MDP_RUL_0002

MARKET RULES

for the Ontario Electricity Market

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Issue 66.0	Baseline 38.0	September 13, 2017
Issue 67.0	Baseline 38.1	December 6, 2017
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Related Documents

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MDP_RUL_0002_01	Introduction & Interpretation of the Market Rules	Issue 11.0
MDP_RUL_0002_01A	Introduction & Interpretation of the Market Rules – Appendices	Issue 3.0
MDP_RUL_0002_02	Participation	Issue 25.0
MDP_RUL_0002_02A	Participation - Appendices	Issue 14.0
MDP_RUL_0002_03	Administration, Supervision, Enforcement	Issue 35.0
MDP_RUL_0002_03A	Administration, Supervision, Enforcement - Appendices	Issue 4.0
MDP_RUL_0002_04	Grid Connection Requirements	Issue 16.0
MDP_RUL_0002_04A	Grid Connection Requirements – Appendices	Issue 15.0
MDP_RUL_0002_05	Power System Reliability	Issue 42.0
MDP_RUL_0002_05A	Power System Reliability - Appendices	Issue 8.0
MDP_RUL_0002_06	Wholesale Metering	Issue 18.0
MDP_RUL_0002_06A	Wholesale Metering - Appendices	Issue 13.0
MDP_RUL_0002_07	System Operation and Physical Markets	Issue 53.0
MDP_RUL_0002_07A	System Operation and Physical Markets - Appendices	Issue 25.0
MDP_RUL_0002_08	Physical Bilateral Contracts and Financial Markets	Issue 18.0
MDP_RUL_0002_08A	Physical Bilateral Contracts and Financial Markets - Appendices	Issue 3.0
MDP_RUL_0002_09	Settlements and Billing	Issue 58.0
MDP_RUL_0002_09A	Settlements and Billing - Appendices	Issue 4.0
MDP_RUL_0002_10	Transmission Service and Planning	Issue 7.0
MDP_RUL_0002_11	Definitions	Issue 63.0

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Authorities

Prepared by
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Reviewed by
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MARKET RULES

for the Ontario Electricity Market - APPENDICES

Connecting Today. Powering Tomorrow.

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Market Rules

Chapter 1

Introduction And Interpretation Of The Market Rules

Connecting Today.
Powering Tomorrow.

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1. Definitions

1.1 Market Rules

1.1.1 The rules set forth in Chapters 1 to 11 are called the Market Rules for the Ontario Electricity Market (the "*market rules*") and constitute the *market rules* made under the authority and for the purposes of the *Electricity Act, 1998*.

1.2 Italicized Expressions

1.2.1 Italicized expressions used in the *market rules* have the meanings ascribed thereto in the definitions set forth in Chapter 11. Words and phrases defined in the *Electricity Act, 1998* have the same meaning when used in the *market rules*.

2. Background and Legislative Authority

2.1 White Paper

2.1.1 In November, 1997, the Government of Ontario issued a White Paper entitled "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario", which set forth the broad framework for electricity sector reform with a view to the establishment of a competitive electricity market in Ontario.

2.2 Market Design Committee

2.2.1 During the course of 1998 and early 1999, the Market Design Committee, a committee created by Order in Council 2156/97 and comprised of representatives of stakeholders and consumers within the electricity industry, in its four quarterly reports made recommendations to the Government of Ontario on the design of the competitive electricity market for Ontario. As part of its responsibilities, the Market Design Committee was tasked with the preparation of initial draft rules governing the Ontario wholesale electricity market for submission to the *Minister*. In late January, 1999, the Market Design Committee submitted a set of draft initial rules to the *Minister*, with such further development of and revisions to the draft initial rules as may be necessary or appropriate being contemplated to be made prior to opening of the competitive markets.

2.3 Legislative Authority

2.3.1 The legislative authority for the *market rules* is contained in the *Electricity Act, 1998*. Specifically, subsection 32(1) of the *Electricity Act, 1998* contemplates that there will be made rules governing the *IESO-controlled grid* and establishing and governing the *IESO-administered markets* related to electricity and *ancillary services*.

3. Market Objective

3.1.1 The objective of the *IESO-administered markets* is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and *ancillary services* in Ontario.

4. Objectives and Status of Market Rules

4.1 Objectives and Status of Market Rules

4.1.1 The objectives of the *market rules* are to govern the *IESO-controlled grid* and to establish and govern efficient, competitive and reliable markets for the wholesale sale and purchase of electricity and *ancillary services* in Ontario.

4.2 Purposes of Market Rules

4.2.1 Accordingly, the *market rules* include provisions:

4.2.1.1 governing the making, *amendment* and *publication* of the *market rules*;

4.2.1.2 governing the conveying of electricity into, through or out of the *IESO-controlled grid* and the provision of *ancillary services*;

4.2.1.3 governing the terms and conditions pursuant to which persons may be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

4.2.1.4 governing the manner in which electricity and *ancillary services* are sold, purchased and *dispatched* in the *IESO-administered markets*;

4.2.1.5 governing standards and procedures to be observed in system *emergencies*;

4.2.1.6 authorizing and governing the giving of directions by the *IESO*;

4.2.1.7 authorizing and governing the making of orders by the *IESO*;

4.2.1.8 providing a mechanism for the resolution of certain disputes arising under the *market rules*;

4.2.1.9 providing mechanisms for monitoring, surveillance and investigation of activities in the *IESO-administered markets* and the conduct of *market participants*; and

4.2.1.10 providing generally for the exercise by the *IESO* of such powers and authority as may be necessary or desirable for the purpose of carrying out its objects in relation to the *IESO-administered markets* and the *IESO-controlled grid*.

4.3 Contractual Force

4.3.1 The *market rules* have the effect of a contract between each *market participant* and the *IESO* by virtue of the execution by the *IESO* and each *market participant* of the *participation agreement* under which each *market participant* and the *IESO* agree to perform and observe the *market rules* so far as they are applicable to each *market participant* and the *IESO* as provided for in the *market rules,* their respective *licences* and *applicable law*.

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4.4A.1 [Intentionally left blank – section deleted]

4.4A.2 [Intentionally left blank – section deleted]

4.4A.2.1 [Intentionally left blank- section deleted]

4.4A.2.2 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]
c. [Intentionally left blank – section deleted]

4.4A.2.3 [Intentionally left blank – section deleted]

4.4A.3 [Intentionally left blank – section deleted]

4.4A.4 [Intentionally left blank – section deleted]

4.4A.4.1 [Intentionally left blank – section deleted]

4.4A.4.2 [Intentionally left blank – section deleted]

a. [Intentinally left blank – section deleted]
b. [Intentinally left blank – section deleted]
c. [Intentionally left blank – section deleted]

4.4A.4.3 [Intentionally left blank – section deleted]

4.4A.5 [Intentionally left blank – section deleted]

4.4A.6 [Intentionally left blank – section deleted]

4.4A.6.1 [Intentionally left blank – section deleted]

4.4A.6.2 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]

4.4B Transitional Scheduling Generator

4.4B.1 Participation in the *IESO-administered market* of a *transitional scheduling generator* is temporary and shall expire when its registration is changed pursuant to Chapter 7, section 2.2.23.

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4.5.1 [Intentionally left blank – section deleted]

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4.5.6.4 [Intentionally left blank – section deleted]

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5. The IESO

5.1 Responsibility for Market Rules

5.1.1 The body corporate responsible for the administration and supervision of the *market rules* is the *IESO*.

5.2 Objects of the IESO

5.2.1 The objects of the *IESO* are specified in subsection 6(1) of the *Electricity Act, 1998*.

5.2.1.1 [Intentionally left blank – section deleted]

5.2.1.2 [Intentionally left blank – section deleted]

5.2.1.3 [Intentionally left blank – section deleted]

5.2.1.4 [Intentionally left blank – section deleted]

5.2.1.5 [Intentionally left blank – section deleted]

5.2.1.6 [Intentionally left blank – section deleted]

5.2.1.7 [Intentionally left blank – section deleted]

5.3 Functions of the IESO

5.3.1 The functions, powers and authority of the *IESO* in relation to the administration and supervision of the *market rules* include:

5.3.1.1 supervising, administering and enforcing the *market rules*;

5.3.1.2 operating the markets related to electricity and *ancillary services* established under the *market rules*;

5.3.1.3 instituting and ensuring through the administration, supervision and enforcement of the *market rules* the effective and efficient implementation of the rules and standards contained in the *market rules*;

5.3.1.4 collecting information and statistics and publishing reports and information relating to the performance of the *IESO-administered markets*;

5.3.1.5 administering the ongoing development of, and *amendments* to, the *market rules*;

5.3.1.6 establishing power system *reliability standards* and maintaining power system *reliability*;

5.3.1.7 undertaking its coordination of power system planning responsibilities;

5.3.1.8 authorizing persons to participate in the *IESO-administered markets* and to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

5.3.1.9 undertaking monitoring, surveillance and investigation of activities in the *IESO-administered markets* and the conduct of *market participants*; and

5.3.1.10 liaising with other bodies having regulatory functions with respect to the *IESO-administered markets* and the *IESO-controlled grid*, such as the *Ontario Energy Board* and the federal Competition Bureau,

the whole of which in accordance with the *market rules*, the by-laws and *licence* of the *IESO* and *applicable law*.

5.4 Compliance with Market Rules

5.4.1 The *IESO* is bound to comply with, observe and perform any duties and obligations imposed on the *IESO* by the *market rules*.

6. Market Participants

6.1 Classes of Market Participants

6.1.1 The classes of *market participants* are described in section 2 of Chapter 2.

6.2 Third Party Rights or Benefits

6.2.1 Unless otherwise expressly stated in the *market rules* or the *Electricity Act, 1998,* a person other than the *IESO* who is not a *market participant* is not entitled to any rights or benefits under the *market rules*.

6.3 Compliance with Market Rules

6.3.1 Subject to the terms of its *licence* and to the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998* and to any regulations enacted under those *Acts*, each *market participant* is bound to comply with, observe and perform any duties and obligations imposed on the *market participant* by the *market rules.*

6.3.2 Except as otherwise provided in these *market rules* or in any standard, policy, guideline, procedure or other document established by the *IESO* pursuant to these *market rules,* a *market participant* may use such information systems, communication systems, business processes, personnel, service providers or other agents as the *market participant*, in its sole discretion, considers appropriate for the purpose of assisting in the performance of its obligations under these *market rules* and under such standard, policy, guideline, procedure or other document provided that, as between the *IESO* and the *market participant*:

6.3.2.1 the *market participant* shall be bound by and fully responsible for all acts or omissions of its personnel, service providers or other agents; and

6.3.2.2 the *market participant* shall remain solely responsible and liable to the *IESO* for the due performance of such obligations.

7. Interpretation and Rules of Construction

7.1 General

7.1.1 In the *market rules*, unless the context otherwise requires:

7.1.1.1 words importing the singular include the plural and vice versa;

7.1.1.2 words importing a gender include any gender;

7.1.1.3 when italicized, other parts of speech and grammatical forms of a word or phrase defined in the *market rules* have a corresponding meaning;

7.1.1.4 an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, any government agency or body politic or collegiate, and any other entity or body or class of entity or body designated by regulation made pursuant to the *Electricity Act, 1998* as coming within the definition of the word "person";

7.1.1.5 a reference to a thing includes a part of that thing;

7.1.1.6 a reference to a Chapter, section, provision, condition, part or appendix is to a Chapter, section, provision, condition, part or appendix of the *market rules*;

7.1.1.7 a reference in a Chapter of the *market rules* to a section is to a section of that Chapter;

7.1.1.8 a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it and a reference to a statute includes all regulations, proclamations, orders in council, rules and by-laws of a legislative nature issued under that statute;

7.1.1.9 a reference to a document or provision of a document, including the *market rules* or a provision of the *market rules*, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;

7.1.1.10 a reference to a person includes that person's executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation) and permitted assigns;

7.1.1.11 a reference to a body (including, without limitation, an institute, association or authority), whether statutory or not, which ceases to exist or whose functions are transferred to another body is a reference to the body which replaces it or which substantially succeeds to its powers or functions;

7.1.1.12 a reference to sections of the *market rules* separated by the word "to" (i.e., "sections 1.1 to 1.4") shall be a reference to the sections inclusively;

7.1.1.13 a reference to a time:

a. without the qualification "EST" is a reference to eastern time, which is the prevailing eastern standard or eastern daylight time in the Province of Ontario;

b. followed by the qualification "EST" is a reference to eastern standard time in the Province of Ontario; and

c. without the qualification "am", "a.m.", "pm" or "p.m." is a reference to time based on a 24-hour clock; and

7.1.1.14 a reference to a month, calendar month, year or calendar year shall mean the period that commences the first hour of the first *trading day* that starts in such month or year and terminates the last hour of the last *trading day* that commences in such month or year.

7.1.1.15 [Intentionally left blank – section deleted]

7.2 Headings

7.2.1 Headings in the *market rules* are inserted for convenience of reference only and shall not affect the interpretation of the *market rules*, nor shall they be construed as indicating that all of the provisions of the *market rules* relating to any particular topic are to be found in any particular Chapter, sub-Chapter, section, subsection, clause, provision, part or appendix.

7.3 Shall, Must and May

7.3.1 The words "shall" and "must" shall be construed as imperative and the word "may" shall be construed as permissive.

7.4 Explanatory Notes

7.4.1 Any provision in this document which is indicated as being an "explanatory note" or a "rule note" shall be deemed not to form a part of the *market rules.* Such explanatory notes or rule notes are inserted for convenience only and shall not affect the interpretation of the *market rules* nor be binding on the *IESO* or on any *market participant*.

7.5 Computation of Time

7.5.1 In the computation of time under these *market rules*, unless a contrary intention appears, if there is a reference to a number of days between two events, they are counted by excluding the day on which the first event happens and including the day on which the second event happens.

7.5.2 In the computation of time under Chapters 2, 3, 6 and 10, unless a contrary intention appears, if the time for doing any act or thing expires on a day which is not a *business day*, the act or thing may be done on the next day that is a *business day.*

7.6 IESO Delegates

7.6.1 Delegation by the *IESO* of its powers and duties under these *market rules* shall be governed by the provisions of the *Governance and Structure By-law*.

7.6A Forms, Policies, Guidelines and Other Documents

7.6A.1 Forms, policies, guidelines and other documents, including but not limited to *market manuals* designed, created, developed, established or implemented by the *IESO* or a panel established by the *IESO* shall be interpreted in accordance with the *market rules* and the Electricity Act, 1998. Where there is any inconsistency between the *market rules* and a form, policy, guideline or other document, including but not limited to a *market manual*, the *market rules* shall prevail to the extent of the inconsistency.

7.7 Other Documents

7.7.1 Subject to section 7.7.4, and unless the context otherwise requires, where reference is made in the *market rules* to the design, creation, development, establishment or implementation of policies, guidelines and other documents by the *IESO* or a panel established by the *IESO*, such policies, guidelines and other documents shall not come into force until adopted by the *IESO Board, published* and notice thereof provided in accordance with section 7.7.2. The *IESO Board* may enter into such consultations, seek such advice and assistance and request such input from one or more persons as the *IESO Board* determines appropriate prior to adopting such policies, guidelines and other documents provided that the *IESO Board* retains the sole discretion to adopt such policies, guidelines and other documents in such form as the *IESO Board* determines appropriate. For certainty, any reference to "other documents" in section 7.7 shall not include forms or *market manuals*.

7.7.2 The policies, guidelines and other documents referred to in section 7.7.1 once adopted by the *IESO Board*, and forms and *market manuals* once prepared by the *IESO* shall be *published* by the *IESO* and notice thereof shall be provided to all *market participants*. The *IESO* and each *market participant* shall thereafter be bound to comply with the provisions of any such policies, guidelines, other documents and the *market manuals*.

7.7.2A The *IESO* shall establish a procedure which shall include but not be limited to processes for the stakeholdering of *market manuals* when the *market manuals* are created and for any subsequent amendments.

7.7.3 The *IESO Board* or a committee of the *IESO Board* established for that purpose may, from time to time, amend, and the *IESO Board* may from time to time replace or repeal, any policies, guidelines and other documents referred to in section 7.7.1. The procedures set forth in sections 7.7.1 and 7.7.2 shall apply equally to any amendment, replacement or repeal of such policies, guidelines and other documents and any reference in such sections to the *IESO Board* shall, with respect to the amendment of such policies, guidelines and other documents be deemed to include a reference to a committee of the *IESO Board* established for that purpose.

7.7.4 Any policy, guideline and other document required by the *market rules* to be implemented as an *amendment* to the *market rules* shall be implemented in accordance with the procedures set forth in section 4 of Chapter 3. Any policy, guideline and other document referred to in section 7.7.1 or in the *market manuals* which, by virtue of its prohibitive or mandatory character or its importance to the efficient operation of the *IESO-administered markets* or the *reliable* operation of the *IESO-controlled grid*, should have a legislative character shall be implemented by the *IESO* as an *amendment* to the *market rules*.

7.8 Currency

7.8.1 All references in:

7.8.1.1 the *market rules*;

7.8.1.2 any form, policy, guideline or other document referred to in section 7.7.1 or 7.7.3, including but not limited to all *market manuals*;

7.8.1.3 a *settlement statement*; or

7.8.1.4 an *invoice*,

to a monetary amount are expressed in Canadian dollars.

7.8.2 Any payment required to be made by or to the *IESO* or by or to a *market participant* pursuant to any of the documents referred to in sections 7.8.1.1 to 7.8.1.4 shall be made in Canadian dollars.

8. Notice, Notification, Service and Filing

8.1 Provision of Notice

8.1.1 Subject to section 8.3, and unless a contrary intention appears, notice is properly given, notification is properly made and service, filing, issuance and submission is properly effected under the *market rules*:

8.1.1.1 by courier or other form of personal delivery;

8.1.1.2 by prepaid first class mail addressed to the person at the address for service (if any) supplied by the person to the sender or, where the person is a *market participant*, to the address shown for that person in the list of *market participants* maintained by the *IESO* pursuant to section 3.1.10 of Chapter 2 or, where the person is the *IESO*, to the registered office of the *IESO*; or

8.1.1.3 by facsimile or electronic mail to a number or reference which corresponds with the address referred to in section 8.1.1.2.

8.2 Time of Notice

8.2.1 Subject to section 8.3, and unless a contrary intention appears, notice, notification, service, filing, issuance or submission shall be treated as having been duly given, made or effected to a person by the sender:

8.2.1.1 where given, made or effected by mail in accordance with section 8.1.1.2 to an address in the Province of Ontario, on the fourth *business day* after the day on which it is mailed;

8.2.1.2 where given, made or effected by mail in accordance with section 8.1.1.2 to an address in Canada outside the Province of Ontario or to an address in the United States, on the sixth *business day* after the day on which it is mailed;

8.2.1.3 where given, made or effected by mail in accordance with section 8.1.1.2 to an address outside Canada or the United States, on the twentieth *business day* after the day on which it is mailed;

8.2.1.4 where given, made or effected by facsimile in accordance with section 8.1.1.3 and a complete transmission report is issued from the sender's facsimile transmission equipment:

a. where notice, notification, service, filing or submission is of the type in relation to which the addressee is obliged to monitor the receipt by facsimile outside of, as well as during, business hours, on the day and at the time of transmission as indicated on the sender's facsimile transmission report; and

b. in all other cases, on the day and at the time of transmission as indicated on the sender's facsimile transmission report, if a *business day* or, if the transmission is on a day which is not a *business day* or is after 5:00 pm (addressee's time), at 9:00 am on the following *business day*;

8.2.1.5 Where given, made or effected by electronic mail in accordance with section 8.1.1.3:

a. where notice, notification, service, filing or submission is of a type in relation to which the addressee is obliged to monitor receipt by electronic mail outside of, as well as during, business hours, on the day and at the time when the notice or notification is recorded by the sender's electronic communication system as having been first received at the electronic mail destination; and

b. in all other cases, on the day and at the time when the notice, notification or document or other material served, filed or submitted is recorded by the sender's electronic communications system as having been first received at the electronic mail destination, if a *business day*, or if that time is after 5:00 pm (addressee's time) or the day is not a *business day*, at 9:00 am on the following *business day*; or

8.2.1.6 in any other case, when the person actually receives the notice, notification or document or other material served, filed or submitted.

8.3 Notice of Directions and Orders

8.3.1 Unless a contrary intention appears, instructions, directions and orders of the *IESO* may be given or issued to *market participants*:

8.3.1.1 in accordance with sections 8.1 or 8.2;

8.3.1.2 by voice communication, in which case the instruction, direction or order shall be deemed validly given or issued at the time of communication.

9. Publication

9.1.1 Subject to section 9.1.2, where any document or information is required by the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO* to be *published* by the *IESO* or, in the case of the *market rules*, to be published by the *Minister*, *publication* shall be effected by placing the document or information on the public *IESO* web site. The document or information shall be deemed to be *published* when the document or information has been so placed.

9.1.2 Where the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO* prescribe a mode of publication other than that described in section 9.1.1 in respect of a specified document or information, the *IESO* shall, in addition to complying with section 9.1.1 comply with the publication requirement applicable to such document or information as is so prescribed. In such a case, the document or information shall be deemed to be published on the date on which the prescribed publication requirement has been satisfied.

10. [Intentionally left blank]

10.1.1 [Intentionally left blank]

10.1.2 [Intentionally left blank]

10A. General Conduct

10A.1 *Market participants* and the *IESO* shall not directly or indirectly engage or attempt to engage in conduct, alone or with another person, that they know, or ought reasonably to know:

10A.1.1 exploits the *IESO-administered markets*, including by, without limitation, exploiting any gap or defect in the *market rules*;

10A.1.2 circumvents any of the *market rules*;

10A.1.3 manipulates any of the *IESO-administered markets*, including by, without limitation, manipulating the determination of a *settlement amount*;

10A.1.4 undermines through any means the ability of the *IESO* to carry out its powers, duties or functions under the *Electricity Act, 1998* or the *market rules*; or

10A.1.5 interferes with the determination of a *market price* or *dispatch* outcome by competitive market forces.

10A.2 Without limiting the availability of any defences that a *market participant* may have with respect to conduct set out in section 10A.1, a *market participant* will not have violated section 10A.1 where it establishes that its conduct was entirely or predominantly caused by:

10A.2.1 a procurement contract as defined in the *Electricity Act, 1998*; or;

10A.2.2 an order of the *Ontario Energy Board* made in accordance with s. 78.1 of the *Ontario Energy Board Act, 1998*.

10A.3 For the purposes of this section 10A, "conduct" includes acts and omissions, but with respect to the *OPA* and *OEFC* only includes acts or omissions in their capacity as *market participants*, and with respect to the *IESO* does not include:

10A.3.1 market design or implementing government policy; and

10A.3.2 the development of the *market rules*, *market manuals* and policies, guidelines, or other documents referenced in section 7.7 of Chapter 1.

11. Information Disclosure

11.1 Disclosure Must be Made Where Required by Market Rules

11.1.1 *Market participants* shall disclose or provide to the *IESO* and/or to other *market participants,* and the *IESO* shall disclose or provide to *market participants*, such information as is required to be disclosed or provided pursuant to the *market rules*. Such information shall be disclosed or provided within the time specified in, and in the form and manner required by, the relevant provisions of the *market rules*. Where no time is specified in relation to the disclosure or provision of specific information, the information shall be disclosed or provided within a reasonable time.

11.2 No Misleading or Deceptive Information

11.2.1 Information disclosed or provided by a *market participant* to the *IESO* and/or to other *market participants* or by the *IESO* to *market participants* pursuant to the *market rules* shall be, to the best of the disclosing person's knowledge, true, correct and complete at the time at which such disclosure or provision is made. Neither the *IESO* nor *market participants* shall knowingly or recklessly disclose or provide information pursuant to the *market rules* that, at the time and in light of the circumstances in which such disclosure or provision is made, is misleading or deceptive or does not state a fact that is required to be stated or that is necessary to make the statement not misleading or deceptive.

11.3 Correction of Incorrect Information

11.3.1 Where a *market participant* or the *IESO* discovers that any information previously disclosed or provided by it to any person pursuant to the *market rules* was, at the time at which it was disclosed or provided, or becomes untrue, incorrect, incomplete, misleading or deceptive, the disclosing person shall immediately rectify the situation and disclose or provide the true, correct, complete, not misleading or not deceptive information to the person to whom the original or currently untrue, incorrect, incomplete, misleading or deceptive information had been disclosed or provided.

11.4 Use of Information by the IESO

11.4.1 Subject to the provisions of sections 3 and 5 of Chapter 3, the *IESO* and any panel established by the *IESO* is entitled to use any data or information obtained in pursuance of the *IESO'*s or the panel's powers, functions or duties under the *market rules*, *applicable law* or the by-laws or *licence* of the *IESO.* The *IESO* may use such information in connection with or to initiate processes provided for in the *market rules* including, but not limited to:

11.4.1.1 a process to *amend* the *market rules* pursuant to section 4 of Chapter 3; or

11.4.1.2 a process to enforce compliance with the *market rules* pursuant to section 6 of Chapter 3.

12. Interpretation Bulletins

12.1.1 [Intentionally left blank]

12.1.2 [Intentionally left blank]

12.1.3 Where the *IESO* receives a request from any person, including a member of a panel established by the *IESO*, a *market participant* or the *IESO Board*, seeking a clarification or posing a question as to the interpretation, application or implementation of a *market rule*, the *IESO* may refer the matter to the *technical panel* and the *technical panel* shall provide such clarification or the answer to such question to the *IESO.*

12.1.4 The *IESO* may, from time to time, either on its own initiative or upon receipt from the *technical panel* of a material clarification of, or answer to, a question concerning the interpretation, application or implementation of a *market rule*, *publish* and give notice of bulletins as to the interpretation, application or implementation of a *market rule*.

12.1.5 A bulletin *published* pursuant to section 12.1.4 shall be binding on the *IESO*, provided that:

12.1.5.1 none of the relevant *market rules* are thereafter *amended*;

12.1.5.2 there is thereafter no amendment to any relevant provisions of the *Electricity Act, 1998;* and

12.1.5.3 the *IESO* has been provided with all relevant facts in respect of which the interpretation or clarification has been requested and all such facts were true at the time the interpretation or clarification was made.

13. Liability and Indemnification

13.1 Liability of IESO

13.1.1 Except as required by section 13.1.2 or as otherwise provided in these *market rules,* the *IESO* shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of a *market participant* whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the *IESO* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual.*

13.1.2 Subject to section 13.1.4, the *IESO* shall indemnify and hold harmless a *market participant* and the *market participant's* directors, officers and employees from any and all claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *market participant* or its directors, officers or employees to the extent that such claims, losses, liabilities, actions, judgements, suits, costs, expenses, disbursements or damages arise out of any willful misconduct by or any act or omission that constitutes gross neglience of the *IESO* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.1.3 For the purposes of section 13.1.2, an act or omission of the *IESO* effected in compliance with these *market rules* or with the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* shall be deemed not to constitute willful misconduct or gross negligence.

13.1.4 Except as otherwise provided in these *market rules* other than in this section 13, in no event shall the *IESO* be liable to indemnify and hold harmless a *market participant* or the *market participant's* directors, officers or employees from or in respect of:

13.1.4.1 any indirect or consequential loss or incidental or special damages including, but not limited to, punitive damages; or

13.1.4.2 any loss of profit, loss of contract, loss of opportunity or loss of goodwill,

and no *market participant* shall assert or attempt to assert against the *IESO* any claim in respect of any of the losses or damages referred to in sections 13.1.4.1 and 13.1.4.2.

13.1.5 Each *market participant* shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims for indemnification that may be made by the *market participant* pursuant to section 13.1.2.

13.2 Liability of Market Participants

13.2.1 Except as required by section 13.2.2 or as otherwise provided in these *market rules,* a *market participant* shall not be liable for any claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements or damages of the *IESO* whatsoever, howsoever arising and whether as claims in contract, claims in tort (including but not limited to negligence) or otherwise, arising out of any act or omission of the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual.*

13.2.2 Subject to section 13.2.4, each *market participant* shall indemnify and hold harmless the *IESO,* the *IESO's* directors, officers and employees and any member of a panel established by the *IESO* from any and all claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO,* its directors, officers or employees or the member of a panel established by the *IESO* to the extent that such claims, losses, liabilities, actions, judgements, suits, costs, expenses, disbursements or damages arise out of any willful misconduct by or any negligent act or omission of the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under these *market rules* or under any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.2.3 For the purposes of section 13.2.2, an act or omission of a *market participant* effected in compliance with the *market rules* or with the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* shall be deemed not to constitute willful misconduct or a negligent act or omission.

13.2.4 Except as otherwise provided in these *market rules* other than in this section 13, in no event shall a *market participant* be liable to indemnify and hold harmless the *IESO,* the *IESO's* directors, officers or employees or a member of a panel established by the *IESO* from or in respect of:

13.2.4.1 any indirect or consequential loss or incidental or special damages including, but not limited to, punitive damages; or

13.2.4.2 any loss of profit, loss of contract, loss of opportunity or loss of goodwill,

and the *IESO* shall not assert or attempt to assert against a *market participant* any claim in respect of any of the losses or damages referred to in sections 13.2.4.1 and 13.2.4.2.

13.2.5 Nothing in this section 13.2 shall be read as limiting the right of the *IESO* to impose a financial penalty or other sanction including, but not limited to, the issuance of a *suspension order*, a *disconnection order* or a *termination order*, on a *market participant* in accordance with the provisions of these *market rules.*

13.2.6 The *IESO* shall have a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims for indemnification that may be made by the *IESO* pursuant to section 13.2.2 including, but not limited to, seeking recovery under any applicable policies of insurance to which the *IESO* or the *market participant,* as the case may be, is a beneficiary.

13.3 Force Majeure

13.3.1 Subject to section 13.3.14, the *IESO* shall not be liable to any *market participant* for any failure or delay in the performance of any of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*, other than the obligation to make payments of money, to the extent that such failure or delay is due to a *force* *majeure event*, provided that the *IESO* shall only be excused from performance pursuant to this section 13.3.1:

13.3.1.1 for so long as the *force majeure event* continues and for such reasonable period of time thereafter as may be necessary for the *IESO* to resume performance of the obligation; and

13.3.1.2 where and to the extent that the failure or delay in performance would not have been experienced but for such *force majeure event*.

13.3.2 Subject to section 13.3.14, a *market participant* shall not be liable to the *IESO* for any failure or delay in the performance of any of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*, other than the obligation to make payments of money, to the extent that such failure or delay is due to a *force majeure event,* provided that the *market participant* shall only be excused from performance pursuant to this section 13.3.2:

13.3.2.1 for so long as the *force majeure event* continues and for such reasonable period of time thereafter as may be necessary for the *market participant* to resume performance of the obligation; and

13.3.2.2 where and to the extent that such failure or delay would not have been experienced but for such *force majeure event*.

13.3.3 Neither the *IESO* nor a *market participant* may invoke a *force majeure event* unless it has given notice in accordance with section 13.3.4 or 13.3.5, respectively.

13.3.4 Where the *IESO* invokes a *force majeure event*, it shall give notice to *market participants* and shall *publish* notice of the *force majeure event* as soon as reasonably practicable but in any event within two *business days* of the date on which the *IESO* becomes aware of the occurrence of the *force majeure event*, which notice shall include particulars of:

13.3.4.1 the nature of the *force majeure event*;

13.3.4.2 the effect that such *force majeure event* is having on the *IESO's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document or referred to in section 7.7 or any *market manual*; and

13.3.4.3 the measures that the *IESO* is taking, or proposes to take, to alleviate the impact of the *force majeure event*.

13.3.5 Where a *market participant* invokes a *force majeure event*, it shall give notice to the *IESO* of the *force majeure event* as soon as reasonably practicable but in any event within two *business days* of the date on which the *market participant* becomes aware of the occurrence of the *force majeure event*, which notice shall include particulars of:

13.3.5.1 the nature of the *force majeure event*;

13.3.5.2 the effect that such *force majeure event* is having on the *market participant's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*; and

13.3.5.3 the measures that the *market participant* is taking, or proposes to take, to alleviate the impact of the *force majeure event*.

13.3.6 Subject to section 13.3.7, where the *IESO* or a *market participant* invokes a *force majeure event*, it shall use all reasonable endeavours to mitigate or alleviate the effects of the *force majeure event* on the performance of its obligations under these *market rules*.

13.3.7 The settlement of any strike, lockout, restrictive work practice or other labour disturbance constituting a *force majeure event* shall be within the sole discretion of the *IESO* or the *market participant*, as the case may be, involved in such strike, lockout, restrictive work practice or other labour disturbance and nothing in section 13.3.6 shall require the *IESO* or the *market participant*, as the case may be, to mitigate or alleviate the effects of such strike, lockout, restrictive work practice or other labour disturbance.

13.3.8 Where the *IESO* invokes a *force majeure event,* it shall notify *market participants* and shall as soon as practicable *publish* notice of any material change in the information contained in the notice referred to in section 13.3.4 or in any previous notice given and *published* pursuant to this section 13.3.8.

13.3.9 Where a *market participant* invokes a *force majeure event*, it shall as soon as practicable notify the *IESO* of any material change in the information contained in the notice referred to in section 13.3.5 or in any previous notice given pursuant to this section 13.3.9.

13.3.10 Where the *IESO* invokes a *force majeure event*, it shall give notice to *market participants* and shall *publish* notice of the cessation of the *force majeure event* and of the cessation of the effects of such *force majeure event* on the *IESO*'s performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.3.11 Where a *market participant* invokes a *force majeure event*, it shall give notice to the *IESO* of the cessation of the *force majeure event* and of cessation of the effects of such *force majeure event* on the *market participant's* performance of its obligations under these *market rules* or under the provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual*.

13.3.12 The *IESO* shall *publish* any notice provided to it pursuant to section 13.3.5, 13.3.9 or 13.3.11.

13.3.13 Nothing in this section 13.3 shall be read as limiting the right of the *IESO* to impose on a *market participant* a sanction, other than a financial penalty, including but not limited to the issuance of a *suspension order*, a *disconnection order* or a *termination order*, in accordance with the provisions of these *market rules.*

13.3.14 Nothing in this section 13.3 shall excuse the *IESO* or a *market participant* from performing any of their respective obligations contained in:

13.3.14.1 those provisions of these *market rules* that govern the *IESO* and the *market participant* during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*;

13.3.14.2 those provisions of any policy, guideline or other document referred to in section 7.7 or any *market manual* that govern the *IESO* and the *market participant* during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*;

13.3.14.3 the *Ontario electricity emergency plan*;

13.3.14.4 the *market participant's emergency preparedness plan*;

13.3.14.5 the *Ontario power system restoration plan*; or

13.3.14.6 the *market participant's restoration participant attachment*,

during an *emergency* or while the *IESO-controlled grid* is in a *high-risk operating state* or in an *emergency operating state*.

13.4 Contractual Liability

13.4.1 The liability and indemnification provisions of sections 13.1 and 13.2 and, where applicable, of any other section of these *market rules* other than this section 13, and the *force majeure* provisions of section 13.3 shall apply to any agreement or contract referred to in these *market rules* or in any policy, guideline or other document referred to in section 7.7 or any *market manual* to which the *IESO* and a *market participant* are parties or to the terms of which the *IESO* and a *market participant* are bound and to all acts or omissions of the *IESO* or the *market participant* in the exercise or performance or the intended exercise or performance of any power or obligation under such agreement, contract, policy, guideline or other document referred to in section 7.7 or any *market manual*. In the event of an inconsistency between such liability, indemnification and *force majeure* provisions and the liability, indemnification and *force majeure* provisions of such agreement, the liability and indemnification provisions of sections 13.1 and 13.2 and, where applicable, of any other section of these *market rules*, and the *force majeure* provisions of section 13.3 shall prevail to the extent of the inconsistency.

14. Exemptions

14.1 Scope of Exemptions

14.1.1 As provided in the Electricity Act, 1998 an *exemption applicant* may apply to the *IESO* for an *exemption* from the application of any obligation or standard which is or may be imposed upon the *exemption applicant* or in respect of the *exemption applicant's facilities* or equipment pursuant to these *market rules, market manuals* or to any standard, policy or procedure established by the *IESO* pursuant to these *market rules*.

14.1.2 In this section 14, a reference to an *exemption applicant* shall, where the context so requires, be deemed to include a reference to an *exemption applicant* to whom an *exemption* has been granted by the *IESO Board*.

14.2 Application Process

14.2.1 An *exemption applicant* shall apply for an *exemption* in accordance with the practices and procedures established by the *IESO Board.*

14.3 Effect of Exemption and Monitoring

14.3.1 Failure by an *exemption applicant* to comply with any of the terms and conditions of an *exemption* imposed pursuant to an order of the *IESO Board*, including without limitation any amendments to such terms and conditions, shall constitute a breach of the *market rules*.

14.3.2 An *exemption applicant* to whom an *exemption* has been granted shall from time to time provide to the *IESO* such information as the *IESO* may request for the purposes of monitoring:

14.3.2.1 compliance by the *exemption applicant* with any terms and conditions of the *exemption*; and

14.3.2.2 the progress of implementation of the *exemption* plan forming part of the *exemption application*, as such *exemption* plan may be amended from time to time with the concurrence of the *IESO Board.*

14.4 Reconsideration, Removal or Transfer of Exemptions

14.4.1 Procedures for the reconsideration, removal or transfer of *exemptions* are included in the practices and procedures referred to in section 14.2.1.

14.5 Costs

14.5.1 Where the *IESO Board* has established and included in the practices and procedures referred to in section 14.2.1 the manner in which the *IESO* will recover from each *exemption applicant* the costs of processing its *exemption application* and, where a panel of the *IESO Board* so decides as a term or condition of the *exemption*, an *exemption applicant* other than the *IESO* shall submit to the *IESO* such costs, commit to the *IESO* in such form as the *IESO* considers appropriate to pay such costs, or both, in the manner specified in the practices and procedures referred to in section 14.2.1.

14.5.2 Where the removal or reconsideration of an *exemption* granted to a *pre-existing facility or equipment* prior to *market commencement date* was prompted as a result of the activities of one or more *market participants* and the *IESO* determines that such *market participant(s)* will benefit from the removal or reconsideration of the *exemption*, unless the costs to be incurred by the *exemption applicant* to comply with the standard of obligation to which the *exemption* relates or with the amended terms and conditions of the *exemption* as the case may be, are recoverable by means of a process or procedure mandated by the *OEB*, costs shall be recovered from each such *market participant* on a pro-rata basis based upon the *IESO's* assessment of the benefit accruing to each such *market participant* from the removal or reconsideration of the *exemption*. No costs shall be recoverable in respect of the removal or reconsideration of an *exemption* granted after the *market commencement date.*

14.5.3 The costs that may be collected and remitted pursuant to section 14.5.2 shall be calculated by the *IESO* by subtracting from the costs to be incurred by the *exemption applicant* to comply with the standard or obligation to which the *exemption* relates or with the amended terms and conditions of the *exemption*, as the case may be, the value of any benefit determined by the *IESO* as accruing to the *exemption applicant* as a result of its compliance with such standard or obligation or such amended terms and conditions.

14.5.4 Where an *exemption* was granted to a *pre-existing facility or equipment* prior to *market commencement date* but section 14.5.2. is not applicable, the costs will be recovered from one or more of the following classes of *market participants* as determined by the *IESO*:

14.5.4.1 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* withdrawn at all *delivery points* determined in accordance with Chapter 9, during such period as may be specified by the *IESO*;

14.5.4.2 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* injected at all *delivery points* , determined in accordance with Chapter 9, during such period as may be specified by the *IESO*;

14.5.4.3 all *market participants* on a pro-rata basis based upon their respective allocated quantities of *energy* withdrawn at all *intertie* metering points, determined in accordance with Chapter 9, during such period as may be specified by the *IESO*; and

14.5.4.4 all *market participants* on a pro-rata basis based on their respective allocated quantities of *energy* injected at all intertie metering points, determined in accordance with Chapter 9, during such period as may be specified by the *IESO*.

14.6 Need for Rule Amendment

14.6.1 Where the *IESO* determines that the benefit of an *exemption* should be extended to all *market participants* or persons or to a class of *market participants* or persons the *IESO* may:

14.6.1.1 where the *exemption* was granted prior to the date on which section 4 of Chapter 3 comes into force, recommend to the *IESO Board* that it advise the *Minister* that an *amendment* to the *market rules* be made accordingly; or

14.6.1.2 where the *exemption* was granted after the date on which section 4 of Chapter 3 comes into force, recommend to the *IESO Board* that the *amendment* process set forth in section 4 of Chapter 3 be initiated with a view to *amending* the *market rules* accordingly.

Market Rules

Chapter 1 Introduction And Interpretation Of The Market Rules - Appendices

Connecting Today.
Powering Tomorrow.

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Market Rules

Reviewed by
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Legal Affairs

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IESO Board

Distribution List

Name	Organization

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Appendix 1.1 – [Intentionally left blank]

Market Rules

Chapter 2

Participation

Connecting Today.
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1. Introduction

1.1 Introduction

1.1.1 This Chapter sets forth:

1.1.1.1 the procedures pursuant to which persons may apply to the *IESO* for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

1.1.1.2 the prudential, technical and other requirements which must be met by prospective *market participants* and by *market participants*;

1.1.1.3 the fees payable by prospective *market participants* and by *market participants*; and

1.1.1.4 the terms and conditions upon which a *market participant* may cease to be a *market participant*.

1.2 Participation

1.2.0 A person who has been issued a *licence* by the *OEB* pursuant to Part V of the Ontario Energy Board, 1998, is subject to all *market rules* relating to the activities authorized by such *licence* and all other applicable *market rules*.

1.2.1 No person shall participate in the *IESO-administered markets* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that person has been authorized by the *IESO* to do so pursuant to this Chapter, provided however that this section 1.2.1 shall not apply to require any authorization in respect of physical loop flows inadvertently arising as a result of transactions between entities located outside the *IESO control area*.

1.2.2 No person shall be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless the *IESO* is satisfied:

1.2.2.1 on the basis of the certification, tests, and inspections referred to in section 6.2, that the person satisfies the technical requirements referred to in that section applicable to all *market participants*;

1.2.2.2 that the person, if it applies to participate in the *real-time markets*, will either satisfy the *prudential support* requirements of Appendix 2.3 and any other financial requirements set forth in the *market rules* applicable to all *market participants* and the *IESO-administered market* in which the person wishes to participate, or in the case of a *capacity market participant,* satisfy the *capacity prudential support* requirements in section 5B;

1.2.2.3 that the person agrees to be bound by these *market rules* by executing the *participation agreement*;

1.2.2.4 that the person holds a *licence* permitting the person to engage in one or more of the activities described in section 57 of the Ontario Energy Board Act, 1998, unless:

a. the person is exempt by regulation enacted pursuant to the *Ontario Energy Board Act, 1998* from the obligation to hold such a *licence*; or

b. the person is not engaging in an activity for which the person requires a *licence* pursuant to section 57 of the Ontario Energy Board Act, 1998; and

1.2.2.5 [Intentionally left blank – section deleted]

1.2.2.6 on the basis of the documentation referred to in section 3.1.2.2, that the person, if it applies for authorization as a *market participant* other than solely as a *financial market participant* or a *capacity auction participant*:

a. is registered for the federal harmonized value-added tax system under Part IX of the *Excise Tax Act* (Canada); or

b. is resident in Canada and is, by virtue of *applicable law*, not liable to pay the federal harmonized value-added tax imposed under Part IX of the *Excise Tax Act* (Canada).

1.2.2A [Intentionally left blank – section deleted]

1.2.3 A person who has been authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* may participate in the market or trading activities to which the authorization to participate relates.

2. Classes of Market Participants

2.1.1 The following classes of persons may apply for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid:*

2.1.1.1 *generators*;

2.1.1.2 *distributors*;

2.1.1.3 *wholesale sellers*;

2.1.1.4 *wholesale consumers*;

2.1.1.5 *retailers*;

2.1.1.6 *transmitters*;

2.1.1.7 *financial market participants*;

2.1.1.8 [Intentionally left blank – section deleted]

2.1.1.9 [Intentionally left blank – section deleted]

2.1.1.10 [Intentionally left blank – section deleted]

2.1.1.11 *capacity market participants;*

2.1.1.12 *capacity auction participants*; and

2.1.1.13 *electricity storage participants.*

3. Application for Authorization

3.1.1 A person who wishes to be authorized by the *IESO* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* must file a completed *application for authorization to participate*.

3.1.2 The application for authorization to participate shall be accompanied by:

3.1.2.1 the non-refundable application fee established from time to time by the *IESO* to defray the costs of processing the application; and

3.1.2.2 unless the *application for authorization to participate* is submitted in respect of an applicant that is applying for authorization to participate in the *IESO-administered markets* solely as a *financial market participant* or a *capacity auction participant*, either:

a. the federal harmonized value-added tax system registration number issued to the applicant by the Canada Customs and Revenue Agency; or

b. where the applicant is resident in Canada and is, by virtue of *applicable law*, not liable to pay the federal harmonized value-added tax under Part IX of the *Excise Tax Act* (Canada), such documentation as may be prescribed in the *Excise Tax Act* (Canada) or described in the policies of the Canada Customs and Revenue Agency to support the exemption from such liability to pay.

