficient clarity to permit the sort of strategic bidding behaviours necessary to allow dispatch in Ontario to be performed in a myopic manner. Furthermore, there are potential CMSC impacts to the strategic bidding required by a myopic process.

Proponents of myopic price and schedules suggest that generators will offer energy below actual cost in order to be available during an hour in which they expect relatively high prices. This strategy will provide sufficient ramp depth to mitigate some of the high and fluctuating prices from a myopic algorithm. In this situation however, any constrained on payments made to generators due to transmission constraints will be insufficient to keep the generators whole to their actual costs which may prevent or at least lessen the desire for generators to make the strategic offers necessary for a myopic methodology to function. The signal quality is further degraded by the fact that the constrained dispatch is using a MIO sequence and not a myopic sequence. With MIO dispatch and transmission impacts separating the pricing algorithm from the dispatch algorithm, it is unclear that the strategic offers necessary to make myopic pricing effective will materialize with an unconstrained price.

To return to that original vision of a one times myopic pricing algorithm would require, as a minimum, some form of myopic locational price signals to the dispatchable facilities in the province. Even then, such a change would have to be well-considered, knowing as we do that New York decided to move to a MIO dispatch algorithm despite the fact they were already paying New York generators on a nodal basis even before implementing MIO.[7] Since myopic dispatch is not likely in Ontario in the near future, there is no reason to send price signals based on a myopic algorithm.

Supplemental Payments for Ramp

Both AMPCO and APPRO suggested a form of supplementary payment. These suggestions served as a very useful basis for stakeholder discussions and helped explore

[7] In New York, generators are settled according to a generator nodal price and loads are settled on a load zonal price.

possible common ground on this issue. Both proposals featured a real-time energy price that would continue to be based on the 12x ramp rate multiplier in the unconstrained sequence, plus some additional payment for ramping generators.

Fundamentally, the IESO does not support the concept of supplementary payments as permanent features of our market design. The IESO agrees with the generator perspective that all producers of energy over the same interval should be paid the same price for that energy. We are wary of creating additional side payments to certain energy producers that would result in an increase in uplift charges to consumers at the cost of an understatement of the value of energy at any particular time, and removal of volatility that should be present in a real-time pricing signal.

The real-time price is the only energy price signal currently in Ontario's wholesale market, and as such it influences the actions of all producers and many consumers. It must send the right signals to generate the right actions. These actions may be in response to spontaneous transient signals which occur due to unanticipated events on the power system, or they may be to modify plans in response to routine price patterns across the day, week or season. It is both reasonable and appropriate if some of these price patterns are influenced by the challenges of meeting morning ramp. Such price signals signify the challenges being experienced in maintaining a supply/demand balance. They ensure that all suppliers and consumers have information available to them so they can take incremental actions that are appropriate, whether they are baseload generators deciding when to take outages or perform tests, or commercial or industrial consumers supplied by local distributing companies who may be able to respond to real-time price signals.

We further believe that exposure to the full set of pricing signals under all supply/demand scenarios is a key ingredient in creating the right investment signals for all forms of generation and consumption. Every decision that weakens the linkage between incremental costs of supply and price by compensating through side payments causes a potential loss of efficiency, and an increased need for other mechanisms such as capacity markets or central planning and procurement to create new investments. Any move that results in differentiated pricing between classes of participants or facilities causes an even more complicated landscape in which it becomes ever-more difficult to understand the relevant drivers and behaviours of participants. This makes any potential market design all the more complicated, given the diversity of revenue streams available to the different participant classes. While this may be the Ontario market of today, it should not serve as the appropriate driver for further market evolution.

Given this background, when considering what would be enduring features of future market evolution, the IESO would find it difficult to support supplementary payments to a subset of generators for their actual use for ramping or for their response to dispatch instructions. However, there is some evidence that supplementary payments may be considered by both generators and consumers if the current twelve times unconstrained price is left in place, recognizing that the current pricing methodology dampens market signals and, at times, limits generator compensation. If used at all, such payments should only be introduced as a temporary measure while progress is made on enduring market evolution initiatives that would render such payments unnecessary.

