

Memorandum

To: Market Pricing Working Group
From: Jessica Greenberg
Date: August 20, 2007
Re: Action Item 43-1: Issue #5 – Simultaneous Use of Ramping Generation Units for Energy and Operating Reserve

At the Market Pricing Working Group meeting #43 on July 19, 2007, the IESO undertook to provide further background information and rationale on the treatment of operating reserve (OR) and energy in the RTU sequence (action item 43-1). This background is explained below.

Current Practice

In the real-time constrained sequence of the DSO, actual ramp rates are used to schedule the amount of energy and OR that can actually be delivered by a generating unit (i.e. 1 x ramp rate for both energy and OR). In the real-time unconstrained sequence (i.e. the market schedule) of the DSO, a unit's ramp rate for energy is multiplied by a factor of 12. The ramp rate multiplier allows a generating unit to provide approximately 12 times the amount of energy than it can actually produce. No multiplier is applied to a unit's OR offered ramp rate.

The 12 times energy ramp rate multiplier was introduced through market rule amendment MR-00189 prior to market commencement. A copy of the approved MR-00189 is attached.

MR-00189 also authorizes the IESO to modify certain constraints within the DSO (refer to R04 within MR-00189) that pertain to the total amounts of energy and OR that can be scheduled from a generating unit each interval. Unmodified, these constraints (sections 6.3.5B.1 and 6.3.5B.2 in Appendix 7.5) would, effectively limit energy ramping to a two times and six times ramp rate multiplier respectively. The modifications made to these constraints effectively eliminate the possibility of them being binding within the market schedule. As a result, within the market schedule, it is possible to schedule a generation unit to provide energy using its full ramping capability and also schedule OR from that same unit.

For the real time constrained sequence these constraints are not modified.

Going Forward

With respect to maintaining the modifications to these constraints within the market schedule with the upcoming change to a 3 times energy ramp rate:

- The constraint defined in section 6.3.5B.1 will still be always binding with a 3 times energy ramp rate (i.e. a TradingPeriodLength of 15 minutes), so the rational provided for MR-00189 remains valid.
- The constraint defined in section 6.3.5B.2 can be binding under a variety of circumstances and thus potentially frustrate the implementation and expected impacts of the 3 times ramp rate. As it is not possible at this time to determine the circumstances where the constraint, unmodified, would be inappropriately binding under a 3 time ramp rate, it is proposed to maintain the modification of this constraint equation until further study can be conducted.

Generation units will continue to be scheduled to provide energy and operating reserve in the real-time constrained sequence on the basis their physical capability and the constraints defined in sections 6.3.5B.1 and 6.3.5B.2 without modification.

Recommendation

The IESO recommends that Action Item 43-1 be closed, but that MPWG Issue 5 remain open to determine whether maintaining RT unconstrained sequence treatment is appropriate with the change to 3 times energy ramp rate.

Sincerely,

Jessica Greenberg
Market Evolution

EXPLANATION FOR AMENDMENT:

During market testing, extreme real-time energy price excursions occurred at times when market conditions would have suggested more moderate changes in real-time energy prices. These extreme price excursions occurred even when there were sufficient offers to satisfy energy and operating reserve requirements.

These extreme energy price excursions occur when energy demand growth within a dispatch interval exceeds the capabilities of some generation facilities to ramp up within that interval to meet the demand. This problem is especially evident during morning load pick-up and when inertia transactions are changing. In these situations, energy prices can move dramatically higher as more and higher priced resources are selected to provide the ramping capability needed for the rapidly increasing demand in that given interval. The market design and the associated real-time dispatch software schedules each 5 minute interval discretely. It does not optimize over longer periods of time and does not anticipate the demands expected in future intervals. The price excursions that appear in the 5 minute market schedule are not usually predicted in the hour-ahead pre-dispatch schedule since the hour-ahead schedule uses the generator ramping capability over the full 60 minutes. These observations were brought to the attention of the Board at their last meeting and subsequently a change was made on a test basis during CODR to the ramp rate assumptions used for the market schedule. The rule amendments proposed would allow that change to continue.