3.1.3 The *IESO* shall, within ten *business days* of receiving an *application for authorization to participate* or within such longer period of time as may be agreed between the *IESO* and the applicant, advise the applicant of any further information or clarification which is required in support of its application if, in the *IESO's* opinion, the application is:

3.1.3.1 incomplete; or

3.1.3.2 contains information with respect to which the *IESO* requires clarification.

3.1.4 If the further information or clarification which is requested by the *IESO* pursuant to section 3.1.3 is not provided to the *IESO's* satisfaction within fifteen *business days* of the request or within such longer period of time as may be agreed between the *IESO* and the applicant, the applicant will be deemed to have withdrawn the *application for authorization to participate*.

3.1.5 The *IESO* shall, within twenty *business days* of receipt of the *application for authorization to participate* or of the further information or clarification requested under section 3.1.3, whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, by order authorize the applicant to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on such terms and conditions as the *IESO* considers appropriate, if:

3.1.5.1 the *IESO* is satisfied that the applicant meets the requirements set out in section 1.2.2; and

3.1.5.2 the applicant has filed with the *IESO* an executed *participant agreement*, in such form as shall be established by the *IESO*, pursuant to which the applicant agrees to be bound by and comply with the *market rules*, provides the certification referred to in section 6.2.1 and certifies that it has adequate qualified employees or other personnel and organizational and other arrangements that are sufficient to enable the applicant to perform all of the functions and obligations applicable to *market participants*, the class of *market participant* of which the applicant forms part and the *IESO-administered market* in which the applicant wishes to participate.

3.1.5A [Intentionally left blank – section deleted]

3.1.5B [Intentionally left blank – section deleted]

3.1.5B.1 [Intentionally left blank – section deleted]

3.1.5B.2 [Intentionally left blank – section deleted]

3.1.5C [Intentionally left blank – section deleted]

3.1.5C.1 [Intentionally left blank – section deleted]

3.1.5C.2 [Intentionally left blank – section deleted]

3.1.6 Subject to section 4.1.1, if the *IESO* is not satisfied that an applicant meets the requirements set out in section 1.2.2 the *IESO* shall, within twenty *business days* of receipt of the *application for authorization to participate* or of the further information or clarification requested under section 3.1.3, whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, by order deny the applicant authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

3.1.7 A person who wishes to dispute an order of the *IESO* made pursuant to section 3.1.5, 3.1.6, or 4.1.1 shall follow the dispute resolution procedures set forth in section 2 of Chapter 3.

3.1.8 An applicant or *market participant* shall forthwith advise the *IESO* of any circumstances which result or are likely to result in a change in the information provided in the *application for authorization to participate* or in any updates thereto.

3.1.9 [Intentionally left blank – section deleted]

3.1.10 The *IESO* shall establish, maintain, update and *publish*:

3.1.10.1 a list of all *market participants* and a list of all *applications for authorization* to *participate* filed with the *IESO*;

3.1.10.2 a list of all *market participants* that will cease to be *market participants* and the time that each listed *market participant* will cease to be a *market participant*;

3.1.10.3 a list of all *market participants* that are the subject of a *suspension order* or a *termination order* and the time at which the rights of each listed *market participant* was suspended or terminated; and

3.1.10.4 a list of all *market participants* that are the subject of an order referred to in section 6.5.1 of Chapter 3, and the time at which such order became effective in respect of each listed *market participant*.

3A. [Intentionally left blank – section deleted]

4. Conditional Authorization

4.1 Conditional Authorization Order

4.1.1 Within twenty *business days* of receipt of an *application for authorization to participate* or of the further information or clarification requested under section 3.1.3, whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, the *IESO* may, if it is satisfied that the applicant meets the requirements set out in section 1.2.2.2, by order conditionally authorize the applicant to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on such terms and conditions as the *IESO* considers appropriate, until such time as the applicant has:

4.1.1.1 satisfied the requirements set out in section 1.2.2.1, section 1.2.2.4 or both, as the case may be; and

4.1.1.1A [Intentionally left blank – section deleted]

4.1.1.2 filed an executed *participation agreement*, in such form as shall be established by the *IESO*, pursuant to which the applicant agrees to be bound by and comply with the *market rules*, provides the certification referred to in section 6.2.1 and certifies that it has adequate qualified employees or other personnel and organizational and other arrangements that are sufficient to enable the applicant to perform all of the functions and obligations applicable to *market participants*, the class of *market participant* of which the applicant forms part and the *IESO-administered market* in which the applicant wishes to participate.

4.1.2 [Intentionally left blank – section deleted]

4.2 Effect and Term of Order

4.2.1 An order issued pursuant to section 4.1.1 that is conditional solely on the satisfaction of the requirements set out in section 1.2.2.1, section 1.2.2.4, or both, shall:

4.2.1.1 stipulate the date by which the applicant must satisfy the requirements of section 1.2.2.1, section 1.2.2.4 or both, as the case may be;

4.2.1.2 no longer be conditional at such time as the *IESO* notifies the applicant that:

a. the applicant has met the requirements of section 1.2.2.1, section 1.2.2.4 or both, as the case may be; and

b. the *IESO* has received from the applicant the executed *participation agreement* referred to in section 4.1.1.2; and

4.2.1.3 lapse on the date referred to in section 4.2.1.1 if the applicant has not, prior to that date, received from the *IESO* the notification referred to in section 4.2.1.2.

4.2.2 An order issued pursuant to section 4.1.1 shall:

4.2.2.1 where the *IESO* provides the notification referred to in section 4.2.1.2, be deemed to constitute the order authorizing the applicant to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on any other terms and conditions noted in the order issued pursuant to section 4.1.1, as of the date of receipt by the applicant of such notification; or

4.2.2.2 where such order lapses in accordance with section 4.2.1.3, be deemed to constitute an order denying the applicant authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* as of the date referred to in section 4.2.1.3.

4.2.3 [Intentionally left blank – section deleted]

4.2.3.1 [Intentionally left blank – section deleted]

4.2.3.2 [Intentionally left blank – section deleted]

4.2.3.3 [Intentionally left blank – section deleted]

4.2.3.4 [Intentionally left blank – section deleted]

4.2.4 [Intentionally left blank – section deleted]

4.2.5 A person to whom a *registered facility* is transferred as contemplated by section 2.5 of Chapter 7, shall be deemed to be a *market participant* as of the commencement of the first *trading day* following completion of the transfer and shall expeditiously pursue and complete the conditions precedent to becoming fully authorized as required by this Chapter.

5. Prudential Requirements

5.1 Purpose

5.1.1 This section 5 sets forth the nature and amount of *prudential support* that must be provided by *market participants* as a condition of participation in the *real-time markets* or of causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid,* and the manner in which *market participants* must provide and maintain such *prudential support* on an on-going basis in order to protect the *IESO* and *market participants* from payment defaults. *Market participants* participating in the *IESO-administered markets* solely as a *capacity market participant* or *capacity auction participant* with a *capacity obligation* shall be subject only to the *capacity prudential support* requirements in section 5B.

5.1.2 The *IESO* shall review the *prudential support* requirements set out in this chapter at least once every three years. The first review shall be completed no later than September 30, 2010.

5.2 Market Participant Obligations

5.2.1 Each *market participant* shall initially and continually satisfy the obligations set forth in this section 5.2 with regard to the provision of *prudential support* as a condition of participating in the *real-time markets* or of causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid*.

5.2.2 Each *market participant* shall provide to the *IESO* and at all times maintain *prudential support* the value of which is not less than the *market participant's prudential support obligation.* For this purpose, the aggregate value of the *prudential support* shall be equal to the value of the undrawn or unclaimed amounts of *prudential support* provided by the *market participant.*

5.2.3 No *market participant* that is required pursuant to section 5.3.9 to provide *prudential support* shall participate in the *real-time markets* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that *market participant* satisfies the *prudential support* requirements of this section and Appendix 2.3.

5.2.4 Each *market participant* shall provide to the *IESO,* on an ongoing basis, such information as the *IESO* may reasonably require for the purpose of determining that *market participant's maximum net exposure.*

5.2.5 If *prudential support* previously provided to the *IESO* by a *market participant* pursuant to section 5.7 (the "*existing support*") is due to expire or terminate and, upon expiry or termination of the *existing support* the total *prudential support* held by the *IESO* in respect of that *market participant* will be less than the *market participant's prudential support obligation* then, at least ten *business days* prior to the time at which the *existing support* is due to expire or terminate, the *market participant* must provide to the *IESO* a replacement *prudential support* which will become effective no later than the expiry or termination of the *existing support*, such that the total *prudential support* provided is equal to the *market participant's prudential support obligation*.

5.2.6 Where a *market participant's prudential support obligation* has been reduced pursuant to section 5.8 and the relevant credit rating is revised or the relevant payment history has changed, whether under section 5.8 or otherwise, such as to result in an increase in the *market participant's prudential support obligation* then, within five *business days,* the *market participant* must provide to the *IESO* additional *prudential support* such that the total *prudential support* provided is equal to the *market participant's prudential support obligation* when calculated on the basis of the revised credit rating.

5.2.7 Where any part of the *prudential support* provided by a *market participant* otherwise ceases to be current or valid for any reason, the *market participant* must immediately so notify the *IESO* and provide to the *IESO*, within two *business days*, a replacement *prudential support* such that the total *prudential support* provided is at least equal to the *market participant's prudential support obligation.*

5.2.8 If, as a result of the *IESO* exercising its rights under a *prudential support* provided by a *market participant* in accordance with section 6.3.3.2 of Chapter 3 and Appendix 2.3**,** the remaining *prudential support* held by the *IESO* in respect of that *market participant* is less than the *market participant's prudential support obligation*, the *market participant* must, within five *business days* of receiving notice of the exercise by the *IESO* of such rights, provide the *IESO* with additional *prudential support* such that the total *prudential support* provided is equal to the *market participant's prudential support obligation*.

5.2.9 A *market participant* to which a *margin call* has been issued pursuant to section 5.4.2 shall respond to such *margin call* in accordance with section 5.6.

5.3 Calculation of Participant Trading Limit, Default Protection Amount and Maximum Net Exposure

5.3.1 The *IESO* shall determine, for each *market participant,* subject to section 5.6.5, a *maximum net exposure* as the sum of the *market participant's trading limit,* the *market participant's default protection amount* and amounts, if any, for which the *market participant* is liable under section 2.5.4 of Chapter 7.

Self Assessed Trading Limit

5.3.2 Subject to section 5.3.3, each *market participant* shall determine and submit to the *IESO*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*, the amount of its *self-assessed trading limit* at least 7 *business days* prior to the start of any *energy market billing period*, even if that *self-assessed trading limit* is zero.

5.3.2.1 [Intentionally left blank]

a. [Intentionally left blank]

b. [Intentionally left blank]

5.3.2.2 [Intentionally left blank]

a. [Intentionally left blank]
b. [Intentionally left blank]

5.3.2A [Intentionally left blank]

5.3.2A.1 [Intentionally left blank]

a. [Intentionally left blank]
b. [Intentionally left blank]

5.3.2A.2 [Intentionally left blank]

a. [Intentionally left blank]
b. [Intentionally left blank]

5.3.2A.3 [Intentionally left blank]

5.3.3 The *self-assessed trading limit* submitted by a *market participant* under section 5.3.2 shall be applicable for all future *energy market billing periods* until a revised *self-assessed trading limit* is submitted by that *market participant* to the *IESO* in accordance with the provisions of section 5.3.2. If a *market participant* submits a *self-assessed trading limit* pursuant to section 5.3.2, that *self-assessed trading limit* shall, as of the next *energy market billing period*, supersede any previous *self-assessed trading limit*, and the previous *self-assessed trading limit* shall not be applicable to any such future *energy market billing periods*.

Minimum Trading Limit

5.3.4 Subject to section 5.6.5, the *IESO* shall establish a *minimum trading limit* for each *market participant* as follows:

5.3.4.1 the *minimum trading limit* for a *metered market participant* shall be equal to the *IESO's* estimate of the *metered market participant's* net *settlement amounts*, excluding estimated *settlement amounts* associated with a *transmission right*, assuming 7 days of participation in the *real-time market* and assuming all *energy* injected or withdrawn is transacted through the *real-time market*. The *IESO* may use a greater number, up to and including 49 days, of participation in the *real-time market* for the determination of a *metered market participant's* minimum *trading limit* if that *metered market participant* was subject to more than one *margin call* per *energy market billing* *period*, provided that any such *margin call* is not the result of a price spike;

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

5.3.4.2 the *minimum trading limit* for a *market participant* that is not a *metered market participant* shall be equal to 25% of the *IESO's* estimate of the *market participant's* net *settlement amounts* for the upcoming *energy market billing period*. In estimating this net *settlement amount*, the *IESO* shall, subject to section 5.3.4.3, use an average of the actual net *settlement amounts* for the 3 most recent *energy market billing periods* in which that *market participant* has transacted in the *real-time market*. The *IESO* may use a greater percentage, up to and including 100%, of the estimated *market participant's* net *settlement amounts* for the determination of a *market participant's minimum trading limit* if that *market participant* was subject to more than one *margin call* per *energy market billing period*, provided that any such *margin call* is not caused by a price spike; and

a. [Intentionally left blank]

b. [Intentionally left blank]

5.3.4.3 the *minimum trading limit* for a *market participant* that is not a *metered market participant* who has not transacted for at least 3 months in the *real-time market*, shall be equal to 25% of the *market participant's* estimate of its net *settlement amount* for the upcoming *energy market billing period*. Such a *market participant* shall provide to the *IESO*, an estimate of its net *settlement amount* for the upcoming *energy market billing period* at least 7 *business days* prior to the start of applicable *energy market billing period*. The *IESO* may adjust the *market participant's minimum trading limit* at any time if that *market participant's* actual net *settlement amounts* for the current *billing period* are projected to differ significantly from the estimate provided.

5.3.4A [Intentionally left blank]

5.3.4A.1 [Intentionally left blank]

a. [Intentionally left blank]

b. [Intentionally left blank]

5.3.4A.2 [Intentionally left blank]

5.3.4B [Intentionally left blank]

5.3.4B.1 [Intentionally left blank]

a. [Intentionally left blank]
b. [Intentionally left blank]
c. [Intentionally left blank]
   i. [Intentionally left blank]
   ii. [Intentionally left blank]
d. [Intentionally left blank]
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Establishing Market Participant Trading Limit

5.3.5 Upon receipt of a *market participant's self-assessed trading limit* under section 5.3.2, the *IESO* shall use the greater of the following two amounts for that *market participant's trading limit* for the upcoming *energy market billing period*:

5.3.5.1 the *market participant's minimum trading limit* for that *energy market billing period* as determined pursuant to section 5.3.4; or

5.3.5.2 the *market participant's self-assessed trading limit* submitted under section 5.3.2.

5.3.6 If a *market participant* does not provide a *self-assessed trading limit* within the timelines specified in section 5.3.2, the *IESO* shall use the greater of the following two amounts for that *market participant's trading limit* for the upcoming *energy market billing period*:

5.3.6.1 the *market participant's minimum trading limit* for that *energy market billing period* as determined pursuant to section 5.3.4; or

5.3.6.2 the *market participant's trading limit* in effect for the current *energy market billing period*.

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5.3.6.4 [Intentionally left blank]

5.3.6.5 [Intentionally left blank]

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5.3.7 Once a *market participant's trading limit* has been established pursuant to section 5.3.5 or 5.3.6, that *market participant* is not permitted to change or request a change to that *trading limit* during the upcoming *energy market billing period*.

Establishing Market Participant Default Protection Amount

5.3.8 The IESO shall, for each energy market billing period, establish a default protection amount for each market participant as follows:

5.3.8.1 for a *metered market participant*, its *default protection amount* shall be equal to the *IESO's* estimate of the *metered market participant's* net *settlement amounts* for that *energy market billing period*, excluding estimated *settlement amounts* associated with a *transmission right*, assuming 21 days of participation in the *real-time market* and assuming all *energy* injected or withdrawn is transacted through the *real-time market*; and

5.3.8.2 for a *market participant* that is not a *metered market participant*, the *default protection amount* shall be equal to the *minimum trading limit* for that *market participant* for that *energy market billing period* as determined by the *IESO* pursuant to section 5.3.4.2 or section 5.3.4.3, as applicable.

Adjusting Trading Limit and Default Protection Amount for Physical Bilateral Contracts

5.3.8A A *metered market participant* with a credit rating of BBB- or higher, subject to any adjustment under section 5.8.2, may request its *minimum trading limit* and *default protection amount* be calculated removing the *energy* quantities associated with the participant's *physical bilateral contracts* registered with the *IESO* provided it submits to the *IESO* the quantity and duration of the applicable *physical bilateral contracts* and it notifies the *IESO* immediately upon a change in the quantity or duration of the *physical bilateral contracts* including the termination of any of the contracts.

5.3.8B If the conditions of 5.3.8A are met the *IESO* shall determine the *metered market participant's minimum trading limit* and *default protection amount* assuming all *energy* injected or withdrawn is transacted through *the real-time market* net of *energy* quantities associated with those *physical bilateral contracts*.

Requirement to Provide Prudential Support

5.3.9 If a market participant's maximum net exposure, as calculated by the IESO, is zero or negative, the market participant is not required to provide any form of prudential support to the IESO. If a market participant's maximum net exposure, as calculated by the IESO, is positive, the market participant must provide an amount of prudential support to the IESO equal to its prudential support obligation.

Price Bases Used for Determining Minimum Trading Limit and Default Protection Amount

5.3.10 The *IESO* shall estimate the net *settlement amounts* for a *market participant* referred to in sections 5.3.4 and 5.3.8 initially based on information provided to the *IESO* by the *market participant* in its *application for authorization to participate* and subsequently using such information as the *IESO* may reasonably require for that purpose and, in each case, on the price bases referred to in

5.3.10A, and the *IESO's estimated market prices* for all other applicable charges for the relevant *energy market billing period*.

5.3.10A When calculating the *minimum trading limit* and the *default protection amount* for *metered market participants* in sections 5.3.4, 5.3.8 and 5.3.8B respectively, the *IESO* shall establish and use as its price basis the following:

5.3.10A.1 for a *metered market participant* other than a *distributor,* the applicable Regulated Price Plan supply cost or its equivalent published by the *OEB*; or

5.3.10A.2 for a *metered market participant* that is a *distributor,* the applicable Regulated Price Conventional Meter Tier 1 price or its equivalent published by the *OEB*.

5.3.10B The *IESO* shall annually review each price basis referred to in section 5.3.10A. The *IESO* shall modify the applicable price basis if it has increased or decreased by 15% or more from the price basis used by the *IESO.*

Reviewing and Modifying Trading Limits, Default Protection Amount and Maximum Net Exposure

5.3.11 The *IESO* shall review the *minimum trading limit* where applicable, and the *trading limit*, default protection amount and *maximum net exposure* of each *market participant* as follows:

5.3.11.1 prior to the start of each *energy market billing period*;

5.3.11.2 within two *business days* after a *market participant's actual exposure* exceeds the *trading limit* for that *market participant*;

5.3.11.3 within two *business days* after it receives notice of any changes to the status of a *market participant* as compared to such status that was in effect when the *market participant's maximum net exposure* was last calculated if the *IESO* determines that the change in such status would have a material impact on the *market participant's maximum net exposure*;

5.3.11.4 when the *IESO* has adjusted a *market participant's minimum trading limit* pursuant to section 5.3.4.3; and

5.3.11.5 when the *IESO* has adjusted its price basis under section 5.3.10B.

5.3.12 The IESO may change the minimum trading limit, trading limit, default protection amount, maximum net exposure or the prudential support obligation for a market participant at any time as a result of a review conducted pursuant to section 5.3.11 and shall promptly notify the market participant of any such change. Any change to a market participant's minimum trading limit, trading limit, default protection amount, maximum net exposure or prudential support obligation shall apply with effect from such time, not being earlier than the time of notification of the changed minimum trading limit, trading limit, default protection amount, maximum net exposure or prudential support obligation to the market participant, as the IESO may specify in the notice. The market participant must supply the IESO, within five business days of the effective date of the change, any additional prudential support that may be required as a result of an increase in the market participant's prudential support obligation that results from such change.

5.4 Monitoring of Actual Exposure and Trading Limit

5.4.1 If at any time the *actual exposure* of a *market participant* is equal to or exceeds 70% and is less than 100% of the *market participant's trading limit*, the *IESO* shall inform the *market participant* of that fact unless the *market participant* has opted for the *no margin call option* pursuant to section 5.6.4. The *market participant* may, but is not required to, make a cash payment to be applied to reduce its *actual exposure* or take other action to prevent its *actual exposure* from reaching its *trading limit*. No interest shall be paid on any such payment.

5.4.1.1 [Intentionally left blank]

5.4.1.2 [Intentionally left blank]

5.4.2 If at any time the actual exposure of a market participant equals or exceeds the market participant's trading limit, the IESO shall issue to the market participant a margin call unless the market participant has opted for the no margin call option pursuant to section 5.6.4.

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5.5 Calculation of Actual Exposure

5.5.1 For the purposes of section 5.4, a *market participant's actual exposure* shall be determined by the *IESO* each *business day* and shall be a dollar amount which is equal to:

5.5.1.1 the aggregate of:

a. all amounts payable by the *market participant* in respect of *billing periods* prior to the current *billing period* which remain unpaid by the *market participant*, whether or not the payment date thereof has yet been reached; and

b. the *IESO's* reasonable estimate of the aggregate hourly and non-hourly *settlement amounts* payable by the *market participant* in respect of transactions which have already occurred in the current *billing period*;

5.5.1.2 less the aggregate of:

a. all amounts payable to the *market participant* in respect of *billing periods* prior to the current *billing period* which remain unpaid, whether or not the payment date thereof has yet been reached; and

b. the *IESO's* reasonable estimate of the aggregate hourly and non-hourly *settlement amounts* payable to the *market participant* in respect of transactions which have already occurred in the current *billing period*.

5.6 Margin Call Requirements and the No Margin Call Option

5.6.1 A *market participant* must satisfy a *margin call* within the time prescribed in section 5.6.2 by paying a portion of the amount payable or which will become payable in respect of the previous or current *energy market billing period*, in accordance with Chapter 9, in an amount sufficient to reduce the *market participant's actual exposure* to no more than the dollar equivalent of 75% of the *market participant's trading limit*. No interest shall be paid on such payments.

5.6.1.1 [Intentionally left blank]

5.6.1.2 [Intentionally left blank]

5.6.2 The time within which a *margin call* must be satisfied under section 5.6.1 shall be by 4:00 pm on the second *business day* following the date of the *margin call*.

5.6.3 For the purposes of the *market rules*, a payment made pursuant to section 5.6.1 shall be applied first to the amount outstanding with respect to the earliest *billing period* under the *market rules* and, if the amount outstanding under the *market rules* in respect of that *billing period* is less than the amount of the payment, then the excess shall be applied to the next earliest *billing period* in respect of which there is an amount outstanding under the *market rules* and so on until there is no excess.

5.6.4 A *market participant* shall not be subject to the *margin call* requirements of sections 5.6.1 and 5.6.2, subject to *IESO* approval, if it elects to use the *no margin call option* using forms and procedures as may be established by the *IESO* in the applicable *market manual*.

5.6.5 The *IESO* shall determine the *market participant's maximum net exposure* for a *market participant* that has selected the *no margin call option* based on 70 days of market activity and assuming all of the *market participant's energy* injected or withdrawn is transacted through the *real-time market.* For non-metered *market participants* the *IESO* shall determine *maximum net exposure* based on an estimate of 100% of their net *settlement amount* for the upcoming *energy market billing period*. A *market participant* that has elected the *no margin call option* shall not have a *trading limit*.

5.6.6 Other than *small distributors*, any *market participant* that elects to use the *no margin call option* shall not be eligible for reductions in its *prudential support obligations* pursuant to section 5.8.

5.7 Obligation to Provide Prudential Support

5.7.1 Each *market participant* must meet its obligation under this section 5 to provide and maintain *prudential support* by providing to the *IESO* and maintaining *prudential support*, the value of which is equal to the *market participant's prudential support obligation*.

5.7.2 A *market participant's prudential support obligation* must be met through the provision to the *IESO* and the maintenance of *prudential support* in one or more of the following forms:

5.7.2.1 a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the *IESO* and provided by:

a. a bank named in a Schedule to the *Bank Act*, S.C. 1991, c.46 with a minimum long-term credit rating of "A" from a major bond rating agency as identified in the list referred to in section 5.8.7; or

b. a credit union licensed by the Financial Services Commission of Ontario with a minimum long-term credit rating of "A" from a major bond rating agency as identified in the list referred to in section 5.8.7.

5.7.2.2 a guarantee in a form acceptable to the *IESO* provided by a person, other than an *affiliate* of the *market participant,* having a credit rating from a major bond rating agency identified on the list referred to in section 5.8.7;

5.7.2.3 marketable securities in the form of Canadian Government treasury bills. Such treasury bills shall be valued as cash at their current market value less 2 percent to take into account the potential eroding effects of interest rate increases;

5.7.2.4 subject to section 5.7.4 and 5.7.4A, a guarantee in a form acceptable to the *IESO* provided by a person that is an *affiliate* of the *market participant* and that has a credit rating from a major bond rating agency identified on the list referred to in section 5.8.7; and/or

5.7.2.5 cash deposits made with the *IESO* by or on behalf of the *market participant* provided that that *market participant* meets the following criteria:

a. the *market participant* was already meeting its *prudential support obligation* in whole or in part through a cash deposit on November 4, 2004; and

b. the *market participant's prudential support obligation* was less than or equal to $200,000 on November 4, 2004 and remains less than or equal to $200,000 thereafter.

5.7.3 For the purposes of sections 5.7.2.1 and 5.7.2.2, the *IESO* shall establish, maintain, update as required and *publish* a list of organizations eligible to provide the *prudential support* referred to in sections 5.7.2.1 and 5.7.2.2 and shall establish, for each such eligible *prudential support* provider, an aggregate limit of the *prudential support* that may be provided by that *prudential support* provider to *market participants.* If aggregate limits are reached for any of these eligible organizations, *market participants* will be required to obtain *prudential support* from other eligible organizations that are still within their respective *prudential support* limits.

5.7.3A Where a *market participant's prudential support obligation* is reduced pursuant to section 5.8.1, 5.8.1A, 5B.5.1 or 5B.5.1A, the *IESO* shall not accept a guarantee from an *affiliate* of the *market participant* pursuant to section 5.7.2.4, unless the *market participant* provides a letter from the applicable major bond rating agency identified in the list referred to in section 5.8.7, stating that the two ratings are not directly linked and are stand alone ratings in relation to each other.

5.7.3B The *IESO* shall not accept a guarantee from an *affiliate* of the *market participant* pursuant to section 5.7.2.4 if the *affiliate* is also a *market participant* and has obtained a reduction of its own *prudential support obligation* pursuant to section 5.8.1, 5.8.1A, 5B.5.1 or 5B.5.1A.

5.7.4 For *market participants*, other than a *distributor*, subject to sections 5.7.3A and 5.7.3B the *IESO* shall not accept a guarantee from a rated *affiliate* of the *market participant* pursuant to section 5.7.2.4 where the value of the guarantee exceeds the following;

Credit Rating Category of Affiliate using Standard and Poor's Rating Terminology	Maximum Amount which May be Guaranteed by Affiliate
AA- and above or equivalent	100% of *maximum net exposure* of all *market participants* guaranteed by *affiliate*
A-, A, A+ or equivalent	Greater of 90% of *maximum net exposure* or $37,500,000 of all *market participants* guaranteed by *affiliate*
BBB-, BBB, BBB+ or equivalent	Greater of 65% of *maximum net exposure* or $15,000,000 of all *market participants* guaranteed by *affiliate*
BB-, BB, BB+ or equivalent	Greater of 30% of *maximum net exposure* or $4,500,000 of all *market participants* guaranteed by *affiliate*
Below BB- or equivalent	0

5.7.4.A For *distributors*, subject to sections 5.7.3A and 5.7.3B the *IESO* shall not accept a guarantee from a rated *affiliate* of the *market participant* pursuant to section 5.7.2.4 where the value of the guarantee exceeds the following:

Credit Rating Category of Affiliate using Standard and Poor's Rating Terminology	Maximum Amount which May be Guaranteed by Affiliate
AA- and above or equivalent	100% of *maximum net exposure* of all *market participants* guaranteed by *affiliate*
A-, A, A+ or equivalent	Greater of 95% of *maximum net exposure* or $45,000,000 of all *market participants* guaranteed by *affiliate*
BBB-, BBB, BBB+ or equivalent	Greater of 80% of *maximum net exposure* or $22,500,000 of all *market participants* guaranteed by *affiliate*
BB-, BB, BB+ or equivalent	Greater of 55% of *maximum net exposure* or $7,500,000 of all *market participants* guaranteed by *affiliate*
Below BB- or equivalent	0

5.7.5 The minimum terms and conditions that shall be included in the *prudential support* shall be as follows:

5.7.5.1 *prudential support* provided in accordance with sections 5.7.2.1, 5.7.2.2 and 5.7.2.4 shall be obligations in writing;

5.7.5.2 *prudential support* provided in accordance with sections 5.7.2.3 and 5.7.2.5 shall be obligations reflected in a written instrument in a form acceptable to the *IESO*;

5.7.5.3 *prudential support* provided in accordance with sections 5.7.2.1, 5.7.2.3 and 5.7.2.5 shall constitute valid and binding unsubordinated obligations to pay to the *IESO* amounts in accordance with its terms which relate to the obligations of the relevant *market participant* under the *market rules*; and

5.7.5.4 *prudential support* provided in accordance with sections 5.7.2.1 to 5.7.2.5 shall permit drawings or claims by the *IESO* on demand to a stated certain amount.

5.8 Reductions in Prudential Support Obligations

5.8.1 Subject to section 5.8.2, the *prudential support obligation* of a rated *market participant,* other than a *distributor,* may be reduced relative to the *market participant's maximum net exposure* by an amount equal to the monetary value prescribed, by the table below, to a credit rating from a major bond rating agency identified in the list referred to in section 5.8.7 issued and in effect in respect of the *market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of *maximum net exposure*
A-, A, A+ or equivalent	Greater of 90% of *maximum net exposure* or $37,500,000
BBB-, BBB, BBB+ or equivalent	Greater of 65% of *maximum net exposure* or $15,000,000
BB-, BB, BB+ or equivalent	Greater of 30% of *maximum net exposure* or $4,500,000
Below BB- or equivalent	0

5.8.1A Subject to section 5.8.2, the *prudential support obligation* of a rated *distributor* may be reduced relative to the *market participant's maximum net exposure* by an amount equal to the monetary value prescribed, by the table below, to a credit rating from a major bond rating agency identified in the list referred to in section 5.8.7 issued and in effect in respect of the *market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of *maximum net exposure*
A-, A, A+ or equivalent	Greater of 95% of *maximum net exposure* or $45,000,000
BBB-, BBB, BBB+ or equivalent	Greater of 80% of *maximum net exposure* or $22,500,000

BB-, BB, BB+ or equivalent	Greater of 55% of *maximum net exposure* or $7,500,000
Below BB- or equivalent	0

5.8.2 Any recommendation to move a *market participant* to "credit watch negative" by any of the major bond rating agencies identified in the list referred to in section 5.8.7 shall be deemed to automatically result in a one-notch reduction in terms of the credit rating (for example, from BBB+ to BBB) of that *market participant* for the purpose of determining the *market participant's prudential support obligation*.

5.8.2A The operation of section 5.8.2 shall be suspended for *distributors* as of November 19, 2002, until February 14, 2003 or until such other date as may be determined by a resolution of the *IESO Board*. The management of the *IESO* shall monitor and report to the *IESO Board* on the credit situation of *distributors* and other *market participants* and the *IESO Board* shall modify the suspension of section 5.8.2 (or, if appropriate, shall expand the scope of the suspension) if the credit situation changes in a way that makes such modification desirable.

5.8.3 Subject to section 5.8.6, the *prudential support obligation* of a *market participant* may be reduced relative to the *market participant's maximum net exposure* or, where applicable, relative to the otherwise applicable *prudential support obligation* calculated in accordance with section 5.3.4B, by an amount equal to the monetary value ascribed, in accordance with section 5.8.4 or 5.8.5, to the *market participant's* historical good payment history in Ontario, which shall be assessed by the *IESO* on the basis of:

5.8.3.1 evidence provided by the *market participant* as to the continuous purchase of electricity by the *market participant* prior to the effective date of the *IESO-administered markets* during which time no call for collateral was issued to that *market participant* to protect the supplier from the risk of a payment default by that *market participant;*

5.8.3.2 verification of the evidence referred to in section 5.8.3.1 by the *IESO*; and

5.8.3.3 the *market participant's* payment history in the *IESO-administered markets* provided that the *market participant's* payment history includes no *event of default*.

5.8.4 The *IESO* shall determine the dollar amount of any allowable reduction in the *prudential support obligation* of an unrated *market participant*, other than a *distributor,* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Non-Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 50% of *maximum net exposure* or $12,000,000
≥5 years, <6 years	Lesser of 30% of *maximum net exposure* or $7,500,000
≥4, <5 years	Lesser of 25% of *maximum net exposure* or $6,000,000
≥3, <4 years	Lesser of 20% of *maximum net exposure* or $4,500,000
≥2, <3 years	Lesser of 15% of *maximum net exposure* or $3,000,000
<2 years	0

5.8.5 If the *market participant* is an unrated *distributor*, the *IESO* shall determine the dollar amount of any allowable reduction in the *market participant's prudential support obligation* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 80% of *maximum net exposure* or $14,000,000
≥5 years, <6 years	Lesser of 65% of *maximum net exposure* or $9,000,000
≥4, <5 years	Lesser of 45% of *maximum net exposure* or $7,500,000
≥3, <4 years	Lesser of 35% of *maximum net exposure* or $6,000,000
≥2, <3 years	Lesser of 25% of *maximum net exposure* or $4,500,000
<2 years	0

For purposes of this section 5.8.5, the historical payment history of a *distributor* that is the transferee under a transfer by-law made pursuant to subsection 145(1) of the Electricity Act, 1998 shall be deemed to include the historical payment history of the *distributor* whose licence has been transferred to the transferee under such by-law. For purposes of this section 5.8.5, the historical payment history of a *distributor* that is the successor at law to two or more *distributors*, shall be deemed to include the historical payment history of the predecessor *distributors*.

5.8.6 The following restrictions shall apply to the provision of reductions in a *market participant's prudential support obligation* as provided for under sections 5.8.1, 5.8.1A, and 5.8.3:

5.8.6.1 subject to the last paragraph of section 5.8.5, a *market participant* shall not be entitled to a reduction in its *prudential support obligation* pursuant to section 5.8.3 using the payment history of an *affiliate*; and

5.8.6.2 a *market participant* that has a credit rating from a major bond rating agency identified in the list referred to in section 5.8.7 shall not be entitled to a reduction in its *prudential support obligation* under section 5.8.3.

5.8.7 For the purposes of this chapter, the *IESO* shall establish, maintain, update as required and *publish* a list of major bond rating agencies eligible to provide the credit ratings mentioned throughout.

5.8.8 The *IESO* shall reduce the *prudential support obligation* of a *distributor* by an amount equal to 60% of the *distributor's* collection of *prudential support,* in the forms specified in section 5.7.2.1, 5.7.2.2, 5.7.2.3, or 5.7.2.4, from the *distributor's* customers. In order to qualify for this reduction in *prudential support obligation* the *distributor* shall provide the *IESO* with an affidavit attesting to the amount of *prudential support* of the types specified in this section which the *distributor* has collected from its customers attached to which by way of exhibits shall be copies of bank statements showing any cash deposits and any applicable letters of credit, guarantees, or Government of Canada T-bills held as *prudential support*. The *IESO* shall first deduct the *distributor's* collection of *prudential support* from the *distributor's* customers before applying any other *prudential support obligation* deductions.

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5B. Capacity Prudential Requirements

5B.1 Purpose

5B.1.1 This section 5B sets forth the nature and amount of *capacity prudential support* that must be provided by *market participants* that are either *capacity auction participants* or *capacity market participants* as a condition of delivering on a *capacity obligation,* and the manner in which such *market participants* must provide and maintain *capacity prudential support* on an on-going basis, in order to protect the *IESO* and *market participants* from payment defaults.

5B.1.2 The *IESO* shall review the *capacity prudential support* requirements set out in this chapter at least once every three years, as part of the review of the *prudential support* requirements pursuant to section 5.1.2.

5B.2 Market Participant Obligations

5B.2.1 Each *market participant* shall initially and continually satisfy the obligations set forth in this section 5B.2 with regard to the provision of *capacity prudential support* as a condition of delivering on a *capacity obligation*.

5B.2.2 No *market participant* that is required to provide *capacity prudential support* shall participate in the *real-time markets* or cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* unless that *market participant* satisfies the requirements of this section 5B.2.

5B.2.3 Each *market participant* shall provide to the *IESO*, on an ongoing basis, such information as the *IESO* may reasonably require for the purpose of determining that *market participant's capacity prudential support obligation*.

5B.2.4 If *capacity prudential support* previously provided to the *IESO* by a *market participant* is due to expire or terminate, and upon expiry or termination of the existing *capacity prudential support*, the total *capacity prudential support* held by the *IESO* in respect of that *market participant* will be less than the *market participant's capacity prudential support obligation*, then at least ten *business days* prior to the time at which the existing security is due to expire or terminate, the *market participant* must provide to the *IESO* replacement *capacity prudential support* which will become effective no later than the expiry or termination of the existing collateral, such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation*.

5B.2.5 Where a *market participant's capacity prudential support obligation* has been reduced pursuant to section 5B.5 and the relevant credit rating is revised or the relevant payment history has changed, such as to result in an increase in the *market participant's capacity prudential support obligation,* then within five *business days,* the *market participant* must provide to the *IESO* additional *capacity prudential support* such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation* when calculated on the basis of the revised credit rating or payment history.

5B.2.6 Where any part of the *capacity prudential support* provided by a *market participant* otherwise ceases to be current or valid for any reason, the *market participant* must immediately so notify the *IESO* and provide to the *IESO*, within two *business days*, replacement *capacity prudential support* such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation.*

5B.2.7 If the *IESO* draws upon part or all of a *market participant's capacity prudential support* in accordance with section 6.3.3.2 of Chapter 3 and the remaining *capacity prudential support* held by the *IESO* in respect of that *market participant* is less than the *market participant's capacity prudential support obligation*, the *market participant* must, within five *business days* of receiving notice from the *IESO*, provide the *IESO* with additional *capacity prudential support* such that the total *capacity prudential support* provided is at least equal to the *market participant's capacity prudential support obligation*.

5B.3 Calculation of Capacity Prudential Support Obligations

5B.3.1 The *IESO* shall determine, in accordance with the applicable *market manual*, for each *market participant*, a *capacity prudential support obligation* for each *obligation period*, based on a percentage of the highest monthly availability payment, less any allowable reductions pursuant to section 5B.5.

5B.3.2 The IESO shall review the capacity prudential support obligation of each market participant as follows:

5B.3.2.1 prior to the start of each *obligation period*;

5B.3.2.2 within two *business days* after it receives notice of any changes to the status of a *market participant* as compared to such status that was in effect when the *market participant's capacity prudential support* was last calculated; or

5B.3.2.3 as a result of either a change in or loss of a *market participant's* credit rating or good payment history reduction calculated in accordance with section 5B.5.

5B.3.3 The *IESO* may change the *capacity prudential support obligation* for a *market participant* at any time as a result of a review conducted pursuant to section 5B.3.2, and shall promptly notify the *market participant* of any such change. Any change to a *market participant's capacity prudential support obligation* shall apply with effect from such time, not being earlier than the time of notification of the change to the *market participant*, as the *IESO* may specify in the notice. The *market participant* must supply the *IESO*, within five *business days* of the effective date of the change, any additional *capacity prudential support* that may be required as a result of an increase in the *market participant's capacity prudential support obligation* that results from such change.

5B.4 Obligation to Provide Capacity Prudential Support

5B.4.1 Each *market participant* must provide to the *IESO* and maintain *capacity prudential support*, the value of which is at least equal to the *market participant's capacity prudential support obligation*. The aggregate value of the *capacity prudential support* shall be equal to the value of the undrawn or unclaimed amounts of *capacity prudential support* provided by the *market participant.*

5B.4.2 A *market participant's capacity prudential support obligation* must be met through the provision to the *IESO* and the maintenance of *capacity prudential support* in the following form:

5B.4.2.1 a guarantee or irrevocable commercial letter of credit, which in both cases must be in a form acceptable to the *IESO* and provided by:

a. a bank named in a Schedule to the Bank Act, S.C. 1991, c.46 with a minimum long-term credit rating of "A" from an *IESO* acceptable major bond rating agency as identified in the list referred to in section 5B.5.7; or

b. a credit union licensed by the Financial Services Commission of Ontario with a minimum long-term credit rating of "A" from an *IESO* acceptable major bond rating agency as identified in the list referred to in section 5B.5.7.

5B.4.3 The following provisions shall apply to a guarantee or irrevocable letter of credit provided in section 5B.4.2.1:

5B.4.3.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 2007 Revision, ICC Publication No. 600 or The International Standby Practices 1998;

5B.4.3.2 the *IESO* shall be named as beneficiary in each letter of credit, each letter of credit shall be irrevocable, partial draws on any letter of credit shall not be prohibited and the letter of credit or the aggregate amount of all letters of credit shall be in the face amount of at least the amount specified by the *IESO*;

5B.4.3.3 the only conditions on the ability of the *IESO* to draw on the letter of credit shall be the occurrence of an *event of default* by or in respect of the *market participant* and a certificate of an officer of the *IESO* that the *IESO* is entitled to draw on the letter of credit, in accordance with the provisions of the *market rules* in the amount specified in the certificate as at the date of delivery of the certificate;

5B.4.3.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. In either case it is the responsibility of the *market participant* to maintain the requisite amount of *capacity prudential support*. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *market participant* shall arrange for and deliver alternative *capacity prudential support* within the time frame mandated by the *market rules* so as to enable the *market participant* to be in compliance with the *market rules*; and

5B.4.3.5 by including a letter of credit as part of its *capacity prudential support*, the *market participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *market participant*.

5B.4.4 For the purpose of section 5B.4.2.1, the *IESO* shall establish, maintain, and publish a list of organizations eligible to provide the *capacity prudential support* referred to in section 5B.4.2.1 and shall establish for each such eligible *capacity prudential support* provider, an aggregate limit of the *capacity prudential support* that may be provided by that *capacity prudential support* provider to *market participants*. If aggregate limits are reached for any of these eligible organizations, *market participants* will be required to obtain *capacity prudential support* from other eligible organizations that are still within their respective *capacity prudential support* limits.

5B.4.5 In the event that the *capacity prudential support* provided by a *market participant* is a greater amount than required by the *market rules*, the *IESO* shall, upon written request by the *market participant*, return to the *market participant* an amount equal to the difference between the value of *capacity prudential support* held by the *IESO* and the *capacity prudential support obligation* of the *market participant* at that time. The *IESO* shall return such amount within five *business days* of the receipt of the request for the return of the amount from the *market participant*. In all circumstances, the *IESO* shall return *capacity prudential support* only after all payments and charges for the final month of a *commitment period* have been settled.

5B.4.6 The minimum terms and conditions that shall be included in the *capacity prudential support* in accordance with section 5B.4.2.1 shall be as follows:

5B.4.6.1 *capacity prudential support* shall be obligations in writing;

5B.4.6.2 *capacity prudential support* shall constitute valid and binding unsubordinated obligations to pay to the *IESO* amounts in accordance with its terms which relate to the obligations of the relevant *market participant* under the *market rules*; and

5B.4.6.3 *capacity prudential support* shall permit drawings or claims by the *IESO* on demand to a stated certain amount, including partial drawings or claims.

5B.4.7 Upon the occurrence of an *event of default*, the *IESO* shall be entitled to exercise its rights and remedies as set out in the *market rules,* or provided for at law or in equity. Without limiting the generality of the foregoing, such rights and remedies shall, in respect of the *capacity prudential support* provided by the *market participant*, include setting-off and applying any and all *capacity prudential support* held against the indebtedness, obligations and liabilities of the *market participant* to the *IESO* in respect of the participation by the *market participant* in the *real-time markets,* including the costs, charges, expenses and fees described in section 5B.4.9.

5B.4.8 Each of the remedies available to the *IESO* under the *market rules* or at law or in equity is intended to be a separate remedy and in no way is a limitation on or substitution for any one or more of the other remedies otherwise available to the *IESO*. The rights and remedies expressly specified in the *market rules* or at law or in equity are cumulative and not exclusive. The *IESO* may in its sole discretion exercise any and all rights, powers, remedies and recourses available under the *market rules* or under any document comprising the *capacity prudential support* provided by the *market participant* or any other remedy available to the *IESO* howsoever arising, and whether at law or in equity, and such rights, powers and remedies and recourses may be exercised concurrently or individually without the necessity of any election.

