

MR-00332-R00 -Reducing the 10-minute synchronized OR requirement

IESO reply to stakeholder comments on CBA and IESO recommendations
SE-37



August 17: Revisions made to page 6

1. Purpose:

On July 16, 2007 stakeholders provided the IESO with written comments on the preliminary cost-benefit analysis (CBA) applied to market rule amendment proposal MR-00332-R00 – an amendment to allow the IESO to reduce the ten-minute synchronized operating reserve requirement by 100 MW in accordance with Northeast Power Coordinating Council’s (NPCC) Regional Reserve Sharing (RRS) program. Stakeholders’ provided comments on (i) the IESO’s analysis and estimation of the costs and benefits attributable to market rule amendment proposal, and (ii) the use of CBA, more generally, as a means to facilitate a more rigorous consideration of rule amendments and whether, and how, the content can be better organized in future CBAs. IESO staff provided stakeholders with their initial feedback to the comments at the July 19, 2007 Market Pricing Working Group meeting and the July 24, 2007 Technical Panel meeting.

The purpose of this memo is to provide a written reply to stakeholders’ comments and to offer the IESO’s recommendations regarding the approval of market rule amendment MR-00332-R00. In this memo, the IESO will limit its reply to those comments that were specific to market rule amendment proposal MR-00332-R00 and update the analysis and estimated costs and benefits accordingly. The IESO found the broader comments on CBA constructive and was in general agreement with the substance of these comments. The IESO will continue to develop its application of cost-benefit analysis by applying this tool on upcoming rule amendments and market design changes and will be guided by these broader comments in this process. As the IESO works through these analyses, it will continue to consult with stakeholders, providing opportunities for further stakeholder comment on how and when a CBA should be applied in the market rule amendment process.

2. IESO reply to stakeholder comments

Stakeholders had three main comments regarding the IESO’s estimated costs and benefits of proposed market rule amendment MR-00332-R00. The IESO addresses each of these comments below.

Comment 1: The efficiency gain in the preliminary draft CBA for MR-00332-R00 is based on an estimated reduction of \$0.91 million in reduced producer costs. The reduction in production cost is a result of the need for less ten-minute synchronized operating reserve – reducing the ten-minute synchronized operating reserve requirement by 100 MW while maintaining the total ten-minute reserve requirement results in the IESO scheduling an average of 44 MW less of the relatively costly ten-minute synchronized operating reserve and instead scheduling 44 MW more of the relatively less expensive ten-minute non-synchronized operating reserve.

However, the IESO is concurrently preparing a further operating reserve related rule amendment to allow dispatchable loads to provide ten-minute synchronized operating reserve. This change will also affect the relative cost of providing ten-minute synchronized operating reserve versus ten-minute non-synchronized operating reserve (10s) within the province and will affect the overall efficiency gains attributable to MR-00332-R00. In particular, with the eventual change in the providers of ten-minute synchronized operating reserve, the IESO's estimated efficiency gains of \$0.91 million in the preliminary draft is an overstatement of the likely efficiency gains attributable to MR-00332-R00. The IESO should revise the estimated efficiency gains to include the impact of dispatchable loads providing ten-minute synchronized operating reserve.

IESO response:

The IESO agrees with the general comment and has revised the estimated efficiency gains attributable to MR-00332-R00 to reflect the expected change to allow dispatchable loads to provide ten-minute synchronized operating reserve.

To separate the efficiency impact of the two operating reserve initiatives, the IESO ran three simulations. The simulations were conducted for the real-time unconstrained schedule for a six month period in 2006.¹ As noted in the preliminary CBA, these simulations provide a measure of the direction of the price change and an upper bound of the magnitude of the price change due to a particular initiative or policy change. Since the simulations ignore participant responses to the change, they are not a projection of the eventual price outcomes. Behaviour responses to the expected price pressures must also be considered before a final projection of the price impact can be made. The three simulations conducted for this CBA can be described as follows. The possible behaviour responses to the simulated price pressures are discussed later in this memo.

