# Market Rule Amendment Proposal

## PART 1 – MARKET RULE INFORMATION

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| Identification No.: | MR-00372-R00 | | |
| Subject: | Settlements | | |
| Title: | CMSC and GCG Treatment for Aggregated Facilities | | |
| Nature of Proposal: | ☐ Alteration | ☐ Deletion | ☒ Addition |
| Chapter: | 9 | Appendix: | |
| Sections: | 2.4A, 3.1.6, 3.1.8, 3.1.9, 3.5.2 | | |
| Sub-sections proposed for amending: | | | |

## PART 2 – PROPOSAL HISTORY

| Version | Reason for Issuing | Version Date |
|---|---|---|
| 1.0 | Draft for Technical Panel Review | September 29, 2010 |
| 2.0 | Publish for Stakeholder Review and Comments | October 1, 2010 |
| 3.0 | Submitted for Technical Panel Review and Vote | October 15, 2010 |
| 4.0 | Recommended by Technical Panel | October 20, 2010 |
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| Approved Amendment Publication Date: | | |
| Approved Amendment Effective Date: | | |

## PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

**Summary**

Northland Power Inc. is proposing market rule amendments that would allow certain types of aggregated facilities to:

1) receive constraint payments to the full extent that the generation component of the aggregated facility is dispatched by the IESO; and

2) receive real-time and day-ahead generation cost guarantee payments based on gross injections from the generation component of the aggregated facility.

This treatment would apply to aggregated facilities that are comprised of a non-dispatchable load that is not station service and a dispatchable generation facility.

**Background**

As per chapter 7, section 2.3 of the market rules, a market participant may apply to the IESO to aggregate several facilities for the purpose of delivering or withdrawing one or more physical services. Upon IESO approval, the aggregated facilities are treated as single registered facility. The market rules currently require that the settlement of all facilities (including aggregated facilities) be based on net injections or withdrawals. As a consequence, under the current market rules aggregated facilities will incur a reduction in CMSC and cost guarantee payments associated with the load portion of an aggregated facility when it is consuming energy. The existing market rules will provide CMSC and cost guarantee payments but only for the amount of generation net of the behind-the-meter load.

For additional background information, refer to Northland's amendment submission MR-00372-Q00.

**Discussion**

The following market rule amendments would be required to implement Northland Power's proposal:

- Create a new defined term "alternate delivery point" which represents injections from the generation component of an aggregated facility used for calculating CMSC and generation cost guarantee payments (refer to R01).

- Specify in Chapter 9, section 2.4A.2, the conditions under which the "alternative delivery point" would apply. It would apply where the IESO has approved a request for aggregation in accordance with Chapter 7, section 2.3.2, and where the aggregated facility is comprised of both a non-dispatchable load that is not station service and a dispatchable generation facility.

- Clarify in Chapter 9, sections 3.1.6, 3.1.8, and 3.1.9 that the existing references to "primary" mean "primary RWM". In addition, all references to primary RWM and other defined terms

**PART 3 – EXPLANATION FOR PROPOSED AMENDMENT**

should be italicized; these changes are highlighted in yellow.

- Create two new variables, ADPI and ADOR, in Chapter 9, section 3.5.2 that will be used for calculating the CMSC associated with the newly defined alternative delivery point for energy and OR, respectively.
- Insert references to ADPI in Chapter 9 sections 4.7B.1.1 and 4.7D.1.1 to permit real-time and day-ahead GCG payments to be based on ADPI, rather than AQEI, where applicable.

**PART 4 – PROPOSED AMENDMENT**

## 2.4A Delivery Points

2.4A.1 The *delivery point* for a given *RWM* shall be determined by the *IESO* in accordance with:

2.4A.1.1 adjusting the *metering data* from that *RWM* in accordance with section 4.2.3 of Chapter 6; and

2.4A.1.2 summing the *metering data* from that *RWM* with *metering data* from all other applicable *RWMs* in accordance with the applicable totalization table comprised in the relevant *meter point* documentation submitted in respect of that *RWM* pursuant to section 1.3 of Appendix 6.5 of Chapter 6.

2.4A.2 For the purposes of the determination of the *settlement amounts* referred to in sections 3, 4 and 5, all references to an *RWM*, an *RWM* m or a *registered facility* k/m shall be deemed to be a reference to the *delivery point* or *alternative delivery point* associated with:

2.4A.2.1 the *RWM*; or

2.4A.2.2 the *RWM* or *RWMs* associated with the *registered facility*,

as the case may be.

An *alternative delivery point* shall apply where the *IESO* has approved an application for the aggregation of *facilities* into a single *registered facility* in accordance with Chapter 7, section 2.3.2, and where the aggregated *facility* is comprised of a *non-dispatchable load* that is not *station service* and a *dispatchable generation facility*.