5B.4.9 The *market participant* agrees to pay to the *IESO* forthwith on demand all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, legal fees on a solicitor and client basis) of or incurred by or on behalf of the *IESO* in the realization, recovery or enforcement of the *capacity prudential support* provided by the *market participant* and enforcement of the rights and remedies of the *IESO* under the *market rules* or at law or in equity in respect of the participation by the *market participant* in the *real-time markets.*

5B.5 Reductions in Capacity Prudential Support Obligations

5B.5.1 Subject to section 5B.5.2, the *IESO* may reduce the *capacity prudential support obligation* of a rated *market participant*, other than a *distributor*, by an amount equal to the monetary value prescribed by the table below, resulting from a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 issued and in effect in respect of the *capacity market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of the *capacity prudential support obligation* before allowable reductions
A-, A, A+ or equivalent	Greater of 90% of the *capacity prudential support obligation* before allowable reductions or $37,500,000
BBB-, BBB, BBB+ or equivalent	Greater of 65% of the *capacity prudential support obligation* before allowable reductions or $15,000,000
BB-, BB, BB+ or equivalent	Greater of 30% of the *capacity prudential support obligation* before allowable reductions or $4,500,000
Below BB- or equivalent	0

5B.5.1A Subject to section 5B.5.2, the *IESO* may reduce the *capacity prudential support obligation* of a rated *distributor* by an amount equal to the monetary value prescribed by the table below, resulting from a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 issued and in effect in respect of the *capacity market participant*.

Credit Rating Category using Standard and Poor's Rating Terminology	Allowable Reduction in Prudential Support
AA- and above or equivalent	100% of the *capacity prudential support obligation* before allowable reductions
A-, A, A+ or equivalent	Greater of 95% of the *capacity prudential support obligation* before allowable reductions or $45,000,000
BBB-, BBB, BBB+ or equivalent	Greater of 80% of the *capacity prudential support obligation* before allowable reductions or $22,500,000
BB-, BB, BB+ or equivalent	Greater of 55% of the *capacity prudential support obligation* before allowable reductions or $7,500,000
Below BB- or equivalent	0

5B.5.2 Any recommendation to move a *market participant* to "credit watch negative" by any of the major bond rating agencies identified in the list referred to in section 5B.5.7, shall be deemed to automatically result in a one-notch reduction in terms of the credit rating (for example, from BBB+ to BBB) of that *market participant* for the purpose of determining the *market participant's capacity prudential support obligation*.

5B.5.3 Where a *market participant's capacity prudential support obligation* reflects a reduction by reason of the *market participant's* credit rating from a major bond agency identified in the list referred to in section 5B.5.7, the *market participant* shall advise the *IESO* in writing immediately upon the *market participant* becoming aware of either a change in or loss of the then current credit rating or the decision of the bond rating agency to place the *market participant* on "credit watch status" or equivalent.

5B.5.4 Subject to section 5B.5.6, the *IESO* may reduce the *market participant's capacity prudential support obligation* in accordance with sections 5B.5.5 or 5B.5.5A based on the *market participant's* historical good payment history in the *IESO-administered markets*, provided that the *market participant's* payment history includes no *event of default*.

5B.5.5 The *IESO* shall determine the dollar amount of any allowable reduction in the *capacity prudential support obligation* of an unrated *market participant*, other than a *distributor*, by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Non-Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 50% of the *capacity prudential support obligation* before allowable reductions or $12,000,000
≥5 years, <6 years	Lesser of 30% of the *capacity prudential support obligation* before allowable reductions or $7,500,000
≥4, <5 years	Lesser of 25% of the *capacity prudential support obligation* before allowable reductions or $6,000,000
≥3, <4 years	Lesser of 20% of the *capacity prudential support obligation* before allowable reductions or $4,500,000
≥2, <3 years	Lesser of 15% of the *capacity prudential support obligation* before allowable reductions or $3,000,000
<2 years	0

5B.5.5A The *IESO* shall determine the dollar amount of any allowable reduction in the *capacity prudential support obligation* of an unrated *distributor* by an amount equal to the monetary value prescribed, by the table below:

Good Payment History Categories for Distributors	Allowable Reduction in Prudential Support
≥6 years	Lesser of 80% of the *capacity prudential support obligation* before allowable reductions or $14,000,000
≥5 years, <6 years	Lesser of 65% of the *capacity prudential support obligation* before allowable reductions or $9,000,000
≥4, <5 years	Lesser of 45% of the *capacity prudential support obligation* before allowable reductions or $7,500,000

≥3, <4 years	Lesser of 35% of the *capacity prudential support obligation* before allowable reductions or $6,000,000
≥2, <3 years	Lesser of 25% of the *capacity prudential support obligation* before allowable reductions or $4,500,000
<2 years	0

5B.5.6 The following restrictions shall apply to the provision of reductions in a *market participant's capacity prudential support obligation* as provided for under sections 5B.5.1, 5B.5.1A, and 5B.5.4:

5B.5.6.1 a *market participant* shall not be entitled to a reduction in its *capacity prudential support obligation* pursuant to section 5B.5.4 using the payment history of an *affiliate*;

5B.5.6.2 a *market participant* that has a credit rating from a major bond rating agency identified in the list referred to in section 5B.5.7 shall not be entitled to a reduction in its *capacity prudential support obligation* under section 5B.5.4; and

5B.5.6.3 a *market participant's* reduction for either a credit rating or good payment history reduction shall be reduced by the amount of any reductions already granted to the *market participant* under section 5.8.

5B.5.7 For the purposes of this chapter, the *IESO* shall establish, maintain, and *publish* a list of major bond rating agencies eligible to provide the credit ratings mentioned in this section 5B.

6. Technical Requirements

6.1 Technical Requirements

6.1.1 Each *market participant, embedded generator, embedded electricity storage participant* and *embedded load consumer* shall, in addition to ensuring that its *facilities* and equipment meet all other applicable technical requirements set forth in these *market rules* ensure that its *facilities*:

6.1.1.1 meet the applicable technical requirements of Appendix 2.2; and

6.1.1.2 are capable of meeting the performance standards referred to in section 7.3.1.4, 7.3A.1.4, 7.4.1.2, 7.5.1.2 or 7.6.1.2, as the case may be, of Chapter 4.

6.2 Certification, Testing and Inspection for Authorization

6.2.1 Each person referred to in section 6.1.1 that applies for authorization as a *market participant* shall, as a condition of obtaining authorization as a *market participant* pursuant to section 3 or 4.1.1, certify to the *IESO* that its *participant workstation* complies with all applicable technical requirements set forth in Appendix 2.2.

6.2.2 Each person referred to in section 6.1.1 that applies for authorization as a *market participant* shall, as a condition of obtaining authorization as a *market participant* pursuant to section 3 or 4.1.1, successfully complete such testing and permit such inspection as the *IESO* may require for the purposes of testing or inspecting whether the person's *participant workstation* meets all applicable technical requirements set forth in Appendix 2.2.

6.3 Certification, Testing and Inspection for Registration of Facilities

6.3.1 Each *market participant* shall, as a condition of obtaining the registration of its *facility* or *boundary entity* as a *registered facility* pursuant to section 2.2 of Chapter 7 or as a condition of obtaining approval to the aggregation of *facilities*:

6.3.1.1 provide the certifications referred to in sections 2.2.3.3 and 2.2.3.4 or in sections 2.3.2.4 and 2.3.2.5 of Chapter 7, as the case may be; and

6.3.1.2 successfully complete the testing and permit the inspection referred to in section 2.2.3.5 or 2.3.2.6 of Chapter 7, as the case may be.

7. Payment Default Procedure

7.1.1 The *events of default* relating to payment and either *prudential support*, *capacity prudential support*, as well as the rights and obligations of the *IESO* and *market participants* upon the occurrence of such *event of default*, are specified in section 6.3 of Chapter 3.

8. Default Levy

8.1 Power to Impose Default Levy

8.1.1 The *IESO* shall be entitled to recover, by means of the imposition of a *default levy* on *non-defaulting market participants,* in accordance with this section 8, the aggregate of any amounts owing to the *IESO* under the *market rules* which have not been paid in full by the *defaulting market participant* and the costs and expenses reasonably incurred by the *IESO* in investigating the default in payment, in realizing on any applicable *prudential support* and in implementing the *default levy*.

8.1.2 The imposition of a *default levy* pursuant to this section 8 shall in no way waive, excuse or relieve a *defaulting market participant* of its obligations under the *market rules* and shall be without prejudice to:

8.1.2.1 such rights or remedies which the *IESO* may otherwise have to recover all amounts owing by the *defaulting market participant*; and

8.1.2.2 the right of the *IESO* to take such other action, including but not limited to the issuance of a *suspension order,* as may be provided for in these *market rules* in respect of the *defaulting market participant's* default in payment.

8.1.3 Where a *defaulting market participant* has defaulted in payment in respect of more than one *IESO-administered market,* the *IESO* shall impose separate *default levies* in respect of each such *IESO-administered market* in accordance with this section 8.

8.1.4 The provisions of this section 8 apply only to a default in payment by a *defaulting market participant* in the *real-time market.* Default in payment by a *defaulting market participant* in the *TR market* shall be addressed in accordance with the provisions of section 4 of Chapter 8.

8.2 Notice of First Default Levy

8.2.1 Where a *market participant* has failed to either remit or cause to be remitted to the *IESO settlement clearing account* the full amount due by that *market participant* by the close of banking business (of the bank at which the *IESO settlement clearing account* is held) on a *market participant payment date*:

8.2.1.1 [Intentionally left blank]

8.2.1.2 [Intentionally left blank]

8.2.1.3 the *IESO* may take such steps as may be permitted by section 6.14 of Chapter 9.

8.2.2 Where the IESO has issued a suspension order or termination order to a defaulting market participant, the IESO may:

8.2.2.1 issue a first *notice of default levy* in accordance with section 8.2.3; and

8.2.2.2 take such steps, if it has not already done so, as may be required to realize, in accordance with section 3 of Appendix 2.3, any *prudential support* held in respect of the *defaulting market participant* the right to realization of which is triggered by the default in payment at issue.

8.2.3 A first *notice of default levy* shall be issued to each *non-defaulting market participant* that participated in the *real-time market* to which the default in payment by the *defaulting market participant* relates during the *billing period* to which such default relates and shall identify:

8.2.3.1 the name of the *defaulting market participant*;

8.2.3.2 the *IESO-administered market* and the *billing period* in respect of which the default in payment by the *defaulting market participant* has occurred;

8.2.3.3 the *defaulting market participant's default amount,* calculated in accordance with section 8.3.1;

8.2.3.4 the amount of the first *default levy* calculated in accordance with section 8.3.2;

8.2.3.5 the value of all *prudential support* held in respect of the *defaulting market participant* the right to realization of which is triggered by the default in payment at issue;

8.2.3.6 the estimated amount of any second *default levy* that may have to be imposed pursuant to section 8.4 in the event of the inability by the *IESO* to realize all of the *prudential support* referred to in section 8.2.3.5 prior to the time noted in section 8.4.1;

8.2.3.7 the *non-defaulting market participant's* share of the first *default levy*, calculated in accordance with section 8.6.1; and

8.2.3.8 the *non-defaulting market participant's* share of the estimated amount of any second *default levy* referred to in section 8.2.3.6.

8.2.4 The first *notice of default levy* shall be issued at least ten days prior to the date on which the *invoice* imposing the first *default levy* on *non-defaulting market participants* is issued by the *IESO* in accordance with section 8.6.2.

8.3 Calculation of Default Amount and First Default Levy

8.3.1 For the purposes of section 8.2.3.3, the *market participant's default amount* shall be the aggregate of:

8.3.1.1 the net *invoice* amount payable by the *defaulting market participant* for the *billing period* in respect of which payment has not been received within the time specified in section 8.2.2, exclusive of any amounts payable on account of financial penalties or damages; and

8.3.1.2 any *default interest* payable in respect of the amount referred to in section 8.3.1.1 that has accrued since the *market participant payment date* referred to in section 8.2.1 in accordance with section 6.14.3 of Chapter 9.

8.3.2 For the purposes of section 8.2.3.4, the amount of the first *default levy* shall be:

8.3.2.1 the aggregate of:

a. the *defaulting market participant's default amount*, calculated in accordance with section 8.3.1; and

b. any costs and expenses reasonably incurred to the date of issuance of the first *notice of default levy* by the *IESO* in investigating the default in payment to which the *default levy* relates, in realizing on any applicable *prudential support* held in respect of the *defaulting market participant* and in implementing the *default levy*;

8.3.2.2 less the aggregate unclaimed or undrawn dollar amount of all *prudential support* held in respect of the *defaulting market participant* the right to realization of which is triggered by the default in payment at issue.

8.3.3 The first *default levy* shall be apportioned amongst and *invoiced* to *non-defaulting market participants* in accordance with sections 8.6.1 and 8.6.2.

8.4 Notice of Second Default Levy

8.4.1 Unless the amount of the first *default levy* is equal to the *defaulting market participant's default amount* the *IESO* shall, on the seventh *business day* following the issuance of *invoices* imposing the first *default levy,* issue a second *notice of default levy* in accordance with section 8.4.2.

8.4.2 The second *notice of default levy* shall be issued to each *non-defaulting market participant* on whom a first *default levy* has been imposed and shall identify:

8.4.2.1 the name of the *defaulting market participant*;

8.4.2.2 the *IESO-administered market* and the *billing period* in respect of which the default in payment by the *defaulting market participant* has occurred;

8.4.2.3 the *defaulting market participant's* residual *default amount,* calculated in accordance with section 8.5.1;

8.4.2.4 the amount of the first *default levy*;

8.4.2.5 the amount of any *prudential support* held in respect of the *defaulting market participant* that has been realized;

8.4.2.6 the amount of any *prudential support* held in respect of the *defaulting market participant* the right to realization of which is triggered by the default in payment at issue and that remains to be realized;

8.4.2.7 the amount of the second *default levy*, calculated in accordance with section 8.5.2; and

8.4.2.8 the *non-defaulting market participant's* share of the second *default levy*, calculated in accordance with section 8.6.1.

8.4.3 The second *notice of default levy* shall be issued at least ten days prior to the date on which the *invoice* imposing the second *default levy* on *non-defaulting market participants* is issued by the *IESO* in accordance with section 8.6.2.

8.5 Calculation of Residual Default Amount and Second Default Levy

8.5.1 For the purposes of section 8.4.2.3, the *defaulting market participant's* residual *default amount* shall be:

8.5.1.1 the aggregate of:

a. the net *invoice* amount payable by the *defaulting market participant* for the *billing period* in respect of which payment has not been received as of the date of issuance of the second *notice of default levy,* exclusive of any amounts payable on account of financial penalties or damages; and

b. any *default interest* payable in respect of the amount referred to in section 8.5.1.1(a) that has accrued since the date of issuance of the first *notice of default levy* in accordance with section 6.14.3 of Chapter 9;

8.5.1.2 less the aggregate of:

a. the amount of the first *default levy*; and

b. any amount that has been recovered by the *IESO* since the date of issuance of the first *notice of default levy* under any *prudential support* held in respect of the *defaulting market participant.*

8.5.2 For the purposes of section 8.4.2.7, the amount of the second *default levy* shall be the aggregate of:

8.5.2.1 the *defaulting market participant's* residual *default amount*, calculated in accordance with section 8.5.1; and

8.5.2.2 any costs and expenses reasonably incurred by the *IESO* in investigating the default in payment to which the *default levy* relates, in realizing any applicable *prudential support* and in implementing the *default levy* since the date on which the first *default levy* was calculated.

8.5.3 The second *default levy* shall be apportioned and *invoiced* to *non-defaulting market participants* in accordance with sections 8.6.1 and 8.6.2.

8.6 Apportionment and Invoicing of Default Levy

8.6.1 For the purposes of sections 8.2.3.7 and 8.4.2.8, the amount of a *default levy* shall be apportioned amongst all *non-defaulting market participants* to whom a *notice of default levy* has been issued in accordance with sections 8.2.3 or 8.4.2 by allocating to each *non-defaulting market participant* a share of the *default levy* calculated as follows:

8.6.1.1 in the case of a *default levy* imposed in respect of a default in the *real-time market*, the share allocated to each *non-defaulting market participant* shall be determined on the basis of the following formula:

[*default amount* x (absolute value of the *non-defaulting market participant's* net *invoice* amount, exclusive of any amounts payable on account of financial penalties or damages, in the *real-time market* for the *real-time market billing period* to which the default in payment by the *defaulting market participant* relates)]	divided by	net transaction dollar amount

Where the *net transaction dollar amount* is:

∑ the absolute value, in dollars, of each *market participant's* net *invoice* amount, for the *real-time market billing period* to which the default in payment by the *defaulting market participant* relates	Minus	the absolute value, in dollars, of the *defaulting market participant's* net *invoice* amount for such *real-time market billing period*;

or

8.6.1.2 [Intentionally left blank – section deleted]

8.6.2 Subject to section 8.6.3, a *non-defaulting market participant's* share of a *default levy* shall be included in or with the first *invoice* scheduled to be issued to the *non-defaulting market participant* pursuant to Chapter 9 following the expiry of the time noted in section 8.2.4 or 8.4.3, as the case may be, in respect of each *IESO-administered market* to which the *default levy* relates.

8.6.3 Where, for any reason, no *invoice* is scheduled to be issued to a *non-defaulting market participant* to whom a second *notice of default levy* has been issued under section 8.4.2, the *IESO* shall issue an *invoice* to that *non-defaulting market participant* comprising the amount of that *non-defaulting market participant's* share of the second *default levy.* Any such *non-defaulting market participant* shall pay to the *IESO* the *invoice* amount on the second *business day* following receipt of the *invoice*.

8.7 Allocation of Default Levy

8.7.1 The *IESO* shall allocate amounts received from *non-defaulting market participants* in respect of a *default levy*:

8.7.1.1 first, to repay any short-term funds borrowed by the *IESO* pursuant to section 6.14.4 of Chapter 9 on account of the *defaulting market participant's* default in payment; and

8.7.1.2 [Intentionally left blank]

8.7.1.3 second, to the payment of amounts owed by the *defaulting market participant* to the *IESO* on account of the *IESO administration charge.*

8.7.2 Amounts received from *non-defaulting market participants* in respect of a *default levy* to cover the reasonable costs and expenses referred to in sections 8.3.2.1 and 8.5.2.2 shall be used to offset the *IESO administration charge.*

8.8 Other Recovery of Default Amounts

8.8.1 Notwithstanding the imposition of a *default levy*, the *IESO* shall take all reasonable steps to recover from the *defaulting market participant*, including by means of the realization of any *prudential support* held in respect of a *defaulting market participant* that has not been realized as at the date of calculation of a second *default levy*, all amounts owing to the *IESO* under the *market rules*. The *IESO* may, but shall not be obliged to, follow the dispute resolution process set forth in section 2 of Chapter 3 for the purpose of obtaining such recovery.

8.8.2 Subject to section 8.8.3, any full or partial recovery made by the *IESO* pursuant to section 8.8.1 shall be distributed to each *non-defaulting market participant* that remitted payment to the *IESO* on account of a *default levy* on a prorated basis according to, and in an amount that does not exceed, the amount so remitted by the *non-defaulting market participant.* Where the *non-defaulting market participant* is, at the relevant time, still a *market participant*, any such amount shall appear as a credit on the next *invoice* scheduled to be issued to that *non-defaulting market participant* under Chapter 9. Where the *non-defaulting market participant* is no longer a *market participant* at the relevant time, any such amount shall be paid to the former *non-defaulting market participant* in such manner as the *IESO* determines appropriate.

8.8.3 In the event that the *IESO* cannot, after taking all reasonable steps to do so, locate a former *non-defaulting market participant* that has remitted payment to the *IESO* on account of a *default levy*, any amount that would otherwise be distributed to such former *non-defaulting market participant* under section 8.8.2 shall:

8.8.3.1 be allocated and distributed to other *non-defaulting market participants* in the manner described in section 8.8.2; or

8.8.3.2 where other *non-defaulting market participants* have already been reimbursed in respect of a *default levy* and are therefore not entitled to payment of any amounts under section 8.8.2, be used to offset the *IESO administration charge.*

8.8.4 Any costs and expenses reasonably incurred by the *IESO* in recovering amounts from a *defaulting market participant* under section 8.8.1 that have not been included in a *default levy* under section 8.3.2.1(b) or 8.5.2.2 shall be included in the *IESO administration charge.*

9. Withdrawal by a Market Participant

9.1.1 Provided that the *market participant* has requested that the *IESO* de-register or transfer any applicable *registered facilities* pursuant to section 2.4 or 2.5 of Chapter 7, a *market participant* shall notify the *IESO* in writing if it wishes to cease to be a *market participant*. The notice shall specify the date of the *trading day* upon which the *market participant* intends to cease to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*. The *trading day* specified shall not be earlier than the *trading day* on which:

9.1.1.1 the last of the *market participant's* applicable *registered facilities* is to be de-registered by the *IESO* and, where applicable, *disconnected* from the *IESO-controlled grid*, determined in accordance with section 2.4 of Chapter 7; or

9.1.1.2 the registration of the last of the *market participant's* applicable *registered facilities* is to be transferred by the *IESO*, determined in accordance with section 2.5 of Chapter 7.

9.1.2 Upon receipt of the notice referred to in section 9.1.1, the *IESO* must *publish* and provide to all *market participants* a further notice stating that:

9.1.2.1 the *IESO* has received a notice under section 9.1.1; and

9.1.2.2 the person who gave the notice has stated that, from the end of the *trading day* specified in the notice, the person intends to cease participating in the *IESO-administered markets* or causing or permitting electricity to be conveyed into, through or out of the *IESO-controlled grid*.

9.1.3 The *markets participant* shall cease to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* no later than the end of the *trading day* specified in the notice given under section 9.1.1.

9.1.4 A *market participant* which has given a notice under section 9.1.1 shall cease to be a *market participant* on the date:

9.1.4.1 specified in the notice referred to in section 9.1.1;

9.1.4.2 on which the last of the *market participant's* applicable *registered facilities* is de-registered by the *IESO* and, where applicable, *disconnected* from the *IESO-controlled grid* pursuant to section 2.4 of Chapter 7;

9.1.4.3 on which the registration for the last of the *market participant's* applicable *registered facilities* has been transferred by the *IESO* pursuant to section 2.5 of Chapter 7;

9.1.4.4 on which all payments due to be paid by it or to it under the *market rules* have been made; or

9.1.4.5 the *market participant* has no further liability under section 2.5.4 of Chapter 7,

whichever is the latest. Any *boundary entity* registered by such *market participant* shall be deemed to be de-registered by the *IESO* as of such date.

9.1.5 A person who ceases to be a *market participant* shall remain subject to and liable for all of its obligations and liabilities as a *market participant* including, but not limited to, a liability under section 8 and an *adjustment period allocation* debit under Chapter 9, sections 6.6.8.2b and 6.8.5.3b resulting from an event that occurred while such person was a *market participant*, which were incurred or arose under the *market rules* prior to or on the *trading day* on which it ceases to be a *market participant* regardless of the date on which any claim relating thereto may be made.

9.1.6 [Intentionally left blank]

10. Market Participant Fees

10.1.1 The *IESO* shall not less than annually *publish* and notify *market participants* of the fees or schedule of fees payable by *market participants* and persons who apply for authorization to become *market participants*, including the application fee referred to in section 3.1.2.1. Such fees or schedule of fees shall be those approved by the *Ontario Energy Board* from time to time pursuant to section 25 of the *Electricity Act, 1998*.

10.1.2 The *IESO* shall recover the relevant fees from each *market participant* or prospective *market participants* in such manner as the *IESO* determines appropriate, including by means of the inclusion of the fees in a billing statement.

10.1.3 Each *market participant* or prospective *market participant* shall pay to the *IESO* the fees stated by the *IESO* to be payable by the *market participant* or prospective *market participant* by the date or dates specified for payment.

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11.1 [Intentionally left blank – section deleted]

11.1.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

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Market Rules

Chapter 2 Participation - Appendices

Connecting Today.
Powering Tomorrow.

Public

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Appendix 2.1 – [Intentionally left blank]

Appendix 2.2 – Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities

1.1 Voice Communications

1.1.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO:*

1.1.1.1 one *high priority path facility* and one *normal priority path facility* at the *dispatch centre, control center* and *authority centre* for each of its *generation facilities* provided that either:

a. the *IESO* has determined that a *high priority path facility* and a *normal priority path facility* are required to enable the *IESO* to maintain *reliable* operation of the *IESO-controlled grid*; or

b. one of the applicable *generation facilities* is a *major generation facility*; or

c. the aggregate rated size of applicable *generation facilities* is 100 MVA or greater; or

d. any one of the applicable *generation facilities* is a *certified black start facility*;

1.1.1.2 subject to section 1.1.1.1, one *normal priority path facility* at the *dispatch centre, control center* and *authority center* for each of its *generation facilities* provided that the aggregate rated size of applicable *generation facilities* is less than 100 MVA;

1.1.1.3 one *high priority path facility* and one *normal priority path facility* for each of its *major generation facilities* that are *attended* generation stations;

1.1.1.4 one commercially available telephone for each of:

a. its *major generation facilities*, *significant generation facilities* and *minor generation facilities* that are *unattended*; and

b. its *self-scheduling generation facilities* with name-plate ratings of less than 10 MW,

the telephone number of which shall be provided by the *generator* to the *IESO*;

1.1.1.5 one *high priority path facility* and one *normal priority path facility* for each of its *major generation facilities*, *significant generation facilities* and *minor generation facilities* that is a *certified black start facility*; and

1.1.1.6 one *normal priority path facility* for each of its *significant generation facilities* and *minor generation facilities* that is attended and is not a *certified black start facility*.

1.1.2 Each *embedded generator* that is not a *market participant* or whose *embedded generation facility* is not a *registered facility* shall, subject to section 1.1.11, provide and maintain the voice communication facilities referred to in sections 1.1.1.1 to 1.1.1.6, as may be applicable, in respect of each of its *embedded generation facilities* that:

1.1.2.1 includes a *generation unit* rated at 20 MVA or higher or that comprises *generation units* the ratings of which in the aggregate equals or exceeds 20 MVA; and

1.1.2.2 has been designated by the *IESO* for the purposes of this section 1.1.2 as requiring such voice communication facilities in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

1.1.3 Each *distributor* whose distribution system is *connected* to the *IESO-controlled grid* and that has control of any step-down transformer secondary breakers or low voltage feeder breakers for its loads shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO:*

1.1.3.1 one *high priority path facility* and one *normal priority path facility* at each location that controls such breakers if the *connection facilities connecting* such distributor's *distribution system* to the *IESO-controlled grid* have ratings that in aggregate equal or exceed 200 MVA; and

1.1.3.2 one *normal priority path facility* at each location that controls such breakers if the *connection facilities connecting* such distributor's *distribution system* to the *IESO-controlled grid* have ratings that in aggregate are less than 200 MVA.

1.1.4 Each *transmitter* whose *transmission system* or part thereof forms part of or is *connected* to the *IESO-controlled grid* shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO*:

1.1.4.1 one *high priority path facility* and one *normal priority path facility* at the dispatch or control center for each such *transmission system*;

1.1.4.2 one *high priority path facility* and one *normal priority path facility* at the *authority center* for each such *transmission system*;

1.1.4.3 one *high priority path facility* and one *normal priority path facility* for each *attended* transformer station forming part of such *transmission system*; and

1.1.4.4 one commercially available telephone for each *unattended* transformer station forming part of such *transmission system*, the telephone number of which shall be provided by the *transmitter* to the *IESO*.

1.1.5 Each *connected wholesale customer* that has control of any step-down transformer secondary breakers or low voltage feeder breakers for its loads shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO*:

1.1.5.1 one *high priority path facility* and one *normal priority path facility* at each location that controls such breakers for each of its *load facilities* that is *connected* to the *IESO-controlled grid* and that includes a *load facility* rated at 200 MVA or higher or that comprises *load facilities* the ratings of which in the aggregate equals or exceeds 200 MVA; and

1.1.5.2 one *normal priority path facility* at each location that controls such breakers for each of its *load facilities* that is *connected* to the *IESO-controlled grid* and that is rated at less than 200 MVA.

1.1.6 Each embedded load consumer whose embedded *load facility*:

1.1.6.1 includes a *load facility* that is rated at 20 MVA or higher or is comprised of *load facilities* the ratings of which in the aggregate equals or exceeds 20 MVA; and

1.1.6.2 has been designated by the *IESO* for the purposes of this section 1.1.6 as requiring voice communication facilities in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*,

shall provide and maintain one *normal priority path facility* for each such *embedded load facility* for the purposes of communicating with the *IESO.*

1.1.6A [Intentionally left blank – section deleted]

1.1.7 Each *high priority path facility* referred to in this section 1.1 shall provide unimpeded voice communications between the *IESO* and the *facility* to which the *high priority path facility* relates and shall:

1.1.7.1 meet the applicable specifications and other requirements set forth in the *participant technical reference manual*;

1.1.7.2 have receiving apparatus that is independent of any *normal priority path facility*;

1.1.7.3 have a communication channel that is and operates in a manner that is geographically and technologically distinct from any *normal priority path facility*;

1.1.7.4 permit the *IESO* to connect and communicate immediately, without the possibility of encountering a busy signal;

1.1.7.5 if an *attended facility*, at all times while the *facility* is attended be answered by live voice by a person in attendance at the *facility;*

1.1.7.6 [Intentionally left blank]

1.1.7.7 be secure from the effects of interruptions in power supply for a period of at least eight hours; and

1.1.7.8 [Intentionally left blank]

1.1.7.9 [Intentionally left blank]

1.1.7.10 not involve any manual intermediate switching.

1.1.8 Each *normal priority path facility* referred to in this section 1.1 shall comply with each of the following elements as may, except with respect to section 1.1.8.5, be commercially available:

1.1.8.1 meet the applicable specifications and other requirements set forth in the *participant technical reference manual*;

1.1.8.2 have receiving apparatus that is independent of any *high priority path facility*;

1.1.8.3 have a communication channel that is and operates in a manner that is geographically and technologically distinct from any *high priority path facility*;

1.1.8.4 be part of a public service telephone network;

1.1.8.5 if an *attended facility,* at all times while the facility is attended, be answered by live voice by a person in attendance at the *facility*;

1.1.8.6 permit and implement caller identification and call waiting;

1.1.8.7 have a separate telephone number dedicated exclusively to receiving voice communications from the *IESO*;

1.1.8.8 be secure against interception of communications by unauthorized third parties; and

1.1.8.9 be secure against disclosure of communications to unauthorized third parties.

1.1.9 Each person that is required by this section 1.1 to provide and maintain voice communication facilities and that applies for authorization as a *market participant* in respect of a *facility* to which such voice communication facilities relate shall:

1.1.9.1 identify, during the authorization or registration processes, the voice communication facilities that it shall provide and maintain in accordance with this section 1.1, the owner of such voice communication facilities and the telephone number or access code, as the case may be, for such voice communication facilities;

1.1.9.2 notify the *IESO* of any change in the telephone number or access code, as the case may be, for the voice communication facilities referred to in section 1.1.9.1, or in the equipment forming part of such voice communication facilities, no less than four days prior to the change being effected; and

1.1.9.3 if it will cease to be the owner of the voice communication facilities referred to in section 1.1.9.1, notify the *IESO* of the succeeding owner of such facilities no less than four days prior to the date on which the change of ownership is effected.

1.1.10 Each person that is required by this section 1.1 to provide and maintain voice communication facilities and that does not apply for authorization as a *market participant* in respect of the *facility* to which such voice communication facilities relate shall:

1.1.10.1 notify the *IESO* of the voice communication facilities that it shall provide and maintain in accordance with this section 1.1, of the owner of such voice communication facilities and of the telephone number or access code, as the case may be, for such voice communication facilities;

1.1.10.2 notify the *IESO* of any change in the telephone number or access code, as the case may be, for the voice communication facilities referred to in section 1.1.10.1, or in the equipment forming part of such voice communication facilities, no less than four days prior to the change being effected; and

1.1.10.3 if it will cease to be the owner of the voice communication facilities referred to in section 1.1.10.1, notify the *IESO* of the succeeding owner of such facilities no less than four days prior to the date on which the change of ownership is effected.

1.1.11 The *IESO* shall provide to a person required by this section 1.1 to maintain a *high priority voice communication facility*, the communication channel for such *high priority voice communication facility* if the *IESO* determines that such communication channel cannot be made available to the person without substantial cost.

1.1.12 Each *electricity storage participant* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall, subject to section 1.1.11, provide and maintain the following voice communication facilities for purposes of communicating with the *IESO:*

1.1.12.1 one high priority path facility and one normal priority path facility at the dispatch centre, control center and authority centre for each of its electricity storage facilities provided that either:

a. the *IESO* has determined that a *high priority path facility* and a *normal priority path facility* are required to enable the *IESO* to maintain *reliable* operation of the *IESO-controlled grid*; or

b. one of the applicable *electricity storage facilities* is a *major electricity storage facility*; or

c. the aggregate of the *electricity storage facility sizes* of the applicable *electricity storage facilities* is 100 MVA or greater.

1.1.12.2 subject to section 1.1.12.1, one normal priority path facility at the dispatch centre, control centre and authority center for each of its *electricity storage facilities* provided that the aggregate of the *electricity storage facility* size ratings of the applicable *electricity storage facilities* is less than 100 MVA;

1.1.12.3 one high priority path facility and one normal priority path facility for each of its *major electricity storage facilities* that are attended electricity storage stations;

1.1.12.4 one commercially available telephone for each of:

a. its *major electricity storage facilities*, *significant electricity storage facilities* and *minor electricity storage facilities* that are *unattended*; and

b. its *self-scheduling electricity storage facilities* with an *electricity storage facility size* of less than 10 MW,

the telephone number of which shall be provided by the *electricity storage participant* to the *IESO*;

1.1.12.5 one normal priority path facility for each of its *significant electricity storage facilities* and *minor electricity storage facilities* that is attended.

1.1.13 Each *embedded electricity storage participant* that is not a *market participant* or whose *embedded electricity storage facility* is not a *registered facility* shall, subject to section 1.1.11, provide and maintain the voice communication facilities referred to in sections 1.1.12.1 to 1.1.12.6, as may be applicable, in respect of each of its *embedded electricity storage facilities* that:

1.1.13.1 includes an *electricity storage unit* with a rated *electricity storage unit size* of 20 MVA or higher or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 20 MVA; and

1.1.13.2 has been designated by the *IESO* for the purposes of this section 1.1.13 as requiring such voice communication facilities in order to enable the *IESO* to maintain the reliability of the *IESO-controlled grid.*

1.2 Technical Requirements for Monitoring and Control

1.2.1 Each *generator* shall, for the purposes of submitting to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided by a *generator* to the *IESO* pursuant to the provisions of Chapters 4 and 5:

1.2.1.1 provide, maintain and connect to each of its applicable *generation facilities* monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.1.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable *generation facilities* and the real-time communication network channel or channels provided by the *IESO*.

1.2.2 Each *connected wholesale customer* shall, for the purposes of submitting to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided by a *connected wholesale customer* to the *IESO* pursuant to the provisions of Chapters 4 and 5:

1.2.2.1 provide, maintain and connect to:

a. where directed by the *IESO* if *transmitter* data is not adequate, each of its *non-dispatchable load facilities* that includes a *non-dispatchable load* rated at 20 MVA or higher or that comprises *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA; and

b. each of its *dispatchable load facilities*,

monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.2.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its *dispatchable load facilities* and *non-dispatchable load facilities* referred to in section 1.2.2.1 and the real-time communication network channel or channels provided by the *IESO*.

1.2.3 Each *transmitter* shall, for the purposes of submitting to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided by a *transmitter* to the *IESO* pursuant to the provisions of Chapters 4 and 5:

1.2.3.1 provide, maintain and connect to each of its applicable transmission assets monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.3.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable transmission assets and the real-time communication network channel or channels provided by the *IESO.*

1.2.4 Each *distributor* shall, for the purposes of submitting to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided by a *distributor* to the *IESO* pursuant to the provisions of Chapters 4 and 5:

1.2.4.1 provide, maintain and connect to each of its applicable distribution assets monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.4.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable distribution assets and the real-time communication network channel or channels provided by the *IESO.*

1.2.5 Each *embedded load consumer* shall, for the purposes of submitting to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided by the *embedded load customer* to the *IESO* pursuant to the provisions of Chapters 4 and 5:

1.2.5.1 provide, maintain and connect to:

a. where directed by the *IESO* if *transmitter* or *distributor* data is not adequate, each of its applicable *non-dispatchable load facilities* that include a *non-dispatchable load* rated at 20 MVA or higher or that comprises *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA; and

b. each of its applicable *dispatchable load facilities*

monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.5.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting facilities enabling the installation of a communication terminal point between the monitoring and control devices for each of its *embedded load facilities* referred to in section 1.2.5.1 and the real-time communication network channel or channels provided by the *IESO*.

1.2.6 Each person referred to in this section 1.2 shall provide access to its equipment, installation space and a reliable power source that meet the specifications and other requirements of the *participant technical reference manual*.

1.2.7 Each *electricity storage participant* shall, for the purposes of submitting to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided by an *electricity storage participant* to the *IESO* pursuant to the provisions of Chapters 4 and 5:

1.2.7.1 provide, maintain and connect to each of its applicable *electricity storage facilities* monitoring and control devices that meet the specifications and other requirements set forth in the *participant technical reference manual*; and

1.2.7.2 provide and maintain, in accordance with the *participant technical reference manual,* a location and supporting *facilities* enabling the installation of a communication terminal point between the monitoring and control devices for each of its applicable *electricity storage facilities* and the real-time communication network channel or channels provided by the *IESO.*

1.3 Dispatch Workstations

1.3.1 Each market participant other than a boundary entity, or a capacity auction participant with a capacity obligation through an hourly demand response resource shall, for the purposes of:

1.3.1.1 the provision to the *IESO* of real-time information required by the *IESO* to direct the operations of the *IESO-controlled grid*;

1.3.1.2 if the person is or will be subject to dispatch by the *IESO*, the receipt of *dispatch instructions*; and

1.3.1.3 the exchange with the *IESO* of other information required to be submitted or received pursuant to Chapter 7 or Chapter 8, other than the submission, receipt of confirmation of and validation of *dispatch data*, *TR bids* in the *TR market* and *physical bilateral contract data*,

provide, install and maintain a *dispatch workstation* that meets the specifications and other requirements set forth in the *participant technical reference manual* and that is configured to support communication with the real-time communication network channel or channels provided by the *IESO* in the manner described in the *participant technical reference manual*.

1.3.2 The *dispatch workstation* referred to in section 1.3.1 shall be located at:

1.3.2.1 the facility to which the *dispatch workstation* relates; or

1.3.2.2 the authority center for the facility to which the dispatch workstation relates so as to permit a response to *dispatch instructions* within the time prescribed by the *participant technical reference manual*.

1.3.3 Each *market participant* that is required by this section 1.3 to provide, install and maintain a *dispatch workstation* shall:

1.3.3.1 prior to commencing participation in the *IESO-administered markets*, notify the *IESO* of the premises at which its *dispatch workstation* will be located; and

1.3.3.2 notify the *IESO* of any change in the location of its *dispatch workstation* no less than four days prior to the date on which the change will be effected.

1.4 Participant Workstations

1.4.1 Subject to section 1.6, each *market participant* shall, for the purposes of conducting secure communications or transactions with the *IESO* using *IESO*-supplied or approved software, provide, install and maintain a *participant workstation* that meets the specifications, definitions and other requirements set forth in the *participant technical reference manual*.

1.4.2 Each *participant workstation* required to be installed and maintained pursuant to section 1.4.1 shall:

1.4.2.1 where the *market participant* is exchanging the information referred to in section 1.4.1 by means of the internet, be configured to support internet communication in the manner described in the *participant technical reference manual* and, if a *TR participant*, to support communication with the communication protocol referred to in Appendix 8.2 of Chapter 8; and

1.4.2.2 where the *market participant* is exchanging the information referred to in section 1.4.1 by means of the private network dedicated communication links, be configured to support communication between the *participant workstation* and the *IESO* in the manner described in the *participant technical reference manual* and, if a *TR participant*, to support communication with the communication protocol referred to in Appendix 8.2 of Chapter 8.

1.5 Re-classification of Facilities

1.5.1 The *IESO* may, for the purposes of this Appendix 2.2 and of section 12 of Chapter 5:

1.5.1.1 re-classify a *small generation facility* as a *minor generation facility*, a *significant generation facility* or a *major generation facility*;

1.5.1.2 re-classify a *minor generation facility* as a *significant generation facility* or a *major generation facility*;

1.5.1.3 re-classify a *significant generation facility* as a *major generation facility*;

1.5.1.4 re-classify a *minor dispatchable load facility* as a *significant dispatchable load facility* or a *major dispatchable load facility*; and

1.5.1.5 re-classify a *significant dispatchable load facility* as a *major dispatchable load facility*,

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

1.5.1A The *IESO* may, for the purposes of this Appendix 2.2 and of section 12 of Chapter 5:

1.5.1A.1 re-classify a *small electricity storage facility* as a *minor electricity storage facility*, a *significant electricity storage facility* or a *major electricity storage facility*;

1.5.1A.2 re-classify a *minor electricity storage facility* as a *significant electricity storage facility* or a *major electricity storage facility*;

1.5.1A.3 re-classify a *significant electricity storage facility* as a *major electricity storage facility*;

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid.*

1.5.2 The *IESO* may, for the purposes of this Appendix 2.2 and of section 12 of Chapter 5:

1.5.2.1 re-classify a *major generation facility* as a *significant generation facility*, a *minor generation facility* or a *small generation facility*;

1.5.2.2 re-classify a *significant generation facility* as a *minor generation facility* or a *small generation facility*;

1.5.2.3 re-classify a *minor generation facility* as a *small generation facility*;

1.5.2.4 re-classify a *major dispatchable load facility* as a *significant dispatchable load facility* or a *minor dispatchable load facility*; and

1.5.2.5 re-classify a *significant dispatchable load facility* as a *minor dispatchable load facility*,

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

1.5.2A The *IESO* may, for the purposes of this Appendix 2.2 and of section 12 of Chapter 5:

1.5.2A.1 re-classify a *major electricity storage facility* as a *significant electricity storage facility*, a *minor electricity storage facility* or a *small electricity storage facility*;

1.5.2A.2 re-classify a *significant electricity storage facility* as a *minor electricity storage facility* or a *small electricity storage facility*;

1.5.2A.3 re-classify a *minor electricity storage facility* as a *small electricity storage facility*;

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

1.5.3 A person whose *facility* has been re-classified pursuant to section 1.5.1, 1.5.1A, 1.5.2 or 1.5.2A shall ensure that its *facilities* and equipment meet the requirements set forth in this Appendix 2.2 and in section 12 of Chapter 5 applicable to the class of *facility* in which its *facility* has been re-classified.

1.6 Terms and Conditions

1.6.1 Where a *market participant* conducts secure communications or transactions with the *IESO* in accordance with section 1.4, sections 1.6.2 to 1.6.5 shall apply.

1.6.2 Each *market participant* shall be solely responsible to ensure the authenticity, integrity and non-repudiation of communications or transactions, as described in the *participant technical reference manual*.

1.6.3 Each *market participant* agrees to:

1.6.3.1 be bound by an authenticated communication or transaction to the same extent, and with the same effect of law, as if the authenticated communication or transaction had existed in a manually signed or otherwise authenticated form;

1.6.3.2 acknowledge that the *IESO* will act in reliance on an authenticated communication or transaction, even where the authenticated communication or transaction contains an error;

1.6.3.3 accept the time-stamp in the validation response or the time stamp of the communication or transaction recorded by the *IESO* as the authoritative record. In the case of a discrepancy, the time stamp of the communication or transaction recorded by the *IESO* shall prevail; and

1.6.3.4 immediately notify the *IESO* if the *market participant* suspects any unauthorized, or inappropriate access to or activity on the *IESO's* systems or information.

1.6.4 The *IESO* may, without notice, temporarily suspend a *market participant's* ability to conduct secure communications or transactions if the *IESO* reasonably suspects unauthorized or inappropriate access to or activity on the *IESO's* systems or information. These suspensions will be for a period of time necessary to permit the thorough investigation of such suspended activity.

1.6.5 The *IESO* shall not be liable for any unauthorized activity and the damages or consequences that may result from the use of secure communications or transactions, unless such violation was solely and directly as a result of the actions of the *IESO*.

Appendix 2.3 – Prudential Support

1. Additional Provisions Regarding Prudential Support

1.1 Determination of Prudential Support Obligations

Prior to participating in the *real-time markets*, the *IESO* shall deliver to each *market participant* a schedule, in the form set forth in the applicable *market manual,* setting out the determination by the *IESO* of that *market participant's prudential support obligations*, which shall be completed by the *IESO* on the basis of the determinations referred to in Section 5 of Chapter 2. Such schedule shall be effective until amended and replaced in accordance with this Appendix.