Simulation 1 (Benchmark): In its first simulation, the IESO simply re-ran the unconstrained market for the six month period. That is, it used all of the same inputs and data (i.e., offers, bids, demand levels), that were used in the actual unconstrained dispatch. This first simulation provides us with a benchmark against which we can measure the price pressure impacts attributable to the various initiatives.

Simulation 2 (RRS in 10n and DL): In the second simulation, the IESO made two modifications. First, the ten-minute non-synchronized operating reserve (10n) and total reserve requirements were reduced by an additional 50 MW in order to reflect the changes made on May 17, 2007 when the IESO implemented changes resulting from NPCC RRS

¹ The simulations were conducted for 6 months: January, March, May, July, September, and November. The simulations compute prices and quantities for each of the 5-minute intervals in the 6 month period.

policy.² The second modification was to reflect the expected future change that would allow dispatchable loads to offer and provide ten-minute synchronized operating reserve.

In order to simulate the impacts of this eventual change, the IESO had to make some assumptions about how the dispatchable loads would offer into the ten-minute synchronized operating reserve market. Currently, there are approximately 700 MW of dispatchable loads (DL) that offer ten-minute non-synchronized operating reserve (10n). For the purpose of simulation 2, the IESO assumed that at least half of these offers would meet IESO technical standards and be eligible to provide synchronized operating reserve. That is, 350 MW of dispatchable load would be capable of offering supply in the ten-minute synchronized operating reserve market. Furthermore, the IESO assumed that the cost of providing ten-minute synchronized operating reserve for these dispatchable loads was the same as providing ten-minute non-synchronized operating reserve. Therefore the IESO also assumed that these 350 MW would be offered into the ten-minute synchronized operating reserve market at the same prices as it is currently being offered into the non-synchronized market.

Simulation 3 (10s initiative): For the third simulation, the IESO simply re-ran the second simulation with the exception that it reduced the ten-minute synchronized operating reserve requirement by 100 MW to fully align Ontario OR requirements with the NPCC's policy on RRS. Note that this change reduces the ten-minute synchronized operating reserve requirement by 100 MW but maintains the existing total ten-minute reserve requirement. The change allows the IESO to schedule up to 100 MW of ten-minute non-synchronized operating reserve instead of the more expensive ten-minute synchronized operating reserve all while maintain the same level of total ten-minute reserve that is scheduled.

A comparison of the price impacts between simulation 2 and simulation 3 provides an indication of the price pressures attributable solely to the reduction of the ten-minute synchronized operating reserve requirement. Table 1 provides the price outcomes for each of the three simulations.

² Recall that the IESO has implemented the NPCC RRS policy in stages the first of which was on January 4, 2006. At that time the IESO reduced the 10n and total reserve requirements by 50 MW. On May 17, 2007, the IESO reduced the 10n and total reserve requirement by an additional 50 MW (for a total of 100 MW). The next step under review is the 10s initiative which is the issue under study in this CBA.

Table 1: Average Simulated Prices Ignoring Behaviour Responses, 6-Month Period 2006

Simulation	10n (\$/MWh)	10s (\$/MWh)	30R (\$/MWh)	MCP (\$/MWh)	Reduction in Production Cost \$ per hour
Simulation 1: (Benchmark)	1.44	3.46	1.41	47.73	
Simulation 2: (10n and DL)	1.15	1.28	1.15	47.51	
Price Change due to 10n and DL (Simulation 1 less Simulation 2)	0.28	2.18	0.26	0.22	148.47
Simulation 3: (10s initiative)	1.15	1.16	1.15	47.51	
Price Change due to 10s initiative (Simulation 2 less Simulation 3)	0.00	0.12	0.00	0.00	2.28