The AMPCO proposal was to dynamically calculate the supplementary payment by comparing a real-time price using a 1x multiplier with the currently-calculated 12x based energy price, and awarding generators an additional payment for their changed outputs during these periods based on the price difference[8]. This approach was offered as a possible enduring market feature to retain a ramp-neutral energy price. This simple concept was offered as the start of an idea to spur on more discussions on alternatives. The proposal would be complicated to implement in the IESO systems[9], and provides a rather arbitrary financial reward to a subset of generators. Implementation would be

[8] AMPCO's submitted written proposal can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060120-AMPCO-response.pdf. The presentation AMPCO gave to the MPWG on this proposal can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060303-Ramp-pricing-option.pdf

[9] The IESO estimated implementation timelines for each of the proposals and were presented to the MPWG at its April 7th meeting. The AMPCO proposal has an expected implementation date of March 2007. The presentation on implementation timelines can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060407-12xRR.pdf

difficult and many details would have to be worked out.[10] Since the IESO does not support such side payments as an enduring feature of our market evolution and since the proposal as contemplated to date requires significant systems development and additional stakeholdering, the IESO does not support any further work on dynamic calculation of supplementary payments to a subset of generation.

The APPRO proposal built from the AMPCO ideas and suggested that all generators receiving a dispatch instruction that differs from their previous instruction would receive a supplementary payment equal to an administratively-set price times the lesser of the total magnitude of changed outputs ordered by the dispatch instructions, or the actually-achieved output changes in response to the dispatch instructions[11]. This payment would be relatively simple to implement from a systems perspective,[12] but would likely face significant challenges when determining the appropriate administrative price for following dispatch instructions.[13] The IESO provided analysis on the number of issued dispatch instructions, to help participants scope out the approximate frequency of such payments[14]. The generation community would have to provide analyses of the approximate costs of moving the output of a generator in response to a dispatch instruction as a basis for determining the price. The most simplistic method would be to use the same price for all generators, ignoring the diversity of costs for different technologies[15]. It is unclear how the "reasonableness" of this price would be determined.

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[10] At the request of the MPWG the IESO performed significant work on the AMPCO proposal to address deficiencies that were identified by the working group. The AMPCO proposal used the unconstrained schedule to determine who should be compensated for ramp and did not consider interactions with the current CMSC infrastructure. IESO staff modified the AMPCO proposal to address these deficiencies. The IESO modified AMPCO proposal can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060324-Constrained-Ramp.pdf

[11] The APPrO presentation given to the MPWG outlining the APPrO proposal can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060324-APPrO-Ramp-Rate-Issues.pdf

[12] The proposed implementation date of the APPrO proposal is December 2006. The presentation on implementation timelines can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060407-12xRR.pdf

[13] Jonathan Falk of NERA has stated that establishing the costs of generators wear and tear would be impossible to estimate to a regulatory certainty. Mr Falk's full presentation can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060407-NERA.pdf

[14] At the request of the MPWG the IESO formulated aggregate statistics on the magnitude of generator dispatch instructions. This presentation can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060407-Ramping-Data.pdf

[15] Jonathan Falk of NERA asserted this simplistic approach would result in some generators being overcompensated for ramping while others would be under compensated. Mr Falk's full presentation can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060407-NERA.pdf

The various initiatives currently being undertaken by the IESO and affected stakeholders to address the problems of erratic dispatch signals should, over time, decrease the size of the payment made under such a scheme. For example, an increase in the compliance threshold for complying with dispatch instructions to 15 MW is expected to provide generators with an opportunity to smooth over significantly more dispatch instructions compared to the current 10 MW dead band. Less movement by generators would have a direct decreasing effect on the supplementary payments. Some participants have pointed out that by having the IESO pay for dispatch changes and having that charge reflected as a separate uplift component paid by consumers, there will be a clear signal to the market of the importance of the erratic dispatch issue. They argue that with a clear signal incentives will be in place for the IESO to address the dispatch problem, thereby improving allocative efficiency in the process.