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2.6.1 Any selling *market participant* may, under the provisions of Chapter 8, submit to the *IESO physical bilateral contract data* that define *physical bilateral contract quantities* of *energy* that it is selling to a specified buying *market participant* in specified hours and at specified *primary RWMs* or *intertie metering points*.

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3.1.6 *Physical bilateral contract quantities* shall be determined for each *settlement hour* by the *IESO* using *physical bilateral contract data* submitted by *selling market participants* and, where so required by the nature of the *physical bilateral contract data*, operating results. The *IESO* shall divide each hourly *physical bilateral contract quantity* into equal *physical bilateral contract quantities* if determination of *settlement amounts* requires quantities for each *metering interval* of each *settlement hour*. The *IESO* shall provide the following variables and data directly to the *settlement process*:

$BCQ_{s,b,h}^{m}$ = *physical bilateral contract quantity* of *energy* (in MWh) sold by *selling market participant* s *to buying market participant* b at *primary RWM* or *intertie metering point* 'm' in *settlement hour* 'h'

$BCQ_{s,b,h}^{m,t}$ = *physical bilateral contract quantity* of *energy* (in MWh) sold by *selling market participant* s to *buying market participant* b at *primary RWM* or *intertie metering point* 'm' for each *metering interval* 't' in *settlement hour* 'h'

= $(1/12) \times BCQ_{s,b,h}^{m}$, for all 12 *metering intervals* 't' in *settlement hour* 'h'

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3.1.8 The *IESO* shall provide the following *TR* data directly to the *settlement process*:

$QTR_{k,h}^{m,n}$ = quantity of *TRs* (in MW) assigned to *market participant* 'k' for transmission from *primary RWM* or *intertie metering point* 'm' to *primary RWM* or *intertie metering point* 'n' for *settlement hour* 'h'

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3.1.9 The *IESO* shall determine the following allocated physical quantities for each *market participant* for each *primary RWM* and each *intertie metering point* using *metering data*, operating results, *physical allocation data* submitted by *metered market participants* and *interchange schedule data*. If physical quantities are provided only for each *settlement hour* (as they may be for *interchange schedules*, *non-dispatchable loads*, self-scheduled *generation facilities*, transitional scheduling generators and intermittent generators), the *IESO* shall, if necessary for settlement purposes, determine the interval amounts defined below by dividing the hourly amounts into twelve equal interval amounts:

$AQEI_{k,h}^{m,t}$ = allocated quantity (in MWh) of *energy* injected by *market participant* 'k' at *primary RWM* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$AQEW_{k,h}^{m,t}$ = allocated quantity (in MWh) of *energy* withdrawn by *market participant* 'k' at *primary RWM* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$AQOR_{r,k,h}^{m,t}$ = allocated quantity (in MW) of *class r reserve* for *market participant* 'k' at *primary RWM* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$AQCR_{k,h}^{m,t}$ = allocated *capacity reserve quantity* (in MW) for *market participant* 'k' at *primary RWM* or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

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3.5.2 Subject to sections 3.5.6, 3.5.7 and 3.5.9 and subject to Appendix 7.6 of Chapter 7, the hourly congestion *management settlement credit* for *market participant* 'k' for *settlement hour* 'h' ("$CMSC_{k,h}$") shall be determined by the following equation:

Let 'BE' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during *settlement hour* 'h'

Let '$BR_r$' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply class r *operating reserve* during *settlement hour* 'h'

Let 'BL' be a matrix of n *price-quantity pairs* bid by *market participant* 'k' to withdraw *energy* by a *dispatchable load* during *settlement hour* 'h'

Let OP(P,Q,B) be a profit function of Price (P), Quantity (Q) and an n x 2 matrix (B) of offered *price-quantity pairs*:

$$OP(P,Q,B) = P \cdot Q - \sum_{i=1}^{s^*} P_i \cdot (Q_i - Q_{i-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Where:
s* is the highest indexed row of B such that Qs* ≤ Q ≤ Qn and where, Q0=0
B is matrix BE, BRr, or BL (see above)
Using the terms below, let CMSC be expressed as follows:

$CMSC_{k,h}$ = $OPE_{k,h} + OPR_{k,h} + OPL_{k,h}$

Where:

$OPE_{k,h}$ represents that component of the *congestion management settlement credit* for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on *energy* production subject to section 3.5.1 and is calculated as follows:

$$OPE_{k,h} = \sum_{m,t} \left[ \begin{array}{l} OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \\ MAX\left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right) \end{array} \right]$$

Where:

MAX[X,Y] = Maximum of X or Y

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t}$ is not equal to the mathematical sign of $AQEI_{k,h}^{m,t} – MQSI_{k,h}^{m,t}$ , the component of $OPE_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