1.2 Provision of Prudential Support

Prior to participating in the *real-time markets*, each *market participant* shall deliver to the *IESO*:

1.2.1 a schedule, in the form set forth in the applicable *market manuals* completed by the *market participant* setting out the *prudential support* with which the *market participant* has elected to satisfy its *prudential support obligation* as set forth in the schedule delivered to it by the *IESO* referred to in section 1.1; and

1.2.2 the *prudential support* as set out in that schedule.

In the event that the sum of all *prudential support* provided by the *market participant* to the *IESO* is a greater amount than required by the *market rules,* the *IESO* shall, upon written request by the *market participant*, return (or direct the custodian to return) to the *market participant* an amount equal to the difference between the value of all *prudential support* then held by or on behalf of the *IESO* and the *prudential support obligation* of the *market participant* at that time. The *IESO* shall return such amount within five *business days* of the receipt of the request for the return of the amount from the *market participant.* In the event the *market participant* has posted one or more different types of *prudential support*, the *IESO* shall return the type of *prudential support as* directed by the *market participant.* Upon the return by the *IESO* to the *market participant* of the amount of any *prudential support*, any security interest or lien granted on such *prudential* *support* will be released immediately and, to the extent possible, without any further action by either party.

1.3 Reduction of Prudential Support Obligation for Credit Rating

Where the *market participant*'s *prudential support obligation* reflects a reduction by reason of the *market participant*'s credit rating from a major bond rating agency identified in the list of such agencies published by the *IESO*, the *market participant* covenants and agrees to advise the *IESO* in writing immediately upon the *market participant* becoming aware of either a change in or loss of the then current credit rating or the decision of the bond rating agency to place the *market participant* on "credit watch status" or equivalent. Where, as a result of either any such change or loss in the then current rating or the placing of the *market participant* on "credit watch status", the *market participant* is no longer entitled under the *market rules* to the same reduction by way of credit rating, the *IESO* shall deliver to the *market participant* an amended schedule setting out the *market participant*'s revised *prudential support obligation*.

1.4 Prudential Support by way of a Third Party Guarantee

Prudential support in the form of a guarantee provided by a third party pursuant to section 5.7.2.2 or 5.7.2.4 of Chapter 2 shall provide for payment by the guarantor to the *IESO* on demand up to the amount stated in the guarantee. The only conditions on the ability of the *IESO* to draw on the guarantee shall be the delivery of copies of an unpaid invoice previously issued to the *market participant* and a certificate of an officer of the *IESO* that a specified amount is owing by the *market participant* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate. Where the *market participant*'s *prudential support* includes a guarantee provided by a third party that has a credit rating from a major bond rating agency identified in the list of such agencies published by the *IESO*, the *market participant* covenants and agrees to advise the *IESO* in writing immediately upon the *market participant* becoming aware of a change in or loss of the then current credit rating issued to the guarantor. Where as a result of the loss of such credit rating, the *market participant* is no longer entitled to meet its *prudential support obligation* in whole or in part through the provision of such a guarantee, the market participant must provide alternative *prudential support* within the time frame mandated in section 5.2 of Chapter 2.

1.5 Reduction of Prudential Support Obligation for Payment History

Where the *market participant*'s *prudential support obligation* reflects a reduction by reason of evidence of the *market participant's* good payment history determined in accordance with sections 5.8.4 or 5.8.5 of Chapter 2 and, for any reason, the *market participant* is no longer entitled under the *market rules* to the same amount of reduction by way of good payment history, the *IESO* shall deliver to the *market participant* an amended schedule setting out the *market participant*'s revised prudential support obligation.

1.6 Prudential Support by way of Letter of Credit

Where a portion of the *market participant*'s *prudential support* is in the form of a letter of credit pursuant to section 5.7.2.1 of Chapter 2, the following provisions shall apply:

1.6.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 2007 Revision, ICC Publication No. 600 or The International Standby Practices 1998;

1.6.2 the *IESO* shall be named as beneficiary in each letter of credit, each letter of credit shall be irrevocable, partial draws on any letter of credit shall not be prohibited and the letter of credit or the aggregate amount of all letters of credit shall be in the face amount of at least the amount specified in its then current schedule;

1.6.3 the only conditions on the ability of the *IESO* to draw on the letter of credit shall be the occurrence of an *event of default* by or in respect of the *market participant* and a certificate of an officer of the *IESO* that the *IESO* is entitled to draw on the letter of credit in accordance with the provisions of the *market rules* in the amount specified in the certificate as at the date of delivery of the certificate;

1.6.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. In either case it is the responsibility of the *market participant* to maintain the requisite amount of *prudential support*. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *market participant* shall arrange for and deliver alternative *prudential support* within the time frame mandated by the *market rules* so as to enable the *market participant* to be in compliance with the *market rules*; and

1.6.5 by including a letter of credit as part of its *prudential support*, the *market participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *market participant*.

1.7 Prudential Support by way of Cash or Treasury Bills

Where any portion of the *market participant*'s *prudential support* is in the form of treasury bills pursuant to section 5.7.2.3 of Chapter 2, the provision of such *prudential support* shall be reflected in a written instrument that is acceptable at the sole discretion of the *IESO* and the following provisions shall apply:

1.7.1 any such treasury bills shall be issued by the Government of Canada and for *IESO* purposes shall be valued at their current market value from time to time less two (2%) percent to take into account the potential eroding effects of interest rate increases on the value of such treasury bills;

1.7.2 the *IESO* shall retain the services of a custodian which shall retain the treasury bills as agent for the *IESO* and not the *market participant*; and

1.7.3 any interest income paid by the treasury bill shall be apportioned to the benefit of the *market participant's prudential support.*

The *IESO* shall have no obligation to pay interest on the cash proceeds from the maturity of a treasury bill, or on any cash deposit held by the *IESO* in accordance with section 5.7.2.5 of Chapter 2.

1.8 Replacement Schedules

The *IESO* and the *market participant* may or, where required to enable the *market participant* to be in compliance with the *market rules*, shall from time to time deliver to one another one or more additional schedules, which schedules shall be in the form approved by the *IESO* from time to time. Where the *IESO* delivers to the *market participant* an additional schedule, each such schedule shall replace the preceding schedule , and shall be effective from the date of its delivery to the *market participant* for all purposes thereafter until such time as a subsequent amended schedule is delivered by the *IESO* to the *market participant*. Where any such amended schedule shows an increase in the *market participant*'s *prudential support obligation* relative to the preceding schedule or requires the provision of alternative *prudential support*, the *market participant* shall deliver such additional or alternative *prudential support* as may be required so as to enable the *market participant* to be in compliance with the *market rules*. Where the *market participant* delivers an amended schedule , modified to reflect additional or alternative forms of *prudential support*, such amended schedule , provided that it is accompanied by such additional or alternative *prudential support*, shall replace the preceding schedule and shall be binding on the *market participant* for all purposes thereafter until such time as a subsequent amended schedule is delivered to the *IESO* by the *market participant*.

1.9 Dispute Resolution

If the *market participant* disagrees with the determination by the *IESO* of any of the amounts of *prudential support obligations* set out on a schedule and such dispute cannot be resolved by the *market participant* and the *IESO*, then the *market participant* shall submit the matter to dispute resolution under section 2 of Chapter 3. Notwithstanding the initiation of the dispute resolution process, the *market participant* shall provide such additional *prudential support* as may be required in order to continue participating in the *real time markets* based on the determination by the *IESO* until the matter has been resolved.

2. Pledge of Prudential Support in the form of Cash or Treasury Bills

2.1 Pledge

Prudential support in the form of cash or treasury bills provided as part of the *market participant*'s *prudential support obligation* in respect of the *market participant*'s participation in the *real-time markets* shall be held by or on behalf of the *IESO* (together with all accretions thereto, all income therefrom and proceeds thereof) and the *market participant* shall assign to the *IESO* all of its present and future right, title and interest in and to such cash and treasury bills as general and continuing collateral security and as a pledge to secure:

2.1.1 subject to section 13 of Chapter 1, all indebtedness, obligations and liabilities of any kind, now or hereafter existing, direct or indirect, absolute or contingent, joint or several, of the *market participant* to the *IESO* in respect of the *market participant*'s participation in the *real-time markets*; and

2.1.2 all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, reasonable legal fees on a solicitor and client basis) incurred by or on behalf of the *IESO*, in the enforcement of its rights under the *market rules* in respect of the participation by the *market participant* in the *real-time markets*.

3. Exercise of Rights and Remedies to Prudential Support

3.1 Exercise of Rights

Upon the occurrence of an *event of default*, the *IESO* shall be entitled to exercise its rights and remedies as set out in the *market rules,* or provided for at law or in equity. Without limiting the generality of the foregoing, such rights and remedies shall, in respect of the *prudential support* provided by the *market participant*, include setting-off and applying any and all *prudential support* held in the form of cash or treasury bills or proceeds of either cash or treasury bills against the indebtedness, obligations and liabilities of the *market participant* to the *IESO* in respect of the participation by the *market participant* in the *real-time markets*. When the *IESO* is reasonably certain that it will be issuing a first *notice of default levy* it shall *publish* the name of the *defaulting market participant.*

3.2 Remedies Cumulative

Each of the remedies available to the *IESO* under the *market rules* or at law or in equity is intended to be a separate remedy and in no way is a limitation on or substitution for any one or more of the other remedies otherwise available to the *IESO*. The rights and remedies expressly specified in the *market rules* or at law or in equity are cumulative and not exclusive. The *IESO* may in its sole discretion exercise any and all rights, powers, remedies and recourses available under the *market rules* or under any document comprising the *prudential support* provided by the *market participant* or any other remedy available to the *IESO* howsoever arising, and whether at law or in equity, and such rights, powers and remedies and recourses may be exercised concurrently or individually without the necessity of any election.

3.3 Application of Prudential Support against Actual Exposure

Except as may be otherwise provided in the *market rules,* all moneys received in respect of the realization of the *prudential support* provided by the *market participant* may, notwithstanding any appropriation by the *market participant* or any other person, be appropriated to such parts of the *market participant*'s *actual exposure or its other obligations,* any interest thereon owing pursuant to the *market rules* or the costs, charges, expenses and fees referred to in section 3.4 and in such order as the *IESO* sees fit, and the *IESO* shall have the right to change any appropriation at any time.

3.4 Payment of Expenses

The *market participant* agrees to pay to the *IESO* forthwith on demand all reasonable costs, charges, expenses and fees (including, without limiting the generality of the foregoing, legal fees on a solicitor and client basis) of or incurred by or on behalf of the *IESO* in the realization, recovery or enforcement of the *prudential support* provided by the *market participant* and enforcement of the rights and remedies of the *IESO* under the *market rules* or at law or in equity in respect of the participation by the *market participant* in the *real-time markets.*

3.5 Deficiency

If the proceeds of the realization of any *prudential support* provided by the *market participant* are insufficient to pay all of the *actual exposure* of the *market participant* or its other obligations to the *IESO*, the *market participant* shall forthwith pay or cause to be paid to the *IESO* any such deficiency. The *IESO* shall provide a calculation of any such deficiency to the *market participant*.

Market Rules

Chapter 3 Administration, Supervision, Enforcement

Connecting Today. Powering Tomorrow.

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Table of Contents

1. Introduction

1.1 Scope of Chapter

1.1.1 This Chapter sets forth:

1.1.1.1 the dispute resolution mechanism applicable to certain disputes arising under the *market rules*;

1.1.1.2 the manner in which market monitoring and surveillance responsibilities will be carried out;

1.1.1.3 the procedures pursuant to which the *market rules* may be amended;

1.1.1.4 the procedures which govern the protection, use and disclosure of *confidential information* by the *IESO* and *market participants*; and

1.1.1.5 the manner in which the *IESO* will monitor, assess and enforce compliance with the *market rules*.

2. Dispute Resolution

2.1 Interpretation and General Procedural Provisions

2.1.1 The provisions of this section 2 shall be liberally construed to secure the most expeditious, just and least expensive determination on its merits of every proceeding conducted hereunder.

2.1.2 Where no procedures are provided for in this section 2 or the applicable *market manual*, a *mediator* or an *arbitrator* may do whatever is reasonably necessary and permitted by law to enable the effective mediation or adjudication of any matter before the *mediator* or the *arbitrator*.

2.1.3 The parties to a dispute may agree to dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7. A *mediator,* an *arbitrator* or the *secretary* may, in the context of the resolution or the attempted resolution of a specific dispute pursuant to this section 2, dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7, including as to any prescribed time periods, if special circumstances or the public interest require, or with the consent of the parties to the dispute. The *secretary's* authority to dispense with, supplement or vary the application of all or any part of the provisions of sections 2.5.3A to 2.7 lapses with respect to a particular dispute once a *mediator* or *arbitrator* is appointed in respect of that dispute.

2.1.4 The *IESO* shall from time to time *publish* and notify *market participants* of the address of the *secretary* for filing purposes.

2.1.5 Unless otherwise specified in this section 2 or otherwise directed by the *secretary*, a *mediator* or an *arbitrator*, only one copy of any document is required to be served or filed.

2.1.6 The following provisions of the *Arbitration Act, 1991* do not apply to any proceeding conducted under this section:

2.1.6.1 subsection 10(1)(b);

2.1.6.2 subsection 13(1)2;

2.1.6.3 subsection 23(1);

2.1.6.4 section 24;

2.1.6.5 subsections 25(3) to 25(5);

2.1.6.6 sections 34, 37, 39, 45, 48 and 53;

2.1.6.7 subsections 54(5) and 54(6); and

2.1.6.8 sections 55 and 56, insofar as they may be applicable to the fees payable to an *arbitrator* and to the extent that such fees have been approved by the *Ontario Energy Board*.

2.2 Application

2.2.1 Subject to sections 2.2.3 and 3.8 and to section 8.8.1 of Chapter 2, the dispute resolution regime provided for in this section 2 shall apply to:

2.2.1.1 any dispute between the *IESO* and any *market participant* which arises under the *market rules*, *market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules*, including with respect to any alleged violation or breach thereof, whether or not specifically identified in the *market rules* as a dispute to which this section 2 applies;

2.2.1.1A a contested matter pursuant to section 6.2B.5 and section 6.2B.9, except as otherwise provided in section 6.2B;

2.2.1.1B a dispute involving an order of the *IESO* issued pursuant to section 6.2B.15, except as otherwise provided in section 6.2B;

2.2.1.2 any denial by the *IESO* of authorization to any person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, out of or through the *IESO-controlled grid*, as to the denial of such authorization;

2.2.1.3 an application by a *generator* or *electricity storage participant* for compensation pursuant to section 6.7.5 of Chapter 5 in respect of an *outage* rejected by the *IESO*;

2.2.1.4 a reviewable decision;

2.2.1.5 a dispute referred to in section section 6.10.1 of Chapter 9;

2.2.1.6 [intentionally deleted];

2.2.1.7 any dispute between the *IESO*, on the one hand, and any *market participant*, *connection applicant* or *metering service provider*, on the other hand, pursuant to the terms of any agreement or contract referred to in these *market rules* or in any policy, guideline or other document referred to in section 7.7 of Chapter 1 or any *market manual*, unless in respect of a given dispute the agreement or contract or the *licence* of a party to the dispute either provides for an alternative dispute resolution mechanism or provides that the dispute resolution regime provided in this section 2 shall not be applicable;

2.2.1.8 a dispute between *market participants* referred to in section 2.1A.6A of Chapter 9 in respect of the apportionment of *energy* associated with *connection station service* and with site specific losses; and

2.2.1.9 the *IESO's* determination under sections 3.2.5, 3.2.6, and 3.2.7 of Chapter 5 regarding the applicability of *reliability standards*.

2.2.1.10 a dispute referred to in section 10.4.8 of Chapter 6; and

2.2.1.11 a dispute referred to in section 6C.1.5 of Chapter 10.

2.2.2 The dispute resolution regime provided for in this section 2:

2.2.2.1 shall apply to a dispute between *market participants* referred to in section 8.4.3 of Chapter 5; and

2.2.2.2 may also apply to any other disputes between *market participants* where all of the *market participants* which are party to the dispute consent in writing to the application thereof.

2.2.2A A *market participant* that has, pursuant to section 2.2.2.2, consented to the application of the dispute resolution regime provided for in this section 2 may, prior to the date on which the *secretary* takes the action referred to in section 2.6.2.1 or 2.6.2.2, as the case may be, withdraw its consent in the event that a *respondent* to a crossclaim objects to the application of such regime.

2.2.3 The dispute resolution process provided for in this section 2 shall not apply to the following:

2.2.3.1 applications by any person to review a *market rule*, which applications shall be governed by section 4;

2.2.3.2 disputes with respect to a proposal to *amend* or not to *amend* any provision of the *market rules*;

2.2.3.3 disputes between the *IESO* and a *market participant* relating to the quantum of the fees chargeable by the *IESO* to the *market participant* to the extent that such fees have been approved by the *Ontario Energy Board*, unless the dispute relates to the manner of calculation of the fees payable by the *market participant* in any given case;

2.2.3.4 [Intentionally left blank]

2.2.3.5 disputes between the *IESO* and a *market participant* relating to a *suspension order* issued by the *IESO* or to a *termination order* issued by the *IESO*, in respect of which an appeal may be filed with the *Ontario Energy Board* pursuant to section 36 of the *Electricity Act, 1998*;

2.2.3.6 disputes between the *IESO* and a *market participant* to the extent that the *licence* of the *IESO* or of the relevant *market participant* provides for an alternative dispute resolution mechanism;

2.2.3.7 disputes between the *IESO* and a *market participant* relating to the standards, criteria or requirements established by a *standards authority* to the extent that an agreement with the relevant *standards authority* provides for an alternative dispute resolution mechanism;

2.2.3.8 an award of an *arbitrator* made pursuant to this section 2;

2.2.3.9 any dispute with respect to which these *market rules,* other than this section 2, provide for an alternative dispute resolution mechanism;

2.2.3.10 any dispute with respect to which these *market rules,* other than this section 2, provide for the non-application of the dispute resolution process provided for in this section 2;

2.2.3.11 a decision of a panel of the *IESO Board*:

(a) granting or rejecting an *exemption application*;

(b) respecting the terms and conditions of an *exemption*, other than with respect to the quantum of the costs payable by the *exemption applicant* or one or more *market participants* pursuant to Chapter 1, section 14.5;

(c) removing or amending an *exemption* or the terms and conditions thereof, other than with respect to the quantum of the costs referred to in Chapter 1, section 14.5;

(d) approving or denying the transfer of an *exemption*; or

(e) respecting *confidential information* provided to the *IESO* as part of or in respect of an *exemption application* including, without limitation the disclosure thereof; and

2.2.3.12 when considering an *exemption application*, including for certainty a reconsideration or transfer of an *exemption*, a determination or decision by a panel of the *IESO Board* regarding the interpretation of the provisions of any *market rule, market manual* or any standard, policy or procedure established by the *IESO* pursuant to the *market rules*.

2.2.3.13 [Intentionally left blank – section deleted]

2.2.4 Subject to such rights of appeal or review as may be prescribed by *applicable law,* an award of an *arbitrator* made pursuant to this section 2 is final and binding on the parties. Without limiting the generality of the foregoing, but subject to sections 2.2.5 and 3.8 and to section 8.8.1 of Chapter 2, where any dispute of a kind described in section 2.2.1 or 2.2.2 arises, the parties concerned shall comply with the procedures set forth in this section 2 before commencing a civil or other proceeding in relation to the dispute, including but not limited to the filing of an appeal pursuant to subsection 36(1) of the *Electricity Act, 1998*.

2.2.5 Nothing in this section 2 shall prevent a party to a dispute from making application to a court of competent jurisdiction in the Province of Ontario for urgent interlocutory or interim injunctive relief.

2.3 Continuing Obligations and Stay of Orders

2.3.1 Subject to section 2.3.3, where a dispute involves the payment or recovery of monetary amounts due under the *market rules*, the amount shall be due and payable at the time specified for payment under the *market rules* notwithstanding initiation of the dispute resolution process.

2.3.2 Subject to section 2.3.3, initiation of the dispute resolution process referred to in this section 2 does not stay implementation of an order made or a direction given to a *market participant* by the *IESO* pursuant to the *market rules*.

2.3.3 Where a dispute in respect of which the dispute resolution process has been initiated involves the payment of a financial penalty imposed upon a *market participant* by the *IESO* under section 6.2, the obligation of the *market participant* to pay the financial penalty shall be stayed pending the outcome of the dispute resolution process.

2.4 [Intentionally left blank – section deleted]

2.5 Notice of Dispute, Negotiation and Response

2.5.1 The complaining person (the "*applicant*") shall, within the time specified in section 2.5.1A, serve a written notice of the dispute (the "*notice of dispute*") on any *respondent*.

2.5.1A Subject to section 2.5.1B, a *notice of dispute* shall be served:

2.5.1A.1 in the case of an application referred to in section 2.2.1.3, within 20 *business days* of the date of receipt of notice by the *generator* or *electricity storage participant* of rejection by the *IESO* of the *outage* in respect of which compensation is claimed pursuant to section 6.7.5 of Chapter 5;

2.5.1A.2 in the case of a dispute that involves a *reviewable decision* referred to in section 5.3.9 of Chapter 6, within 20 *business days* of the date of receipt by the *metering service provider* of notice of the revocation of its registration by the *IESO*;

2.5.1A.3 in the case of a dispute referred to in section 6C.1.5 of Chapter 10, within 20 *business days* of the *market participant* receiving the relevant *settlement statement* with the adustments specified in accordance with section 6C of Chapter 10;

2.5.1A.4 in the case of a dispute referred to in section 6.10.1 of Chapter 9, except for those matters identified in section 6.8.12.4 of Chapter 9, within the time specified in section 6.10.2.3 of Chapter 9;

2.5.1A.4A in the case of a dispute referred to in section 2.1A.6A of Chapter 9, within 20 *business days* of the date of receipt of the first *invoice* that reflects the apportionment that is the subject-matter of the dispute;

2.5.1A.4B in the case of a dispute referred to in section 10.4.8 of Chapter 6, within 20 business days of:

(a) the IESO notifying the market participant of the the IESO's determination if the IESO concludes pursuant to section 10.4.5.1 of Chapter 6 that no further action is required; or

(b) receipt of the settlement statement on which the adjustment is reflected if the IESO concludes an adjustment is required pursuant to section 10.4.5.2 of Chapter 6;

2.5.1A.4C in the case of a dispute involving an order, direction, instruction or decision of the *IESO*, including a matter referred to in section 6.8.12.4 of Chapter 9 that involves an order, direction, instruction or decision of the *IESO* relating to a compliance and enforcement action described in section 6 of Chapter 3, issued on or after January 1, 2004 not otherwise addressed by subsections 2.5.1A.1 to 2.5.1A.4A, within two years of the date of receipt of the order, direction, instruction or decision;

2.5.1A.4D in the case where the *market participant* contests the *notice of intention* under section 6.2B.3, within the timelines set out in section

6.2B.3 and the *response to the notice of intention* shall be deemed to constitute the *notice of dispute*;

2.5.1A.4E in the case of a dispute involving one or more orders referred to in section 6.2B.15, within the timelines set out in section 6.2B.16;

2.5.1A.4F 2.5.1A.4F in the case of a dispute referred to in section 7.6.5 of Chapter 7, within 20 *business days* of:

(a) the *IESO* notifying the *market participant* of its determination if the *IESO* determines pursuant to section 7.6.3.2 of Chapter 7 that the *market participant* is not entitled to compensation; or

(b) the receipt of the *settlement statement* on which the compensation is reflected if the *IESO* determines pursuant to section 7.6.3.2 of Chapter 7 that the *market participant* is entitled to compensation;

2.5.1A.4G in the case of matters referred to in section 6.8.12.4 of Chapter 9, except for a compliance and enforcement action described in section 6 of Chapter 3, within 20 *business days* of the *market participant* receiving the relevant *settlement statement* with the adustments specified in accordance with the relevant provision; and

2.5.1A.5 in all other cases, within the applicable limitation period set out in the Limitations Act, 2002.

2.5.1B Commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date* and in regards to sections 2.5.1A.1, 2.5.1A.3, 2.5.1A.4, 2.5.1A.4B, and 2.5.1A.4F, in no circumstance shall a *notice of dispute* be served more than 24 months following the earlier of:

(a) the initial date when the *IESO* would have the right or obligation to settle the transaction, charge or payment that is the subject of the dispute; or

(b) the date on which the IESO issues an invoice in respect of the transaction, charge or payment that is the subject of the dispute.

This section and section 2.5.1A shall apply whether or not the transaction, charge or payment that is the subject of the dispute was capable of being identified or discovered within the time specified in section 2.5.1A and this section 2.5.1B. Notwithstanding the foregoing, where entitlement to a settlement amount is prescribed by applicable law, in no circumstance shall a notice of dispute be served beyond the limitation period, if any, provided pursuant to applicable law.

2.5.2 The *notice of dispute* shall be in such form as may be established by the *IESO,* shall be signed by a person with authority to bind the *applicant* and shall specify, in reasonable detail and to the best of the *applicant*'s knowledge:

2.5.2.1 the nature of and basis for the complaint;

2.5.2.2 the *market rules* in issue;

2.5.2.3 the parties to the dispute and the name of any person having knowledge of or who may be directly affected by the dispute;

2.5.2.4 a concise summary of the facts underlying the dispute;

2.5.2.5 the relief sought and a summary of the grounds for such relief; and

2.5.2.6 any documentation upon which the *applicant* intends to rely in support of its complaint.

2.5.3 [Intentionally left blank – section deleted]

2.5.3A Upon service of a *notice of dispute*, the applicant and the respondent to a notice of dispute shall make good faith efforts to negotiate for a minimum period of thirty days to resolve the dispute between them. In regards to disputes where an *IESO* determination is still pending, as contemplated in sections 6.8.15 of Chapter 9 and section 10.4.8 of Chapter 6, the thirty-day period to resolve the dispute through good faith negotiations shall not commence until the *IESO* has completed its determination. Each person who is a party to a dispute shall, to this end, designate an individual with authority to negotiate the matter in dispute and to participate in such negotiations. The parties to the dispute may conduct the good faith negotiations in any manner they so agree.

2.5.3B Communications made in the course of negotiations are confidential, are made without prejudice and are not subject to voluntary disclosure in any subsequent proceeding or to be voluntarily produced into evidence for any purpose other than as reflected in a settlement agreement.

2.5.3C In the event that a dispute is not settled through good faith negotiations, a party may file with the *secretary,* on written notice served on each other party, a copy of the *notice of dispute,* together with proof of service of the *notice of dispute* on each other party. The *notice of dispute* shall be accompanied by a summary of the *notice of dispute* for *publication* in accordance with section 2.9.2.1.

2.5.4 A *respondent* shall, within ten *business days* of the filing of a *notice of dispute* with the *secretary* under section 2.5.3C, serve a written response (the "*response*") on the *applicant* and on any *respondent* to a counterclaim or crossclaim identified in the *response*, and shall file with the *secretary* a copy of the *response,* together with proof of service of the *response* on the *applicant* and on any such *respondent*.

2.5.5 The *response* shall be in such form as may be established by the *IESO*, shall be signed by a person with authority to bind the *respondent* and shall specify, in reasonable detail and to the best of the *respondent's* knowledge:

2.5.5.1 the information referred to in sections 2.5.2.1 to 2.5.2.4, to the extent that the *respondent* disagrees with the information relating thereto set forth in the *notice of dispute*;

2.5.5.2 a concise *response* to the allegations made against the *respondent* in the *notice of dispute*;

2.5.5.3 the relief sought, a summary of the grounds for such relief and, where the relief sought includes a counterclaim or crossclaim against the *applicant* or against any other *respondent*, the information referred to in sections 2.5.2.1 to 2.5.2.4 as it pertains specifically to such counterclaim or crossclaim; and

2.5.5.4 any documentation upon which the *respondent* intends to rely in support of its *response*, including as to any counterclaim or crossclaim, and which was not identified by the *applicant*.

2.5.6 The *response* shall be accompanied by a summary of the *response* for *publication* in accordance with section 2.9.2.1.

2.5.6A A *respondent* to a counterclaim or crossclaim shall, within ten *business days* of service of a *response* or of a response to a counterclaim or crossclaim, serve a written response to the counterclaim or crossclaim on the *applicant* and on any other *respondent* and shall file with the *secretary* a copy of the response to the counterclaim or crossclaim, together with proof of service of the response to the counterclaim or crossclaim on the *applicant* and on any other *respondent*, including a *respondent* to a counterclaim or crossclaim identified in the response to the counterclaim or crossclaim.

2.5.6B The response to the counterclaim or crossclaim shall be in such form as may be established by the *IESO*, shall be signed by a person with authority to bind the *respondent* and shall specify, in reasonable detail and to the best of the *respondent's* knowledge:

2.5.6B.1 the information referred to in sections 2.5.2.1 to 2.5.2.4, to the extent that the *respondent* disagrees with the information relating thereto set forth in the *response* containing the counterclaim or crossclaim;

2.5.6B.2 a concise response to the allegations made against the *respondent* in the *response* containing the counterclaim or crossclaim;

2.5.6B.3 the relief sought, a summary of the grounds for such relief and, where the relief sought includes a counterclaim or a crossclaim against the *applicant* or another *respondent*, the information referred to in sections 2.5.2.1 to 2.5.2.4 as it pertains specifically to such counterclaim or crossclaim; and

2.5.6B.4 any documentation upon which the *respondent* intends to rely in support of its response to the counterclaim or crossclaim, including as to any counterclaim or crossclaim, and which was not identified by the *applicant* or by the *respondent* whose *response* contains the counterclaim or crossclaim.

2.5.6C The response to a counterclaim or crossclaim shall be accompanied by a summary of the response for *publication* in accordance with section 2.9.2.1.

2.5.7 Subject to sections 2.1.3 and 2.5.9, the *secretary* shall reject and shall not take any further action with respect to a *notice of dispute*, a *response*, or a response to a counterclaim or crossclaim that does not comply with the provisions of this section 2.5.

2.5.7.1 [Intentionally left blank – section deleted]

2.5.7.2 [Intentionally left blank – section deleted]

Where the *secretary* rejects a *notice of dispute*, a *response* or a response to a counterclaim or crossclaim pursuant to this section 2.5.7, the *secretary* shall so notify the *applicant* and the *respondent* filing the *response* or the response to the counterclaim or crossclaim, as the case may be, and shall provide written reasons for the rejection.

2.5.8 [Intentionally left blank – section deleted]

2.5.9 Where the *secretary* rejects a *response* or a response to a counterclaim or crossclaim pursuant to section 2.5.7:

2.5.9.1 such rejection shall be without prejudice to the right of the *applicant* or the *respondent* whose *response* includes the counterclaim or crossclaim, as the case may be, to proceed with the resolution of the dispute in accordance with section 2; and

2.5.9.2 where such rejection relates to a *response*, section 2.6.1 shall not apply to the dispute and the *applicant* may following receipt of the notice referred to in section 2.5.7 request that the *secretary* take the action referred to in section 2.7.1.

2.6 Mediation

2.6.1 Subject to sections 2.6.1A and 2.6.1B, no party to a dispute may proceed to arbitration of the dispute until such time as the mediation process described in this section 2.6 has been terminated in accordance with section 2.6.14.

2.6.1A Absent agreement of the parties, section 2.6.1 shall not apply to:

2.6.1A.1 an application by a *generator* or *electricity storage participant* for compensation pursuant to section 6.7.5 of Chapter 5 in respect of an *outage* rejected by the *IESO*;

2.6.1A.2 a dispute referred to in section 6.10.1 of Chapter 9, except those matters described in section 6.8.12.4 of Chapter 9;

2.6.1A.3 a dispute that involves a *reviewable decision* referred to in section 5.3.9 of Chapter 6; or

2.6.1A.4 a dispute referred to in section 2.5.9.2.

2.6.1B Where all of the parties to a dispute so agree, the parties may dispense with mediation in respect of the dispute. In such a case, the parties shall file with the *secretary* a notice of intent to dispense with mediation in such form as may be established by the *IESO*.

2.6.2 Subject to section 2.6.2C, within five *business days* of the filing of a *notice of dispute* in respect of an application to which section 2.6.1A.1 applies or of the earlier of the filing of a *response* or of the expiry of the time for filing a *response* pursuant to section 2.5.4 in all other cases, the *secretary* shall, provided that the *secretary* is satisfied that the dispute is one to which section 2.2.1 or 2.2.2 applies and that the dispute has not been resolved:

2.6.2.1 in the case of a dispute referred to in section 2.6.1A, upon receipt of the notice referred to in section 2.6.1B or upon receipt of the request referred to in section 2.5.9.2, take the action referred to in section 2.7.1 or 2.7.1D, as the case may be; or

2.6.2.2 in any other case, subject to section 2.6.2A, assign one member of the *dispute resolution panel* who is independent of the parties to inquire into and act as *mediator* in respect of the dispute and shall advise the parties to the dispute as to the identity and address for service of the *mediator*.

Where the *secretary* is not satisfied that the dispute is one to which section 2.2.1 or 2.2.2 applies, the *secretary* shall so advise the parties.

2.6.2A Where all of the parties to a dispute so agree, they may appoint a qualified person that is not a member of the *dispute resolution panel* to mediate the dispute. In such a case, the parties shall advise the *secretary* as to the identity and address for service of the *mediator*.

2.6.2B A *mediator* appointed under section 2.6.2A shall not be required in any proceeding to give testimony with respect to information obtained in the course or resolving or attempting to resolve the dispute.

2.6.2C Where a *response* or a response to a counterclaim or crossclaim contains a counterclaim or crossclaim against another *respondent*, the *secretary* shall not take the action referred to in section 2.6.2.1 or 2.6.2.2 until five *business days* following:

2.6.2C.1 the filing of the response to a counterclaim or crossclaim in respect of the last counterclaim or crossclaim filed in the same dispute; or

2.6.2C.2 the expiry of the time for filing a response to a counterclaim or crossclaim pursuant to section 2.5.6A in respect of the last counterclaim or crossclaim filed in the same dispute,

whichever is the earlier.

2.6.3 The *mediator* shall fix a date, time and place for the mediation session, which date shall be no more than seven *business days* from the date of notice of his or her appointment or such later date as may be agreed by each party to the dispute, and shall attempt to assist the parties to resolve their dispute. The *mediator* may continue the mediation session at such times and places as the *mediator* determines in an effort to assist the parties in resolving their dispute.

2.6.4 Each party shall send to the mediation session a representative who has the authority to bind the party.

2.6.5 Prior to participating in a mediation session, the parties must sign and file with the *secretary* an agreement that statements made at a mediation session are confidential, are made without prejudice and are not subject to voluntary disclosure in any subsequent proceeding or to be voluntarily produced into evidence for any purpose.

2.6.6 Mediation sessions shall be private and there shall be no stenographic record of any mediation session. The parties and their representatives may attend mediation sessions. Other persons may attend only with the permission of all of the parties, with the consent of the *mediator* and upon such conditions including, but not limited to, conditions relating to confidentiality, as the *mediator* determines appropriate.

2.6.7 *Confidential information* disclosed to a *mediator* by the parties or by other persons in the course of the mediation shall not be divulged by the *mediator*. All records, reports or other documents prepared for the mediation and received by a *mediator* while serving in that capacity shall be treated as confidential unless all of the parties to the dispute otherwise agree.

2.6.8 The *mediator* may conduct joint and separate meetings with the parties and make oral and written recommendations for settlement. Recommendations for settlement made, and views expressed by, the *mediator* at such meetings or at a mediation session are confidential and are not subject to voluntary disclosure in any subsequent proceeding and are not voluntarily to be produced into evidence for any purpose.

2.6.9 The *mediator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation which is not *confidential information* and which the *mediator* considers relevant to the conduct of the mediation, and the *mediator* shall provide any such information or documentation to the parties in advance of the mediation session at which such information or documentation is to be considered.

2.6.10 The *mediator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation pertaining to a party to the dispute which is *confidential information* and which the *mediator* considers relevant to the conduct of the mediation. Such *confidential information* shall not, without the consent of the party to whom the *confidential information* relates, be disclosed by the *mediator* to the other parties to the dispute.

2.6.11 Whenever he or she considers necessary, the *mediator* may, with the consent of the parties and upon such conditions relating to confidentiality as the *mediator* determines appropriate, obtain expert advice concerning technical aspects of the dispute. Arrangements for obtaining such advice shall be made by the *mediator* or a party, as the *mediator* shall determine.

2.6.12 If an agreement to resolve the dispute is reached through mediation, it shall be reduced to writing, signed by the parties and filed with the *secretary*. The terms of the agreement shall be confidential, provided that if, in the case of a dispute referred to in section 2.2.1, the agreement consists of, embodies or reflects an element which, in the opinion of the *IESO Board*, is an important matter of public policy or interest having regard to the provisions of the *Electricity Act, 1998*, the *IESO* shall *publish* a statement describing such important matter of public policy or interest.

2.6.13 The *mediator* may terminate the mediation by written notice of termination whenever, in the judgement of the *mediator*, further efforts at mediation would not contribute to a resolution of the dispute between the parties. The *mediator* shall provide each party with a copy of the written notice of termination and shall file a copy of the notice of termination with the *secretary*, in each case together with a copy of any agreed statement of fact and/or of issues referred to in section 2.6.15.

2.6.14 The mediation shall be terminated on the earlier of:

2.6.14.1 the date of execution by the parties of the agreement referred to in section 2.6.12;

2.6.14.2 the date of the notice of termination referred to in section 2.6.13; or

2.6.14.3 the date that is ten *business days*, or such longer period as may be agreed by each party to the dispute, from the date of the first mediation session.

2.6.15 If the parties are unable to reach any agreement to resolve the dispute on or prior to the date referred to in section 2.6.14.2 or 2.6.14.3 they shall nonetheless make good faith efforts to arrive at an agreed statement of fact and/or of issues relating to the dispute.

2.6.16 If the parties are unable to reach any agreement to resolve the dispute on or prior to the date referred to in section 2.6.14.3, the *mediator* shall issue a written notice of termination unless the *mediator* has, prior to that date, issued the written notice of termination referred to in section 2.6.13. The *mediator* shall provide each party with a copy of the notice of termination issued pursuant to this section 2.6.16, together with a copy of any agreed statement of fact and/or of issues referred to in section 2.6.15, and file a copy of the foregoing with the *secretary*.

2.6.17 The parties are responsible for their own costs and legal expenses incurred in respect of the mediation. The parties must bear equally the *costs of the mediation* unless otherwise agreed to by the parties.

2.6.18 Upon termination of the mediation, the *mediator* shall file with the *secretary* an invoice containing an itemized statement of the *costs of the mediation*, together with all bills and other supporting documentation relating thereto.

2.6.19 Upon receipt of the invoice referred to in section 2.6.18, the *secretary* shall provide a copy of the invoice to the *IESO* and the *IESO* shall submit an invoice to each of the parties to the mediation in respect of their respective shares of the *costs of the mediation*. Each party shall, within *ten business days* of the date of receipt of such invoice, pay to the *IESO* the amount owing thereunder. Such invoice shall be considered to create an obligation under the *market rules* to pay the amount specified in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

2.6.20 Where a *mediator* dies, resigns or otherwise becomes incapable of acting as *mediator* in respect of a dispute prior to termination of the mediation, subject to section 2.6.2A, the *secretary* shall assign another member of the *dispute resolution panel* to inquire into and act as *mediator* in respect of the dispute. With the consent of the parties to the mediation, the new *mediator* may continue the mediation. In the absence of such consent, the *mediator* shall commence the mediation anew and the time period prescribed in section 2.6.14.3 shall be extended accordingly.

2.7 Arbitration

2.7.1 Subject to section 2.7.1C, within five *business days* of:

2.7.1.1 the earlier of the filing of a *response* or of the expiry of the time for filing a *response* pursuant to section 2.5.4, where the dispute is one to which section 2.6.1A.1, 2.6.1A.2 or 2.6.1A.3 applies;

2.7.1.1A the filing of the request referred to in section 2.5.9.2, where the dispute is one to which that section applies;

2.7.1.2 the filing of a notice of intent to dispense with mediation pursuant to section 2.6.1B, where the dispute is one to which that section applies;

2.7.1.2A the filing of the *notice to elect* referred to section 6.2B.7 electing subsection 6.2B.7.1; or

2.7.1.3 the filing of the notice of termination referred to in section 2.6.13 or 2.6.16, in any other case,

the *secretary* shall, subject to section 2.7.1A, in accordance with the *Governance and Structure By-law* provide the parties with a list of at least three names of members of the *dispute resolution panel* available to arbitrate the dispute. No person who acted as a *mediator* in respect of a dispute may be included on the list of members available to arbitrate the same dispute.

2.7.1A Where all the parties to a dispute so agree, they may appoint a qualified person that is not a member of the *dispute resolution panel* to arbitrate the dispute. In such a case, the parties shall advise the *secretary* as to the identity and address for service of the *arbitrator*.

2.7.1B An *arbitrator* appointed under section 2.7.1A shall not be required in any proceeding to give testimony with respect to information obtained in the course or resolving or attempting to resolve the dispute.

2.7.1C Where a *response* or a response to a counterclaim or crossclaim filed in respect of a dispute to which section 2.6.1A applies contains a counterclaim or crossclaim against another *respondent*, the *secretary* shall not take the action referred to in section 2.7.1.1 until five *business days* following:

2.7.1C.1 the filing of the response to a counterclaim or crossclaim in respect of the last counterclaim or crossclaim filed in the dispute; or

2.7.1C.2 the expiry of the time for filing a response to a counterclaim or crossclaim pursuant to section 2.5.6A in respect of the last counterclaim or crossclaim filed in the dispute,

whichever is the earlier.

2.7.1D Within five *business days* of the filing of a *notice of dispute* in respect of an application to which section 2.6.1A.1 applies, subject to section 2.7.1A, the *secretary* shall in accordance with the *Governance and Structure By-law* provide the *applicant* with a list of at least three names of members of the *dispute resolution panel* available to determine the amount of any compensation payable to the *applicant*. Where the *applicant* fails to select an *arbitrator* within ten *business days* of receipt of such list, subject to section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the *arbitrator* in respect of the application and shall by written notice so advise the *applicant*. The *arbitrator* shall be deemed to have been appointed as of the date of such notice.

2.7.1E In the case of an application referred to in section 2.7.1D:

2.7.1E.1 sections 2.7.2, 2.7.8, 2.7.9, 2.7.10 and 2.7.32 shall not apply; and

2.7.1E.2 all other sections of this section 2.7 shall be read:

a. without regard to references to a *respondent*; and
b. by replacing all references to the word "party" or "parties" with the word "*applicant*".

2.7.2 The parties shall make good faith efforts to agree on the appointment of one of the members named on the list referred to in section 2.7.1 as the arbitrator to hear the dispute. Where the parties so agree, they shall by written notice so advise the *secretary*. Such member shall be the *arbitrator* for purposes of the resolution of the dispute and shall be deemed to have been appointed as of the date of such notice.

2.7.3 [Intentionally left blank]

2.7.4 [Intentionally left blank]

2.7.5 Where the parties to a dispute have failed to select an *arbitrator* within ten *business days* of receipt of the list referred to in section 2.7.1, or advise the *secretary* in accordance with section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the *arbitrator* in respect of the dispute and shall by written notice so advise the parties. The *arbitrator* shall be deemed to have been appointed as of the date of such notice.

2.7.6 An *arbitrator* shall be independent of the parties and shall act impartially. An *arbitrator* who is or becomes aware of circumstances that may give rise to a reasonable apprehension of bias shall promptly disclose them to the *secretary* and the parties.

2.7.7 An *applicant* shall, within thirty days of the appointment of the *arbitrator*, serve on any *respondent*, and file with the *arbitrator*, a written statement containing its submissions on each issue in dispute. At the same time, the *applicant* shall serve and file a list of all documents which it intends to file at the arbitration, copies of all such documents, and a list of witnesses intended to be called or to provide written evidence-in-chief at the hearing of the arbitration together with a concise written summary of the anticipated evidence of each witness. The *applicant* must indicate if it will be represented by legal counsel or some other representative and provide such person's name and address for service.

2.7.8 A *respondent* shall, within thirty days of the date of receipt of the *applicant's* materials referred to in section 2.7.7, serve on an *applicant* and on any other *respondent*, and file with the *arbitrator*, a written statement containing its submissions on each issue in dispute. At the same time, the *respondent* shall serve and file a list of all documents which it intends to file at the arbitration, copies of all such documents, and a list of witnesses intended to be called or to provide written evidence-in-chief at the hearing of the arbitration together with a concise written summary of the anticipated evidence of each witness. A *respondent* must indicate if it will be represented by legal counsel or some other representative and provide such person's name and address for service.

2.7.9 The *applicant* may, within ten days of receipt of the *respondent's* materials referred to in section 2.7.8, serve and file written reply submissions.

2.7.10 Where a *respondent* has made a counterclaim or a crossclaim in his or her *response*, the *respondent* shall, for purposes of the application of sections 2.7.7 to 2.7.9 and, where appropriate, of section 2.7.19, be treated as an *applicant* and the person against whom the counterclaim or the crossclaim has been made shall be treated as a *respondent* in respect of the counterclaim or crossclaim.