In order to provide greater stability in the scheduling process and to better align the pre-dispatch and real-time schedules, it is proposed to amend the definition of the Trading Period Length input to the dispatch algorithm. This input parameter is used to determine the maximum generation output levels of a generation facility at the end of the dispatch interval. In the determination of both the market schedule (unconstrained) and the real-time schedule (constrained), the value of this parameter is currently set at 5 minutes, which corresponds to the dispatch period for these schedules. In the determination of the pre-dispatch schedule, this parameter is currently set at 60 minutes, which corresponds to the dispatch period of this schedule.

This proposed amendment would permit the IMO to establish a longer Trading Period Length in the market schedule (unconstrained) to overcome the problems identified above. With a longer Trading Period Length within the market schedule (unconstrained), generation facilities will have larger ramping capability and there will be less need to select additional higher cost resources to meet the increasing demand. As a result, less extreme price excursions will occur.

The real-time schedule (constrained) will continue to use the 5 minute Trading Period Length. Therefore, discrepancies will increase between the real-time schedule and the market schedule (unconstrained). As a consequence, congestion management settlement credit (CMSC) payments will increase. However, the decreases in energy prices, resulting from the change in the ramp time in the market schedule, are expected to offset increases in CMSC payments.

It should be noted that using a longer Trading Period Length in the determination of the market schedule is judged to be a transitional provision. It is expected that a longer term solution will need to be considered which could include a day-ahead market with unit commitment, increased generator self-scheduling, contracted ramp capability, or multi-period optimization.

PROPOSAL:

4.13 General Parameters

4.13.1 Parameters

TradingPeriodLength

Being either 60 minutes, in respect of a pre-dispatch schedule, or 5 minutes, in respect of a constrained real-time schedule, or a variable number of minutes, as determined by the IMO, in respect of a market schedule. as the case may be

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MARKET RULE AMENDMENT PROPOSAL

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DOCUMENT SUBMITTED FOR: _____ DATE RESPONSE REQUIRED BY: _____
 Information Purpose _____
 Consultation _____
 Approve the document for IMO Board recommendation April 16, 2002

RULE AMENDMENT APPROVAL INFORMATION:

MR number: MR-00189-R01
 Submitted by: IMO staff

Submitted to TP: April 15, 2002 Approved by TP: April 16, 2002
 IMO TP Minutes Document Reference: IMOTP 103-1

Submitted to Board: April 16, 2002 Approved by Board: _____
 IMO Board Minutes Document Reference: _____

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REASON FOR AMENDMENT:

Nature of Amendment:

Alteration		Deletion		Addition	x
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Subject: Increasing Facility Ramping Capability in Market Schedule – Difference
 Between Market Schedule and Real-Time Schedule Inputs

Subject: Chapter 7 Appendix _____ ^{1st/2nd} Level 6.4.2
 Section _____

Sub-section(s) proposed for amending: 6.4.2.8 (new)

EXPLANATION FOR AMENDMENT:

The proposed rule amendments to section 6.4.2 of Chapter 7 are consequential to those specified in MR-00189-R00.

The proposed rule amendments highlighted below specify differing inputs to the provisional market schedule relating to the ramping capability of facilities to that of the real-time schedule.

PROPOSAL:

6.4 Provisional Market Schedules and Market Prices

- 6.4.1 Subject to section 8.4 the *IMO* shall, within five minutes after the end of each *dispatch interval*, use the *dispatch algorithm* to determine a provisional *market schedule* and provisional *market prices* for that *dispatch interval* based on the most recent *real-time schedule* for such *dispatch interval*.
- 6.4.2 Subject to section 8.4 for the purpose of determining the provisional *market schedule* and provisional *market prices* for any *dispatch interval*, the *IMO* shall use the same information and data used for determining the *real-time schedule* for that *dispatch interval*, except that:
 - 6.4.2.1 the *unconstrained IMO-controlled grid model* shall be used;
 - 6.4.2.2 subject to section 3.1.2 of Appendix 7.5, the initial conditions to be used for any *dispatch interval* in the provisional *market schedule* shall be the final conditions of the provisional *market schedule* for the preceding *dispatch interval*;
 - 6.4.2.3 the total demand (including losses) to be satisfied within a *dispatch interval* in the provisional *market schedule* shall be set at the *IMO's* best estimate of its actual value, as determined from real-time system data;
 - 6.4.2.4 total system *energy losses* determined in the *real-time schedule* shall be represented as an increase in *non-dispatchable load* within the *IMO control area*;
 - 6.4.2.5 any *registered facility* in respect of which a *forced outage* has been detected during a *dispatch interval* shall be recognized by an adjustment to the input data;
 - 6.4.2.6 subject to section 6.4.2A, the estimated deviations between scheduled quantities and actual quantities shall be represented as a change in *non-dispatchable load* in the *IMO control area*; and
 - 6.4.2.7 subject to section 6.4.2A, the *market schedule* shall reflect dispatch adjustments computed using scheduled injections from the *constrained schedule*, outlined in Appendix 7.5; and

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6.4.2.8 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*.