Aside from our general objection to the long-term incorporation of supplementary payments to a subset of generators, the IESO has some concerns associated with the general philosophy of supplementary payments for dispatch changes. Generators can only earn revenue by producing energy, and they can only produce energy if they are dispatched up to do so. Is it reasonable for consumers to make a supplementary payment to generators in such circumstances? Frequently, generators are requested to change dispatch as a result of the actions of other generators. If a generator either fails or is shutting down of its own volition, is a charge for the corresponding dispatch instructions to that generator, plus the dispatch to other generators to compensate for the change appropriate? Clearly, there are many other circumstances which could bring into question the appropriateness of supplementary payments for movement. Also, there would have to be a market monitoring process required to ensure there weren't excessive supplementary payments being made through intentional actions. If the total dollars are small, then perhaps many generalizations are appropriate and reasonable.

On an interim basis, such a supplementary payment scheme may be reasonable as a means to compensating for known shortfalls in the market's current pricing/payment process if some of these challenges can be addressed, and if the generators can provide the IESO with a price to be applied to generator movement, with a well-developed rationale that is found to be reasonable to the IESO and its Board.

Multi-Interval Optimization

Over the past three years, there have been many discussions about the possibility of introducing the same multi-interval optimization methodology that currently exists in the constrained sequence, into the unconstrained sequence and have the real-time energy price calculated in that way. There is some common-sense appeal to proceeding with this, as in theory it takes a step towards better aligning the pricing calculations with the dispatch decisions. Alignment between pricing and dispatch is considered to be the goal in all real-time markets. However, enthusiasm for achieving some progress towards that goal must be weighed against the effort or costs to achieve it. MIO is a complicated process. While generators are developing some familiarity with MIO through the dispatch process, consumers have no experience with MIO. The move to implement MIO in the unconstrained sequence is generally not supported by either the generation or consumer community.

Generators are concerned that adding the inter-temporal optimization of the MIO logic to the unconstrained sequence would make the pricing process even less intuitive or transparent than the current process. They further state that the dispatch advisories they currently receive from the MIO software in the constrained sequence are of low quality and have eroded their confidence in the logic. And finally, they have concerns that the price calculation would become dependent on forecast demand in future intervals, as produced by the IESO's Load Predictor program (LP).

The IESO does not consider the further erosion in transparency of the pricing algorithm by introducing MIO as an issue, mainly because there already exists little transparency with the simultaneous optimization of the energy market with the three reserve markets. We observe the New York experiences with MIO and understand that while replication of the actual calculation is not possible, there is a reasonable correlation between pricing results and expectations given similar supply-demand scenarios of the past. However, we must be cautious when drawing from New York's experiences given that New York calculates nodal prices which increases the likelihood of predictable pricing relative to the Ontario situation, assuming no locational pricing and the use of an unconstrained pricing sequence continues in Ontario.

Regarding the dispatch advisory inaccuracies, we observe that the most inaccurate dispatch advisories are for those that correlate with the longest look-ahead timeframe, and that actual dispatch instructions are very minimally affected by such long looks ahead. A MIO price calculation will be driven by the "dispatch instructions" that the unconstrained sequence would derive, and like the actual constrained dispatch instructions, they too should be minimally affected by the longer look ahead capabilities of MIO.

Regarding the concerns of the accuracy of the load predictor, the IESO recognizes that no forecasting tool can be 100% accurate, and we further recognize that we currently manually adjust the LP forecast to compensate for system challenges that may be presented by non compliance to dispatch instructions. It may well be that price should not be set using a manually-adjusted LP forecast. There are at least two possible ways to address this concern. One would be to delay the price calculation until actual conditions are known for all relevant intervals needed for the MIO process to run. This would create an ex-post price that was potentially only available up to an hour after the fact. This method is likely unacceptable to participants. A second option could be to create a parallel LP forecast that could not be overridden by the IESO system operators to address system problems. Either of these approaches, and perhaps others, would have to be further developed with stakeholders.