2.7.11 The *arbitrator* shall fix a date, time and place for the hearing following:

2.7.11.1 in the case of an application referred to in section 2.7.1B, the filing of the *applicant's* materials referred to in section 2.7.7; and

2.7.11.2 in all other cases, the service and filing of the *respondent's* materials referred to in section 2.7.8 or, where applicable, the materials of a *respondent* to the counterclaim or crossclaim referred to in section 2.7.10, which date shall be no more than sixty days from the date of the service and filing referred to in section 2.7.8 or, where applicable, of the service and filing referred to in section 2.7.10, whichever is the later, or such later date as may be agreed by each party to the arbitration. The *arbitrator* shall file with the *secretary* a notice of the date, time and place so fixed.

2.7.12 A *market participant* who might be directly affected by the award of the *arbitrator* in a dispute referred to in section 2.2.1 or 2.2.2.1 and, in the case of an application referred to in section 2.7.1D or of a dispute referred to in section 2.2.2.1, the *IESO*, may apply to the *arbitrator*, on notice to the parties, no less than five *business days* prior to the date of the hearing, for leave to intervene at the hearing. Parties may make submissions on the application for leave to intervene. The *arbitrator* may, in his or her sole discretion, grant leave to intervene to any *market participant* who demonstrates that it has an interest in the subject matter of the arbitration and may be directly affected by the decision in the arbitration, on such terms and subject to such rights of participation as the *arbitrator* considers reasonable.

2.7.13 The procedures governing the arbitration shall be determined by the *arbitrator*, except as provided for under the market rules and by sections 19 to 22, 25 (other than 25(3) to 25(5)) to 33, 36, 36 and 40 to 44 of the *Arbitration Act, 1991*.

2.7.13.1 The *arbitrator* shall dismiss the *notice of dispute* and take no further action with respect to the *notice of dispute* if the *notice of dispute* was served outside of the timelines set forth in section 2.5.1A.

2.7.14 Nothing in writing shall be accepted in evidence at the hearing nor any witness be permitted to give evidence at the hearing, in both cases by or on behalf of an *applicant* or a *respondent*, except with leave of the *arbitrator*, unless the party has complied with the requirements set forth in section 2.7.7 or 2.7.8, as the case may be.

2.7.15 Any party to a dispute may apply to the *arbitrator* for, and the *arbitrator* may order, such further and other production as the *arbitrator* sees fit, provided that the *arbitrator* may not order the production by the *market surveillance panel* or the *market assessment unit* of *confidential information* which relates to a person who is not a party to the dispute. Evidence may be admitted by the *arbitrator* even if not admissible as evidence in a court of law.

2.7.16 The *arbitrator* may, with the consent of all parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation which is not *confidential information* and which the *arbitrator* considers relevant to the conduct of the arbitration, and the *arbitrator* shall provide any such information or documentation to the parties in advance of the hearing at which such information or documentation is to be considered.

2.7.17 The *arbitrator* may, with the consent of the parties, request an agent, employee, officer or director of the *IESO*, or a member of a panel established by the *IESO*, to provide him or her with any information or documentation pertaining to a party which is *confidential information* and which the *arbitrator* considers relevant to the conduct of the arbitration. Subject to section 2.8.1, the *arbitrator* shall provide any such information or documentation to the parties in advance of the hearing at which such information or documentation is to be considered.

2.7.18 Whenever he or she considers necessary, the *arbitrator* may, upon such conditions as to confidentiality as the *arbitrator* determines appropriate and upon notice to the parties, obtain expert advice concerning technical aspects of the dispute. Arrangements for obtaining such advice shall be made by the *arbitrator* or a party, as the *arbitrator* shall determine, provided that where such arrangements are made by the *arbitrator*, the *arbitrator* shall provide to the parties advance notice of the identity of the expert advisor.

2.7.19 At the hearing, the *applicant* shall provide its case in chief, followed by the *respondent* in response, and then the *applicant* in reply.

2.7.20 Witnesses shall be examined under oath or affirmation and shall be made available for cross-examination. Nothing in this section 2.7.20 shall preclude the *arbitrator* from dispensing with the oral examination-in-chief of a witness provided that a written statement of the witness's evidence is provided in such form as the *arbitrator* determines appropriate.

2.7.21 Subject to section 2.8.1, the arbitration shall be open to the public and all documents filed will form part of the public record of the proceedings.

2.7.22 The *arbitrator* shall deliver his or her award in writing, with reasons, within 30 days of completion of the hearing or within such longer period as may be agreed by each party to the dispute.

2.7.23 The *arbitrator* shall file a copy of his or her award with the *secretary*.

2.7.24 Where, in the case of a dispute referred to in section 2.2.1.1 or 2.2.1.1A, the *arbitrator* concludes that a *market participant* has violated a provision of the *market rules*, the *arbitrator* may in his or her award impose such financial penalties, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable, provided that:

2.7.24.1 no financial penalty shall be imposed on a *market participant* unless the *arbitrator* determines that the breach of the *market rules* could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; and

2.7.24.2 in fixing the amount of the penalty, the *arbitrator* shall have regard to the criteria set forth in section 6.6.7.

An award of the *arbitrator* under this section shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the *Electricity Act, 1998.*

2.7.25 Where, in the case of a dispute referred to in section 2.2.1.1 the *arbitrator* concludes that the *IESO* has violated, misinterpreted or misapplied a *market rule*, the *arbitrator* may, subject to section 13 of Chapter 1 and to any other provision of these *market rules* pertaining specifically to liability, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable. Without limiting the generality of the foregoing, where the *arbitrator* determines that the breach, misinterpretation or misapplication of a *market rule* by the *IESO* was intentional or could have been avoided by the exercise of due diligence by the *IESO*, the *arbitrator* shall direct the *IESO* to comply with the *market rules* or to interpret or apply the *market rules* in a particular manner. Any such direction may be included in the summary referred to in section 2.9.2.4.

2.7.25A Subject to section 13 of Chapter 1 and to any other provision of these *market rules* pertaining specifically to liability, the *arbitrator* may, in the case of a dispute referred to in section 2.2.1.2, 2.2.1.4 or 2.2.1.5, in addition to the orders referred to in section 2.7.26, 2.7.27 or 2.7.29, as the case may be, assess such damages or make such further and other orders or directions as the *arbitrator* considers just and reasonable.

2.7.26 Where a dispute referred to in section 2.2.1.1 relates to the terms and conditions upon which the *IESO* has authorized a person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, the *arbitrator* may confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* on such other terms and conditions, if any, which the *arbitrator* determines are just and reasonable. An award of the *arbitrator* under this section 2.7.26 may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the Electricity Act, 1998.

2.7.27 The *arbitrator* may:

2.7.27.1 in the case of a dispute referred to in section 2.2.1.2, confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*, on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable;

2.7.27.2 in the case of a dispute referred to in section 2.2.1.5, and subject to section 2.7.29B, make such orders or directions as the *arbitrator* considers just and reasonable, and an award of the *arbitrator* under this section 2.7.27 may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the

IESO for purposes of the *market rules* and the application of the appeal provisions of section 36 of the Electricity Act, 1998.

2.7.27A Notwithstanding section 2.7.27, in regards to those matters specified in section 2.5.1B, an arbitrator shall not order the *IESO* to take any action or make any adjustment in regards to any settlement amount which was invoiced, or the *IESO* had the right or obligation to invoice, more than 24 months before the date on which the *market participant* served the *notice of dispute*. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, an arbitrator shall not order the IESO to take any action or make any adjustment in regards to such settlement amount beyond the limitation period, if any, provided pursuant to *applicable law*.

2.7.28 In the case of an application referred to in section 2.2.1.3, the *arbitrator* may determine that no compensation is payable to the *applicant* or may order the *IESO* to pay compensation to the *applicant* in such amount and within such time as may be fixed by the *arbitrator* in accordance with any applicable provisions of section 6.7.5 of Chapter 5.

2.7.29 In the case of a dispute referred to in section 2.2.1.4:

2.7.29.1 where the dispute relates to the *reviewable decision* referred to in section 2.1.2 of Chapter 6, the *arbitrator* may confirm the order of the *IESO* or set aside the order of the *IESO* and order the *IESO* to authorize the person to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of the relevant *connection point* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25 and shall be deemed to be a decision or order of the *IESO* for purposes of the *market rules* and the application of the appeal provisions of section 36 of the Electricity Act, 1998;

2.7.29.2 where the dispute relates to the *reviewable decision* referred to in section 5.3.9 of Chapter 6, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to reinstate the registration of the *metering service provider* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable and the award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25;

2.7.29.3 where the dispute relates to the *reviewable decision* referred to in section 5.1.12 of Chapter 6, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to register the person as a *metering service provider* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25; or

2.7.29.4 where the dispute relates to the *reviewable decision* referred to in section 4.4.3 or 6.1.5 of Chapter 6, the *arbitrator* may confirm the order or decision of the *IESO* or set aside the order or decision of the *IESO* and order the *IESO* to register the *metering installation* on such terms and conditions, if any, which the *arbitrator* determines are just and reasonable, and such award of the *arbitrator* may include the direction to the *IESO* referred to in section 2.7.25.

2.7.29A In the case of a dispute referred to in section 2.2.2.1, the *arbitrator* may:

2.7.29A.1 determine an alternative apportionment of the *energy* associated with *connection station service* and with site specific losses amongst all applicable *market participants*; and

2.7.29A.2 determine whether, and the extent to which, any such alternative apportionment should be applied, by means of payments amongst the applicable *market participants*, to any period prior to the date on which the *IESO* gives effect to the proportions filed pursuant to section 2.1A.6B of Chapter 9.

2.7.29B Subject to section 2.7.27A, in the case of a dispute referred to in section 6.10.1 of Chapter 9, the *arbitrator* may, in considering whether to order the *IESO* to adjust *settlement statements* of multiple *market participants*, take into account:

2.7.29B.1 the dollar amount that is the subject-matter of the dispute;

2.7.29B.2 the time elapsed since the event that is the subject-matter of the dispute took place; and

2.7.29B.3 the *IESO's* ability to perform such adjustments.

2.7.30 In the case of a dispute referred to in section 2.2.2.2, the *arbitrator* may make such award, including but not limited to an award of damages, as is just and reasonable in the circumstances.

2.7.31 [Intentionally left blank]

2.7.32 Subject to section 2.7.32A, the *arbitrator* may make such award as to costs as he or she determines just and reasonable provided that, except in exceptional cases:

2.7.32.1 where in the context of a dispute referred to in section 2.2.1 the award consists of damages for breach of the *market rules*, costs, including the *costs of the arbitration*, shall be awarded to the successful party;

2.7.32.2 where the award consists of the imposition of penalties on a *market participant*, costs, including the *costs of the arbitration*, shall be awarded to the *IESO*; and

2.7.32.3 where the award consists of the direction to the *IESO* to comply with the *market rules* or to interpret or apply a *market rule* in a particular manner pursuant to section 2.7.25, costs, including the *costs of the arbitration*, shall be awarded to the *market participant* seeking the direction.

2.7.32A Where an award relates to an application referred to in section 2.7.1D and:

2.7.32A.1 the award consists of a determination by the *arbitrator* that the *applicant* is not entitled to any compensation pursuant to section 6.7.5 of Chapter 5; or

2.7.32A.2 no award as to costs is made pursuant to section 2.7.32B,

the *applicant* shall be responsible for his or her own costs and legal expenses associated with his or her participation in the arbitration and, subject to any determination of the *arbitrator* pursuant to section 2.7.33, shall bear the *costs of the arbitration*.

2.7.32B Where an award relates to an application referred to in section 2.7.1D and the award consists of a determination by the *arbitrator* that the *applicant* is entitled to compensation pursuant to section 6.7.5 of Chapter 5, the *arbitrator* may determine that some or all of:

2.7.32B.1 the *applicant's* costs and legal expenses associated with his or her participation in the arbitration; and

2.7.32B.2 the applicant's share of the costs of the arbitration,

be recovered by the *applicant*. Where the *arbitrator* makes such an award as to costs, the amount of such recoverable costs shall be paid by the *IESO* and recovered by the *IESO* in the same manner as the compensation referred to in section 6.7.5 of Chapter 5.

2.7.33 A person who intervenes in an arbitration shall be responsible for his or her own costs and legal expenses associated with his or her participation in the arbitration. The *arbitrator* may, in appropriate circumstances, require that an intervenor bear a portion of the *costs of the arbitration*.

2.7.34 An award of the *arbitrator* shall be enforceable in the manner provided in the *Arbitration Act, 1991*.

2.7.35 Where, in the case of a dispute referred to in section 2.2.1, the award consists of the payment of monies to the *IESO* or to a *market participant*, such award shall be considered to create an obligation under the *market rules* to pay the amount stated in the award and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly. Except as may otherwise be provided in the award, any monies payable pursuant to an award shall be payable within 30 days of the date of the award.

2.7.36 Failure to comply with an award of an *arbitrator* in respect of a dispute referred to in section 2.2.1 constitutes a breach of the *market rules*.

2.7.37 Upon completion of an arbitration, the *arbitrator* shall file the record of the arbitration proceedings with the *secretary*. Where such record contains *confidential information* in respect of which a claim for confidentiality has been confirmed by the *arbitrator* pursuant to section 2.8.1, the *confidential information*, together with the stenographic record of any in camera hearings relating thereto, shall be sealed in an envelope clearly marked "CONFIDENTIAL" or otherwise identified as confidential and protected from disclosure prior to filing with the *secretary*.

2.7.38 Upon completion of the arbitration, the *arbitrator* shall file with the *secretary* an invoice containing an itemized statement of the *costs of the arbitration*, together with copies of all bills and other supporting documentation relating thereto.

2.7.39 Upon receipt of the invoice referred to in section 2.7.38, the *secretary* shall submit a copy of the invoice to the *IESO* and the *IESO* shall submit an invoice to each of the parties to the arbitration and, where applicable, each intervenor, in respect of their respective shares of the *costs of the arbitration*. Each such person shall, within ten *business days* of receipt of such invoice, pay to the *IESO* the amount owing thereunder. Such invoice shall be considered to create an obligation under the *market rules* to pay the amount specified in the invoice and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

2.7.40 Where an *arbitrator* dies, resigns, is removed or otherwise becomes incapable of acting as an *arbitrator* in respect of a dispute prior to completion of the arbitration, a replacement shall, with the consent of all of the parties to the arbitration, be selected by the *secretary* from among the remaining members of the *dispute resolution panel* in accordance with the *Governance and Structure By-law*. In the absence of such consent, subject to section 2.7.1A, the *secretary* shall forthwith provide the parties with a revised list of at least three names of members of the *dispute resolution panel* available to fill the vacancy and the parties shall make good faith efforts to agree on the appointment of one of the members named in the list as the replacement *arbitrator*. Where the parties so agree, they shall so advise the *secretary*.

2.7.41 [Intentionally left blank]

2.7.42 Where the parties have failed to select a replacement *arbitrator* within ten *business days* of receipt of the list referred to in section 2.7.40, subject to section 2.7.1A, the *secretary* shall, in accordance with the *Governance and Structure By-law*, appoint one member of the *dispute resolution panel* to be the replacement *arbitrator* and shall by written notice so advise the parties.

2.7.43 With the consent of the parties to the arbitration, once the *arbitrator* has been replaced, the *arbitrator* may continue the arbitration. In the absence of such consent, the replacement *arbitrator* shall commence the arbitration anew.

2.8 Confidentiality

2.8.1 Any party may claim that a document, or information contained in a document, to be produced in the context of the arbitration of a dispute is *confidential information*. The party making such a claim shall provide to the *arbitrator* in writing the basis for its assertion. If the claim of confidentiality is confirmed by the *arbitrator*, having regard, where applicable, to the provisions of section 5, the *arbitrator* shall establish requirements for the protection of such document or information as may be necessary to protect the confidentiality and commercial value of such document or information, including requirements for disclosure of same only to counsel and/or other independent advisor who has filed an undertaking as to confidentiality satisfactory to the *arbitrator* and for in camera hearings at which only representatives of the disclosing party and such counsel and/or other independent advisor may be present.

2.8.2 Members of the *dispute resolution panel* shall enter into such confidentiality agreement as may be required by the *IESO Board*.

2.9 Record-Keeping and Publication

2.9.1 Subject to section 2.9.1A, the *secretary* shall maintain a record of all dispute resolution proceedings conducted under this section 2. Upon the completion of a given dispute resolution proceeding, the *secretary* shall transfer the record to the *IESO*, addressed to the Chair of the Board of Directors of the *IESO* for archiving. The Chair shall be responsible for ensuring that all measures are taken to prohibit access by any other person to any portion of such record which may be sealed and marked "CONFIDENTIAL" or otherwise identified as being confidential, except as may be required by *applicable law* or permitted by the provisions of section 5.

2.9.1A For the purposes of section 2.9.1, the record referred to therein shall not include any record pertaining to or arising from the mediation of a dispute other than:

2.9.1A.1 the name and address for service of the person appointed to act as the *mediator* in respect of the dispute;

2.9.1A.2 the agreement referred to in section 2.6.5;

2.9.1A.3 the settlement agreement referred to in section 2.6.12;

2.9.1A.4 the notice of termination of mediation referred to in section 2.6.13 or 2.6.16;

2.9.1A.5 the agreed statement of fact and/or issues referred to in section 2.6.13 or 2.6.16; and

2.9.1A.6 information and documentation pertaining to the *costs of the mediation*, including the invoice referred to in section 2.6.18.

2.9.2 The *secretary* shall arrange for *publication* by the *IESO* of the following:

2.9.2.1 the summaries referred to in sections 2.5.3C, 2.5.6 and 2.5.6C as may be applicable upon the appointment of the *arbitrator*;

2.9.2.2 notice of the appointment of an *arbitrator* and the address for service of the *arbitrator*;

2.9.2.3 notice of the date, time and place fixed for hearing pursuant to section 2.7.11; and

2.9.2.4 a summary of the award of an *arbitrator* filed pursuant to section 2.7.23, which may include the information required by section 2.7.25.

2.9.3 The *IESO* shall *publish* the fees payable to members of the *dispute resolution panel* involved in the resolution or the attempted resolution of a dispute pursuant to this section 2, as such fees may from time to time be fixed in accordance with the provisions of the *Governance and Structure By-law*.

2.10 Audit

2.10.1 The activities of the *dispute resolution panel* shall be audited in accordance with procedures adopted from time to time by the *IESO*.

3. Market Surveillance

3.1 [Intentionally left blank – section deleted]

3.2 Establishment and Staffing of Market Assessment Unit

3.2.1 A *market assessment unit* shall be established by the *IESO* to perform the functions given to it under the *market rules* and to support, in the manner agreed to by the *IESO* and the *OEB*, the *market surveillance panel.*

3.2.2 [Intentionally left blank – section deleted]

3.2.3 [Intentionally left blank – section deleted]

3.2.4 [Intentionally left blank – section deleted]

3.3 Market Monitoring Functions

3.3.1 The *market assessment unit* shall conduct such monitoring, evaluation, analysis and reporting activities in support of the work of the *market surveillance panel* as may be agreed between the *IESO* and the *OEB*.

3.3.1.1 [Intentionally left blank – section deleted]

3.3.1.2 [Intentionally left blank – section deleted]

3.3.1.3 [Intentionally left blank – section deleted]

3.3.1A Notwithstanding any other provision of Chapter 3, the *IESO* shall provide the *market surveillance panel* with such information as it may require from time to time.

3.3.2 [Intentionally left blank – section deleted]

3.3.2A [Intentionally left blank – section deleted]

3.3.3 [Intentionally left blank – section deleted]

3.3.3A [Intentionally left blank – section deleted]

3.3.4 [Intentionally left blank – section deleted]

3.3.5 [Intentionally left blank – section deleted]

3.3.5A *Market participants* shall provide the *market assessment unit* with the data identified in the detailed catalogue adopted and published by the *market surveillance panel* in accordance with the *OEB* by-laws.

3.3.6 [Intentionally left blank – section deleted]

3.3.7 [Intentionally left blank – section deleted]

3.3.8 [Intentionally left blank – section deleted]

3.3.8A [Intentionally left blank – section deleted]

3.3.8B [Intentionally left blank – section deleted]

3.3.9 [Intentionally left blank – section deleted]

3.3.10 [Intentionally left blank – section deleted]

3.3.10A [Intentionally left blank – section deleted]

3.3.11 [Intentionally left blank – section deleted]

3.3.12 [Intentionally left blank – section deleted]

3.3.13 [Intentionally left blank – section deleted]

3.4 [Intentionally left blank – section deleted]

3.5 [Intentionally left blank – section deleted]

3.6 [Intentionally left blank – section deleted]

3.7 [Intentionally left blank – section deleted]

3.8 Dispute Resolution and Other Relief

3.8.1 The dispute resolution procedures under section 2 shall not apply to the activities of the *market assessment unit* under this section 3.

3.8.2 Nothing in this section 3 shall prevent the *IESO* or any other person from asserting any rights they may have under any *applicable law* or under the *market rules*.

3.9 [Intentionally left blank – section deleted]

3.10 [Intentionally left blank – section deleted]

4. Rule Amendments

4.1 Introduction and Interpretation

4.1.1 This section 4 sets forth the procedures pursuant to which *amendments* to the *market rules* may be made by the *IESO* and embodies the mechanism for review of the *market rules* for purposes of the application of subsection 35(4) of the Electricity Act, 1998.

4.1.2 This section 4 must be read and construed subject to the *Governance and Structure By-law.*

4.2 Amendment Process Generally

4.2.1 Under section 32 of the *Electricity Act, 1998*, the *IESO Board* has the authority and responsibility to *amend* these *market rules*. The *technical panel* is authorized, through the *Governance and Structure By-law*, to support the *IESO Board* in the development and consideration of *amendments* to the *market rules*. The *urgent rule amendment committee* is authorized, through the *Governance and Structure*

By-law, to support the *IESO Board* in the development, consideration and making of *urgent rule amendments*.

4.2.2 In formulating *amendments* to the *market rules*, the *IESO Board*, the *technical panel* and the *urgent rule amendment committee* shall take into consideration the objects of the *IESO* as set forth in the *Electricity Act*, *1998*.

4.2.3 The *IESO Board* may review, from time to time, the work and proceedings of the *technical panel* and issue to the *technical panel* such directions as the *IESO Board* from time to time determines appropriate. Such directions may relate to one or more proceedings respecting particular proposed *amendments* to or reviews of the *market rules* or may be of more general application. For certainty, such directions may include termination of the consideration of a particular proposed *amendment* to, or review of, the *market rules.* The *technical panel* shall comply with such directions. In addition, nothing in this section 4 shall prohibit the *technical panel* from consulting with the *IESO Board* regarding the role the *technical panel* will play in reviewing a request for an *amendment* or review of the *market rules*.

4.2.4 A *market participant* or any other interested person may file a written submission (the **"***amendment submission*") with the *IESO*, at such address as may be *published* by the *IESO* from time to time, to propose one or more *amendments* to the *market rules* or to identify any provision of the *market rules* in respect of which the *market participant* or the other interested person considers that an *amendment* or review may be necessary or desirable. The *amendment submission* shall include a statement of the reasons for which an *amendment* to or review of the *market rules* may be necessary or desirable.

4.2A Rule Amendments Initiated by the IESO Board

4.2A.1 The *IESO Board* may at any time determine on its own initiative or at the request of any person that an *amendment*, including a *minor amendment*, to or a review of a *market rule* may be necessary or desirable and shall *publish* and give notice of its intention to consider such *amendment* or review, together with a statement of the reason for which such *amendment* or review may be necessary or desirable:

4.2A.1.1 to all market participants;

4.2A.1.2 to the *technical panel*;

4.2A.1.3 where such *amendment* or review relates to or may affect any provision of section 2, to the *secretary* of the *dispute resolution panel*; and

4.2A.1.4 where such *amendment* or review relates to or may affect any provision of section 3, to the Chair of the *market surveillance panel*,

inviting such persons to make, within such reasonable period as shall be specified in the notice, written submissions to the *IESO Board* concerning the matter. The reasonable period shall not be less than 7 days.

4.2A.2 Sections 4.3.9 to 4.3.11 and 4.3.13 to 4.3.20 shall apply, with such modifications as the context may require, to consideration by the *IESO Board* of a proposed *amendment*, other than a *minor amendment* which shall be made in accordance with section 4.7, or review pursuant to this section 4.2A, it being understood that the references in those sections to the *technical panel* shall be considered references to the *IESO Board*, unless and to the extent that the *IESO Board* directs the *technical panel* to participate in the matter.

4.2A.3 Sections 4.7.1 to 4.7.6, other than sections 4.7.1.1 and 4.7.1.2, apply with such modifications as the context may require to consideration by the *IESO Board* of a *minor amendment* pursuant to this section 4.2A, it being understood that the references in those sections to the *technical panel* shall be considered references to the *IESO Board*, unless and to the extent that the *IESO Board* directs the *technical panel* to participate in the matter.

4.3 Requests for Review or Amendment of Market Rules

4.3.1 The provisions of this section 4.3 apply to requests made by the *IESO Board*, and *amendment submissions* made by a *market participants* or any other interested person for an *amendment* or review of the *market rules*, and do not apply:

4.3.1.1 except as expressly provided in section 4.4.3 or 4.2A.2, to proposed *amendments* to which sections 4.4 or 4.2A, respectively, apply;

4.3.1.2 to *urgent amendments* to the *market rules*, which shall be made in accordance with section 4.6; and

4.3.1.3 to *amendments* to the *market rules* which are required to be made or reconsidered further to an order of the *Ontario Energy Board* pursuant to the provisions of the Electricity Act, 1998, which shall be made in accordance with section 4.8.

4.3.2 Upon receipt of the *amendment submission, t*he *technical panel* may request that the person submitting the *amendment submission* provide further particulars with respect to the *amendment submission*.

4.3.3 [Intentionally left blank]

4.3.4 [Intentionally left blank]

4.3.5 The *technical panel* shall report to the *IESO Board* and, where applicable, give notice to the *market participant* or other interested person who made an *amendment submission* as to whether the proposed *amendment* or the request for consideration of an *amendment* or review is, in the opinion of the *technical panel*:

4.3.5.1 of such a nature that consideration of the *amendment submission* is warranted and the extent of the consultation that the *technical panel* intends to take with *market participants* and other interested persons in the consideration of the *amendmen*t;

4.3.5.1A of such a nature that it raises only a *minor amendment*, in which case the *amendment submission* shall be dealt with in accordance with the provisions of section 4.7;

4.3.5.1B of such a nature that a clarification or interpretation of the applicable *market rule* is warranted, in which case the *amendment submission* shall be dealt with in accordance with the provisions of section 12 of Chapter 1; or

4.3.5.2 with reasons specified in the report and notice, of such a nature that no consideration of the *amendment submission* is warranted,

provided that the *technical panel* shall not make the determination referred to in section 4.3.5.2 where the request was made by the *IESO Board* unless the *IESO Board*, in its request, so permits.

4.3.6 The *technical panel* shall nonetheless further consider or not consider the *amendment submission*, as the case may be, if it is directed to do so by the *IESO Board.*

4.3.7 Where the *technical panel* decides or is required to further consider an *amendment submission* pursuant to section 4.3.5 or 4.3.6, the *IESO* shall *publish*and give notice to all *market participants* and to any person who made the *amendment submission,* of the particulars of the *amendment submission* and of any comments which the *technical panel* may wish to make in respect of the *amendment submission*. The notice and *publication* may, at the request of *technical panel*, invite *market participants* and other interested persons to make written submissions to the *technical panel* concerning the *amendment submission*, within such reasonable period as shall be determined by the *technical panel*, and as specified in the *publication* and notice. This reasonable period shall not be less than 7 days.

4.3.8 The written submissions referred to in section 4.3.7 must be filed with the *technical panel* within the time specified in the notice and *publication* and may indicate whether the *market participant* or the other interested person considers that a meeting is necessary or desirable in connection with the *amendment submission* and, if so, the reasons why such meeting is necessary or desirable.

4.3.9 The *technical panel* may at any time give notice, and invite *market participants* or other interested persons, to make such additional written submissions within such reasonable time as the *technical panel* determines appropriate.

4.3.10 The *technical panel* shall consider all written submissions received within the prescribed time pursuant to section 4.3.8 or 4.3.9 and may, where the *technical panel* considers it necessary or desirable, schedule and hold meetings in accordance with section 4.3.11.

4.3.10A In its consideration of an *amendment submission*, the *technical panel* shall also consider any unsolicited written submissions that are received in time for the *technical panel* meeting at which the applicable *amendment submission* is being considered.

4.3.11 The *technical panel* shall advise the *IESO Board* of the date, time and place scheduled for any meeting referred to in section 4.3.10 and the *IESO* shall, no less than seven days prior to the date fixed for a meeting, *publish* and give notice of same to *market participants* and to any person who filed written submissions pursuant to section 4.3.8 or 4.3.9. Any *market participant* and any other interested person may attend and, at the discretion of the *technical panel,* participate in any such meetings.

4.3.12 Where the *amendment submission* relates to or may affect:

4.3.12.1 any provision of section 2, the *technical panel* shall, prior to conducting any meetings pursuant to section 4.3.11 or, in the absence of such meetings, prior to voting on the matter, consult with the *secretary* of the *dispute resolution panel* with respect to the matter; and

4.3.12.2 any provision of section 3, the *technical panel* shall, prior to conducting any meetings pursuant to section 4.3.11 or, in the absence of such meetings, prior to voting on the matter, consult with the Chair of the *market surveillance panel* with respect to the matter.

4.3.13 The *technical panel* shall, as soon as reasonably practicable following any meetings and consultations which may have been held pursuant to sections 4.3.11 and 4.3.12, or any other consultations that the *technical panel* decides are appropriate, convene on one or more occasions as may be necessary to consider and vote on the *amendment* resulting from an *amendment submission*. Prior to the *technical panel* voting on an *amendment*, the *IESO* shall, at the request of *technical panel*, *publish,* and give notice to all *market participants* and to any person who made the *amendment submission* or written submission to which the proposed *amendment* relates, of the proposed *amendment* that will be the subject of the *technical panel's* vote. The notice and *publication* shall, at the request of the *technical panel*, invite *market participants* and other interested persons to make written submission to the *technical panel* concerning the subject *amendment*, within such reasonable period as shall be determined by the *technical panel* and specified in the notice and *publication*. This reasonable period shall not be less than 7 days.

4.3.14 Following the conclusion of the deliberations referred to in section 4.3.13, the *technical panel* shall submit a written report to the *IESO Board* setting out:

4.3.14.1 the recommendations of the *technical panel* and the reasons for its recommendations;

4.3.14.2 where the recommendations of the *technical panel* include a proposal to *amend* the *market rules*, a copy of the proposed text of the amendment and a summary of any objections to the *amendment submission* which may have been contained in the written submissions referred to in section 4.3.8, 4.3.9, 4.3.10A or 4.3.13 or brought to the attention of the *technical panel* during any meetings held pursuant to section 4.3.11 or otherwise;

4.3.14.3 a summary of the procedure followed by the *technical panel* in considering the matter;

4.3.14.4 a summary of the views of the *secretary* of the *dispute resolution panel* or the Chair of the *market surveillance panel*, as the case may be, provided during the consultations referred to in section 4.3.12;

4.3.14.5 a record of the vote of each member of the *technical panel* in respect of each of the recommendations made in the report;

4.3.14.6 a summary of any objections raised by any member of the *technical panel* to the recommendations, if such objecting member so requests; and

4.3.14.7 a statement of the objects of the *IESO* considered by the *technical panel* in formulating the *amendment* as required by section 4.2.2.

4.3.15 The *IESO* shall *publish* the recommendations contained in the report of the *technical panel* referred to in section 4.3.14 and give notice thereof to all *market participants* and to any person who made an *amendment submission* or written submission to which the recommendations relate. In this notice and *publication*, the *IESO* shall, at the request of the *technical panel*, invite *market participants* and other interested persons to make written submissions to the *IESO Board* concerning the subject *amendment*, within seven *business days* of the date of giving of notice, objecting to the *technical panel's* recommendation and setting forth the reasons for the objection. At the request of the *IESO Board*, the *technical panel* shall provide to the *IESO Board* copies of all written submissions received pursuant to section 4.3.8, 4.3.9, 4.3.10A or 4.3.13, together with particulars of any written submissions which were made before the *technical panel* during the course of any meetings that may have been held pursuant to section 4.3.11.

4.3.16 [Intentionally left blank]

4.3.17 As soon as reasonably practicable following receipt of the report of the *technical panel* referred to in section 4.3.14 or, where written submissions have been requested pursuant to section 4.3.15, following the expiry of the deadline for written submissions referred to in that section, the *IESO Board* shall convene on one or more occasions as may be necessary to consider the report of the *technical panel*, together with any written submissions received pursuant to section 4.3.15, and shall vote on the matter in accordance with the provisions of the *Governance and Structure By-law*.

4.3.18 Where the *IESO Board* decides against the adoption of an *amendment* to the *market rules*, the *IESO* shall *publish*such decision and shall give notice of the decision to all *market participants* and to any person who made an *amendment submission* or written submission to which the decision relates. Where the *IESO Board* decides in favour of the adoption of the *amendment* to the *market rules,* either as recommended by the *technical panel* or with changes made by the *IESO Board* in its consideration of the *amendment*, the *IESO* shall publish such decision, together with a copy of the *amendment*, in accordance with the provisions of the *Governance and Structure By-law* and the Electricity Act, 1998, and shall give notice of the decision to all *market participants* the *Ontario Energy Board* and to any person who made the *amendment submission* or written submission to which the decision relates.

4.3.19 Where, in accordance with the *Governance and Structure By-law*, the *IESO Board* refers a recommendation contained in a report of the *technical panel* either back to the *technical panel* for further consideration and vote, or to any other person that the *IESO Board* deems appropriate, the *IESO Board* shall so advise the *technical panel*, with reasons, and shall *publish*such decision and give notice of the decision to all *market participants* and to any person who filed an *amendment submission* or written submission to which the decision relates. The *technical panel* shall, as soon as reasonably practicable following receipt of the decision of the *IESO Board*, convene to reconsider its recommendation. The *technical panel* may enter into such further consultations with such persons, and conduct such meetings, as it determines appropriate for purposes of its reconsideration.

4.3.20 Sections 4.3.14 to 4.3.18 shall apply, with such modifications as may be required by the context, to the reconsideration of a recommendation pursuant to section 4.3.19.

4.4 Rule Amendments Initiated by the Technical Panel

4.4.1 The provisions of this section 4.4 do not apply to *minor amendments* proposed by the *technical panel*, which shall be made in accordance with section 4.7.

4.4.2 Where the *technical panel* on its own initiative determines at any time that an *amendment* to or a review of a *market rule* may be necessary or desirable, it shall submit a report of its intention to consider such *amendment* or review to the *IESO Board*, together with the reasons for its determination.

4.4.3 Sections 4.3.7 to 4.3.20 shall apply, with such modifications as the context may require, to consideration of the matter raised in the *review notice*, it being understood that the reference in those sections to an *amendment submission* shall be a reference to the *review notice*.

4.5 [Intentionally left blank]

4.5.1 [Intentionally left blank]

4.5.2 [Intentionally left blank]

4.5.3 [Intentionally left blank]

4.6 Urgent Amendments

4.6.1 *Urgent amendments* to the *market rules* shall be made by the *IESO Board* or the *urgent rule amendment committee*, if so authorized by the *IESO Board* pursuant to the *Governance and Structure By-law*, following such consultations with such persons as the *urgent rule amendment committee* or the *IESO Board*, as the case may be, considers appropriate.

4.6.2 Where an *urgent amendment* is made pursuant to section 4.6.1 by the *urgent rule amendment committee*, such *amendment* shall forthwith be reported to the *IESO Board*.

4.6.3 The *IESO Board* shall, in accordance with the provisions of the *Governance and Structure By-law*, convene on one or more occasions as may be necessary to consider the report and vote to either:

4.6.3.1 confirm the *urgent amendment*, in the form made by the *urgent rule amendment committee* or in such form as the *IESO Board* deems appropriate; or

4.6.3.2 reject the *urgent amendment* and stay the implementation thereof.

4.6.4 Where an *urgent amendment* is made by the *IESO Board* or the *urgent rule amendment committee* pursuant to section 4.6.1, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of such *urgent amendment* and shall give notice thereof to all *market participants*.

4.6.5 Where an *urgent amendment* is confirmed by the *IESO Board* pursuant to section 4.6.3.1 in a form other than that made by the *urgent rule amendment committee*, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of such *urgent amendment* and shall give notice thereof to all *market participants*.

4.6.6 Where the *IESO Board* rejects and stays the implementation of an *urgent amendment* pursuant to section 4.6.3.2, the *IESO* shall forthwith *publish* and give notice, including the effective date and time, of its decision to all *market participants*.

4.7 Minor Amendments

4.7.1 If the *technical panel* considers that it is necessary or desirable to make a *minor amendment* to the *market rules*, either on its own initiative or upon receipt of an *amendment submission,* the *technical panel* shall hold such consultations with such persons, or ask for written submissions only from such *market participants*, if any, as the *technical panel* considers appropriate and shall:

4.7.1.1 where such *minor amendment* relates to or may affect any provision of section 2, consult with the *secretary* of the *dispute resolution panel*; or

4.7.1.2 where such *minor amendment* relates to or may affect any provision of section 3, consult with the Chair of the *market surveillance panel*, and each of the *secretary* and the Chair shall consult such members of their respective panels as they determine appropriate prior to consulting with the *technical panel.*

4.7.2 After holding any consultations or receiving any written submissions pursuant to section 4.7.1, the *technical panel* shall convene on one or more occasions as may be necessary to consider and vote on the matter and shall thereafter submit a written report to the *IESO Board* containing the information set forth in section 4.3.14.

4.7.3 [Intentionally left blank]

4.7.4 [Intentionally left blank]

4.7.5 As soon as reasonably practicable following the receipt of the report of the *technical panel* referred to in section 4.7.2 the *IESO Board* shall convene on one or more occasions as may be necessary to consider and vote on the *minor amendment* in accordance with the *Governance and Structure By-law* and shall:

4.7.5.1 approve the *minor amendment* as submitted by the *technical panel* or with any changes that the *IESO Board* determines are appropriate; or

4.7.5.1A reject the *minor amendment*, or

4.7.5.2 refer the matter back to the *technical panel.*

4.7.5A The *IESO* shall *publish* the *IESO Board* decision made pursuant to section 4.7.5, together with a copy of the *amendment*, in accordance with the provisions of the *Governance and Structure By-law* and the *Electricity Act, 1998*, and shall give notice of the decision to all *market participants,* the *Ontario Energy Board* and to any person who made the *amendment submission* or made a written submission to which the decision relates.

4.7.6 Sections 4.3.7 to 4.3.20 shall, unless and to the extent that the *IESO Board* directs otherwise, apply with such modifications as the context may require to the further consideration by the *technical panel* of a matter referred to it under section 4.7.5.2.

4.8 Amendments Subject to Order of the Ontario Energy Board

4.8.1 Upon receipt of an order of the *Ontario Energy Board* made pursuant to the provisions of the *Electricity Act, 1998* from which no appeal, review or petition to the Lieutenant Governor in Council can or has been taken, the *IESO Board* shall either:

4.8.1.1 refer the matter, including consideration of any consequential *amendments* arising from the matter, to the *technical panel*, and the provisions of sections 4.3.7 to 4.3.20 shall, unless and to the extent that the *IESO Board* directs otherwise, apply with such modifications as the context may require to the reconsideration of the *amendment* to the *market rules* which is the subject of the order; or

4.8.1.2 following such consultations as the *IESO Board* considers appropriate, make an *amendment* to the *market rules* including any consequential *amendments* arising from the matter. The *IESO* shall *publish* the *amendment* and shall give notice of the *amendment* to all *market participants* and the *Ontario Energy Board*.

4.8.2 Upon receipt of an order of the *Ontario Energy Board* made pursuant to subsection 35(6) or 38(4) of the *Electricity Act, 1998* from which no appeal, review or petition to the Lieutenant Governor in Council can or has been taken, the *IESO Board* shall make an *amendment* to the *market rules* in the manner and within the time specified by the *Ontario Energy Board* in its order, including any consequential *amendments* arising from the matter, following such consultations as the *IESO Board* considers appropriate. The *IESO* shall *publish* the *amendment* and shall give notice of the *amendment* to all *market participants* and the *Ontario Energy Board*.

4.9 Experts and Other Assistance

4.9.1 The *technical panel* may, subject to the *Governance and Structure By-law* of the *IESO* and to budgetary approval of the Chief Executive Officer of the *IESO,* hire such consulting assistance and seek such expert external advice as may be necessary or desirable for the purpose of the fulfillment of its responsibilities under this section 4. Where the Chief Executive Officer of the *IESO* does not approve such request, the *technical panel* may appeal such decision to the Chair of the *IESO Board.*

4.9.1A Consultants and expert external advisors hired pursuant to section 4.9.1 shall enter into such confidentiality agreement as may be required by the Chair of the *technical panel*.

4.9.2 In carrying out any of its responsibilities under this section 4, the *technical panel* may, through the Chief Executive Officer of the *IESO*, solicit the assistance of any director, officer or employee of the *IESO* and may use the facilities of the *IESO*.

4.9.3 Where the *technical panel* at any time considers it necessary or desirable to do so, it may establish working groups to assist it in the fulfillment of its responsibilities under this section 4, which working groups shall operate in accordance with such terms and conditions, including as to the scope of their work and as to participation in such working groups, as the *technical panel* may reasonably determine to be appropriate. The *technical panel* shall notify the *IESO Board* of its intention to establish a working group and the *IESO* shall *publish* and give notice to all *market participants,* the person who made the *amendment submission* and any other interested party that made written submissions in respect of the proposed *amendment* to which the working group relates of such intention.

4.9.4 The *IESO Board* may, at any time in fulfilling its responsibilities under this section 4, including but not limited to for the purposes of section 4.8.2, call upon the assistance of the *technical panel*.

4.10 [Intentionally left blank]

4.10.1 [Intentionally left blank]

4.10.2 [Intentionally left blank]

4.10.3 [Intentionally left blank]

4.11 [Intentionally left blank]

4.11.1 [Intentionally left blank]

4.12 Audit

4.12.1 The activities of the *technical panel* shall be audited in accordance with procedures adopted from time to time by the *IESO*.

5. Accessibility and Confidentiality of Information

5.1 Accessibility

5.1.1 Subject to section 5.7.1, all persons shall have an equal opportunity for open and non-discriminatory access to all information, other than *confidential information*, required by the *market rules* to be made available to *market participants*, the *IESO* or other persons.

5.1.2 Subject to section 5.7.1, all information, other than *confidential information*, required by the *market rules* to be made available to *market participants*, the *IESO* or other persons shall be *published* or otherwise made available in the manner and within the time prescribed in the *market rules*. Where no time is specified in respect of the provision of a particular piece of information, such information shall be made available within a reasonable time.

5.1.3 All *market participants* shall have an equal opportunity for access to information, other than *confidential information*, made available pursuant to the *market rules*.

5.1.3A Notwithstanding sections 5.1.1, 5.1.2, 5.1.3 or any other sections of the *market rules*, the *IESO* may withhold information that if disclosed may, in the reasonable opinion of the *IESO*, pose a security threat to the *reliable* operations of the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions.

5.1.4 In this section 5:

5.1.4.1 a reference to the *IESO* shall include a reference to a panel established by the *IESO;* and

5.1.4.2 a reference to information shall mean information however recorded, whether in printed form, on film, by electronic means or otherwise.

5.2 Confidentiality

5.2.1 Each *market participant* and the *IESO* shall keep confidential any *confidential information* which comes into the possession or control of that *market participant* or the *IESO* or of which the *market participant* or the *IESO* becomes aware.

5.2.2 No *market participant* or the *IESO* shall:

5.2.2.1 disclose *confidential information* to any person except as permitted by the *market rules*;

5.2.2.2 permit access to *confidential information* by any person not authorized to have such access pursuant to the *market rules*; or

5.2.2.3 use or reproduce *confidential information* for a purpose other than the purpose for which it was disclosed or another purpose contemplated by the *market rules*.

5.2.3 Each *market participant* and the *IESO* shall:

5.2.3.1 prevent access to *confidential information* which is in its possession or control by any person not authorized to have such access pursuant to the *market rules*, including by appropriate means of destruction or disposal in cases where the *confidential information* is not required or is at the relevant time no longer required to be retained by it pursuant to the *market rules*; and

5.2.3.2 ensure that any person to whom it discloses *confidential information* observes the provisions of this section 5.2 in relation to that *confidential information*.

5.2.4 Each *market participant* and the *IESO* shall, promptly upon becoming aware of a breach or a threatened breach of the provisions of this section 5 with respect to an item of *confidential information*:

5.2.4.1 so notify any person to whom the *confidential information* relates or by whom it was provided;

5.2.4.1A if a *market participant*, so notify the *IESO*; and

5.2.4.2 take such reasonable steps as may be required to prevent or assist in the prevention of, as the case may be, the unauthorized disclosure, access to, use or reproduction of *confidential information* that may result from such breach or threatened breach.