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- 6.4.2A Until the date that is the first day of the seventh calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, in determining the provisional *market schedule* and provisional *market prices* for any *dispatch interval*, the *IMO* shall not have regard to the estimated deviations referred to in section 6.4.2.6 or to the dispatch adjustments referred to in section 6.4.2.7.

EXPLANATION FOR AMENDMENT:

The proposed rule amendments to section 3.2.1 of Appendix 7.5 are consequential to those specified in MR-00189-R00.

The proposed rule amendments highlighted below specify differing inputs to the provisional market schedule relating to the ramping capability of facilities to that of the real-time schedule.

PROPOSAL:**3.2 Inputs to and Form of the Market Scheduling and Pricing Process**

- 3.2.1 The form of and inputs to the market scheduling and pricing process shall differ from the *dispatch* scheduling and pricing process described in section 2 only as follows:
- 3.2.1.1 all constraints that limit the ability of *energy* to flow from one node to another node within the *IMO control area* shall be removed. The market scheduling and pricing process shall assume that all *physical services* are provided and consumed in the *IMO control area* at a single, undesignated location connected to each *intertie zone* only by a single notional *intertie*. Any link between *intertie zones* that lie outside the *IMO control area* shall be removed;
 - 3.2.1.1A all area constraints on *ten-minute operating reserve* shall be removed;
 - 3.2.1.1B the market model shall produce a uniform price for *energy* and for each class of *operating reserve* in the *IMO control area*. The projected *market schedule* shall also produce prices for *energy* and for each class of *operating reserve* in each of the *intertie zones* adjoining the *IMO control area*. No *intertie zone* prices are required to be produced by the provisional, preliminary and final *market schedules* as these values are subsequently derived from the uniform Ontario prices produced by those *market schedules* and the projected *market schedule intertie congestion prices*;
 - 3.2.1.2 *security* constraints shall be ignored except for those that impact on *intertie* flows;
 - 3.2.1.2A constraints imposed on *offers* and *bids* that relate to transmission loading relief shall be ignored. Constraints relating to *generation facility outage* schedules and *contracted ancillary services* shall remain;
 - 3.2.1.3 except for flows across *interties*, transmission losses shall not be associated with transmission line flows. Transmission losses other than in respect of flows across *interties* shall be represented as an increase in *non-dispatchable load*;

3.2.1.3A subject to section 3.2.1.3B, the flow across each *intertie* for all *dispatch intervals* within a *dispatch hour* in the provisional, preliminary and final *market schedules* shall be equal to the flow on that *intertie* determined for that same *dispatch hour* in the *market schedule* corresponding to the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*;

3.2.1.3B where the limits on flows between *control areas* change in real-time as a result of an unplanned *intertie outage*, it shall be possible to reduce those limits in the provisional, preliminary and final *market schedules*;

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3.2.1.4 any imports or exports between the *IMO control area* and other control areas required by the *IMO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* shall not be represented directly but shall be represented as an increase or a decrease in *non-dispatchable load*; and

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3.2.1.5 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*.

EXPLANATION FOR AMENDMENT:

The proposed rule amendments to section 6.4.2 of Chapter 7 are consequential to those specified in MR-00189-R00.

The proposed rule amendments highlighted below specify differing inputs to the provisional market schedule relating to the ramping capability of facilities to that of the real-time schedule.