Table 1 outlines the hourly average price over the 6-month simulation period for each class of reserve and for energy under each of the three simulations. A comparison of the price differences between Simulation 1 and Simulation 2 (price pressure attributable to 10n and DL initiatives), and the price differences between Simulation 2 and Simulation 3 (price pressure attributable to 10s initiative) is also provided in the light grey coloured rows of the table. Finally, an estimate of the hourly average reduction in production cost is provided for each of Simulation 2 and Simulation 3 in the final column of the table.³

The results of the three simulations indicate the following:

- The combination of the additional 50 MW reduction in the ten-minute non-synchronized operating reserve requirement and allowing dispatchable loads to

³ The hourly reduction in production cost was derived from the simulation model. In each simulation and for each five-minute interval, the total cost of meeting the market demand was computed based on the accepted energy and reserve offers. The simulated hourly reduction cost from the 10n and DL initiative was then estimated as the difference between the total cost of meeting the market demand in simulation 1 and the total cost of meeting demand in simulation 2. Similarly, the hourly reduction cost from the 10s initiative was estimated as the difference between the total cost of meeting the market demand in simulation 2 and the total cost of meeting demand in simulation 3.

provide ten-minute synchronized operating reserve results in downward pressure on all prices with the ten-minute synchronized operating reserve price declining the most – a reduction in the average hourly ten-minute synchronized operating reserve price of \$2.18/ MWh.

- The incremental price impact of reducing the 10 minute synchronized reserve (10s) requirement by 100 MW is minimal relative to the simulation 2. The simulations essentially indicate that once dispatchable loads are allowed to provide 10 minute synchronized reserve, reducing the 10 minute synchronized reserve requirement by 100 MW will have little further price impact – only the 10 minute synchronized reserve price will be affected, declining by an average of \$0.12/MWh.
- Much of the initial efficiency gains attributable to the reduction of the 10 minute synchronized reserve requirement described in the preliminary CBA will likely be realized once dispatchable loads are permitted to provide 10 minute synchronized reserve. The simulations indicate that reducing the 10 minute synchronized reserve requirement by 100 MW after dispatchable loads are permitted into the market would result in only a modest reduction in production cost (as measured in the unconstrained schedule) of \$2.28 per hour. As a point of comparison, in the preliminary CBA, when the impact of allowing dispatchable loads to provide 10 minute synchronized reserve was ignored, the unconstrained simulation indicated a production cost savings of \$87 per hour.⁴

Allowing dispatchable loads to provide 10 minute synchronized reserve has a similar impact as reducing the 10 minute synchronized reserve requirement in terms of how it impacts market prices and overall production cost. Allowing dispatchable loads into the 10 minute synchronized reserve market essentially increases the amount of supply of the product – to the extent that this supply has a lower marginal cost (lower offer price) than the existing supply, the result is lower prices and also lower overall production cost. Reducing the 10 minute synchronized reserve requirement by 100 MW but maintaining the overall 10 minute reserve requirement means lower demand for the relatively higher cost product – this also results in lower prices for reserve and reduced production cost as more of the relatively less expensive 10 minute non-spin reserve is scheduled and less of the more expensive 10 minute synchronized reserve is scheduled. The two initiatives represent substitute initiatives in terms of their ability to reduce production costs and achieve efficiencies.

In short, the IESO's estimate of efficiency gains in the preliminary CBA and hence the net benefit attributable to the 10s initiative is likely an overstatement of the net benefits attributable to the initiative once dispatchable loads are permitted to provide 10 minute synchronized reserve. Furthermore, it is the IESO's position that ~~provided~~ dispatchable loads

⁴ Of course, since these simulations are of the unconstrained sequences, they do not necessarily provide an estimate of what the actual cost savings would be following the reduction in the 10 minute synchronized reserve requirement. Instead, these cost savings are realized in the constrained schedule – the one that reflects that actual dispatch of generation. In the preliminary CBA, the IESO made a rough estimate of the actual production cost savings using the results of the unconstrained simulation and shadow prices. The IESO's estimate of the actual production cost savings in the preliminary CBA was an average of \$207 per MWh.