5.2.5 Each *market participant* shall maintain internal measures relating to the protection of *confidential information* that enable the *market participant* to comply and monitor compliance with its obligations under this section 5.

5.2.6 The *IESO* shall maintain internal measures, including measures referred to in section 5.7.2, relating to the protection of *confidential information* that enable the *IESO* to comply and monitor compliance with its obligations under this section 5.

5.3 Exceptions

5.3.1 Unless prohibited by *applicable law* or by the provisions of these *market rules* other than this section 5, nothing in sections 5.2, 5.4 or section 5.5.1A of Chapter 5 shall prevent:

5.3.1.1 the disclosure, use or reproduction of information if the information is, at the time of disclosure, generally and publicly available other than as a result of a breach of confidence by the *market participant* or the *IESO* who wishes to disclose, use or reproduce the information or by any person to whom the *market participant* or the *IESO* has disclosed the information;

5.3.1.2 the disclosure of confidential information by a market participant or the IESO to:

a. a director, officer or employee of the *market participant* or of the *IESO* where such person requires the *confidential information* for the due performance of that person's duties and responsibilities and, in the case of the *IESO* for information that is classified highly confidential pursuant to section 5.4.2.6, where the person has the required security clearance assigned by the *IESO*; or

b. a legal or other professional advisor, auditor or other consultant of the *market participant* or of the *IESO* where such persons require the information for purposes of the *market rules* or of an agreement entered into pursuant to the *market rules* or for the purpose of advising the *market participant* or the *IESO* in relation thereto;

5.3.1.3 the disclosure, use or reproduction of *confidential information*:

a. by the *market participant* or person that provided the *confidential information* pursuant to the *market rules*;

b. with the consent of the *market participant* or person that provided the *confidential information* pursuant to the *market rules*; or

c. in the case of *settlement* data*, metering data* or data contained in the *metering registry*, by or with the consent of the *market participant* to whom such data relates;

5.3.1.4 the disclosure, use or reproduction of *confidential information* to the extent required by *applicable law* or by a lawful requirement of:

a. any government or governmental body, regulatory body, authority or agency having jurisdiction over a *market participant* or the *IESO* or an *affiliate* of a *market participant* or of the *IESO*; or

b. any stock exchange having jurisdiction over a *market participant*, the *IESO* or an *affiliate* of a *market participant* or the *IESO*;

5.3.1.5 except as otherwise provided in section 2, the disclosure, use or reproduction of *confidential information* if required in connection with legal proceedings, mediation, arbitration, expert determination or other dispute resolution mechanism relating to the *market rules* or to an agreement entered into pursuant to the *market rules* or for the purpose of advising a person in relation thereto;

5.3.1.5A if required by the *IESO Board* or a committee established by the *IESO Board*, the disclosure, use or reproduction of *confidential information* if required in connection with the issuance of *suspension*, *termination* or *disconnection orders* in respect of one or more *market participants* the revocation of the registration in respect of one or more *metering service providers* and any show cause hearings in respect thereof under section 5.3 of chapter 6 or section 6.2A;

5.3.1.6 the disclosure of *confidential information* if required to ensure the safety of any person, prevent the damage of equipment, prevent the violation of any *applicable law*, or to maintain the *reliability* of the *IESO-controlled grid*;

5.3.1.7 the disclosure, use or reproduction of *confidential information* as an unidentifiable component of an aggregate sum;

5.3.1.8 the disclosure by the *IESO* of *confidential information* to a *transmitter* for the purposes of:

a. the safe and reliable management, operation and maintenance of its *transmission system* to the extent that *confidential information* is required pursuant to the terms of the *operating agreement*; or

b. the verification or reconciliation of the collection and administration of any applicable *transmission services charges*;

5.3.1.9 the disclosure by the IESO of confidential information to a market participant:

a. during an *emergency* or where the *IESO-controlled grid* is in an *emergency operating state* or a *high-risk operating state*; or

b. where an *emergency*, an *emergency operating state* or a *high-risk operating state* is anticipated by the *IESO*;

to the extent that such disclosure would, in the *IESO's* opinion:

c. assist the *market participant* in responding to the conditions referred to in sections 5.3.1.9(a) and 5.3.1.9(b); or

d. assist the *IESO* in restoring the *IESO-controlled grid* to a *normal operating state*;

5.3.1.10 disclosure by the IESO of confidential information to a standards authority, a control area operator, a security coordinator or an interconnected transmitter;

5.3.1.11 disclosure by the IESO of confidential information to the market surveillance panel;

5.3.1.12 subject to sections 5.3.7 and 5.3.8, disclosure by the *IESO* of *confidential information* to a *market monitoring unit* relating to an investigation regarding conduct or activities which may have an adverse impact on market efficiency or effective competition; or

5.3.1.13 subject to section 5.3.10 and at the sole discretion of the *IESO*, disclosure by the *IESO* of *confidential information* in the form of a *basecase,* for the purposes of conducting reliability based power system studies directly to, or to a consultant of, a *market participant*, a *connection applicant,* or to a person planning to construct or modify a *facility*.

5.3.2 Prior to making any disclosure pursuant to section 5.3.1.2(b), the person wishing to disclose the information shall inform the proposed recipient of the confidential nature of the *confidential information* to be disclosed and shall use all reasonable endeavours, including but not limited to the execution of an appropriate confidentiality agreement, to ensure that the recipient keeps the *confidential information* confidential in accordance with the provisions of section 5.2 and does not use the *confidential information* for any purpose other than that permitted under section 5.3.1.2(b).

5.3.3 Prior to making any disclosure pursuant to section 5.3.1.4, 5.3.1.5 or 5.3.1.5A, a person being requested or demanded to disclose the *confidential information* shall advise the person affected by the request or demand as soon as reasonably practicable so as where possible to permit the affected person to challenge such request or demand or seek terms and conditions in respect of any such disclosure.

5.3.4 In making any disclosure pursuant to section 5.3.1.6, the disclosing person shall advise the person affected by the disclosure as soon as is reasonably practicable and shall use all reasonable endeavours to protect the confidentiality of the *confidential information* insofar as may be reasonably practicable in the circumstances.

5.3.5 Where the *IESO* makes any disclosure pursuant to section 5.3.1.8:

5.3.5.1 [Intentionally left blank – section deleted]

5.3.5.2 the *transmitter* to whom the disclosure is made shall use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.8 and shall use all reasonable endeavours to protect the confidentiality of such *confidential information*.

5.3.6 Where the *IESO* makes any disclosure pursuant to section 5.3.1.9:

5.3.6.1 the *IESO* shall advise the *market participant* affected by the disclosure as soon as is reasonably practicable in the circumstances; and

5.3.6.2 the *market participant* to whom the disclosure is made shall use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.9 and shall use all reasonable endeavours to protect the confidentiality of such *confidential information* as may be reasonably practicable in the circumstances.

5.3.7 Where the *IESO* proposes to disclose any *confidential information* pursuant to section 5.3.1.12 the *IESO* shall either require the *market monitoring unit* to demonstrate that their governing documents limit further disclosure, or enter into a non-disclosure agreement with the *market monitoring unit.* The *market monitoring unit's* governing documents or non-disclosure agreement shall:

5.3.7.1 establish a legally enforceable obligation to treat *confidential information* provided by the *IESO* as confidential. Such obligation shall be of a continuing nature and survive the termination of any investigation for which the *confidential information* has been requested;

5.3.7.2 require the *market monitoring unit* to whom the disclosure is made to promptly notify the *IESO* of any third party requests for additional disclosure of the *confidential information* and seek appropriate relief to prevent or, if it is not possible to prevent, to limit disclosure in the event that a subpoena or other compulsory process seeks to require disclosure of *confidential information* provided by the *IESO*;

5.3.7.3 require the *market monitoring unit* to whom the disclosure is made to use the *confidential information* so disclosed solely for the purposes referred to in section 5.3.1.12, and to use all reasonable endeavours to protect the confidentiality of such *confidential information* as may be reasonably practicable in the circumstances; and

5.3.7.4 require the *market monitoring unit* to whom the disclosure is made to destroy or return *confidential information* provided by the *IESO* at the conclusion or resolution of the investigation or five *business days* after a request to destroy or return *confidential information* from the *IESO* is received by the *market monitoring unit*.

5.3.8 Prior to making any disclosure pursuant to section 5.3.1.12, the *IESO* shall advise the *market participant* affected by the request as soon as reasonably practicable so as where possible to permit the affected *market participant* to challenge such request or seek terms and conditions in respect of any such disclosure. The *IESO* shall not be required to advise the affected *market participant* if the *IESO* reasonably determines that such notification will jeopardize the investigation.

5.3.9 *Confidential information* provided by a *market monitoring unit* to the *IESO* shall be destroyed or returned to the *market monitoring unit* that provided the *confidential information* at the conclusion or resolution of the investigation or five *business days* after a request to destroy or return *confidential information* from the *market monitoring unit* is received by the *IESO*.

5.3.10 Prior to making any disclosure pursuant to section 5.3.1.13, the *IESO* shall enter into a non-disclosure agreement directly with, or with the consultant of, a *market participant,* a *connection applicant,* or with a person planning to construct or modify a *facility*. The non-disclosure agreement shall:

5.3.10.1 establish a legally enforceable obligation to treat *confidential information* provided by the *IESO* as confidential. Such obligation shall be of a continuing nature and survive the completion of any reliability based power system study for which the *confidential information* was required;

5.3.10.2 require that the *confidential information* so disclosed is used solely for the purposes referred to in the non-disclosure agreement and in section 5.3.1.13, and to use all reasonable efforts to protect the confidentiality of such *confidential information*; and

5.3.10.3 require the destruction or return of the *confidential information* provided by the *IESO* at the conclusion of the reliability based power system study*,* or five *business days* after a request for the destruction or return of the *confidential information* from the *IESO* is received.

5.4 Classification of Information

5.4.1 The *IESO* shall establish the following three levels of *confidentiality classification* for information that may be in the possession or control of the *IESO*:

5.4.1.1 public;

5.4.1.2 [Intentionally left blank]

5.4.1.3 [Intentionally left blank]

5.4.1.4 [Intentionally left blank]

5.4.1.5 confidential; and

5.4.1.6 highly confidential.

5.4.2 Subject to section 5.4.3, information in the possession or control of the *IESO* that is listed in the *information confidentiality catalogue* and that is identified therein as:

5.4.2.1 public is information that is not *confidential information* including, but not limited to, information required by the *market rules* or the *licence* of the *IESO* to be *published*, and may be disclosed to, accessed by, reproduced or used by any person without restriction;

5.4.2.2 [Intentionally left blank]

5.4.2.3 [Intentionally left blank]

5.4.2.4 [Intentionally left blank]

5.4.2.5 confidential is *confidential information* that is provided to the *IESO* by a *market participant,* a *standards authority*, a *security coordinator*, a *control area operator*, an *interconnected transmitter*, or that is provided to the *IESO* by a person other than a *market participant* and that relates to a *market participant*; or that originates with or is created by the *IESO* and that relates to a *market participant*, and may only be disclosed by the *IESO* to or accessed by:

a. where the *confidential information* was provided to the *IESO* by a person, that person;

b. any person that the *IESO* has reasonable grounds to believe has been authorized by the person referred to in section 5.4.2.5(a) to access or receive such *confidential information*;

c. any authorized person within the *IESO*; and

d. the *market participant* to whom the *confidential information* relates.

5.4.2.6 highly confidential is *confidential information* that is provided to the *IESO* by a *market participant,* or by a person other than a *market participant,* or that originated within or is created by the *IESO*, and requires restricted access within the *IESO*, and may only be disclosed by the *IESO* to or accessed by:

a. where the *confidential information* was provided to the *IESO* by a person, that person;

b. any person that the *IESO* has reasonable grounds to believe has been authorized by the person referred to in section 5.4.2.6(a) to access or receive such *confidential information*; and

c. any person within the *IESO* that has the required security clearance assigned by the *IESO* and requires the *confidential information* for the purpose of the due performance of that person's duties and responsibilities.

5.4.3 Where:

5.4.3.1 the *information confidentiality catalogue* provides, in respect of any particular item of *confidential information*, that such *confidential information* is to be automatically re-classified within a different *confidentiality classification* following the expiry of the period of time identified in the *information confidentiality catalogue*, such *confidential information* shall be deemed for all purposes to be re-classified within such other *confidentiality classification* on and after the expiry of such period of time;

5.4.3.2 *confidential information* is re-classified by the *IESO* within a different *confidentiality classification* in accordance with any one of sections 5.5.3 to 5.5.6, such *confidential information* shall be deemed for all purposes to be re-classified within such other *confidentiality classification* on and after the date of such re-classification.

5.4.4 Where the *IESO* amends the *information confidentiality catalogue* to include an additional item of information, the *IESO* shall classify such information within the *confidentiality classification* that is, in the *IESO's* opinion, appropriate having regard to:

5.4.4.1 the adverse impact that disclosure of the information may reasonably be expected by the *IESO* to have on:

a. the person that provides the information;

b. the person to whom the information relates or such other person as the *IESO* has reasonable grounds to believe may be adversely affected by disclosure of the information;

c. the efficient operation of the *IESO-administered markets*;

d. the *reliable* operation of the *IESO-controlled grid*;

e. the *IESO*; and

f. the security of the *integrated power system*, the *IESO-administered markets* or those of neighbouring jurisdictions.

5.4.4.2 [Intentionally left blank]

5.4.4.3 [Intentionally left blank]

5.4.4.4 [Intentionally left blank]

5.4.4.5 [Intentionally left blank]

5.4.4.6 the proprietary nature and degree of confidentiality of the information, to the extent known by the *IESO*; and

5.4.4.7 the *IESO's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *IESO* is a party.

5.4.5 Where a *market participant* provides to the *IESO* information that is not listed in the *information confidentiality catalogue*, the *IESO* shall:

5.4.5.1 subject to sections 5.4.6, 5.4.7, 5.4.9.2 and 5.4.10, classify that information within the *confidentiality classification* designated by the *market participant* in accordance with section 5.4.11 at the time that it provides such information to the *IESO* or pursuant to section 5.4.9.2(b); and

5.4.5.2 respect any restrictions requested by the person to be imposed in respect of the disclosure, use, reproduction or provision of access to such information that are additional to the restrictions pertaining to that *confidentiality classification* as described in section 5.4.2 unless, in the *IESO's* opinion, such additional restrictions:

a. would interfere with the ability of the *IESO* to maintain the *reliability* of the *IESO-controlled grid* or to operate the *IESO-administered markets* in an efficient manner; or

b. are inconsistent with the *IESO's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *IESO* is a party.

5.4.6 Where the *IESO* disagrees with the *confidentiality classification* designated by a *market participant* pursuant to section 5.4.5.1, the *IESO* shall so notify the *market participant*, which notice shall specify:

5.4.6.1 the grounds upon which the *IESO* disagrees with the *confidentiality classification* designated by the *market participant*;

5.4.6.2 the *confidentiality classification* that the *IESO* considers to be appropriate for the information; and

5.4.6.3 the time within which the *market participant* may make representations to the *IESO* in support of the *confidentiality classification* designated by it.

5.4.7 Following the time noted in section 5.4.6.3, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* shall:

5.4.7.1 where it agrees with the *confidentiality classification* designated by the *market participant*, classify the information within such *confidentiality classification*; or

5.4.7.2 where it continues to disagree with the *confidentiality classification* designated by the *market participant*, classify the information within the *confidentiality classification* referred to in section 5.4.6.2 or, subject to section 5.4.8, such other *confidentiality classification* that the *IESO* considers to be appropriate for the information,

and shall so notify the *market participant*.

5.4.8 For the purposes of section 5.4.7.2, the *IESO* shall not classify the information within a *confidentiality classification* other than the *confidentiality classification* referred to in section 5.4.6.2 unless such other *confidentiality classification* has, pursuant to section 5.4.2, associated with it provisions relating to disclosure and access that are more restrictive than those associated with the *confidentiality classification* referred to in section 5.4.6.2.

5.4.9 Where a *market participant* fails to designate a *confidentiality classification* for information submitted to the *IESO* pursuant to section 5.4.5.1 at the time at which it submits such information to the *IESO*, the *IESO* shall:

5.4.9.1 as soon as reasonably practicable following receipt of the information, notify the *market participant* that it must, within five *business days* of the date of receipt of the notice, designate a *confidentiality classification* for the information, failing which the *IESO* will classify the information within the confidential *confidentiality classification*; and

5.4.9.2 temporarily classify the information within the confidential *confidentiality classification* until:

a. the expiry of the period referred to in section 5.4.9.1 or within such longer period of time as may be agreed between the *IESO* and the *market participant*; or

b. the date on which the *market participant* designates a *confidentiality classification* for the information,

whichever is the earlier.

5.4.10 Where a *market participant* fails to designate a *confidentiality classification* for information submitted to the *IESO* pursuant to section 5.4.5.1 within the time referred to in section 5.4.9.2(a), the *IESO* shall classify the information within the confidential *confidentiality classification*.

5.4.11 For the purposes of sections 5.4.5.1 and 5.4.9.2(b), a *market participant* shall designate the *confidentiality classification* for information submitted pursuant to those sections having regard to:

5.4.11.1 the adverse impact that disclosure of the information may reasonably be expected by the *market participant* to have on itself;

5.4.11.2 the adverse impact that disclosure of the information may reasonably be expected by the *market participant* to have on any person to whom the information relates or on such other person as the *market* *participant* may have reasonable grounds to believe may be adversely affected by disclosure of the information;

5.4.11.3 the proprietary nature and degree of confidentiality of the information; and

5.4.11.4 the *market participant's* obligations relating to confidentiality of and access to information under the *market rules*, *applicable law* or any agreement to which the *market participant* is a party.

5.5 Reclassification of Information

5.5.1 The *confidentiality classification* of any *confidential information* that is referred to in the *information confidentiality catalogue*, that is in the possession or control of the *IESO* and that has not been automatically re-classified in accordance with section 5.4.3.1 shall be reviewed by the *IESO*:

5.5.1.1 in the case of *confidential information* other than *confidential information* classified as highly confidential, no less than once in every three calendar years; and

5.5.1.2 in the case of *confidential information* classified by the *IESO* as highly confidential, no less than once in every seven calendar years,

with a view to determining, in accordance with section 5.5.2, whether the *confidential information* can be re-classified within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than those associated with the existing *confidentiality classification*.

5.5.2 The *IESO* shall make the determination referred to in section 5.5.1 having regard to the factors noted in section 5.4.4.

5.5.3 Where the *IESO* determines, in accordance with the review conducted pursuant to section 5.5.1 that *confidential information* can be re-classified within another *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification*, the *IESO* shall:

5.5.3.1 [Intentionally left blank]

5.5.3.2 [Intentionally left blank]

5.5.3.3 where the *confidential information* was provided by a *market participant* or relates to a particular *market participant*, notify the *market participant* that provided the *confidential information* or to which the *confidential information* relates of its intention to re-classify the *confidential information*, which notice shall specify:

a. the grounds upon which the *IESO* has determined it appropriate to re-classify the *confidential information*;

b. the *confidentiality classification* that the *IESO* considers appropriate for purposes of the re-classification of the *confidential information*; and

c. the time within which the *market participant* may object to the re-classification of the *confidential information*.

5.5.4 Where:

5.5.4.1 a *market participant* fails, within the time referred to in section 5.5.3.3(c), to object to the re-classification of *confidential information* that relates to it but that was not provided by it to the *IESO*, the *IESO* may re-classify the information within the *confidentiality classification* referred to in section 5.5.3.3(b) or within such other *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are more restrictive than the *confidentiality classification* referred to in section 5.5.3.3(b), and shall notify the *market participant* accordingly;

5.5.4.2 a *market participant* fails, within the time referred to in section 5.5.3.3(c), to object to the re-classification of *confidential information* that was provided by it to the *IESO*, the *IESO* shall not re-classify the *confidential information*; or

5.5.4.3 a *market participant* objects to the re-classification of *confidential information* within the time referred to in section 5.5.3.3(c), the *IESO* shall not re-classify the *confidential information* except as may be agreed between the *IESO* and the *market participant*.

5.5.5 The *IESO* shall, at the request of a *market participant*, re-classify *confidential information* provided by that *market participant* within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification* provided that the *IESO* is satisfied that such re-classification would not be inconsistent with the factors referred to in section 5.4.4.

5.5.6 Where a *market participant* indicates, at the time at which it designates a *confidentiality classification* for *confidential information* pursuant to section 5.4.5.1, that the *confidential information* may be automatically re-classified within a *confidentiality classification* that has, pursuant to section 5.4.2, associated with it provisions relating to disclosure or access that are less restrictive than the existing *confidentiality classification*, the *IESO* shall re-classify such *confidential information* accordingly provided that the *IESO* is satisfied that such re-classification would not be inconsistent with the factors referred to in section 5.4.4.

5.5.7 Amendments to the *information confidentiality catalogue* shall be subject to review by the *technical panel* and approval by the *IESO Board* until the end of 2003.

5.6 Cost of Access and Electronic Data Sharing

5.6.1 Nothing in this section 5 shall prevent information which is made available by means of electronic communications from being provided on a read-only basis.

5.6.2 Each *market participant* and any other person accessing, retrieving or storing information *published* or otherwise made available by the *IESO* shall be responsible for its own costs of accessing, retrieving or storing such information.

5.7 Conditions of Access

5.7.1 Where a request for access to or disclosure of information in the possession or control of the *IESO* is made by a *market participant* pursuant to these *market rules*, the *IESO* shall only provide such access or disclosure if:

5.7.1.1 the *IESO* is satisfied that it is not precluded by these *market rules* from providing such access or disclosure to the *market participant;* and

5.7.1.2 the provision of such access or disclosure would not impose a significant burden on the *IESO*, having regard to the *IESO's* resources.

5.7.2 Where the *IESO* makes *confidential information* accessible by means of electronic communications, the *IESO* shall implement access control protocols that differentiate between *market participants* but that need not differentiate between individuals, whether within the same *market participant* or otherwise.

6. Enforcement

6.1 Introduction

6.1.1 This section sets forth the rules pursuant to which the *IESO* shall monitor, assess and enforce compliance with the *market rules*, including by means of the imposition of financial penalties, the issuance of non-compliance letters, *suspension orders, termination orders* and *disconnection orders* and the taking of such other enforcement actions as provided for in these *market rules*.

6.1.2 The *IESO* shall undertake such monitoring as it considers necessary to determine whether *market participants* are complying with the *market rules*.

6.2 Procedures Concerning Alleged Breaches of the Market Rules

6.2.1 This section shall not apply to the issuance by the *IESO* of a *suspension order* or *termination order*, which shall be governed by the provisions of section 6.3A or 6.4, respectively, or to the issuance by the *IESO* of an order referred to in section 6.2A.1, which shall be governed by the applicable provisions of section 6.2A and 6.5.

6.2.1A This section 6 shall not apply in respect of:

6.2.1A.1 a breach of any performance standard set forth in the *market rules*; or

6.2.1A.2 a failure to pass a test set forth in the *market rules* or, where applicable, the *Ontario power system restoration plan*,

by an *ancillary service provider* in the provision of *regulation* or *black start capability* under a *contracted ancillary service* contract, which shall be governed, by the provisions of section 7 and by the provisions of sections 4.10.2.1 and 4.10.2.2 of Chapter 5.

6.2.2 Where the *market rules* provide for consequences or sanctions in respect of a breach by a *market participant* of a particular *market rule* or *market rules*, those consequences or sanctions shall apply in the circumstances and in the manner provided for in the relevant sections of the *market rules* in addition to such sanctions as may be imposed pursuant to this section 6.2.

6.2.3 If the *IESO* considers, on its own initiative or upon receipt of written information from any person, that a *market participant* may have breached or may be breaching the *market rules* and that, in the circumstances and if the breach is established, it would be appropriate that a sanction or sanctions be imposed on that *market participant*, the *IESO* shall notify the *market participant* of:

6.2.3.1 details of the alleged breach and of the time within which the breach must be remedied;

6.2.3.2 details of the evidence on the basis of which the *IESO* considers that the *market participant* may have breached or may be breaching the *market rules*;

6.2.3.3 details of the sanctions which may be imposed if the breach is established;

6.2.3.4 the time within which the *market participant* may make written representations in response to the allegations; and

6.2.3.5 the right of the *market participant* to request a meeting with the *IESO* to discuss the matter.

6.2.4 Following expiry of the time noted in section 6.2.3.4, and after consideration of any representations made by the *market participant* pursuant to that section, the *IESO* may:

6.2.4.1 determine that the *market participant* has not breached the *market rules*;

6.2.4.2 subject to section 6.2.5, determine that the *market participant* is in breach of the *market rules*;

6.2.4.3 request that the *market participant* provide further information in relation to the alleged breach; or

6.2.4.4 conduct such further investigation into the matter as the *IESO* determines appropriate.

6.2.5 Where a *market participant* has requested a meeting pursuant to section 6.2.3.5, the *IESO* shall provide the *market participant* with a reasonable opportunity to meet with the *IESO* to discuss the allegations. In such case, the *IESO* shall not make the determination noted in section 6.2.4.2 until such reasonable opportunity has been given.

6.2.6 A *market participant* shall comply with any request for information made by the *IESO* pursuant to section 6.2.4.3.

6.2.7 Subject to section 6.2.7A, where the *IESO* determines that a *market participant* has breached the *market rules*, the *IESO* may by order do any one or more of the following:

6.2.7.1 direct the *market participant* to do, within a specified period, such things as may be necessary to comply with the *market rules*;

6.2.7.2 direct the *market participant* to cease, within a specified period, the act, activity or practice constituting the breach;

6.2.7.3 impose additional or more stringent record-keeping or reporting requirements on the *market participant*;

6.2.7.4 issue a non-compliance letter in accordance with section 6.6;

6.2.7.5 impose financial penalties in accordance with section 6.6 indicating the time within which payment of the financial penalty must be made to the *IESO*, provided that no such penalties shall be imposed unless the *IESO* is satisfied that the breach could have been avoided by the exercise of due diligence by the *market participant* or that the *market participant* acted intentionally; or

6.2.7.6 take such other action as may be provided for in Appendix 3.1 in respect of the *market rule* that has been breached by the *market participant*.

6.2.7.7 [Intentionally left blank – section deleted]

6.2.7A If the *IESO* is satisfied that the *market participant* has breached section 10A of Chapter 1, and the *IESO* proposes to issue one or more orders under section 6.2.7, the *IESO* shall serve a *notice of intention* on the *market participant* in accordance with section 6.2B. The *IESO* may include in the *notice of intention* any or all alleged breaches of the *market rules* that were included in the notice issued under section 6.2.3. If the *IESO* does not include in the *notice of intention* an alleged breach described in the notice issued under section 6.2.3, excluding an alleged breach of section 10A of Chapter 1, then the *IESO* may make one or more orders under section 6.2.7 respecting that alleged breach.

6.2.8 An order imposing financial penalties on a *market participant* pursuant to section 6.6 shall, subject to section 2.3.3, be considered to create an obligation under the *market rules* to pay the amount stated in the order and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

6.2.9 Failure to comply with an order of the *IESO* made pursuant to section 6.2.7 constitutes a breach of the *market rules*.

6.2A Persistent Breaches of the Market Rules

6.2A.1 If a *market participant* has breached the *market rules* on a persistent basis, the *IESO* may:

6.2A.1.1 issue that *market participant* a *suspension order* under section 6.3A;

6.2A.1.2 issue that *market participant* a *termination order* under section 6.4; or

6.2A.1.3 deregister some or all of the *market participant's registered facilities* under section 6.5.

6.2A.2 Where the *IESO* intends to act pursuant to section 6.2A.1, the *IESO* shall provide the *market participant* with a notice stating:

6.2A.2.1 the nature of the action to be taken;

6.2A.2.2 the grounds and any evidence on which the *IESO* relies on in support of the intended action;

6.2A.2.3 the time within which the *market participant* may make written representations to the *IESO* as to why such action should not be taken; and

6.2A.2.4 the right of the *market participant* to request a hearing before the *IESO Board* or a committee of the *IESO Board* established for such purpose to show cause why such action should not be taken.

6.2A.3 The *IESO* shall provide a copy of any notice issued under section 6.2A.2 to the *OEB* and to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are connected.

6.2A.4 If the *market participant* has requested a hearing, the *IESO Board* or a committee of the *IESO Board* established for such purpose shall conduct a hearing providing the *market participant* with a reasonable opportunity to show cause as to why such action should not be taken against it. Following the hearing, the *IESO Board* or the committee of the *IESO Board* established for such purpose may:

6.2A.4.1 approve the action that the *IESO* intends to take; or

6.2A.4.2 make any other appropriate order, including an order referred to in section 6.2.7.

6.2A.5 If the *market participant* has not requested a hearing, the *IESO* shall consider any written representations received from the *market participant* and may take any action specified in the notice issued under section 6.2A.2 or make any other appropriate order, including an order referred to in section 6.2.7.

6.2A.6 The *IESO* shall *publish* a notice of any actions taken under section 6.2A.4 or 6.2A.5 and provide a copy to the *OEB* and the *transmitter*, *distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* who is the subject of the notice are connected.

6.2B Alleged Breaches of Section 10A of Chapter 1

6.2B.1 For the purposes of section 6.2B, excluding sections 6.2B.19 and 6.2B.20, a reference to section 10A of Chapter 1 shall be deemed to include all breaches described in the *notice of intention*.

6.2B.2 If the *IESO* is satisfied that the *market participant* has breached section 10A of Chapter 1, the *IESO* shall, prior to making any order under section 6.2.7, serve a written *notice of intention* on the *market participant*. The notice shall set out the following:

6.2B.2.1 the *market rules* that the *IESO* is satisfied that the *market participant* has breached;

6.2B.2.2 the reasons the *IESO* intends to determine that the *market participant* has breached section 10A of Chapter 1;

6.2B.2.3 the proposed order or orders under section 6.2.7;

6.2B.2.4 the *market participant's* right to contest the *notice of intention* pursuant to section 6.2B.3; and

6.2B.2.5 the time within which the *market participant* may contest the *notice of intention*.

6.2B.3 If the *market participant* wishes to contest the *notice of intention*, it shall serve a *response to the notice of intention* on the *IESO* within 20 *business days* of receipt of the *notice of intention*.

6.2B.4 If the *market participant* does not contest the *notice of intention* within 20 *business days* of the receipt of the *notice of intention*, the *IESO* may determine that the *market participant* has breached section 10A of Chapter 1 and impose one or more orders under section 6.2.7.

6.2B.5 If the *market participant* contests the *notice of intention*, the *market participant* and the *IESO* shall attempt to resolve the matter through good faith negotiations in accordance with sections 2.5.3A and 2.5.3B, except that the *response to the notice of intention* shall replace the *notice of dispute* referred to in section 2.5.3A and shall be served in accordance with section 2.5.1A.4D.

6.2B.6 Notwithstanding sections 2.5.3C and 2.5.4, if the parties are unable to resolve the matter through good faith negotiations, the mediation process described in section 2.6 shall apply and either party may file with the *secretary* on written notice to each other party a copy of the *notice of intention* and *response to the notice of intention* together with proof of service. The *secretary* and *mediator* shall rely on the *notice of intention* and *response to the notice of intention* in lieu of the *notice of dispute* and *response* for the purposes of section 2.6. The *IESO* shall provide a summary of the matter for *publication* in accordance with section 2.9.2.1.

6.2B.7 If the parties are unable to resolve the matter through the mediation process, then within 5 *business days* of the filing of the written notice terminating the mediation process, as referred to in section 2.6.1B, 2.6.13 or 2.6.16, the *market participant* shall file with the *secretary* and serve on the *IESO* a *notice to elect* electing one of the following available options:

6.2B.7.1 that the matter be referred to an *arbitrator* pursuant to the process described in section 2.7;

6.2B.7.2 that the *IESO* apply to the *Ontario Energy Board* to make a determination and findings of fact as described in section 6.2B.11; or

6.2B.7.3 not to pursue the matter under either subsections 6.2B.7.1 or 6.2B.7.2.

6.2B.8 Where the *market participant* elects not to pursue the matter under section 6.2B.7.3 or does not make any election as described in section 6.2B.7, the *IESO* may determine that the *market participant* has breached section 10A of Chapter 1 and impose one or more orders under section 6.2.7.

6.2B.9 Where the *market participant* elects that the matter be referred to an *arbitrator* pursuant to section 6.2B.7.1, section 2.7 shall apply. For the purposes of section 2.7, the *IESO* shall be deemed to be the *applicant* and the *market participant* shall be deemed to be the *respondent*.

6.2B.10 Where the *market participant* elects that the *IESO* apply to the *Ontario Energy Board* pursuant to section 6.2B.7.2, the *IESO* shall bring the application to the *Ontario Energy Board* within 20 *business days* of the service of the *notice to elect*.

6.2B.11 In an application brought pursuant to section 6.2B.10, the *IESO* shall request that the *Ontario Energy Board* make the following:

6.2B.11.1 a determination of whether the *market participant* has breached section 10A of Chapter 1; and

6.2B.11.2 findings of fact relevant to the imposition of one or more orders by the *IESO* under section 6.2.7.

6.2B.12 Where the *IESO* applies for a hearing before the *Ontario Energy Board* pursuant to section 6.2B.10 and the *Ontario Energy Board* dismisses the proceeding without a hearing under subsection 4.6(1)(b) of the Statutory Powers Procedure Act, the *notice to elect* shall be deemed to be a request for arbitration under section 6.2B.7.1 and the *IESO* shall refer the matter to an *arbitrator* in accordance with section 6.2B.9.

6.2B.13 Where the *Ontario Energy Board* holds a hearing referred to in section 6.2B.11 and determines that the *market participant* has not breached section 10A of Chapter 1, subject to any rights of appeal or review, the *IESO* shall adopt the *Ontario Energy Board*'s findings.

6.2B.14 Where the *Ontario Energy Board* holds a hearing referred to in section 6.2B.11 and determines that the *market participant* has breached section 10A of Chapter 1, subject to any rights of appeal or review, the matter shall return to the *IESO* and the *IESO* shall adopt the *Ontario Energy Board's* determination on breach.

6.2B.15 Where the matter returns to the *IESO* under section 6.2B.14, the *IESO* may issue one or more orders pursuant to section 6.2.7 and, in doing so:

6.2B.15.1 shall adopt and apply all findings of fact made by the *Ontario Energy Board;* and

6.2B.15.2 may adopt and apply any information from the record of the hearing before the *Ontario Energy Board*,

that are relevant to the order or orders under section 6.2.7 but may not rely on any additional evidence.

6.2B.16 If the *market participant* wishes to dispute the *IESO*'s order or orders issued pursuant to section 6.2B.15, it shall serve a *notice of dispute* on the *IESO* within 20 *business days* of receipt of the order or orders.

6.2B.17 Where the *market participant* disputes the order or orders issued by the *IESO* pursuant to section 6.2B.15, the *market participant* and the *IESO* shall attempt to resolve the matter in accordance with sections 2.5 and 2.6.

6.2B.18 The arbitration process set out in section 2.7 shall not apply to disputes as described in section 6.2B.16. An order issued under section 6.2B.15 may be appealed as provided for in section 36 of the Electricity Act, 1998 upon the filing of a notice under section 2.6.1B, 2.6.13 or 2.6.16 terminating the mediation process.

6.2B.19 The *IESO* shall, pursuant to section 6.2B.2, serve a *notice of intention* no later than six years after the day on which the alleged breach of section 10A of Chapter 1 was discovered by the *IESO*. Where the *IESO* fails to serve a *notice of intention* within the time provided, no finding of breach of section 10A of Chapter 1 shall be made pursuant to the *market rules* in respect of that conduct.

6.2B.20 For the purposes of section 6.2B.19, the term "discovered" has the meaning prescribed in section 5(1) of the Limitations Act, 2002.

6.3 Events of Default

6.3.1 An *event of default* occurs if a *market participant* or the person that has provided *prudential support* or *capacity prudential support* in relation to the *market participant*:

6.3.1.1 does not make a payment in full required under the *market rules* when due;

6.3.1.2 fails to provide payment in full of any amount claimed by the *IESO* under any *prudential support* or *capacity prudential support;*

6.3.1.3 fails to provide and maintain *prudential support* or *capacity prudential support* required to be supplied under the *market rules* within the time required;

6.3.1.4 has a licence (including a *licence*), permit or other authorization necessary to carry on its principal business suspended, revoked or otherwise cease to be in full force and effect, provided that where a *market participant* holds more than one *licence* and only one such *licence* has been suspended, revoked or otherwise ceases to be in full force and effect, the *event of default* and any action taken by the *IESO* with respect thereto shall relate only to such *licence*;

6.3.1.5 ceases or threatens to cease to carry on its business or a substantial part of its business;

6.3.1.6 becomes insolvent or is unable to pay all or some of its debts when they fall due for payment;

6.3.1.7 seeks to enter into an arrangement, composition or compromise with, or makes an assignment for the benefit of, all or any class of its creditors;

6.3.1.8 has a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction appointed in respect of any of its property that is used in or relevant to the performance of its obligations under the *market rules* or its *licence*;

6.3.1.9 is the subject of an order appointing an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any jurisdiction;

6.3.1.10 is wound up, dissolved, or otherwise has ceased to exist or is the subject of an application for winding up or dissolution, or any analogous procedure, under the laws of any jurisdiction, unless the notice of winding up or dissolution is discharged or withdrawn; or

6.3.1.11 ceases to satisfy any material requirement imposed upon it as a condition of its authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

6.3.2 A *market participant* shall notify the *IESO* immediately upon:

6.3.2.1 the occurrence of an *event of default* or any circumstance that may give rise to an *event of default* referred to in sections 6.3.1.4 to 6.3.1.11; or

6.3.2.2 the appointment of a receiver or receiver and manager or person having a similar or analogous function under the laws of any relevant jurisdiction in respect of any property of the *market participant* or the *market participant's prudential support* provider, or *capacity prudential support* provider.

6.3.3 Where a *market participant* or a person providing *prudential support* or *capacity prudential support* on behalf of that *market participant* commits an *event of default,* the *IESO* may:

6.3.3.1 issue to the *market participant* a *notice of intent to suspend* stating that the *market participant* will be suspended unless it remedies the *event of default* within 2 *business days* or such longer period as specified in the notice;

6.3.3.2 immediately draw upon part or all of the *market participant's prudential support*or *capacity prudential support* for either the amount of any money owing to the *IESO* under the *market rules* or where the *market participant's prudential support* or *capacity prudential support* is due to expire or terminate and has not been replaced as required under section 5.2.5, 5A.2.3 or 5B.2.4 of Chapter 2, the undrawn part of the *prudential support* notwithstanding the provisions of section 5.7.2.5 of Chapter 2 until such time as the *market participant* has replaced its *prudential support* or *capacity prudential support*; and

6.3.3.3 set-off any amounts due or credited to the *market participant* under the *market rules,* including those set out in section 4.8.2 of Chapter 9, and any program administered through the billing and *settlement* systems of the *IESO* against any amounts owed by the *market participant.*

6.3.4 Where the *IESO* issues a *notice of intent to suspend* under section 6.3.3.1 or a *suspension order* under sections 6.3A.1.1 and 6.3A.1.2 to a *market participant* that is a party to a *physical bilateral contract,* the *IESO* shall:

6.3.4.1 deem any *physical bilateral contract quantities* to be zero for the period from the date the *event of default* occurs until it is remedied if that *market participant* is the *selling market participant*; or

6.3.4.2 rescind or refuse to accept any initial or revised *physical bilateral contract data* relating to a *dispatch day* after the date of the *event of default* if that *market participant* is the *buying market participant*.

6.3.5 [Intentionally left blank – section deleted]

6.3.6 A *market participant* may remedy an *event of default* by:

6.3.6.1 satisfying any outstanding financial or other obligations that gave rise to the *event of default,* including any applicable *default interest* and any costs and expenses incurred by the *IESO* as a result of the *event of default*; and

6.3.6.2 proving to the reasonable satisfaction of the *IESO* that the facts or circumstances which constituted the *event of default* no longer exist.

6.3.7 Notwithstanding that the *event of default* has been remedied, the *IESO* may impose any condition on the right of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including:

6.3.7.1 establishing a lower *trading limit* in respect of the *market participant* than would otherwise be the case under section 5.3 of Chapter 2;

6.3.7.2 establishing a more frequent continuing schedule of payments than would otherwise be the case under Chapter 9; or

6.3.7.3 imposing a more stringent *prudential support obligation* than would otherwise be the case under section 5 of Chapter 2.

6.3A Suspension of a Market Participant

6.3A.1 The *IESO* may issue a *suspension order* to a *market participant* if:

6.3A.1.1 the *market participant* has not remedied an *event of default* within the time specified in the *notice of intent to suspend*;

6.3A.1.2 an *event of default* specified in sections 6.3.1.5 to 6.3.1.10 has occurred in relation to the *market participant*; or

6.3A.1.3 the *IESO* has determined under section 6.2A that a *suspension order* should be issued because the *market participant* has persistently breached the *market rules*.

6.3A.2 The *IESO* shall *publish* the details of the *suspension order* and provide a copy of the *suspension order* to the *OEB* and the *transmitter, distributor* and/or other *market participant* to whose *facilities* the suspended *market participant* is connected.

6.3A.3 To the extent specified in the *suspension order,* a *suspended market participant* is ineligible to trade or enter into any transaction in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*.

6.3A.4 The *IESO* may do one or more of the following to give effect to a *suspension order*:

6.3A.4.1 reject any bid, offer or TR bid submitted by the suspended market participant;

6.3A.4.2 set-off any amounts otherwise due to the *suspended market participant* against any amounts owed by the *suspended market participant* under the *market rules*;

6.3A.4.3 issue a disconnection order to the transmitter, distributor and/or other market participant to whose facilities the suspended market participant's facilities are connected and provide a copy to the OEB; or

6.3A.4.4 make such further order or issue such directions to the *suspended market participant* as the *IESO* determines appropriate.

6.3A.5 The *IESO* shall lift a *suspension order* if the *event of default* which triggered its issuance is remedied to the satisfaction of the *IESO* and there are no other *events of default* in existence with respect to the *suspended market participant*.

6.3A.6 Notwithstanding that the *suspension order* has been lifted, the *IESO* may impose any condition on the right of a *market participant* that has been subject of a *suspension order* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.4 Termination of a Market Participant

6.4.1 The *IESO* may issue a *termination order* to a *market participant* if:

6.4.1.1 the market participant is a suspended market participant and has not remedied the event of default that triggered the suspension order within 5 business days of the issuance of the suspension order;

6.4.1.2 the *market participant* is a *suspended market participant* and has notified the *IESO* that the *market participant* is not likely to remedy the *event of default* that triggered the issuance of the *suspension order*;

6.4.1.3 the *market participant* has been wound up, dissolved, or otherwise has ceased to exist; or

6.4.1.4 the *IESO* has determined under section 6.2A that a *termination order* should be issued because the *market participant* has persistently breached the *market rules*.

6.4.2 The *IESO* shall *publish* the details of the *termination order* and provide a copy of the *termination order* to the *OEB* and to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected.

6.4.3 When the *IESO* issues a *termination order*, it may at the same time, if it has not already done so, issue a *disconnection order* to the *transmitter, distributor* and/or other *market participant* to whose *facilities* the *terminated market participant's facilities* are connected and provide a copy to the *OEB*.

6.4.4 A *terminated market participant* that re-applies for authorization shall be required to comply with the provisions of section 3 of Chapter 2. The *IESO* may impose any conditions on the right of the *terminated market participant* to participate in *the IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of *the IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.5 De-Registration of a Market Participant's Facilities

6.5.1 The *IESO* may deregister some or all of a *market participant's registered facilities* if the *IESO* has determined under section 6.2A that the *market participant* has persistently breached the *market rules*.

6.5.2 Deregistering some or all of a *market participant's registered facilities* terminates all of the rights of the *market participant* in respect of those *registered facilities* to participate in the *IESO-administered markets* or in respect of those *registered facilities* to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of those *registered facilities*.

6.5.3 If the *IESO* deregisters some or all of a *market participant's registered facilities*, it may at the same time issue a *disconnection order* to the relevant *transmitter, distributor* and/or other *market participant* to whose *facilities* the *market participant's facilities* which is subject of the deregistration are connected and provide a copy to the *OEB*.

6.5.4 A *market participant* that wishes to re-register *registered facilities* that have been deregistered shall comply with the provisions of section 2 of Chapter 7. The *IESO* may impose any conditions on right of the *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* that the *IESO* determines are appropriate, including the conditions noted in sections 6.3.7.1 to 6.3.7.3.

6.5A Disconnection Order

6.5A.1 Each *transmitter, distributor* and other *market participant* to whom a *disconnection order* is issued pursuant to sections 6.3A.4.3, 6.4.3 or 6.5.3 shall, subject to this section 6.5A, on the date and at the time specified in the *disconnection order*, *disconnect* the *facilities* or equipment referred to in the *disconnection order*.