PROPOSAL:

6.4 Provisional Market Schedules and Market Prices

- 6.4.1 Subject to section 8.4 the *IMO* shall, within five minutes after the end of each *dispatch interval*, use the *dispatch algorithm* to determine a provisional *market schedule* and provisional *market prices* for that *dispatch interval* based on the most recent *real-time schedule* for such *dispatch interval*.
- 6.4.2 Subject to section 8.4 for the purpose of determining the provisional *market schedule* and provisional *market prices* for any *dispatch interval*, the *IMO* shall use the same information and data used for determining the *real-time schedule* for that *dispatch interval*, except that:
 - 6.4.2.1 the *unconstrained IMO-controlled grid model* shall be used;
 - 6.4.2.2 subject to section 3.1.2 of Appendix 7.5, the initial conditions to be used for any *dispatch interval* in the provisional *market schedule* shall be the final conditions of the provisional *market schedule* for the preceding *dispatch interval*;
 - 6.4.2.3 the total demand (including losses) to be satisfied within a *dispatch interval* in the provisional *market schedule* shall be set at the *IMO's* best estimate of its actual value, as determined from real-time system data;
 - 6.4.2.4 total system *energy losses* determined in the *real-time schedule* shall be represented as an increase in *non-dispatchable load* within the *IMO control area*;
 - 6.4.2.5 any *registered facility* in respect of which a *forced outage* has been detected during a *dispatch interval* shall be recognized by an adjustment to the input data;
 - 6.4.2.6 subject to section 6.4.2A, the estimated deviations between scheduled quantities and actual quantities shall be represented as a change in *non-dispatchable load* in the *IMO control area*; ▼
 - 6.4.2.7 subject to section 6.4.2A, the *market schedule* shall reflect dispatch adjustments computed using scheduled injections from the *constrained schedule*, outlined in Appendix 7.5; ▼

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6.4.2.9 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*; and

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6.4.2.9 in accordance with section 2.11.2 of Appendix 7.5, the *market schedule* may use a different ramp rate for *operating reserve* to that of the *real-time schedule*.

6.4.2A Until the date that is the first day of the seventh calendar month following the *market commencement date*, calculated from the first day of the calendar month immediately following the month in which the *market commencement date* occurs, in determining the provisional *market schedule* and provisional *market prices* for any *dispatch interval*, the *IMO* shall not have regard to the estimated deviations referred to in section 6.4.2.6 or to the dispatch adjustments referred to in section 6.4.2.7.

EXPLANATION FOR AMENDMENT:

The proposed rule amendments to section 3.2.1 of Appendix 7.5 are consequential to those specified in MR-00189-R00.

The proposed rule amendments highlighted below specify differing inputs to the provisional market schedule relating to the ramping capability of facilities to that of the real-time schedule.

PROPOSAL:**3.2 Inputs to and Form of the Market Scheduling and Pricing Process**

- 3.2.1 The form of and inputs to the market scheduling and pricing process shall differ from the *dispatch* scheduling and pricing process described in section 2 only as follows:
- 3.2.1.1 all constraints that limit the ability of *energy* to flow from one node to another node within the *IMO control area* shall be removed. The market scheduling and pricing process shall assume that all *physical services* are provided and consumed in the *IMO control area* at a single, undesignated location connected to each *intertie zone* only by a single notional *intertie*. Any link between *intertie zones* that lie outside the *IMO control area* shall be removed;
 - 3.2.1.1A all area constraints on *ten-minute operating reserve* shall be removed;
 - 3.2.1.1B the market model shall produce a uniform price for *energy* and for each class of *operating reserve* in the *IMO control area*. The projected *market schedule* shall also produce prices for *energy* and for each class of *operating reserve* in each of the *intertie zones* adjoining the *IMO control area*. No *intertie zone* prices are required to be produced by the provisional, preliminary and final *market schedules* as these values are subsequently derived from the uniform Ontario prices produced by those *market schedules* and the projected *market schedule intertie congestion prices*;
 - 3.2.1.2 *security* constraints shall be ignored except for those that impact on *intertie* flows;
 - 3.2.1.2A constraints imposed on *offers* and *bids* that relate to transmission loading relief shall be ignored. Constraints relating to *generation facility outage* schedules and *contracted ancillary services* shall remain;
 - 3.2.1.3 except for flows across *interties*, transmission losses shall not be associated with transmission line flows. Transmission losses other than in respect of flows across *interties* shall be represented as an increase in *non-dispatchable load*;