~~meet the IESO's technical and facility registration requirements the IESO cannot~~ should not be precluded ~~them~~ from providing 10-minute synchronized operating reserve provided that they meet the IESO's technical and facility registration requirements. In light of TFCO's analysis, such precluding dispatchable loads from providing 10-minute synchronized operating reserves ~~ion w~~ could contravene one of the purposes of the *Electricity Act, 1998*, namely the provision to generators, retailers and consumers of non-discriminatory access to transmission and distribution systems in Ontario. As a result, the estimate of net benefits associated with the CBA of the 10s initiative needs to be modified accordingly to reflect the expected provision of 10 minute synchronized reserve by dispatchable loads. The CBA is updated later in section 3 of this memo.

Comment 2: The CBA reports that there is little or no impact on reliability and estimates this impact at \$28 per year. Although the reliability impact may in fact be quite small, the CBA lacks sufficient detail for stakeholders to accept this result. The IESO should provide more explanation of the NPCC analysis and why it applies to Ontario.

IESO response:

The Control Performance Working Group (CO-1) of the Task Force on Coordination of Operation (TFCO) performed a statistical analysis of the impact of *regional reserve sharing* on reliability. The analysis was based on the ISO New England (ISONE) system and was deemed to be applicable to other NPCC Areas.

The analysis considers the probability of a second generation contingency occurring before the Area Control Error (ACE) is recovered sufficiently from an initial generation contingency and where the resulting ACE exceeds -1900 MW. The time taken to recover ACE following the first contingency was based on historical performance however assumed that regional reserve sharing energy becomes unavailable unexpectedly and as a result ACE can't be recovered as quickly, the exposure to a second contingency occurring is increased. In New England cascading events can occur when the under generation exceeds 1900 MW.

The ISONE analysis was based on the assumption that cascading events would occur when an ACE of -1900 MW is reached (this was characterized in the study as an "adverse reliability event"). The consequences of such cascading events can vary significantly depending on circumstances. In Ontario, sudden generation imbalances in excess of 1765 MW can adversely impact the Eastern Interconnection. However, generation imbalances well in excess of this amount can be tolerated where it is not the result of a single contingency. The ISONE example is based on successive generation losses and not a single source contingency and as a result, the analysis performed for the NE system can be considered a conservative estimate of the frequency of adverse reliability events occurring in Ontario (i.e. it would happen less frequently in Ontario).

In conclusion, the IESO believes that this specific rule amendment will not affect reliability.

Stakeholders should also be aware that the IESO is currently challenging the NPCC requirement for synchronized reserve. There is no longer a NERC standards requirement for synchronized reserve and most other reliability regions do not have a synchronized reserve requirement. In support of the TFCO recommendation to allow dispatchable load participation in synchronized reserve the IESO asked the Task Force on System Studies (TFSS) to provide an analysis of the reliability impact. IESO staff led the effort on the a working group and they concluded that synchronized reserve is not required. This analysis will be provided in support of market rule amendment MR-00333: Allowing Dispatchable Loads to Provide 10-minute Synchronized Reserve.

Comment 3: The preliminary CBA for MR-00332-R00 makes no allowance for the likely detrimental impact on dynamic efficiency which although difficult to quantify would further reduce benefits.

IESO Response:

The IESO maintains the position that implementing MR-00332-R00 will not have a detrimental impact on dynamic efficiency. In support of this view, the IESO makes the following comments.

- In general, a change to a market that improves allocative efficiency will also provide the appropriate long-run signals for investment and hence promote dynamic efficiency. In some instances, the efficient long-run signal is for some firms or technologies to exit the market. For example, if the industry long-term demand for a product declines, then it will be efficient for some firms – those firms that produce the product at the highest cost – to shut down their operations. In this instance, the revenues that these firms will be earning will no longer be sufficient to cover their avoidable operating costs.⁵ In other words, the social value that people place on this product (how much they are willing to pay the firm to produce it) is less than what it cost the firm to produce the product. By exiting the industry, the firm will be able to divert the resource used in the production of this product to other activities that will provide the firm with a positive return above its avoidable cost – activities for which the social value is higher than the cost of carrying out the activity. Putting this in the context of CBA and changes within the electricity industry, it should not be assumed that changes in the market that cause prices to fall will necessarily lead to detrimental impacts on investment and hence dynamic inefficiency. In the case of MR-00332-R00, the change is a reflection that Ontario no longer requires or has the same demand for ten-minute synchronized reserve. By purchasing less of this product, it will send a signal (through lower