6.5A.2 Nothing in this section 6.5A is intended to prevent a *transmitter, distributor* or other *market participant* from taking action to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*; provided, however, that such *transmitter, distributor* or other *market participant* shall coordinate to the fullest extent practicable any such action with the *IESO*.

6.5A.3 Without limiting the generality of section 8.3 of Chapter 1, a *disconnection order* may be issued by the IESO to a *transmitter, distributor* or other *market participant* pursuant to sections 6.3A.4.3, 6.4.3 or 6.5.3 by voice communication.

6.6 Non-compliance Letters and Financial Penalties

6.6.1 This section 6.6 sets forth the manner in which the *IESO* will pursuant to section 6.2.7 issue non-compliance letters and fix financial penalties to be imposed on *market participants* for breaches of the *market rules*.

6.6.2 Where the *IESO* has determined that it is appropriate to issue a letter of non-compliance or impose a financial penalty upon a *market participant*, the *IESO* shall:

6.6.2.1 determine the level of non-compliance by the *market participant* in accordance with section 6.6.3;

6.6.2.2 determine the rate of recurrence of non-compliance by the *market participant* in accordance with section 6.6.4;

6.6.2.3 based on the determinations made in accordance with sections 6.6.2.1 and 6.6.2.2, issue a non-compliance letter or impose a financial penalty; and

6.6.2.4 where a determination is made to impose a financial penalty, fix the amount of the penalty in accordance with section 6.6.6.

6.6.2A When determining the particular level of non-compliance referred to in section 6.6.2.1, the *IESO* shall establish:

- whether all of the conditions for a level have been met; and
- that the manner and time, proposed by the *market participant*, within which the non-compliance event will be remedied are reasonable under the circumstances.

If a *market participant*

- meets some but not all of the conditions of any single level; or
- proposes a manner and time in which the non-compliance event will be remedied that are not reasonable under the circumstances in the opinion of the *IESO*,

then the *IESO* shall assign what it considers to be the appropriate non-compliance level.

6.6.3 The *IESO* shall determine the level of non-compliance referred to in section 6.6.2.1 as follows:

6.6.3.1 Level "L1" shall apply where the *market participant*:

i. failed to comply, in part, with the requirements of a *market rule*, and
ii. on its own initiative informed the *IESO* on a timely basis of:
   - the reasons for the non-compliance, and
   - the manner and time in which the non-compliance will be remedied.

6.6.3.2 Level "L2" shall apply where the *market participant*:

i. failed to comply in whole with the requirements of a *market rule*, and
ii. on its own initiative informed the *IESO* on a timely basis of:
   - the reasons for the non-compliance, and
   - the manner and time in which the non-compliance will be remedied.

6.6.3.3 Level "L3" shall apply where the *market participant*:

i. failed to comply, in whole or in part, with the requirements of a *market rule*,

ii. did not on its own initiative inform the *IESO* on a timely basis of the non-compliance; but

iii. did inform, at the *IESO*'s request and within the time specified in the request, the *IESO* of:

- the reasons for the non-compliance, and
- the manner and time in which the non-compliance will be remedied.

6.6.3.4 Level "L4" shall apply where the *market participant*:

i. failed to comply, in whole or in part, with the requirements of a *market rule*,

ii. did not on its own initiative inform the *IESO* on a timely basis of the non-compliance; and

iii. did not inform, at the *IESO*'s request and within the time specified in the request, the *IESO* of:

- the reasons for the non-compliance, and
- the manner and time in which the non-compliance will be remedied.

6.6.4 The *IESO* shall determine the rate of recurrence of non-compliance referred to in section 6.6.2.2 based on the frequency and duration with which the *market participant* has been found by the *IESO* to be in breach of the *market rules*.

6.6.5 [Intentionally left blank – section deleted]

6.6.6 Where the *IESO* has determined, based on the determinations made under section 6.6.2, that the applicable sanction is the imposition of a financial penalty, the *IESO* shall, subject to section 6.6.6A, consider the factors listed in section 6.6.7 and impose a financial penalty on the *market participant* within the ranges set out in the following table.

Level of Non-Compliance	Range of Sanctions
L1	Non-compliance letter or up to $2,000.00
L2	Non-compliance letter or up to $4,000.00
L3	Non-compliance letter or up to $6,000.00
L4	$1,000.00 to $10,000.00

6.6.6A The *IESO* may impose on a *market participant* a financial penalty in excess of the amount otherwise provided for in section 6.6.6 and no greater than $1,000,000 per occurrence, where:

6.6.6A.1 the market participant has breached a market rule while a declaration that the IESO-controlled grid is in an emergency operating state or a high-risk operating state was in effect;

6.6.6A.2 the *market participant* breached a *market rule* while a declaration that *market operations* have been suspended was in effect;

6.6.6A.3 the *IESO Board* determines that the impact of the *market participant*’s breach of a *market rule* on either the *IESO-administered markets* or the *reliability* of the *integrated power system* is particularly severe; or

6.6.6A.4 the rate of recurrence of non-compliance by the *market participant* with the *market rules* is of such frequency or duration as to warrant the imposition of a higher financial penalty.

6.6.6B Where at least one of the conditions of 6.6.6A are met and the *IESO* has determined that the applicable sanction is the imposition of a financial penalty, the *IESO* shall, consider the factors listed in section 6.6.7 and impose a financial penalty on the *market participant* within the ranges set out in the following table.

	Non-Compliance Level (Severity and Breach History)							
Impact Level	**Low**		**Moderate**		**High**		**Severe**	
	Range Limit		Range Limit		Range Limit		Range Limit	
	Min	Max	Min	Max	Min	Max	Min	Max
Low Little or None	$2,000	$25,000	$2,000	$50,000	$3,000	$75,000	$5,000	$100,000
Medium Material	$2,000	$100,000	$4,000	$250,000	$6,000	$450,000	$10,000	$600,000
High Severe	$4,000	$250,000	$8,000	$500,000	$12,000	$750,000	$20,000	$1,000,000

The *IESO* shall establish the penalty range at the intersection of the determined impact level and non-compliance level in accordance with the applicable *market manual* which includes:

- The *IESO* shall determine the impact level by examining all the impacts of the breach under investigation and selecting an appropriate impact level.

- The *IESO* shall determine the non-compliance level by examining breach history contributions, severity, and any aggravating or mitigating adjustments.

6.6.7 In fixing the amount of the financial penalty within the ranges described in the tables set forth in sections 6.6.6 and 6.6.6B, the *IESO* shall have regard to:

6.6.7.1 the circumstances in which the breach occurred;

6.6.7.2 the severity of the breach;

6.6.7.3 the extent to which the breach was inadvertent, negligent, deliberate or otherwise;

6.6.7.4 the length of time the breach remained unresolved;

6.6.7.5 the actions of the *market participant* on becoming aware of the breach;

6.6.7.6 whether the *market participant* disclosed the matter to the *IESO* on its own or whether it was prompted to do so;

6.6.7.7 any benefit that the *market participant* obtained or may have obtained as a result of the breach;

6.6.7.8 any previous breach by the *market participant* of the *market rules* or of the conditions of its *licence*;

6.6.7.9 the actual or potential impact of the breach on other *market participants*;

6.6.7.10 the actual or potential impact of the breach on the *IESO-administered markets* as a whole;

6.6.7.10A the actual or potential impact of the breach on the *reliability* of the *integrated power system*;

6.6.7.11 any sanctions that may be imposed on the *IESO* by a *standards authority* as a result of the breach;

6.6.7.12 the immediacy of the threat that the breach poses to the *reliability* of the *integrated power system* or the *IESO-administered market*;

6.6.7.13 presence and quality of the *market participant*'s compliance program;

6.6.7.14 whether on its own initiative, a *market participant* has undertaken to reasonably compensate the *IESO-administered market* for the value of any benefit it obtained as a result of the breach; and

6.6.7.15 such other matters as the *IESO* considers appropriate.

6.6.8 Where Appendix 3.1 provides for the imposition of a formula-based penalty in respect of the breach of a *market rule*, the *IESO* may issue a letter of non-compliance pursuant to section 6.6.2.3 or impose a financial penalty upon the *market participant*, the amount of which shall be determined by the application of the following formula:

$$P = D \times T \times C$$

Where:

P = the amount of the financial penalty, in dollars

D = the deviation from the applicable obligation in the *market rules*, expressed in terms of MW, MVAR, kV, power factor or other determinant, as specified in Appendix 3.1 in respect of the particular *market rule*

T = the duration of the breach, expressed in hours or fractions of hours

C = the amount determined in accordance with section 6.6.9 in respect of the particular *market rule*

6.6.9 The amount C referred to in section 6.6.8 shall be determined, in respect of the breach of a particular *market rule*, by multiplying the *market price* prevailing at the time of the breach by an amount determined by the *IESO* having regard to the criteria set forth in section 6.6.7 and to the factors noted in sections 6.6.6A.1 to 6.6.6A.4, where applicable.

6.6.10 Where Appendix 3.1 specifies more than one sanction in respect of the breach of a particular *market rule*, the *IESO* may impose all of the sanctions so specified on the *market participant* provided that no financial penalty may be imposed in respect of a breach for which the *IESO* has issued a letter of non-compliance pursuant to section 6.6.2.3. Nothing in this section 6.6.10 shall prevent the *IESO* from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a letter of non-compliance has been issued or if there is any repetition or continuation of such breach.

6.6.10A In respect of a breach of section 7.5.8A of Chapter 7, the *IESO* may:

6.6.10A.1 issue a letter of non-compliance or impose a financial penalty upon the *market participant* pursuant to sections 6.6.2.3, and 6.6.6; and

6.6.10A.2 adjust *settlement amounts* paid or payable to a *registered market participant* such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts* that the *registered market participant* received or avoided due to an act or omission or a course of conduct of either the *registered market participant* alone or the *registered market participant* by agreement or arrangement with one or more other *market participants* that led to the breach of section 7.5.8A of Chapter 7.

6.6.11 Nothing in this section 6.6 shall preclude the *IESO* from making an order under one or more of sections 6.2.7.1, 6.2.7.2, 6.2.7.3 or 6.2.7.6 in respect of a breach of the *market rules* with respect to which a sanction has been imposed pursuant to this section 6.6.

6.6.12 [Intentionally left blank]

6.6.12.1 [Intentionally left blank]

6.6.12.2 [Intentionally left blank]

6.6.13 [Intentionally left blank – section deleted]

6.6.14 No additional financial penalty may be imposed in respect of a breach of the *market rules* for which a financial penalty has already been imposed pursuant to this section 6.6 provided that nothing in this section 6.6.14 shall prevent the *IESO* from imposing a financial penalty for failure by a *market participant* to remedy a breach in respect of which a financial penalty has been imposed or if there is any repetition or continuation of such breach.

6.7 Officers and Agents

6.7.1 If any director, officer, employee partner or agent of a *market participant* does any act or refrains from doing any act which if done or omitted to be done, as the case may be, by a *market participant* would constitute a breach of the *market rules*, such act or omission shall be deemed for the purposes of this section 6 to be the act or omission of the *market participant*.

7. Financial Penalties for Certain Contracted Ancillary Service Providers

7.1 Penalties Specified in Contracts

7.1.1 An *ancillary service provider* providing *regulation* or *black start capability* under a *contracted ancillary service* contract that:

7.1.1.1 breaches any performance standard set forth in the *market rules*; or

7.1.1.2 fails to pass a test set forth in the *market rules*, the *contracted ancillary service* contract or, where applicable, the *Ontario power system restoration plan*,

in respect of such *contracted ancillary service* shall be subject to such financial penalties and other *sanctions* as may be specified in the applicable *contracted ancillary service* contract and to the provisions of section 4.10.2.1 of Chapter 5.

Market Rules

Chapter 3 Administration, Supervision, Enforcement - Appendices

Power to Ontario.
On Demand.

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Appendix 3.1 – Application of Enforcement Actions

Non-compliance	Enforcement Action
Chapter 4, section 3.1.2	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 4, section 3.3.1.6	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 4, section 6.1.6	Sanctions as per section 6.6.5 or 6.6.6 Disconnection order as per section 6.5
Chapter 5, section 3.4.1.1	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.4.1.2	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required including its restoration (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.5.1.1	Formula based penalty as per section 6.6.8 of Chapter 3 where; D= load shedding capability required including its restoration (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.6.1.1	Formula based penalty as per section 6.6.8 where; D= nominal generation capacity (*MCR*) barring declared limitations (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 3.7.1.1	Formula based penalty as per section 6.6.8 where; D= load shedding capability required (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9

Non-compliance	Enforcement Action
Chapter 5, section 6.3.10	Formula based penalty as per section 6.6.8 where: D = the amount by which the *offer* made is less than the MW which the *generator* had agreed would be *offered* in support of the *planned outage* or the extension to or rescheduling of an *outage*. C = *market price* x amount to be determined by the *IESO* under section 6.6.9
App 5.1, section 1.2.1	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.4	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.2	Formula based penalty as per section 6.6.8 where; D= ramp rate deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.5	Formula based penalty as per section 6.6.8 where; D= ramp rate deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.3	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
App 5.1, section 1.2.6	Formula based penalty as per section 6.6.8 where; D= resource deviation (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9.
Chapter 5, section 10.3.3	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9
Chapter 5, section 10.3.4	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9

Non-compliance	Enforcement Action
Chapter 5, section 10.3.5	Formula based penalty as per section 6.6.8 where; D= deviation from direction (MW) C= *Market Price* x amount determined by the *IESO* under section 6.6.9

Market Rules

Chapter 4
Grid Connection Requirements

Connecting Today.
Powering Tomorrow.

Issue Date: February 26, 2021

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1. Introduction

1.1.1 This Chapter sets forth rules to assist the *IESO* in maintaining the *reliability* of the *IESO-controlled grid* by:

1.1.1.1 requiring all *market participants* to adhere to established standards for all equipment *connected* to the *IESO-controlled grid* and to comply with certain other obligations relating generally to *connection* to the *IESO-controlled grid* and to participation in the *IESO-administered markets*; and

1.1.1.2 setting forth certain reliability-related obligations of *embedded generators* and *embedded electricity storage participants* that may not be market participants.

1.1.2 Section 7.5 of Chapter 1 does not apply to this Chapter and any action or event that is required to occur on or by a stipulated time or day under this Chapter or pursuant to a direction, instruction, or order made by the *IESO* under this Chapter shall occur on or by that time, whether or not a business hour, or on or by that day, whether or not a *business day*, unless otherwise specified in this Chapter or in the direction, instruction or order of the *IESO*.

1.1.3 For the purposes of this Chapter, "maintaining" *reliability* shall include re-establishing or restoring *reliability* and "maintain" and "maintenance" shall be interpreted accordingly.

1.1.4 Nothing in this Chapter is intended to prevent *market participants* from acting to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*, provided that the *market participants* coordinate any such actions that may affect the *reliability* of the *IESO-controlled grid* with the *IESO* to the fullest extent practicable.

2. Equipment Standards

2.1.1 All *market participants* shall ensure that their equipment and *facilities* connected to the *IESO-controlled grid* adhere to all applicable *reliability standards*.

2.1.2 All *market participants* shall maintain and operate their equipment and *facilities* in accordance with *applicable law*, *good utility practice* and all applicable *reliability standards*.

2.1.3 The standards described in this Chapter shall be implemented through compliance with the requirements of this Chapter, through *connection agreements* between *transmitters* and *market participants* that are *connected* or seek to *connect* to the *IESO-controlled grid* and through *operating agreements* between the *IESO* and *transmitters*.

2.1.4 [Intentionally left blank]

2.1.5 No *transmitter* or *market participant* shall place into service a new or modified *connection facility* until the *IESO* has determined that the *connection facility* complies with this Chapter.

2.1.6 Nothing in this Chapter shall be deemed to interfere with the right of each *transmitter* and *distributor* to establish standards and criteria for the design, construction, and operation of equipment connected to their systems, provided that such standards and criteria:

2.1.6.1 are applied in a non-discriminatory manner to all *market participants* and *connection applicants connecting* or seeking to *connect* to the *IESO-controlled grid*;

2.1.6.2 satisfy *reliability standards* and any minimum general performance standards set forth in Appendix 4.1; and

2.1.6.3 shall be subject to review by the *IESO* in the event there is a dispute regarding compliance with this section 2.1.6 and to the right of the *IESO* to override the application of such standards and criteria in the event it determines that they do not so comply.

2.1.7 Subject to compliance with the standards set forth in this Chapter and to sections 6.1.6 and 6.1.7, each *market participant* and *connection applicant* shall have the right to *connect* to the *IESO-controlled grid* or to modify its existing *connection facilities* to the *IESO-controlled grid* without undue delay.

3. Performance Standards and Obligations of Market Participants

3.1 General Requirement

3.1.1 The minimum general performance standards for all equipment *connected* to the *IESO-controlled grid* are set forth in Appendix 4.1. Specific performance standards applicable to the equipment of *generators*, *electricity storage participants*, *connected wholesale customers*, *distributors connected* to the *IESO-controlled grid* and *transmitters* are set forth in Appendices 4.2 to 4.4, respectively.

3.1.2 Each *market participant* shall ensure that its equipment connected to the *IESO-controlled grid* meets all applicable performance standards in Appendix 4.1 and each *generator, electricity storage participant*, *connected wholesale customer*, *distributor* connected to the *IESO-controlled grid* and *transmitter* shall ensure that its equipment connected to or forming part of the *IESO-controlled grid* meets all applicable performance standards in Appendices 4.2 to 4.4, respectively.

3.1.3 Each *embedded generator* or *embedded electricity storage provider* shall ensure that its equipment meets all applicable performance requirements in Appendix 4.3.

3.2 Development of Rules for Waivers of Standards

3.2.1 [Intentionally left blank]

3.2.1.1 [Intentionally left blank]

3.2.1.2 [Intentionally left blank]

3.2.2 [Intentionally left blank]

3.2.2.1 [Intentionally left blank]

3.2.2.2 [Intentionally left blank]

3.2.3 A *generator* or *electricity storage participant* may comply with its requirement to provide reactive power either by modifying any of its *generating units* or *electricity storage units* that do not comply with any standard with respect to the provision of reactive power, or by obtaining reactive power from other appropriate *generating units, electricity storage units* or *market participants.* The *IESO* shall determine whether these other *generating units, electricity storage units* or *market participants* are in sufficiently close electrical proximity to the non-compliant *generating unit* or *electricity storage unit* so as to provide the comparable or equivalent reactive power.

3.3 Obligations of Transmitters

3.3.1 Each *transmitter* shall:

3.3.1.1 [Intentionally left blank]

3.3.1.2 coordinate the design of equipment proposed to be *connected* to the *IESO-controlled grid* to achieve compliance with this Chapter;

3.3.1.3 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.3.1.4 [Intentionally left blank]

3.3.1.5 satisfy the data requirements set forth in this Chapter to model the static and dynamic performance of the *IESO-controlled grid*;

3.3.1.6 obtain the prior approval of the *IESO* for all changes in or removals of equipment or *facilities connected* to the *IESO-controlled grid* that could impact on the reliable operation of the *IESO-controlled grid*;

3.3.1.7 operate its portion of the *IESO-controlled grid* such that, during a *normal operating state*, electricity may be transferred continuously at a *connection point*;

3.3.1.8 operate its portion of the *IESO-controlled grid* such that the fault level at any *connection point* does not exceed the limits specified in the relevant *connection agreement*;

3.3.1.9 operate its portion of the *IESO-controlled grid* to minimize the number and duration of interruptions at a *connection point*;

3.3.1.9A follow *good utility practice* to promptly return *transmission facilities* and equipment to service after an interruption;

3.3.1.10 [Intentionally left blank]

3.3.1.11 [Intentionally left blank]

3.3.1.12 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.3.1.13 upon the request of the *IESO*, enter into an *operating agreement* with the *IESO*.

3.4 Obligations of Generators

3.4.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall:

3.4.1.1 [Intentionally left blank]

3.4.1.2 [Intentionally left blank]

3.4.1.3 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of its equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.4.1.4 [Intentionally left blank]

3.4.1.5 [Intentionally left blank]

3.4.1.6 operate its equipment in accordance with its *connection agreement*;

3.4.1.7 [Intentionally left blank]

3.4.1.8 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.4.1.9 notify the *IESO* upon the submission of a *connection request* to a *transmitter*.

3.5 Obligations of Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

3.5.1 Each *connected wholesale customer* and each *distributor connected* to the *IESO-controlled grid* shall:

3.5.1.1 [Intentionally left blank]

3.5.1.2 [Intentionally left blank]

3.5.1.3 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of its equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.5.1.4 [Intentionally left blank]

3.5.1.5 [Intentionally left blank]

3.5.1.6 operate its equipment in accordance with its *connection agreement*;

3.5.1.7 [Intentionally left blank]

3.5.1.8 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.5.1.9 notify the *IESO* of the submission of a *connection request* to a *transmitter* pursuant to section 3.5.1.1.

3.6 Obligations of Electricity Storage Participants

3.6.1 Each *electricity storage participant* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall:

3.6.1.1 permit and participate in any commissioning, inspection, and testing that the *IESO* requires of its equipment that is or is to be *connected* to the *IESO-controlled grid*;

3.6.1.2 operate its equipment in accordance with its *connection agreement*;

3.6.1.3 complete and return to the *IESO* those portions of the *IESO catalogue of reliability-related information* relevant to its *facilities*; and

3.6.1.4 notify the *IESO* upon the submission of a *connection request* to a *transmitter*.

4. Connection Agreements

4.1.1 Each *connected wholesale customer* and each *distributor*, *generator* and *electricity storage participant* connected to the *IESO-controlled grid* shall have a signed *connection agreement*, in such form as may be prescribed by the OEB, with the applicable *transmitter* with whom it is *connected.*

4.1.2 Each embedded *facility* that is a *market participant* shall have a signed connection agreement, in such form as may be prescribed by the *OEB*, with the applicable *distributor* with whom it is *connected.*

5. Compliance, Inspection, Testing, and Monitoring

5.1 General Requirements

5.1.1 Each *transmitter*, *generator, electricity storage participant*, *connected wholesale customer* or *distributor connected* to the *IESO-controlled grid* shall have the obligation to test and monitor its equipment to ensure and maintain compliance with all applicable *reliability standards* required by these *market rules*. The requirement to conduct and pay for such activities shall be specified in each *connection agreement*. If any *transmitter*, *generator, electricity storage participant, distributor* or *connected wholesale customer connected* to the *IESO-controlled grid* in respect of which no relevant waiver has been granted by the *IESO* fails to comply with the provisions of this Chapter, the *IESO* shall notify the *transmitter* and the connecting party of such non-compliance and shall ask that the parties achieve prompt compliance with this Chapter, subject to the imposition of such penalties for failure to comply as may be specified in these *market rules*. Pending such compliance, the *IESO* may direct the *transmitter* and the connecting party to operate their respective equipment and *facilities* so as to maintain the *reliability* of the *IESO-controlled grid*.

5.1.2 The results of all compliance monitoring and performance testing required by this Chapter to be performed shall be made available to the *IESO* upon request.

5.1.3 Each *transmitter*, *generator, electricity storage participant*, *distributor* and *connected wholesale customer connected* to the *IESO controlled grid* shall maintain records that set forth the results of all performance testing and monitoring conducted to demonstrate compliance with this Chapter in each case for 7 years from the date of the testing or monitoring activity. Each *transmitter, generator, electricity storage participant, distributor* and *connected wholesale customer* shall make such records available to the *IESO* upon request.

5.1.4 Parties to a *connection agreement* shall bear the cost of monitoring and testing their equipment and *facilities* for compliance with this Chapter. The *IESO* may request a *transmitter, generator, electricity storage participant, distributor* or *connected wholesale customer connected* to the *IESO-controlled grid* to attach to its equipment or *facilities* such test or monitoring equipment as the *IESO* determines appropriate and that is not required by the relevant *connection agreement* to be so attached, provided that such test or monitoring equipment does not adversely affect the performance of the connecting party's equipment or *facilities*. If the test or monitoring equipment required by the *IESO* is intended to provide a general benefit to the *IESO-controlled grid*, and is not otherwise required to ensure compliance of the specific *market participant's* equipment, the *IESO* shall bear the costs of such additional test or monitoring equipment and the costs of operating and attaching such equipment to the *transmitter's, generator's, electricity storage participant's, distributor's* or *connected wholesale customer's* equipment or *facilities*. All such costs shall be subject to verification and audit by the *IESO*.

5.1.5 Parties to a *connection agreement* that propose to perform a test on equipment that requires a change to the normal operation of such equipment shall give such prior notice to the *IESO* as the *IESO* shall require if such test could have an adverse impact on the *reliable* operation of the *IESO-controlled grid*. If the *IESO* determines that the proposed test could adversely affect the *reliability* of the *IESO-controlled grid*, the *IESO* may direct that the parties modify the testing procedure or the time scheduled for the test to avoid any threat to *reliability*. If such activities cannot avoid a threat to *reliability* to a degree acceptable to the *IESO*, the *IESO* shall not permit the test.

5.1.6 Where the IESO believes that the equipment of a *transmitter, generator, electricity storage participant, distributor* or *connected wholesale customer* connected to the *IESO-controlled grid* does not comply with the requirements of this Chapter, and that such non-compliance poses a threat to the reliable operation of the *IESO-controlled grid*, the IESO may direct the *transmitter, generator,* *electricity storage participant*, *distributor* or *connected wholesale customer* to modify such equipment to comply with this Chapter.

5.1.7 Section 5.1.6 applies regardless of whether a waiver has been granted to the relevant *transmitter, generator, electricity storage participant*, *distributor* or *connected wholesale customer* by the *IESO* in respect of the non-complying equipment.

5.2 IESO-Required Tests of Generators and Electricity Storage Participants

5.2.1 In addition to any tests required by a connection agreement, the IESO may require a generator or *electricity storage participant* to test any generation facility or *electricity storage facility* connected to the *IESO-controlled grid* in order to determine whether such *facility* meets the requirements of this Chapter. The relevant *generator* or *electricity storage participant* shall comply with such request. If possible, the IESO shall permit such tests to be performed during the next scheduled *planned outage* of the facility. If the IESO determines that a test is required for reliability reasons prior to the next scheduled *planned outage* of the *facility*, the IESO shall cooperate with the *generator* or *electricity storage participant* to ensure that the test is conducted in a manner designed to create the minimum impact on the operation of that *facility*.

5.2.2 Tests conducted under this section 5.2 shall be conducted in accordance with procedures that have been agreed upon by the *IESO* and the relevant *generator* or *electricity storage participant*. The *IESO* shall provide the relevant *generator* or *electricity storage participant* with the parameters of the model derived from such tests.

5.2.3 Section 5.1.4 shall apply to determine the allocation to and the recovery by the *IESO* of any costs incurred by a *generator* or *electricity storage participant* to assist in the performance of the tests required under this section 5.2.

5.3 IESO-Required Tests of Interconnections

5.3.1 The *IESO* may perform or require *transmitters* to perform tests to verify the magnitude of the power transfer capability of *interconnections* whenever:

5.3.1.1 a new *interconnection* between the *IESO-controlled grid* and a *neighboring electricity system* is placed into operation, augmented or substantially modified; or

5.3.1.2 the *IESO* has reasonable grounds to believe that power transfer capability across that *interconnection* has materially changed.

5.3.2 Prior to performing or directing the performance of the tests referred to in section 5.3.1, the *IESO* shall provide as much advance notice as practicable to *market participants* and other *interconnected transmitters* whose systems, equipment or *facilities* could be materially affected by the tests. All *market participants* shall cooperate with the *IESO* and/or the relevant *transmitter* in planning, preparing for and conducting tests to assess the technical performance of *interconnections* on the *IESO-controlled grid*.

5.3.3 The *IESO* may temporarily direct the operation of *generation facilities* or *electricity storage facilities* during the testing of *interconnections* if and to the extent necessary to obtain operational conditions on the *IESO-controlled grid* that are required in order to achieve valid test results. The *IESO* shall plan the timing of tests so that the duration of the tests and the variation in the *dispatch* of the *generation facility* or *electricity storage facility* relative to its *dispatch* under non-test conditions are minimized to the extent possible.

5.3.4 Any costs that are incurred by a *generator* or *electricity storage participant* to assist in the performance of the tests required under section 5.3 that are otherwise unrecoverable shall be recovered from *market participants* in accordance with section 4.8 of Chapter 9. All such costs shall be subject to verification and audit by the *IESO* before being so recovered.

6. Establishing or Modifying IESO-Controlled Grid Facilities and Connections

6.1 General Requirements

6.1.1 Subject to the *reliability standards* required by these *market rules* and to sections 6.1.7, 6.1.22 and 6.1.23, the requirements associated with the design and construction of *connections* to the *IESO-controlled grid* shall be established between the *connecting market participant* or *connection applicant* and the *transmitter* with whom the *market participant* or *connection applicant* seeks to *connect*.

6.1.2 [Intentionally left blank]

6.1.2.1 [Intentionally left blank]

6.1.2.2 [Intentionally left blank]

6.1.3 [Intentionally left blank]

6.1.4 [Intentionally left blank]

6.1.4.1 [Intentionally left blank]

6.1.4.2 [Intentionally left blank]

6.1.5 The *IESO* shall, upon receipt of a *request for connection assessment* referred to in section 6.1.6, assess the impact of a new or modified *connection* to the *IESO-controlled grid* on the *reliability* of the *integrated power system* by means of a *connection assessment* conducted in accordance with the provisions of sections 6.1.14 to 6.1.18**.**

6.1.6 A *connection applicant* shall:

6.1.6.1 file a *request for connection assessment* to obtain the assessment referred to in section 6.1.5 and the approval of the *IESO* in accordance with the provisions of sections 6.1.14 to 6.1.18; and

6.1.6.2 where applicable, obtain the approval of the *IESO* pursuant to section 6.1.22.

Without limiting the generality of sections 6.1.14 and 6.1.15, the *IESO* shall define the form and content of information required for a *request for connection assessment*. The *connection applicant* shall notify the *transmitter* of the filing of such request for *connection assessment.*

6.1.7 If the *IESO* determines as part of a *connection assessment* that a new or modified *connection* will have an adverse effect on the *reliability* of the *integrated power system,* the *IESO* shall describe such adverse effects in its report on the *connection assessment* and of the system upgrades required to mitigate such adverse effects. No *market participant, connection applicant* or *transmitter* shall establish such new or modified *connection* unless the required system upgrades described in the *connection assessment* are designed and implemented to the satisfaction of the *IESO*.

6.1.8 [Intentionally left blank]

6.1.9 Each *transmitter* shall, subject to obtaining any required approvals therefor and to the completion by the *IESO* of a *connection assessment* in accordance with section 6.1.5 and sections 6.1.14 to 6.1.18, and, if applicable, such further assessment and resulting approval as contemplated by sections 6.1.22 and 6.1.23, undertake the design and construction of any upgrades to its portion of the *IESO-controlled grid* that are required by the *IESO* to ensure the *reliability* of the *IESO-controlled grid*.

6.1.10 Each *transmitter* shall, if required by its *licence*, or an order of the *OEB* or by an agreement between the *transmitter* and the *connection applicant*, use its best efforts to undertake the design and construction of any *connection facilities* that are necessary to bring about any new or modified *connections* to the *IESO-controlled grid* that have been the subject of a *connection assessment* completed in accordance with sections 6.1.14 to 6.1.18 and, if applicable, sections 6.1.22 and 6.1.23 on a timely basis and in accordance with the requirements of this Chapter.

6.1.11 [Intentionally left blank]

6.1.12 [Intentionally left blank]

6.1.13 [Intentionally left blank]

6.1.14 The *IESO* shall establish procedures describing the manner and timing for the processing of *requests for connection assessment.*

6.1.15 A *connection applicant* shall file with the *IESO*:

6.1.15.1 a *request for connection assessment*, the supporting documentation referred to in section 6.1.6 and such other supporting documentation that meets the requirements of the procedures referred to in section 6.1.14;

6.1.15.2 a deposit in such amount as may be specified in the procedures referred to in section 6.1.14; and

6.1.15.3 an executed agreement in the form set forth in the procedures referred to in section 6.1.14 pursuant to which the *connection applicant* agrees, subject to section 6.1.17, to pay to the *IESO* an amount equal to all of the costs and expenses incurred by the *IESO* in completing the *connection assessment* associated with the *request for connection assessment* subject to section 6.1.17.

6.1.16 The *IESO* shall process each *request for connection assessment* in accordance with the procedures referred to in section 6.1.14 and as follows:

6.1.16.1 the *IESO* shall, unless the *request for connection assessment* is withdrawn or deemed to have been withdrawn pursuant to the procedures referred to in section 6.1.14, conduct a *connection assessment* in respect of the subject-matter of the *request for connection assessment* in accordance with the procedures referred to in section 6.1.14;

6.1.16.2 the *IESO* shall provide to the *connection applicant* and to the applicable *transmitter* a copy of the report of the results of the completed *connection assessment* referred to in section 6.1.16.1;

6.1.16.3 provided that the *connection applicant* has met the requirements of section 6.1.15, within such time as may be specified in the procedures referred to in section 6.1.14,

a. [Intentionally left blank]

b. [Intentionally left blank]

c. [Intentionally left blank]

the *IESO* shall conduct a *connection assessment* in respect of the subject-matter of the *request for connection assessment* in accordance with the procedures referred to in section 6.1.14;

6.1.16.4 the *IESO* shall provide to the *connection applicant* and the applicable *transmitter* a copy of the report of the results of the completed *connection assessment* referred to in section 6.1.16.3, together with notice of its approval or disapproval of the new or modified *connection* that is the subject-matter of the *connection assessment*;

6.1.16.5 the *IESO* shall advise the *Ontario Energy Board* of the results of the *connection assessment* referred to in section 6.1.16.3; and

6.1.16.6 provided that the *connection applicant* has, within such time or times following the date of completion of the *connection assessment* that relates to its *request for connection assessment* as may be specified in the procedures referred to in section 6.1.14, filed with the *IESO* such confirmation or evidence, as the case may be and as may be specified in such procedures, of its intention to proceed with the new or modified *connection* that is the subject-matter of its *request for connection assessment*:

a. the *connection applicant* shall retain the priority allocated to its *request for connection assessment*; and

b. the *IESO* shall include the results of such *connection assessment* in such subsequent *connection assessment*, conducted within the times specified in the procedures referred to in section 6.1.14, as may be appropriate.

c. [Intentionally left blank – section deleted]

6.1.17 Where the *IESO* conducts a *connection assessment* that relates to two or more *requests for connection assessment*, the *IESO* shall apportion the costs relating to the *connection assessment* amongst the applicable *connection applicants* in accordance with the procedures referred to in section 6.1.14 and shall reflect such apportionment in the agreement referred to in section 6.1.15.3.

6.1.18 Where:

6.1.18.1 the *IESO* conducts a *connection assessment* that relates to two or more *requests for connection assessment*; and

6.1.18.2 one or more of the *connection applicants* withdraws or is deemed to have withdrawn its *request for connection assessment*,

the *IESO* shall apportion the costs relating to the *connection assessment* amongst applicable *connection applicants* in accordance with the procedures referred to in section 6.1.14.

6.1.19 [Intentionally left blank]

6.1.20 The *IESO* shall submit an *invoice* to each *connection applicant* upon completion of the *connection assessment* which relates to the *connection applicant's request for connection assessment* in an amount equal to:

6.1.20.1 all of the *IESO's* costs and expenses relating to the processing of the *connection applicant's request for connection assessment* and to the conduct of the *connection assessment;* or

6.1.20.2 where section 6.1.17 or 6.1.18 applies, the portion of the costs and expenses referred to in section 6.1.20.1 apportioned to the *connection applicant*;

minus

6.1.20.3 the amount of any deposit paid pursuant to section 6.1.15.2.

6.1.21 A *connection applicant* shall, within ten *business days* of receipt of an *invoice* referred to in section 6.1.20, pay to the *IESO* the amount owing thereunder. Such *invoice* shall be considered to create an obligation under the *market rules* to pay the amount specified therein and such amount may, without prejudice to any other manner of recovery available at law, be recovered accordingly.

6.1.22 No *connection applicant* shall establish a new or modify an existing *connection* to the *IESO-controlled grid* in a manner that differs materially from the configuration or technical parameters that were used by the *IESO* as the basis upon which it approved such new or modified *connection* in accordance with section 6.1.14 to 6.1.18 unless the applicable *connection applicant* has obtained the approval of the *IESO* for the change in configuration or technical parameter.

6.1.23 The *IESO* shall approve a change in configuration or technical parameter referred to in section 6.1.22 unless the *IESO* determines that such change will have an adverse effect on the *reliability* of the *integrated power system*. Where the *IESO* does not approve such change, no *connection applicant* shall establish the applicable new or modify the applicable existing *connection* to the *IESO-controlled grid* unless the required system upgrades described in the *connection assessment* are designed and implemented to the satisfaction of the *IESO*.

6.1A Upgrades to Ensure Reliability

6.1A.1 Each *transmitter* shall, subject to obtaining any required approvals therefor, undertake the design and construction of any upgrades to its portion of the *IESO-controlled grid* that are required by the *IESO* to ensure the *reliability* of the *IESO-controlled grid*.

6.2 Voluntary Disconnection

6.2.1 A *connected market participant* may *disconnect* from the *IESO-controlled grid* any *registered facility* that has been de-registered in accordance with section 2.4 of Chapter 7 following the completion of all applicable operating and decommissioning procedures referred to in the *connection agreement* applicable to the *registered facility*.

6.3 Disconnection by Transmitter, Distributor or Market Participant

6.3.1 A *transmitter* may *disconnect* from the *IESO-controlled grid* the *facilities* or equipment of a *market participant* in accordance with the *market rules* and *applicable law*.

6.3.1.1 [Intentionally left blank]

6.3.1.2 [Intentionally left blank]

6.3.1.3 [Intentionally left blank]

6.3.1A Subject to section 6.4.3, a *transmitter* shall notify the *IESO* prior to *disconnecting* from the *IESO-controlled grid* the *facilities* or equipment of a *market participant* for any reason other than in response to a *disconnection order*.

6.3.2 Each *transmitter*, *distributor* and other *market participant* to whom a *disconnection order* is issued pursuant to section 6.4 shall, subject only to section 3.4.1.5 or 3.7.1.5 of Chapter 5, as the case may be, on the date and at the time specified in the *disconnection order*, *disconnect* the *facilities* or equipment referred to in the *disconnection order*.

6.3.3 Without limiting the generality of section 8.3 of Chapter 1, a *disconnection order* may be issued by the *IESO* to a *transmitter*, *distributor* or other *market participant* pursuant to section 6.4 by voice communication.

6.4 Disconnection During an Emergency or For Safety or Reliability Reasons

6.4.1 During an *emergency*, the *IESO* may:

6.4.1.1 direct a connected *market participant* to reduce the power transferred at the *connection point* to zero in an orderly manner; and

6.4.1.2 issue a *disconnection order* to a *transmitter*, *distributor* or other *market participant* directing such *transmitter*, *distributor* or other *market participant* to *disconnect* a person's *facilities* or equipment from the *IESO-controlled grid*, its *transmission system*, its *distribution system* or from a host *market participant*, as the case may be.

6.4.2 Where the *IESO* becomes aware of a threat to the safety of any person, damage to equipment, or the environment or to the *reliability* of the *integrated power system* that requires urgent action, the *IESO* may issue a *disconnection order* directing the relevant *transmitter* or *distributor* to *disconnect* a person's *facilities* or equipment from the *IESO-controlled* grid, its *transmission system* or its *distribution* system, as the case may be.

6.4.2A Where the *IESO* becomes aware that a person has *connected facilities* or equipment to the *IESO-controlled grid*:

6.4.2A.1 without the approval of the *IESO* including, where applicable, but not limited to the approval referred to in section 6.1.22;

6.4.2A.2 in a manner that does not comply with the requirements of the *market rules* or *applicable law*;

6.4.2A.3 in a manner that does not comply with the requirements identified in a *connection assessment* associated with that person's *facilities* or equipment; or

6.4.2A.4 where applicable, in a manner other than that determined satisfactory by the *IESO* pursuant to section 6.1.7 or 6.1.23,

the *IESO* may issue a *disconnection order* directing the relevant *transmitter* to *disconnect* the person's *facilities* or equipment from the *IESO-controlled grid*.

6.4.2B Where the *IESO* becomes aware that a *generator* or *electricity storage participant* has synchronized (respectively) either a *generation unit* or an *electricity storage unit* to the *IESO-controlled grid* other than in accordance with section 11.2 of Chapter 7, the *IESO* may issue a *disconnection order* directing the relevant *transmitter* to *disconnect* the *generation unit* or *electricity storage unit* from the *IESO-controlled grid*.

6.4.3 A *transmitter* may, in accordance with the provisions of its *licence*, any code issued by the *OEB* with which the *transmitter* is required to comply, or the *market rules*, immediately *disconnect* from the *IESO-controlled grid* the *facilities* or equipment of a person where:

6.4.3.1 such action is urgently required to ensure the safety of any person, prevent the damage of equipment, or the environment;

6.4.3.2 the urgency is such that there is insufficient time to notify the *IESO* prior to such action being taken; and

6.4.3.3 the *transmitter* is the operator of a connection facility.

A *transmitter* that *disconnects* a person's *facilities* or equipment pursuant to this section 6.4.3 shall promptly inform the *IESO* that such action has been taken.

6.5 Obligation to Reconnect After Disconnection

6.5.1 A *transmitter*, *distributor* or other *market participant* to whom a *disconnection order* was issued pursuant to section 6.4 shall, in accordance with the direction referred to in section 6.5.2, reconnect the relevant *facilities* or equipment to the *IESO-controlled grid*, its *transmission system*, its *distribution system* or to the host *market participant*, as the case may be, once:

6.5.1.1 the *transmitter*, *distributor* or other *market participant*, as the case may be, and the *IESO* are satisfied that the *emergency* which prompted the *disconnection* no longer exists; or

6.5.1.2 where the *disconnection* occurred for reasons other than an *emergency*, the *transmitter*, *distributor* or other *market participant*, as the case may be, and the *IESO* are satisfied that the reason for the *disconnection* no longer exists.

6.5.2 A *transmitter*, *distributor* or other *market participant* to whom a *disconnection order* was issued pursuant to section 6.4 may reconnect the relevant *facilities* and equipment only under direction from the *IESO* provided that the person whose *facilities* or equipment were *disconnected* has carried out any demonstration required pursuant to section 6.5.3 to the reasonable satisfaction of the *transmitter*, the *distributor* or other *market participant*, as the case may be, and the *IESO*.

6.5.3 Prior to reconnection, the *transmitter*, *distributor* or other *market participant*, as the case may be, or the *IESO* may require the person whose *facilities* or equipment were *disconnected* to demonstrate that it has taken all necessary steps to prevent the recurrence of any event that prompted the *disconnection* that was within the control of the person.

6.5.3A A *transmitter* that has *disconnected* from the *IESO-controlled grid* the *facilities* or equipment of a person in circumstances other than where it has received from the *IESO* a *disconnection order* directing it to do so shall inform the *IESO* prior to reconnecting such *facilities* or equipment.

6.5.4 Any agreement between a *transmitter* and a *market participant* as to the payment of any costs associated with *disconnection* and reconnection shall be contained in their *connection agreement*.

7. Provision of Connection-Related Information

7.1 Provision of Information

7.1.1 [Intentionally left blank]

7.1.2 A *market participant* that becomes aware of any material change to or inconsistency with any information or data previously supplied to another *market participant* or to the *IESO* in accordance with a new or modified *connection* that could affect the *reliability* of the *IESO-controlled grid* shall promptly notify the *IESO* and such other *market participant* in writing of that change or inconsistency.

7.1.3 Each *generator* or *electricity storage participant* whose *facility* is *connected* to the *IESO-controlled grid*, *connected wholesale customer* and *distributor* connected to *the IESO-controlled grid*, and *transmitter* shall provide to the *IESO connection-related reliability information* as applicable prior to placing any *connected facility* into service.

7.1.4 Each *embedded generator* whose *embedded generation facility* includes a *generation unit* rated at greater than 10 MVA and that is designated by the *IESO* for the purposes of this section 7.1 shall provide to the *IESO connection-related reliability information* as may be requested by the *IESO*.

7.1.5 Each *embedded generator* that:

7.1.5.1 participates in the *IESO-administered markets* and whose *embedded generation facility* includes a *generation unit* rated at 1 MW or higher;

7.1.5.2 is a non-market participant and whose *embedded generation facility* includes a *generation unit* rated at 10 MVA or higher,

and that is not required to provide data pursuant to section 7.1.4, shall provide the *IESO* with applicable *connection-related reliability information*.

7.1.6 Each *variable generator* shall provide data to the *IESO* in accordance with the applicable *market manual* for the purposes of deriving forecasts of the amount of *energy* that the *variable generator* is capable of producing.

7.1.7 Each *embedded electricity storage participant* whose *embedded electricity storage facility* includes an *electricity storage unit* with an *electricity storage unit size* greater than 10 MVA and that is designated by the *IESO* for the purposes of this section 7.1 shall provide to the *IESO* the information described in Part A of Appendix 4.6 as may be requested by the *IESO*.