The consumers are, as stated earlier, less familiar with the MIO logic than the generators. They have seen the 12 days of simulation results that the IESO produced over December, 2004 through February, 2005, and heard that the average price calculated using the MIO algorithm was on average very similar to the 12x result[16]. More simulations might provide them with additional comfort. However, they also know that while MIO is effective at preparing the system for known, future circumstances, it has no ability to prepare for contingencies, or unexpected events. Therefore, in terms of price calculations after generator contingencies, the MIO-derived price will be very similar to the outcome with a 1x myopic ramp rate multiplier. This higher post-contingency price would be paid to all generators, including baseload generators, which from their perspective, is not a reasonable outcome.

The evaluation of these various alternatives is not straightforward. In particular, it is very cumbersome for the IESO to simulate MIO pricing, since it is based on a complex logic that optimizes choices over time, considering both energy bids and offers, and operating reserve offers. To do these simulations requires the IESO to dedicate its sandbox test environment totally to a simulation. This results in a significant impact on other initiatives that need testing in an off-line, real-time environment. The value of these simulations can also be questioned, as they produce a result which does not benefit from participants adapting to the new prices in real time. Both domestic participants and importers and exporters of power to/from Ontario will adjust to the new price signals. This adjustment can significantly dampen the resultant price outcomes in real time, with the largest adjustment likely occurring to the exports that would be successfully scheduled from Ontario. It is these adjustments, or arbitrage, that generate changes to allocative efficiency, both within the province and inter-jurisdictionally. To the extent that the pricing change more closely aligns the prices to the dispatch costs, then the behavioural adjustments will result in greater allocative efficiency. Since the pricing simulations don't have the benefit of driving such participant actions, they can only serve to provide directional guidance, perhaps some indication of relative price patterns across time, and probably an upper and likely extreme bound of any price effects.

[16] In sandbox simulations it was found that prices would on average be between 0.5% lower and 2.6% higher depending upon the MIO methodology chosen. The results of the simulation can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/mp_wg_2005jul08_MIO_Pricing.pdf.

In the case of the MIO price simulations, the degree of change in average price was small, leading us to conclude that the pricing impact of changing to MIO is probably within the bounds in which arbitrage will drive the MIO prices to be very similar to the prices created by the 12x algorithm, but with possible efficiency gains. There are some analyses of current constrained shadow prices that suggest that the MIO algorithm will, on average, increase the prices in the ramp-up periods, lower prices in the ramp-down periods, and otherwise, on average be somewhat similar to past prices. If these patterns were to materialize, then a change to MIO pricing could yield efficiency gains through load reductions (particularly exports to New York) and generating units wanting to come on line sooner during load pick up periods to respond to higher prices. And we would expect additional exports, or units wanting to come off line sooner, in ramp down periods in response to lower prices.

There are other complications to pursuing a MIO price calculation. Firstly, three different MIO pricing proposals have been considered in the past;

1) MIO incremental which calculates the price by considering the lowest-price resource on line to meet incremental demand in any interval,
2) MIO high-slice which uses the offer of the highest price facility providing energy to set price, and,
3) Modified MIO that collects costs incurred in preparing for a future ramping challenge and reflects them all in the interval in which the challenge occurs.

All three of these produce different price calculations, with MIO incremental being the lowest average price, and MIO high-slice the highest. The consultant report commissioned by the IESO states that the modified MIO is an unsound basis to proceed in that collection of costs for future intervals will have consequences in coordinating the simultaneous optimization of energy and operating reserve markets across all intervals. They conclude that since only MIO incremental aligns with the actual dispatch logic, it should form the basis of any MIO price calculation method. While this appears to be sound advice, this decision would have to be discussed and explored further with stakeholders.