⁵ In the short run, a firm will continue to operate in the market as long as the revenues that it earns are sufficient to cover all of its avoidable cost and at least part of its fixed cost.

prices) to providers of this product of the long-run social value of the product. This may lead to exit of some ten-minute synchronized reserve providers.

- If however, due to some market failure in an industry, short run market prices were not sending the efficient long-term signal for investment (i.e., were too low so that there was already underinvestment), then a change that would cause short run prices to decline further could lead to reduced dynamic efficiency if it further reduces the incentives for investment. To this point the IESO notes that there currently is no evidence that there is underinvestment in resources with the ability to provide ten-minute synchronized reserve. In fact, based on the view stated above that “synchronized reserve is not required” there may currently be an overinvestment in generator capabilities to provide synchronized reserve. Moreover, after considering the effect of allowing dispatchable loads in the ten-minute synchronized reserve market, the incremental impact of MR-00332-R00 is minimal and unlikely to have any significant impact on investment decisions regardless.

3. Update of CBA for MR-00332-R00

Based on the results discussed above the IESO has revised the CBA for MR-00332-R00 as follows.

Predicted participants’ responses and the projected equilibrium outcome:

The simulations indicate that after accounting for the impact of (allowing dispatchable loads to provide ten-minute synchronized reserve) approval of MR-00332-R00 will have no downward price pressure on there will be no downward pressure on the ten-minute non-synchronized reserve price, the 30-minute reserve price or the energy price. The only downward price pressure will be with respect to the ten-minute synchronized reserve and the price pressure will be modest – an average decline of \$0.12/MWh or roughly a 10% decline.

Based on the lack of material price pressure, the IESO projects that approval of MR-00332-R00 will not lead to changes in offer or bidding behaviours of dispatchable participants or reduced consumption from non-dispatchable consumers in the short run. The only projected change will be the reduction in the amount of ten-minute synchronized reserve scheduled and a subsequent increase in the amount of ten-minute non-synchronized reserve. The unconstrained simulations indicate that the average hourly substitution of synchronized for non-synchronized reserve would be roughly 17 MW in the unconstrained schedules. The average hourly substitution between the two classes of reserve will likely be higher in the constrained sequence.

The change will lead to a reduction in the hourly uplift. The change in uplift is equal to the change in payments made to the ten-minute synchronized and ten-minute non-synchronized reserve providers. The IESO estimates this change to be roughly \$31.68 on average per hour.⁶

⁶ The change in uplift is measured as the change in the ten-minute synchronized reserve price times the current typical ten-minute synchronized reserve requirement [(\$1.28 -\$1.16) x 236 MW = \$30.68] plus the projected

This amounts to an average annual reduction in uplift paid by Ontario consumers and exporters of roughly $\$31.68 \times 8760$ hours per year or $\$277,517$ per year. In the preliminary CBA, the IESO estimated that Ontario consumers will realize roughly 93% of this uplift savings with the remaining 7% will be realized by exporters. This will represent a reduction in revenues to Ontario current Ontario generators providing ten-minute non-synchronized.

The change will also lead to a production cost savings for the province. The hourly average production cost savings based on the unconstrained sequence is estimated to be $\$2.28$. On an annual basis, this represents a reduction in production cost of $\$2.28 \times 8760$ hours per year or $\$20,000$. The actual cost savings will be realized in the constrained sequence and is expected to be higher than the estimate provided under the unconstrained sequence. In this sense, the $\$20,000$ is a lower bound estimate of the impact. These cost savings will be realized by those generators currently providing ten-minute synchronized reserve.