- 3.2.1.3A subject to section 3.2.1.3B, the flow across each *intertie* for all *dispatch intervals* within a *dispatch hour* in the provisional, preliminary and final *market schedules* shall be equal to the flow on that *intertie* determined for that same *dispatch hour* in the *market schedule* corresponding to the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*;
- 3.2.1.3B where the limits on flows between *control areas* change in real-time as a result of an unplanned *intertie outage*, it shall be possible to reduce those limits in the provisional, preliminary and final *market schedules*;
- 3.2.1.4 any imports or exports between the *IMO control area* and other control areas required by the *IMO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* shall not be represented directly but shall be represented as an increase or a decrease in *non-dispatchable load*;
- 3.2.1.5 in accordance with section 4.13.1 of Appendix 7.5, the *market schedule* may use different trading period length to that of the *real-time schedule*;
and
- 3.2.1.6 in accordance with section 2.11.2 of Appendix 7.5, the *market schedule* may use a different ramp rate for *operating reserve* to that of the *real-time schedule*.

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EXPLANATION FOR AMENDMENT:

The proposed rule amendments to section 2.11 of Chapter 7 Appendix 7.5 are consequential to those specified in MR-00189-R00.

In order to provide greater stability in the scheduling process, it is proposed to allow the operating reserve ramp rate submitted by market participants to be increased for the purpose of real-time market scheduling.

This proposed amendment would permit the IMO to establish a higher operating reserve ramp rates in the market schedule (unconstrained) to overcome the problems identified in MR-00189 R00. With a higher operating reserve ramp rate within the market schedule (unconstrained), generation facilities will have larger ramping capability and there will be less need to select additional higher cost resources to meet the operating reserve requirements. As a result, less extreme price excursions will occur.

The real-time schedule (constrained) will continue to use the operating reserve ramp rates as submitted by market participants. Therefore, discrepancies will increase between the real-time schedule and the market schedule (unconstrained). As a consequence, congestion management settlement credit (CMSC) payments will increase. However, the decreases in energy prices, resulting from the change in the ramp time in the market schedule, are expected to offset increases in CMSC payments.

It should be noted that using higher operating reserve ramp rates in the market schedule is judged to be a transitional provision.

PROPOSAL:

2.11 Inter-temporal Linkages

2.11.1 The *dispatch* scheduling and pricing process shall solve one *dispatch* period at a time, but shall respect the ramp rate limits applicable to *generation facilities* and *dispatchable load facilities* between *dispatch* periods.

2.11.2 In respect of a *real-time market scheduling* process, the *operating reserve ramp rates* submitted by *market participants* may be increased to levels determined by the *IMO*.

EXPLANATION FOR AMENDMENT:

The proposed rule amendments to section 6.3.5B of Appendix 7.5 are consequential to those specified in MR-00189-R00.

In the event that a TradingPeriodLength greater than 30 minutes is determined, the constraint equations defined in sections 6.3.5B.1 and 6.3.5B.2 become binding and would effectively limit the TradingPeriodLength to 10 minutes and 30 minutes respectively.

To prevent this, the proposed rule amendments provide for the constraint equation defined in section 6.3.5B1 to be modified when the TradingPeriodLength is determined to be more than 10 minutes. Similarly, the constraint equation defined in section 6.3.5B2 should also be modified when the TradingPeriodLength is determined to be more than 30 minutes.

PROPOSAL:

6.3 Operating Reserve

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6.3.5B Constraints are imposed in real-time dispatch scheduling to recognize that the amount by which a *generation facility's* energy output is scheduled to change during a *dispatch interval* modifies the amount of *operating reserve* that the *generation facility* can reliably provide. For instance, if the *generation facility* ramps up during the *dispatch interval*, then the amount of *ten-minute operating reserve* it can provide within ten minutes of the start of the *dispatch interval* will be reduced.

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6.3.5B.1

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \{RS10, RNS10\}}} Reserve_{r(g),c} \leq Generation_g^{start} + ReserveMaximum10_g$$

{ g ∈ OFFERS }

6.3.5B.2

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \text{RESERVECLASSES}}} Reserve_{r(g),c} \leq Generation_g^{start} + ReserveMaximum30_g$$

{ g ∈ OFFERS }

6.3.5C The constraints of 6.3.5B are imposed in real-time market scheduling and consistent with the TradingPeriodLength determined by the IMO in accordance with section 4.13.1 of Appendix 7.5.