Secondly, a decision would also have to be made on how to treat minimum output levels of generators. The current 12x price calculation ignores unit minimums, allowing the price to be calculated by “dispatching” units to levels below minimum outputs. The constrained MIO program recognizes unit minimums and will not dispatch a generator into this region. Consistent with trying to align dispatch with pricing, the IESO would be proposing to respect unit minimums in any MIO pricing implementation. Generally, respecting unit minimums will have an average price lowering effect. This too would need stakeholder review.

Thirdly, a decision would have to be made regarding possible production cost guarantee payments to generators requested to move early by the MIO program when their offer prices may exceed the incremental price in the interval. These costs are currently covered using congestion management settlement credits derived by comparing the unconstrained schedule to the constrained dispatch. The validity of such an approach with MIO in the pricing algorithm and whether or not additional cost guarantees are warranted would need to be analyzed, designed and discussed with stakeholders.

Systems developments needed to support a MIO pricing algorithm are thought to be manageable, but somewhat time consuming. Efforts to define the many technical details of a MIO implementation would likely be significant, requiring several months of effort by the IESO and its stakeholders. Implementation of a MIO pricing solution would likely not be prior to March, 2007.

All things equal, the IESO believes a move to a MIO pricing algorithm is the best option, as it moves the market down the path of aligning dispatch costs and price, and therefore brings with it some modest efficiency gains. However, the complexity of designing the MIO pricing algorithm, and the significant stakeholder uneasiness regarding a MIO implementation combine to cast significant doubt on MIO pricing implementation at this time. We believe that answering the question of whether MIO implementation is worth the effort for both the IESO and its stakeholders, depends on the expected time horizon of other market evolution initiatives.

Status Quo - Addressing Other Priorities

A fourth possibility that must be considered is that of continuing with the current pricing regime on a further-extended, temporary basis. This could be the preferable option if other market evolution initiatives are seen as the highest priority. For example, the planned retirement of coal-fired generation in Ontario and the associated greater use of natural gas-fired generation may lead to some operability concerns that could be best addressed with a full-featured day-ahead market. The existing generation fleet has very flexible operating characteristics when compared to the expected replacements, which will likely result in less ramping capability with this new generation fleet. This decrease in flexibility will increase the importance of developing a day-ahead market in Ontario that includes day ahead commitment of dispatchable resources based on a 24-hour optimization. While the day-ahead coordination could be done with some modification to the IESO’s Day Ahead Commitment Process, a full-featured day-ahead market is by far the preferred solution.

As stated earlier, the current pricing model is a contributor to some allocative (dispatch) inefficiencies, mainly reflected in the volume of export transactions that are currently deemed economic. This source of inefficiency is due to the degree of misalignment between the energy price which is charged to all consumers, including electricity exports, and the cost of dispatch required to support the export. While 12x is a contributor, it is not likely the biggest contributor, with the unconstrained pricing model causing the largest divergence between costs of dispatch at any point in the province and the energy price. If status quo is chosen, then this source of inefficiency may warrant additional examination.

Dispatch inefficiencies within Ontario are limited since the actual dispatch of Ontario resources is directed by the constrained sequence, which uses appropriate ramp rates and a MIO process. However, several generators have stated that the lack of reward for peaking plants caused by the 12x algorithm during both ramp-constrained periods or post-contingency operation could cause them to not invest in future ramp capability or improved ramp capability in existing facilities, and could even lead to a degradation in current ramping capabilities.

Participants are able to offer their generation at prices which they choose. Those offers are used by the MIO-based constrained sequence to dispatch generation in the lowest-cost fashion. In parallel, the current 12x-based unconstrained algorithm is determining a different set of resources to meet the required dispatch. If the constrained sequence has used a generator that was not needed by the unconstrained sequence, that facility is provided additional compensation above the market price to ensure that the facility's costs of additional production are covered, with those costs being defined as the offer prices submitted by the facility. Hence, the only limit on revenues available to the peaking or ramping facility dispatched to operate by the constrained algorithm, is the normal limiting competitive forces.