Finally, given that the change will impact uplifts payments and not energy payments, it will not affect rebates or charges within the Global Adjustment or OPG rebate accounts.

Table 2 provides a summary of the annual welfare impacts attributable to MR-00332-R00.

difference in the ten-minute synchronized reserve and ten-minute non-synchronized reserve price times 100 MW - the maximum amount of MW substituted- $[(\$1.16-1.15) \times 100 \text{ MW} = \$1]$ for a total decline of $\$31.68$ per hour on average.

Table 2: Welfare Impacts of MR-00332-R00

Item	Ont. Cons.	Ont. Gen.	Exporters	Importers	Net Change
Energy Pay/Rev	\$0	\$0	\$0	\$0	\$0
OR Pay/Rev	0.93% x \$277,517 = \$258,091	(\$277,517)	0.07% x \$277,517 = \$19,426	\$0	\$0
Production Cost Savings	\$0	\$20,000	\$0	\$0	\$20,000
GA/OPG Rebate	\$0	\$0	\$0	\$0	\$0
Total Benefit/Cost	\$258,091	(\$257,517)	\$19,426	\$0	\$20,000

Table 2 indicates a net welfare gain of approximately \$20,000 per year. The welfare gain comes from the production cost savings attributable to the reduced need for ten-minute synchronized reserve and a substitution toward the less costly ten-minute non-synchronized reserve to meet the provinces total ten minute reserve requirement. This estimated net benefit is likely a lower bound estimate of the possible net efficiency gains attributable to MR-00332-R00.

Sensitivity analysis:

The \$20,000 estimate of efficiency gains represents a lower bound estimate as it is derived based on the following assumptions:

- At least half of the current dispatchable loads will provide ten-minute synchronized reserve once approval is granted. If less dispatchable loads provide the synchronized product, MR-00332-R00 will provide more efficiency gains. The assumption of 350 MW may be an overstatement if OPA programs for conservation and demand management are more attractive to these consumers and hence they leave the dispatchable load market either permanently or during key times during the year. Furthermore, the rule amendment to allow dispatchable loads to provide ten-minute synchronized reserve may take a few months.
- The analysis above assumed that it would happen immediately. If MR-00332-R00 was implemented prior to the enabling of dispatchable loads to provide ten-minute synchronized reserve, then the estimated efficiency gains of \$20,000 is likely understated –

the amount of the understatement will increase with the length of time that it takes to approve the dispatchable load OR initiative.

- The estimate is derived using the savings estimated in the unconstrained sequence. Actual production costs are incurred based on dispatch – this is reflected in the constrained sequence. Operating reserve costs are typically higher in the constrained sequence.

The \$20,000 estimate of efficiency gains represents a lower bound estimate as it is derived based on the following assumptions:

- If the assumption of 350 MW of dispatchable load providing synchronized reserve is too low, then MR-00332-R00 will lead to less annual efficiency gains.

Based on these assumptions, the IESO may provide a sensitivity band around the estimates of roughly \$10,000 so that the estimated net efficiency gains would range from \$10,000 per year to \$30,000 per year.

4. IESO recommendation

The CBA presented a range of outcomes regarding the estimated efficiencies of reducing the synchronized ten-minute OR requirement by 100 MW as permitted through participation in NPCC's Regional Reserve Sharing program. The assessment considered the change compared to: the status quo, and the expected future scenario where dispatchable loads are allowed to provide synchronized ten minute reserve in Ontario.

Depending on the assumptions, the net efficiency gains are between \$10,000 and \$30,000 per year. The cost of making this change is a one-time cost of roughly \$5,000. This one time cost would be covered after the first year of implementation. As a result, MR-00332-R00 would satisfy the Kaldor-Hicks criteria.

Since the range of net benefits is positive, the IESO supports the proposed market rule amendment MR-00332-R00 and will be requesting that the Technical Panel recommend this amendment to the IESO Board for approval.