Where applicable, $AQEI_{k,h}^{m,t}$ shall be replaced by $ADPI_{k,h}^{a,t}$, in the above equation, where:

$ADPI_{k,h}^{a,t}$ = the quantity (in MW) of *energy* injected by *market participant* 'k' at *alternative delivery point* 'a' in *metering interval* 't' of *settlement hour* 'h'

$OPR_{k,h}$ represents that component of the *congestion management settlement credit* for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the provision of *operating reserve* subject to section 3.5.1 and is calculated as follows:

$$OPR_{k,h} = \sum_{m,t,r} \left[ \begin{array}{l} OP(PROR_{r,h}^{m,t}, SQROR_{r,k,h}^{m,t}, BR_r) - \\ MAX\left(OP(PROR_{r,h}^{m,t}, DQSR_{r,k,h}^{m,t}, BR_r), OP(PROR_{r,h}^{m,t}, AQOR_{r,k,h}^{m,t}, BR_r)\right) \end{array} \right]$$

During any *metering interval* 't' within *settlement hour* 'h' in which the mathematical sign of $DQSR_{r,k,h}^{m,t} – SQROR_{r,k,h}^{m,t}$ is not equal to the mathematical sign of $AQOR_{r,k,h}^{m,t}$ - $SQROR_{r,k,h}^{m,t}$, the component of $OPR_{k,h}$ at location m, determined in accordance with section 3.1.4A, or *intertie metering point* 'm' for that *metering interval* 't' shall equal zero.

Where applicable, $AQOR_{r,,k,h}{}^{m,t}$ shall be replaced by $ADOR_{r,k,h}{}^{a,t}$, in the above equation, where:

$ADOR_{r,k,h}{}^{a,t}$ = quantity (in MW) of *class r reserve* for *market participant* 'k' at *alternative delivery point* 'a' in *metering interval* 't' of *settlement hour* 'h'

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## 4.7B Real-Time Generation Cost Guarantee Payments

4.7B.1 The *IESO* shall determine on a *per-start* basis, for each *generation facility* that has met the eligibility criteria for the real-time generation cost guarantee specified in sections 2.2, 5.7 and 6.3A of Chapter 7, the following:

4.7B.1.1 the sum of the following revenues earned in each *dispatch interval* during the period from synchronisation until the end of the *minimum generation block run-time* or the end of the *minimum run-time*, whichever comes first:

a. *energy market* prices multiplied by the sum of the applicable AQEI or ADPI and any applicable *physical allocation data*, for *energy* injected up to and including the *minimum loading point*; and

b. any congestion management *settlement* credit payments resulting from the *facility* being constrained on in order to meet its *minimum loading point*; and

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## 4.7D Day-Ahead Generation Cost Guarantee Payments

4.7D.1 The *IESO* shall determine on a *per-start* basis, for each *generation facility* that has met the criteria set out in chapter 7, sections 2.2C and 6.3B, a day-ahead generation costs guarantee on the basis of the following:

4.7D.1.1 the sum of the following revenues earned in each *dispatch interval* during the period from synchronisation to the end of the *minimum generation block run-time*:

a. *energy market prices* multiplied by the sum of the applicable AQEI or ADPI and any applicable *physical allocation data*, for *energy* injected up to and including the *minimum loading point*;

b. any congestion management *settlement* credit payments resulting from the *facility* being constrained on in order to meet its *minimum loading point*; and

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## PART 5 – IESO BOARD DECISION RATIONALE

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# Market Rule Amendment Proposal

## PART 1 – MARKET RULE INFORMATION

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|---|---|---|---|---|
| Identification No.: | MR-00372-R01 | | | |
| Subject: | Settlements | | | |
| Title: | CMSC and GCG Treatment for Aggregated Facilities | | | |
| Nature of Proposal: | ☐ Alteration | ☐ Deletion | ☐ Addition | |
| Chapter: | 11 | Appendix: | | |
| Sections: | | | | |
| Sub-sections proposed for amending: | | | | |

## PART 2 – PROPOSAL HISTORY – REFER TO MR-00372-R00

| Version | Reason for Issuing | Version Date |
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Provide a brief description of the following:

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- Alternative solutions considered.
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**Summary**

Refer to R00

**Background**

Refer to R00

**Discussion**

In order to implement Northland Power's proposal, it is proposed to create a new defined term "alternate delivery point" which represents injections from the generation component of an aggregated facility used for calculating CMSC and generation cost guarantees.

## PART 4 – PROPOSED AMENDMENT

*alternative delivery point* means a *delivery point* representing injections from the generation component of an aggregated *facility*, used for calculating congestion management *settlement* credits and, where applicable, generation cost guarantees;

## PART 5 – IESO BOARD DECISION RATIONALE

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