The IESO does not understand why market payments cannot provide sufficient revenues to support ramping capabilities. We have heard generators state that to include these costs in offers is problematic, but we have not fully appreciated this problem. We concur with our consultant's report which states that offers that fairly reflect the costs of ramping are very legitimate, and that the current combination of energy payments and constrained-on payments should provide sufficient revenues to cover any costs incurred to provide ramping capability[17].

Use of constrained-on payments to compensate specific generators for their costs of dispatch is not preferred. In fact, the IESO has been asked to examine whether

[17] Jonathan Falk of NERA has stated in his report and presentation that the CSMC regime compensates generators for costs when requested to move out of economic merit. Mr Falk states that if a generator is not receiving adequate compensation through CMSC they should increase their offers, and if increasing their offers results in the generator not being dispatched then they should not have been dispatched. This is the efficient result. Mr Falks' presentation can be found here: http://www.ieso.ca/imoweb/pubs/consult/mep/MP_WG-20060407-NERA.pdf

constrained-on payments are permitting generators to recoup all costs; at least one participant has commented that they do not. As stated earlier, the IESO believes that all generators producing energy at a particular time should be paid the same price, yet constrained-on payments effectively create a "pay as bid" component to the real-time pricing. However, as a temporary measure to permit the development of other necessary market evolution initiatives, the 12x ramp rate unconstrained sequence and the resultant congestion management settlement credits could continue as a basis for market pricing and cost recovery by generators.

Summary

There are many potential evolutionary paths for Ontario's electricity market. There is strong consensus that Ontario's wholesale market will benefit from a full-featured day-ahead market. As discussed in this report, the evolving Ontario generation fleet could bring new and different operational challenges, some of which could have reliability impacts that may also be addressed with strong, market-based day-ahead mechanisms. A successful day-ahead market needs active demand-side participation, which will likely require active load representation. And active participants will want convenient and liquid forward contracting opportunities with a diverse set of counterparties. If we are able to establish such an industry, we will be well positioned to have a self-sustaining electricity market. All of these potential changes and activities will build from the real-time price. It is unlikely that such a mature industry structure as this will be based on a real-time price that is the product of an unconstrained pricing algorithm, or one that ignores the physical abilities of the resources being dispatched. Ultimately, the real-time price must have a more effective way of reflecting actual costs of dispatch in the price.

With so much of our evolution ahead of us, the direction we take in addressing the 12x ramp rate multiplier alone, should be recognized as relatively short lived, in market terms. Implementation timelines should be brief, and implementation costs should be small. Fortunately, all of the potential solutions being considered are not likely to exceed IESO's budgeted development funds. If a potential solution will require heavy investments by either the IESO staff or stakeholders then it should be seen as having a significant opportunity cost, which may be grounds to reject it.

Of the three options we are still considering, each has its challenges. The MIO option is the IESO's preferred option, as it moves closest towards aligning price and dispatch. However, MIO is likely to be difficult to implement, both from an IESO systems perspective, but more significantly from the anticipated stakeholder process needed to complete the technical design, and the efficiency improvements gained from a MIO implementation are likely real, but modest. Unless stakeholder alignment can be achieved in short order, the opportunity costs of proceeding with MIO may be too great, resulting in delays in progress on the other substantive evolution issues like day-ahead market. Supplementary payments to generators for their dispatch movement can be considered as a short-term solution if it permits the IESO and stakeholders to move on to address the other evolution initiatives. A price for generator movement would have to be developed and the rationale for any particular figure would need to be seen as reasonable. Further, some assurances would have to be forthcoming that the payments under this option would not be duplicated through routine constrained-on payments. The final option is to continue with the status quo and move immediately to addressing more enduring market features like the day-ahead market. This latter option relies on generators to incorporate the incremental costs of generator movement in their offers, and therefore receive the required revenues, either through energy payments or constrained-on payments. The practicalities of these various options will be further explored with stakeholders, by receiving their feedback in the coming weeks.