7.1.8 Each *embedded electricity storage participant* that:

7.1.8.1 participates in the *IESO-administered markets* and whose *embedded electricity storage facility* includes an *electricity storage unit* with an *electricity storage unit size* of 1 MW or higher;

7.1.8.2 is a non-market participant and whose *embedded electricity storage facility* includes an *electricity storage unit* with a maximum *electricity storage unit size* of 10 MVA or higher,

and that is not required to provide data pursuant to section 7.1.7, shall provide the *IESO* with the data listed in Part B of Appendix 4.6.

7.2 [Intentionally left blank]

7.3 Monitoring Information Provided by Generators to the IESO

7.3.1 Subject to section 7.3.2, in order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each:

7.3.1.1 *generator* (i) whose *generation facility* is *connected* to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

7.3.1.2 *embedded generator* (i) that is not a *market participant* or whose *embedded generation facility* is not a *registered facility*; (ii) whose *embedded generation facility* includes a *generation unit* rated at greater than 20 MVA or that comprises *generation units* the ratings of which in the aggregate exceeds 20 MVA; and (iii) that is designated by the *IESO* for the purposes of this section 7.3.1 as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*,

shall provide the *IESO* with the data listed in Appendix 4.15 on a continual basis. Such data shall not be modified by the *generator* and shall be provided:

7.3.1.3 with equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2; and

7.3.1.4 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.19.

7.3.2 Section 7.3.1 does not apply to:

7.3.2.1 a *small generation facility*;

7.3.2.2 a *self-scheduling generation facility* that has a name-plate rating of less than 10 MW; or

7.3.2.3 an *intermittent generator* or *a transitional scheduling generator* that is comprised solely of a *generation unit* rated at less than 20 MW or of *generation units* the ratings of which in the aggregate is less than 20 MW unless designated by the *IESO* at the time of registration as affecting the *reliability* of the *IESO-controlled grid*.

7.3.2A Each *variable generator* not otherwise subject to any communication requirements specified in this chapter shall at a minimum, meet the medium performance standards set forth in Appendix 4.19 for the purposes of providing data in accordance with section 7.1.6.

7.3.3 [Intentionally left blank – section deleted]

7.3.4 The *IESO* shall *publish,* as soon as practicable following each *dispatch hour*, the actual *generation capacity* (in MW) and hourly *energy* production (in MWh) for each *generation unit* based on information provided to it by *market participants. Generation capacity* and *energy* production for *generation units* with rating less than 20 MVA can be aggregated by station.

7.3.5 The *IESO* shall, as soon as practicable prior to each *dispatch hour,* endeavour to provide a confidential forecast produced by the *forecasting entity* to each *registered market participant* for each of their *variable generation facilities* as specified in the applicable *market manual*. The *IESO* shall determine and *publish* the date when the confidential forecasts will first become available.

7.3.6 The *IESO* shall, as soon as practicable following each *dispatch hour,* provide the confidential forecast produced by the *forecasting entity* for each *dispatch interval* in the preceding *dispatch hour,* to each *registered market participant* for each of their *variable generation facilities* as specified in the applicable *market manual.*

7.3A Monitoring Information Provided by Electricity Storage Participants to the IESO

7.3A.1 Subject to section 7.3A.2, in order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each:

7.3A.1.1 *electricity storage participant* (i) whose *electricity storage facility* is *connected* to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

7.3A.1.2 *embedded electricity storage participant* (i) that is not a *market participant* or whose *embedded electricity storage facility* is not a *registered facility*; (ii) whose *embedded electricity storage facility* includes an *electricity storage unit* with a rated *electricity storage unit size* greater than 20 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which exceed 20 MVA; and (iii) that is designated by the *IESO* for the purposes of this section 7.3A.1 as being required to provide such data in order to enable the IESO to maintain the reliability of the *IESO-controlled grid*,

shall provide the *IESO* with the data listed in Appendix 4.24 on a continual basis. Such data shall not be modified by the *electricity storage participant* and shall be provided:

7.3A.1.3 with equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2; and

7.3A.1.4 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.25.

7.3A.2 Section 7.3A.1 does not apply to:

7.3A.2.1 a *small electricity storage facility*

7.3A.3 The *IESO* shall *publish*, as soon as practicable following each *dispatch hour*, the actual *electricity storage capacity* (in MW) and hourly injections of *energy* (in MWh) for each *electricity storage unit* based on information provided to it by *market participants. Electricity storage capacity* and *energy* production for *electricity storage units* with a rated *electricity storage unit size* of less than 20 MVA can be aggregated by station.

7.4 Monitoring Information Provided by Transmitters to the IESO

7.4.1 In order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each *transmitter* shall provide the *IESO* with the data listed in Appendix 4.16 on a continual basis. Such data shall not be modified by the *transmitter* and shall be provided:

7.4.1.1 with equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2; and

7.4.1.2 in accordance with the performance standards set forth in Appendix 4.20 and, subject to section 7.6A, Appendix 4.21.

7.4.2 [Intentionally left blank]

7.5 Monitoring Information Provided to the IESO by Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

7.5.1 In order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each *connected wholesale customer* and each *distributor connected* to the *IESO-controlled grid* shall provide the *IESO* with the data listed in Appendix 4.17 on a continual basis. Such data shall not be modified by the *connected wholesale customer* or *distributor connected* to the *IESO-controlled grid*, as the case may be, and shall be provided:

7.5.1.1 with equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2; and

7.5.1.2 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.22.

7.5.2 A *distributor* that is not *connected* to the *IESO-controlled grid* and that is designated by the *IESO* for the purposes of this section 7.5.2 as being required to provide the data listed in Appendix 4.17 in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid* shall comply with the obligations set forth in section 7.5.1.

7.6 Monitoring Information Provided by Embedded Load Customers to the IESO

7.6.1 In order to permit the *IESO* to direct the operations of the *IESO-controlled grid*, each *embedded load consumer* that is designated by the *IESO* for the purposes of this section 7.6.1 as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid* shall provide the *IESO* with the data listed in Appendix 4.18 on a continual basis. Such data shall not be modified by the *embedded load consumer* and shall be provided:

7.6.1.1 with equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2; and

7.6.1.2 subject to section 7.6A, in accordance with the performance standards set forth in Appendix 4.23.

7.6A Alternative Arrangements for Submission of Data Measurements

7.6A.1 *Market participants* may propose to the *IESO* an alternative arrangement to make data measurements or equipment status changes available to the *IESO* communications interface within times different than those specified in Appendix 4.19, 4.21, 4.22, 4.23, or 4.25.

7.6A.2 Where an alternative arrangement proposed pursuant to section 7.6A.1 relates to the requirement to make data measurements or equipment status changes available at the *IESO* communications interface within less than 2 seconds from the change in field monitored quantity or field status change, as the case may be, the *IESO* shall approve the alternative arrangement if:

7.6A.2.1 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of providing the data measurements or equipment status changes in such a manner that such data will be displayed on the communications terminals located at the *IESO's* principal and back-up control centers within less than 8 seconds from the change in field monitored quantity or field status change; and

7.6A.2.2 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of meeting such other *reliability*-related performance standards and other requirements as may be specified by the *IESO*, including but not limited to time consistency of data, and loss of data from electrically adjacent stations.

7.6A.3 Where an alternative arrangement proposed pursuant to section 7.6A.1 relates to the requirement to make data measurements or equipment status changes available at the *IESO* communications interface within less than 10 seconds from the change in field monitored quantity or field status change, as the case may be, the *IESO* shall approve the alternative arrangement if:

7.6A.3.1 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of providing the data measurements or equipment status changes in such a manner that such data will be displayed on the communications terminals located at the *IESO's* principal and back-up control centers within less than 20 seconds from the change in field monitored quantity or field status change; and

7.6A.3.2 the proposed alternative arrangement demonstrates to the satisfaction of the *IESO* that the *market participant's facilities* and equipment are capable of meeting such other *reliability*-related performance standards and other requirements as may be specified by the *IESO*, including but not limited to time consistency of data, and loss of data from electrically adjacent stations.

7.6A.4 Upon approval of an alternative arrangement proposed and reviewed under this section, the *IESO* may incorporate the alternative arrangement as an alternative standard in the *market rules*.

7.7 Reliability, Maintenance and Repair of Monitoring and Control Equipment

7.7.1 Each person referred to in section 7.3.1, 7.4.1, 7.5.1, 7.5.2 or 7.6.1, as the case may be, shall maintain the monitoring and control equipment referred to in Appendices 4.15 to 4.18 as applicable, in accordance with *good utility practice* and shall ensure that such equipment:

7.7.1.1 has an overall mean time between failures of:

a. no less than three years; or

b. no less than five years, if the equipment is designated by the *IESO* as significant for purposes of enabling the *IESO* to maintain the *reliability* of the *IESO-controlled grid*;

7.7.1.1A each person referred to in section 7.7.1 shall report and schedule with the *IESO* all planned changes to monitoring equipment referred to in section 7.7.1.1 and associated potential and current transformers and other devices affecting the accuracy or the reliability of such equipment;

7.7.1.2 is secure from the effects of interruptions in power supply for a period of at least eight hours.

7.7.2 Each person referred to in section 7.7.1 and 7.3.2A shall respond to an *outage* of or defect in the equipment referred to in section 7.7.1 or the applicable *market manual*:

7.7.2.1 immediately, in the case of equipment relating to *facilities* to which the high performance information monitoring standard applies pursuant to Appendices 4.19 to 4.23 and Appendix 4.25 other than *significant generation facilities, significant dispatchable load facilities* and *significant electricity storage facilities*.

a. [Intentionally left blank]
b. [Intentionally left blank]
c. [Intentionally left blank]
d. [Intentionally left blank]
e. [Intentionally left blank]
f. [Intentionally left blank]
g. [Intentionally left blank]
h. [Intentionally left blank]

7.7.2.2 no later than the next day following the day on which the *outage* or defect is discovered, in the case of equipment relating to *significant generation facilities, significant electricity storage facilities, significant dispatchable load facilities, variable generation,* and *facilities* to which the medium performance information monitoring standard applies pursuant to Appendices 4.19 to 4.23 and Appendix 4.25.

a. [Intentionally left blank]
b. [Intentionally left blank]
c. [Intentionally left blank]
d. [Intentionally left blank]
e. [Intentionally left blank]
f. [Intentionally left blank]

7.7.3 Each person referred to in section 7.7.1 and 7.3.2A shall ensure that the equipment referred to in section 7.7.1 or the applicable *market manual* is restored to a fully operational state following an *outage* of or defect in such equipment as follows:

7.7.3.1 in the case of equipment relating to the *facilities* referred to in section 7.7.2.1, within 24 hours of the time at which the *outage* or defect is discovered;

7.7.3.2 in the case of equipment relating to the *facilities* referred to in section 7.7.2.2, within 48 hours of the time at which the *outage* or defect is discovered; and

7.7.3.3 in all other cases, within 14 days of the time at which the *outage* or defect is discovered.

7.7.4 The *IESO* may direct a person referred to in section 7.7.1 and 7.3.2A to respond and restore the equipment referred to in section 7.7.1 or the applicable *market manual* to a fully operational state following an *outage* of or defect in such equipment within such longer or shorter time periods than those referred to in sections 7.7.2 and 7.7.3 based on the immediate or short-term impact of the unavailability of the equipment on the reliable operation of the *IESO-controlled grid*, provided that where a person is directed to respond and restore any such equipment in less than 24 hours, the person shall use commercial best efforts to achieve such direction.

7.7.5 Each person referred to in section 7.7.1 shall notify the *IESO* of any *planned outage* of the equipment referred to in section 7.7.1 no less than four days prior to the *planned outage*.

7.8 Re-Classification of Facilities

7.8.1 The *IESO* may, for the purposes of sections 7.3 to 7.6:

7.8.1.1 re-classify a *small generation facility* as a *minor generation facility*, a *significant generation facility* or a *major generation facility*;

7.8.1.2 re-classify a *minor generation facility* as a *significant generation facility* or a *major generation facility*;

7.8.1.3 re-classify a *significant generation facility* as a *major generation facility*;

7.8.1.4 re-classify a *minor dispatchable load facility* as a *significant dispatchable load facility* or a *major dispatchable load facility*; and

7.8.1.5 re-classify a *significant dispatchable load facility* as a *major dispatchable load facility*,

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

7.8.2 The *IESO* may, for the purposes of sections 7.3 to 7.6:

7.8.2.1 re-classify a *major generation facility* as a *significant generation facility*, a *minor generation facility* or a *small generation facility*;

7.8.2.2 re-classify a *significant generation facility* as a *minor generation facility* or a *small generation facility*;

7.8.2.3 re-classify a *minor generation facility* as a *small generation facility*;

7.8.2.4 re-classify a *major dispatchable load facility* as a *significant dispatchable load facility* or a *minor dispatchable load facility*; and

7.8.2.5 re-classify a *significant dispatchable load facility* as a *minor dispatchable load facility*,

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

7.8.2A The *IESO* may, for the purposes of sections 7.3A:

7.8.2A.1 re-classify a *small electricity storage facility* as a *minor electricity storage facility*, a *significant electricity storage facility* or a *major electricity storage facility*;

7.8.2A.2 re-classify a *minor electricity storage facility* as a *significant electricity storage facility* or a *major electricity storage facility*;

7.8.2A.3 re-classify a *significant electricity storage facility* as a *major electricity storage facility*;

where the *IESO* determines that such re-classification is required to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

7.8.2B The *IESO* may, for the purposes of sections 7.3A:

7.8.2B.1 re-classify a *major electricity storage facility* as a *significant electricity storage facility*, a *minor electricity storage facility* or a *small electricity storage facility*;

7.8.2B.2 re-classify a *significant electricity storage facility* as *a minor electricity storage facility* or a *small electricity storage facility*;

7.8.2B.3 re-classify a *minor electricity storage facility* as a *small electricity storage facility*;

where the *IESO* determines that such re-classification will not adversely affect the ability of the *IESO* to maintain *reliability* of the *IESO-controlled grid*.

7.8.3 A person whose *facility* has been re-classified pursuant to section 7.8.1, 7.8.2, 7.8.2A or 7.8.2B shall:

7.8.3.1 ensure that its *facilities* and equipment meet the requirements set forth in section 7.3, 7.4, 7.5 or 7.6, as the case may be; and

7.8.3.2 comply with the requirements of section 7.7,

applicable to the class of *facility* in which its *facility* has been re-classified.

MDP_RUL_0002_04A

Market Rules

Chapter 4

Grid Connection Requirements - Appendices

Connecting Today.
Powering Tomorrow.

Issue Date: December 1, 2021

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Distribution List

Name	Organization

Table of Contents

Appendix 4.1 – IESO-Controlled Grid Performance Standards

Ref	***Item***	***Requirement***
	Transmission System	
1	Frequency variations	All *equipment* shall be capable of continuously operating in the range between 59.5 Hz and 60.5 Hz.
2	Voltage variations	Under normal conditions voltages are maintained within the range below. Transmission Voltage: Nominal (kV) 500 230 115 Maximum Continuous (kV) 550 250* 127* Minimum Continuous (kV) 490 220 113 *In northern Ontario, the maximum continuous voltage for the 230 and 115 kV systems can be as high as 260 kV and 132 kV respectively
3	[Intentionally left blank]	
4	[Intentionally left blank]	
5	[Intentionally left blank]	
6	[Intentionally left blank]	
7	[Intentionally left blank]	
8	[Intentionally left blank]	

Appendix 4.2 – Requirements for Generation and Electricity Storage Facilities Connected to the IESO-Controlled Grid

The performance requirements set out below shall apply to *generation facilities* subject to a *connection assessment* finalized after September 21, 2020. Performance of alternative technologies shall be comparable with that of conforming conventional synchronous generation with an equal apparent power rating.

These performance requirements shall also apply to *electricity storage units* at all times while connected to the *IESO-controlled grid*, unless the *IESO* identifies specific performance requirements that are not applicable to an *electricity storage unit* for those with a *connection assessment* finalized after January 18, 2021. Due consideration will be given to inherent limitations.

Each *facility* that was authorized to *connect* to the *IESO-controlled grid* prior to September 21, 2020 shall remain subject to the performance requirements in effect for each associated system at the time its authorization to *connect* to the *IESO-controlled grid* was granted or agreed to by the *market participant* and the *IESO* (i.e. the "original performance requirements"). These original performance requirements shall prevail until the main elements of an associated system (e.g. governor control mechanism, main exciter, power inverter) are replaced or substantially modified. At that time, the associated system that is replaced or substantially modified shall meet the applicable performance requirements detailed below. All other systems, not affected by replacement or substantial modification, shall remain subject to the original performance requirements.

Category	*Generation facilities* or *electricity storage facilities* directly connected to the *IESO-controlled grid* shall have the capability to:
1. Off-Nominal Frequency Operation	Operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region bounded by straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz) and the straight lines on a log-linear scale defined by the points (0.0 s, 61.8 Hz), (8 s, 61.8 Hz), and (600 s, 60.6 Hz).
2. Speed/Frequency Regulation	Regulate speed/frequency with an average droop based on maximum active power adjustable between 3% and 7% and set at 4% unless otherwise specified by the *IESO*. Regulation deadband shall not be wider than ±0.06%. Speed/frequency shall be controlled in a stable fashion in both interconnected and island operation. A sustained 9% change of applicable rated active power as defined in category 4 after 10 s in response to a step change of speed of 0.5% during interconnected operation shall be achievable. Due consideration will be given to inherent limitations such as mill points and gate limits when evaluating active power changes. Control systems that inhibit primary frequency response shall not be enabled without *IESO* approval.
3. Voltage Ride-Through	Ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration. For Inverter-based units, momentary current cessation or reduction of output current during system disturbances is not permitted without *IESO* approval.
4. Active Power	Continuously supply all levels of active power output within a +/- 5% range of its rated terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. For *electricity storage facilities*, rated active power values shall be separately specified for both injection and withdrawal operations. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted.
5. Reactive Power	Continuously (i.e., dynamically) inject or withdraw reactive power at the high-voltage terminal of the main output transformer[1] up to 33% of the applicable rated active power at all levels of active power, and at the typical *transmission system* voltage, except where a lesser continually available capability is permitted with the *IESO's approval*. A conventional synchronous unit with a power factor range of 0.90 lagging and 0.95 leading at rated active power connected via a main output transformer impedance not greater than 13% based on *generation unit* rated apparent power is acceptable. Reactive power losses or charging between the high-voltage terminal of the main output transformer and the *connection point* shall be addressed in a manner permitted by *IESO* approval.
6. Automatic Voltage Regulator (AVR)	Regulate voltage automatically within ±0.5% of any setpoint within ±5% of rated voltage at the low-voltage terminal of the main output transformer if the transformer impedance is not more than 13% based on the rated apparent power of the *generation facility* or *electricity storage facility* or at a point approved by the *IESO*. Reactive power-voltage droop or AVR reference load current compensation shall not be enabled without *IESO* approval. The equivalent time constants shall not be longer than 20 ms for voltage sensing and 10 ms for the forward path to the exciter output.
7. Excitation System for Synchronous Machines Greater than 20 MVA or any Synchronous Machines *within Facilities* Greater than 75 MVA	Provide (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage, respectively, while supplying the field winding of the *generation unit* or *electricity storage unit* operating at nominal voltage under open circuit conditions; (b) An excitation transformer impedance not greater than 10% on excitation system base; (c) A voltage response time to either ceiling not more than 50 ms for a 5% step change from rated voltage under open-circuit conditions; and (d) A linear response between ceilings.
8. Power System Stabilizer (PSS) for Synchronous Machines within Facilities Greater than 75 MVA	Provide (a) A change of power and speed input configuration; (b) Positive and negative output limits not less than ±5% of rated AVR voltage; (c) Phase compensation adjustable to limit angle error to within 30° between 0.2 Hz and 2.0 Hz under conditions specified by the *IESO*, and (d) Gain adjustable up to an amount that either increases damping ratio above 0.1 or elicits poorly damped exciter modes of oscillation at maximum active output unless otherwise specified by the *IESO*. Due consideration will be given to inherent limitations. For *electricity storage units, Power System Stabilizer shall be disabled while withdrawing*.
9. Phase Unbalance	Provide an open circuit phase voltage unbalance not more than 1% and operate continuously with a phase voltage unbalance as high as 2% at the high-voltage terminal of its main output transformer.
10. Armature and Field Limiters	Provide short-time capabilities specified in IEEE/ANSI 50.13 and continuous capability determined by either maximum field current, maximum stator current, core-end heating, or minimum field current. More restrictive limiting functions, such as steady state stability limiters, shall not be enabled without *IESO* approval.

11. Technical Characteristics	Exhibit, at the high-voltage terminal of its main output transformer, performance comparable to an equivalent synchronous *generation unit* with characteristic parameters within typical ranges. Inertia, unsaturated transient impedance, transient time constants, and saturation coefficients shall be within typical ranges (e.g. H > 1.2 Aero-derivative, H > 1.2 Hydroelectric units less than 20 MVA, H > 2.0 Hydroelectric units 20 MVA or larger, H > 4.0 Other synchronous units, X'd < 0.5, T'd0 > 2.0, and S1.2 < 0.5) except where permitted by *IESO* approval.
12. Reactive Power Response to Voltage Changes of Inverter-Based Units	For a constant voltage at the high-voltage terminal of the main output transformer, achieve a sustained reactive power change of 30% of *generation facility* or *electricity storage facility* rated apparent power at the low-voltage terminal of the main output transformer within 3s following a step change no larger than 4% to the AVR voltage reference. AVR response to the voltage error signal must be consistent over the entire operating range.

[1] A main output transformer steps up the voltage from the *generation unit/facility* to the transmission voltage level.

Appendix 4.3 – Requirements for Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

The performance requirements set out below shall apply to *connected wholesale customers* and *distributors* that are connecting equipment or *facilities* to the *IESO-controlled grid* or to their *distribution systems* after January 18, 2021.

Equipment connected within a *connected wholesale customer's* or *distributor's facilities* or *distribution systems* that was authorized to *connect* prior to January 18, 2021 shall remain subject to the performance requirements in effect at the time its authorization to *connect* was granted (i.e. the "original performance requirements"). These original performance requirements shall prevail until the main elements of an associated system are replaced or substantially modified. At that time, the associated system that is replaced or substantially modified shall meet the applicable performance requirements detailed below. All other systems not affected by replacement or substantial modification, shall remain subject to the original performance requirements.

Category	***Requirement***
1. Power Factor	*Connected wholesale customers* and *distributors* connected to the *IESO-controlled grid* shall operate at a power factor within the range of 0.9 lagging to 0.9 leading as measured at the *defined meter point*.
2. Under Frequency Load Shedding	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* may be required to participate in under frequency load shedding
3. Remedial Action Schemes	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* may be required to participate in *remedial action schemes*.
4. Voltage Reduction	*Distributors* connected to the *IESO-controlled grid* with directly *connected load facilities* of aggregated rating above 20 MVA and with the capability to regulate *distribution* voltages under load, shall install and maintain *facilities* and equipment to provide *voltage reduction capability*.
5. [Intentionally left blank]	
6. [Intentionally left blank]	
7. [Intentionally left blank]	
8. [Intentionally left blank]	
9. Testing and Compliance Monitoring	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* shall test and maintain their equipment in accordance with all applicable *reliability standards*.
10. Metering	*Connected wholesale customers* and *distributors connected* to the *IESO-controlled grid* shall comply with metering codes and standards set by the *IESO*.
11. Voltage Ride-Through	Equipment connected within a *connected wholesale customer's* or a *distributor's facility* or *distribution system* that is connected to the *IESO-controlled grid* shall ride through routine switching events and design criteria contingencies on the *transmission system* assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless either disconnected by configuration or a failure to do so has been assessed and confirmed by the *IESO* as having no material adverse effect on the operation of the *IESO-controlled grid*.

12. Generation Units **and *Electricity Storage Units***	Any *generation unit* or *electricity storage unit* connected within a *connected wholesale customer's* or a *distributor's facility* or *distribution system* that is connected to the *IESO-controlled grid* shall meet, at a minimum, the performance requirements for Off-Nominal Frequency Operation (category 1), Speed/Frequency Regulation (category 2), and Voltage Ride-Through (category 3) specified in Appendix 4.2. If a *connected wholesale customer* injects active power into the *IESO-controlled grid*, all performance requirements specified in Appendix 4.2 are applicable to the *generation units* and *electricity storage units* installed within their *facility*. Note: These performance requirements shall apply to *electricity storage units* and *generation units* at all times while connected within a *connected wholesale customer's* or *distributor's facilities* or *distribution system* that is connected to the *IESO-controlled grid*, unless the *IESO* identifies specific performance requirements that are not applicable to an *electricity storage unit* or *generation unit* for those with a *connection assessment* finalized after January 18, 2021. Due consideration will be given to inherent limitations.

Appendix 4.4 – Transmitter Requirements

Ref	***Item***	***Requirement***
1	Abrupt Voltage Changes	Voltage changes shall not normally exceed 4% of steady state rms for capacitor switching operations. Voltage changes shall not normally exceed 10% of steady state rms for line switching operations
2	Frequency Variations	All equipment shall be capable of continuous operation within the range of 59.5 to 60.5 Hz and have the capability to operate for 10 minutes in the range 58 to 61.5 Hz.
3	Load Shedding Facilities	Each *transmitter* shall comply with *IESO* requirements for automatic under-frequency load shedding in accordance with its *operating agreement.* Each *transmitter* shall be able to manually drop up to 50% of its load within 10 minutes.
4	Automatic Reclosure	Transmission circuits shall be equipped with timed, single-shot automatic re-closing facilities. Reclosure shall only be initiated by protections that operate when it is highly likely that the fault is not permanent. Reclosure within 5 seconds of fault detection is allowed only in exceptional circumstances. Angle supervision shall be provided on all breakers rated at 230 kV and above. Automatic reclosure shall remain enabled only for a limited period of time, usually about 40 seconds, following initiation.
5	Thermal Ratings	• *Market participants* that own and operate transmission equipment shall provide the *IESO* with the continuous and limited time thermal ratings for their transmission circuits and transformers. • *Market participants* shall provide this information to the *IESO* via a data link with a minimum update rate of 5 minutes or as agreed to by the *IESO*. For backup and pre-dispatch purposes, *market participants* shall provide a thermal rating table in a suitable format to facilitate *IESO* applications to perform thermal rating interpolation. • Where other equipment (e.g. wavetraps) is more limiting, *market participants* shall provide the *IESO* with the thermal rating of the most restrictive element. • *Generators* and *connected wholesale customers* that own and operate transmission equipment that is part of the *IESO-controlled grid* shall provide the *IESO* with the continuous and limited time thermal ratings for their transmission circuits and transformers only if required by the *IESO* to maintain *reliable* operation of the *IESO-controlled grid*. • Limited time thermal ratings shall be 15-minute ratings, unless mutually agreed by the *IESO* and *market participant.*
6	Protective System Requirements	Protection systems shall be constructed and maintained in accordance with all applicable *reliability standards*.
7	*IESO* Information Requirements	The *transmitter* shall provide any information that the *IESO* deems necessary to direct the operation of the *IESO-controlled grid*. This Information, including, but not limited to, voltages, flows, and equipment status shall be telemetered continually to the *IESO*.
8	Voltage Reduction	*Transmitters* with the ability to regulate *distribution* voltages under load shall install and maintain facilities and equipment to provide *voltage reduction capability*.
9	Telecommunications	Communication channels shall have a level of reliability that is consistent with the required performance of the associated protection system. Telecommunications shall be designed to assure adequate signal transmission during transmission disturbances and may be provided with means to verify proper signal performance. Equipment may be monitored to assess its readiness and be powered by batteries or other sources independent of the *IESO*.
10	Testing and Compliance Monitoring	*Transmitters* shall test and maintain their equipment in accordance with all applicable *reliability standards.*
11	Metering	*Transmitters* shall comply with the metering codes and standards set by the *IESO*.

Appendix 4.5 – [Intentionally left blank]

Appendix 4.5A – [Intentionally left blank]

Appendix 4.6 – [Intentionally left blank]

Appendix 4.7 – [Intentionally left blank]

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Appendix 4.12 – [Intentionally left blank]

Appendix 4.13 – [Intentionally left blank]

Appendix 4.14 – [Intentionally left blank]

Appendix 4.15 – IESO Monitoring Requirements: Generators

The following information, as a minimum, shall be available on a continual basis to the *IESO* from:

(a) any *generator* (i) whose *generation facility* is connected to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

(b) any *embedded generator* (i) that is not a *market participant* or whose *embedded generation facility* is not a *registered facility*; (ii) whose *embedded generation facility* includes a *generation unit* rated at greater than 20 MVA or that comprises <u>*generation units*</u> the ratings of which in the aggregate exceeds 20 MVA; and (iii) that is designated by the *IESO* for the purposes of section 7.3.1 of this Chapter as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

TYPE	INFORMATION REQUIREMENTS
Major generation facility	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the *IESO* as required for: (i) determination of operating *security limits*; (ii) to maintain *reliable* operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *generation units* rated greater than or equal to 100 MVA, the standard requirement as defined in part a) for each *generation unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *generation units* rated at less than 100 MVA: (i) for a group of *generation units* if those *generation units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *generation units*, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as defined in part a) for each *generating unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). d) For *generation facilities* that have been aggregated pursuant to Chapter 7 section 2.3:

TYPE	INFORMATION REQUIREMENTS
	(i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid* or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each *generating unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *generation unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). e) For frequency changers: (i) total MW and MX at either frequency; or (ii) if so designated by the *IESO* as required for determination of operating *security limits*, total MW and MX at both frequencies. f) For synchronous condensers: (i) total MX. 2. Voltage: a) For each *generation unit*, unit terminal voltage, except if *generation units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *generation units*. 3. Frequency: a) For each *generation unit* or *generation facility* providing *black start capability*, frequency of the applicable *generation unit* or *generation facility*. 4. Equipment Status a) Unit mode (i.e. generator, condenser, pump) for each *generation unit* capable of different modes of operation. b) *AGC* status for each *generation unit* providing *regulation*. c) AVR and Stabilizer Status for each *generating unit* with a rated capacity ≥ 100 MVA. Stabilizer status reporting is only required if it can be switched off by *generation facility* personnel remotely or at the *facility*. d) AVR and Stabilizer status for each *generation unit* with a rated capacity ≤ 100 MVA if the status of this equipment is designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid*. Stabilizer status reporting is only required if it can be switched on or off by *market participant* operating personnel remotely or at the *facility*. e) Synchronizing Breaker status for each *generation unit*. Where a *generation facility* is designed such that no low voltage synchronizing breaker is installed for each *generation unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *generation unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where a *generation facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. f) *Remedial Action Scheme* status for each applicable *generation unit*.
Significant generation facility and minor generation facility	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX):

<table>
<tr><th>TYPE</th><th>INFORMATION REQUIREMENTS</th></tr>
<tr><td>connected to IESO-controlled grid</td><td>
a) The standard requirement for active and reactive power is the provision of net MW and net MX or gross MX. Gross MW and gross MX or net MX are also to be provided, if designated by the IESO as required for:
(i) determination of operating security limits;
(ii) to maintain reliable operation of the IESO-controlled grid;
(iii) for compliance monitoring purposes; or
(iv) if provision of only the standard requirement values as defined above would have a negative impact on other market participants through reduced operating security limits.
b) For generation facilities that have not been aggregated pursuant to Chapter 7 section 2.3:
(i) for a group of generation units if those generation units are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these generation units, and total gross MW and gross MX or net MX shall be provided if designated by the IESO as required using the criteria listed above in part a);
(ii) if designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid or for compliance monitoring purposes, the standard requirement as defined in part a) for each generating unit shall be provided, and gross MW and gross MX or net MX for each generation unit shall be provided if designated by the IESO as required using the criteria listed above in part a).
c) For generation facilities that have been aggregated pursuant to Chapter 7 section 2.3:
(i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total gross MW and gross MX or net MX shall be provided if designated by the IESO as required using the criteria listed above in part a); or
(ii) if so designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each generating unit shall be provided, and gross MW and gross MX or net MX for each generation unit shall be provided if designated by the IESO as required using the criteria listed above in part a).
d) For frequency changers:
(i) total MW and MX at either frequency; or
(ii) if so designated by the IESO as required for determination of operating security limits, total MW and MX at both frequencies.
e) For Synchronous Condensers:
(i) Total MX.
2. Voltage:
a) For generation units that are VAR dispatchable, unit terminal voltage, except if the generation units are connected to a common low voltage bus section, then the bus section voltage is adequate for those generation units.
3. Frequency:
a) For each generation unit or generation facility providing black start capability, frequency of the applicable generation unit or facility.
4. Equipment Status
a) Unit mode (i.e. generator, condenser, pump) for each generation unit capable of different modes of operation.
b) AVR and Stabilizer Status for each generation unit if the status of this equipment is designated by the IESO as required for determination of operating security limits or to maintain reliable
</td></tr>
</table>

TYPE	INFORMATION REQUIREMENTS
	operation of the *IESO-controlled grid*. Stabilizer status reporting is only required if it can be switched on or off by *market participant* operating personnel remotely or at the *facility*. c) Synchronizing Breaker Status for each *generation unit*. Where a *generation facility* is designed such that no low voltage synchronizing breaker is installed for each *generation unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *generation unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where a *generation facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. d) *Remedial Action Scheme* status for each applicable *generation unit*.
Self-scheduling generation facility with a name-plate rating of less than 10 MW	None
Intermittent and transitional scheduling generator	• if a major generation facility, as described above for a major generation facility • if a significant generation facility, as described above for a significant generation facility • if a *minor generation facility*, as described above for a *minor generation facility* if designated by the *IESO* at the time of registration as affecting the *reliability* of the *IESO-controlled grid* • if a small generation facility, none
Small generation facility	None
Minor generation facility that is embedded in a distribution system and registered as a dispatchable generator	• Total active power (MW) output of the individual *generation unit* or of the aggregated resource. • Unit status if the *facility* is comprised of a single *generation unit*. • Aggregated resource status if the *facility* is comprised of aggregated resources, i.e. if at least one unit of the aggregated resource is synchronized, the aggregated resource is synchronized or if no unit in the aggregated resource is synchronized, the aggregated resource is not synchronized. • Reactive Power (MX) output, if requested by the *IESO* for reliable operation of the *IESO-controlled grid*, of individual *generation units* or of the aggregated resource.

Appendix 4.16 – IESO Monitoring Requirements: Transmitters

The following information regarding the *IESO-controlled grid*, as a minimum, shall be available on a continual basis to the *IESO* from *transmitters*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

Equipment Type	Voltage Level	Monitored Status	Monitored Quantities
Station Bus			
Bus Voltage	50 kV and higher		Specified phase-phase and phase to ground voltages measured at different buses. Note: a line voltage may be used if bus PTs are not available.
Frequency	50 kV and higher		As directed by the *IESO* for points on the *IESO-controlled grid* that are significant for reliability purposes. High accuracy PTs & measurements of frequency are required at a number of stations at the discretion of the *IESO*.
TRANSFORMATIO N			
Autotransformers	50 kV and above	Isolating switches As described in the “Reactive Devices” section below for ancillary equipment associated with the transformer	Megawatts and Megavars for the high voltage winding for each transformer Megawatts and Megavars for the low voltage winding for each transformer, if other than station service is connected to the tertiary winding. ULTC tap positions for the transformer The *IESO* may require the monitoring of any Off-Load Tap Changer positions.
Phase Shifting Transformers	50 kV and higher	Bypass and isolating switches	Voltage, MW and MVAR may be required as directed by the *IESO* All transformer tap positions

Equipment Type	Voltage Level	Monitored Status	Monitored Quantities
Step Down Transformers	50 kV and higher	Bypass and isolating switches	MW and MVAR Phase to ground Voltage, for each winding measured on the high voltage side. Where only LV PTs are available: MW and phase to phase voltages for each LV winding ULTC tap positions.
Voltage Regulating Transformers	50 kV and higher	Bypass and isolating switches	MW and MVAR may be required as directed by the *IESO* ULTC tap positions for the transformer The *IESO* may require the monitoring of any Off-Load Tap Changers.
Isolating Devices			
Breakers and Switches	50 kV and higher including connected tertiaries	All Circuit breakers, including bus tie breakers All breakers connecting loads for each tertiary winding of autotransformer other than that for Station Service Each capacitor breaker All line disconnect switches All transformer disconnect and by-pass switches All bus sectionalizing switches All isolating switches for reactors and capacitors where circuit breakers are not provided All in line switches as specified Note: The status of breaker isolating switches is not required	
	Below 50 kV	Breakers of Low Voltage Capacitors, Reactors, Transformers that are part of or have an impact on the *IESO-controlled grid* or that are subject to a contracted ancillary services contract including by means or within the scope of an *operating agreement* Each reactor or condensor breaker.	

Equipment Type	Voltage Level	Monitored Status	Monitored Quantities
Isolating and by-pass switches	50 kV and higher	Isolating and bypass switches for each transformer Bus sectionalizing switches Reactor and capacitor isolation	
Circuits			
Circuit forming part of the *IESO-controlled grid*	50 kV and higher		MW and MVAR line flow at each terminal
Circuit that is an interconnection with another control area	50 kV and higher		• MW and MVAR line flow • (MW from the billing meter point) where practical
Special Protection Schemes			
Remedial Action Schemes (RAS)	50 kV and higher	As directed by the *IESO* on a case-by-case basis. Where so directed, must include all associated capacitors and reactors breaker status.	As directed by the *IESO* on a case-by-case basis.
Reactive Devices			
Capacitors, Synchronous Condensors, Reactors, Static Var Compensators, FACTS	All levels designated by the *IESO* as affecting the *reliability* of the *IESO-controlled grid*	Breaker Status	MVARs where output is variable.

Appendix 4.17 – IESO Monitoring Requirements: Connected Wholesale Customers and Distributors

The following information, as a minimum, shall be available on a continual basis to the *IESO* from all *distributors connected* to the *IESO-controlled grid*, *distributors* designated pursuant to section 7.5.2 and *connected wholesale customer*s. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. A *connected wholesale customer* that is also a *generator* shall also comply with the applicable requirements of Appendix 4.15.

TYPE	MONITORED QUANTITIES
Distributor connected to the *IESO-controlled grid* or designated pursuant to section 7.5.2	• Where high voltage (HV) Potential Transformers (PTs) are available: Circuits: (where applicable) • Megawatt (MW), megavars (MVARs) and direction of power flow at each terminal connected to the *IESO-controlled grid*. Transformers: • MW, MVARS • phase to ground voltages for each HV winding as specified by the *IESO* • Where only low voltage PTs are available: • MW, MVARs for each Low Voltage (LV) winding, and • phase to phase voltage for each LV winding as specified by the *IESO*. • Under Load Tap Changer (ULTC) tap positions. • Off Load Tap Changer (OLTC) tap positions may be required, as directed by the *IESO* • Status of breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid*, or that are subject to a contracted ancillary services contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the connected *wholesale customer* • Status of: • All breakers 50 kV and above. • All line disconnect switches 50 kV and above. • All transformer disconnect and by-pass switches 50 kV and above. • All bus sectionalising switches 50 kV and above. • transformer LV winding breakers and bus tie breakers for DESN type step-down transformers connected to the *IESO-controlled grid* The status of breaker isolating switches is not required. • *Remedial Action Schemes* as directed by the *IESO* on a case by case basis.

TYPE	MONITORED QUANTITIES
Connected wholesale customers	For: • All dispatchable loads; and Each *non-dispatchable load facility* that includes a *non-dispatchable load* rated at 20 MVA or higher or is comprised of *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA, in each case where directed by the *IESO* if transmitter data is not adequate the following shall be monitored: Where high voltage PTs are available: Circuits: (where applicable) • Megawatts (MW), and Megavars (MVAR) and direction of power flow at each terminal connected to the *IESO-controlled grid*. Transformers: • Megawatts (MW), and Megavars (MVAR) and • phase to ground voltages for each HV winding as specified by the *IESO*. Where only low voltage PTs are available: • MW, MVARs from each LV winding, and • phase to phase voltages for each LV winding as specified by the *IESO*. • Under Load Tap Changer (ULTC) tap positions. • Off Load Tap Changer (OLTC) tap positions may be required, as directed by the *IESO* • Status of: • All breakers 50 kV and above. • All line disconnect switches 50 kV and above. • All transformer disconnect and by-pass switches 50 kV and above. • All bus sectionalising switches 50 kV and above. • Transformer LV winding breakers and bus tie breakers for DESN type step-down transformers connected to the *IESO-controlled grid* • Breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid* or that are subject to a contracted *ancillary services* contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the *connected wholesale customer* The status of breaker isolating switches is not required • *Remedial Action Schemes (RAS)* as directed by the IESO

Appendix 4.18 – IESO Monitoring Requirements: Embedded Load Consumers

The following information, as a minimum, shall be available on a continual basis to the *IESO* from all *embedded load consumers* designated by the *IESO* pursuant to section 7.6.1. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. An *embedded load consumer* that is also a *generator* shall also comply with the applicable requirements of Appendix 4.15.

TYPE	SIZE	MONITORED QUANTITIES
Dispatchable load		• Megawatts (MW), • megavars (MVAR) as designated by the *IESO* as required to maintain *reliable* operation of the *IESO-controlled grid*, • phase to phase voltages as specified by the *IESO*, and • status of breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid* or that are subject to a *contracted ancillary services* contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the *embedded load consumer*
Non-dispatchable load	For a *non-dispatchable load facility* that includes a *non-dispatchable load* rated at 20 MVA or higher or that is comprised of *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA	Where directed by the *IESO* if *transmitter* or *distributor* data is not sufficient, • MW, MVAR, • phase to phase voltages as specified by the *IESO*; and • status of breakers or isolating switches for low voltage capacitors that are part of the *IESO-controlled grid* or that are subject to a *contracted ancillary services* contract including by means or within the scope of an agreement similar in nature to an *operating agreement* entered into with the *embedded load consumer*

Appendix 4.19 – IESO Monitoring Requirements: Generator Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *generators* referred to in section 7.3.1 of this Chapter when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

FUNCTION	Major generation facility or significant generation facility (High Performance)	Minor generation facility and intermittent generator or transitional scheduling generator designated pursuant to section 7.3.2.3 (Medium Performance)	Small generation facility
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	1. Less than 10 seconds from change in field monitored quantity or 2. If the *minor generation facility* is embedded within a *distribution system,* less than one minute from change in field monitored quantity unless otherwise designated by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.	Not applicable
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	1. Less than 10 seconds from field status change or 2. If the *minor generation facility* is embedded within a *distribution system*, less than one minute from change in equipment status unless otherwise designated by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.	Not applicable

FUNCTION	Major generation facility or significant generation facility (High Performance)	Minor generation facility and intermittent generator or transitional scheduling generator designated pursuant to section 7.3.2.3 (Medium Performance)	Small generation facility
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
IESO scan period for Equipment Status	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
Data Skew	Maximum: 4 seconds	Not applicable	Not applicable
[Intentionally left blank – section deleted]			
[Intentionally left blank – section deleted]			

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

Appendix 4.20 – IESO Monitoring Requirements: Transmitter Performance Standards

The following performance levels, as a minimum, shall be achieved on a continual basis by all *transmitters* when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

PERFORMANCE LEVEL	FACILITIES
For transmission facilities or assets designated by the *IESO* as high performance at the time of registration, must meet the high performance levels in Appendix 4.21	All facilities and assets at 50 kV and above which are monitored for system limits such as transformer or switching stations All transformer and switching stations with interconnected ties An RTU which collects information at several locations on the *electricity system* Step-down transformer facilities that supply a *dispatchable load facility* that is required to meet high performance monitoring standard All other facilities where medium performance is not specified below
For transmission facilities or assets designated by the *IESO* as medium performance at the time of registration, must meet the medium performance levels in Appendix 4.21	Step-down transformer facilities that supply a *dispatchable load facility* that is required to meet medium performance monitoring standard Step-down transformer facilities that supply a *non-dispatchable load facility* that includes a *non-dispatchable load* rated at 20 MVA or higher or that comprises *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA Facilities and assets at 50 kV and above designated by the *IESO* as requiring medium performance

Appendix 4.21 – IESO Monitoring Requirements: Transmitter Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *transmitters* when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

FUNCTION	Transmission facilities or assets identified as high performance in Appendix 4.20	Transmission facilities or assets identified as medium performance in Appendix 4.20
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	Less than 10 seconds from change in field monitored quantity
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	Less than 10 seconds from field status change
Data Skew	Maximum: 4 seconds	N/A
IESO scan period for data measurements	Maximum: 4 seconds*	Minimum:** 4 seconds
IESO scan period for equipment status	Maximum: 4 seconds*	Minimum:** 4 seconds

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

Appendix 4.22 – IESO Monitoring Requirements: Distributors and Connected Wholesale Customer Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *distributors connected* to the *IESO-controlled grid*, *distributors* designated pursuant to section 7.5.2 and *connected wholesale customers* when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. A *connected wholesale customer* that is also a *generator* shall also comply with the requirements of Appendix 4.19.

FUNCTION	Major Dispatchable Load Facility and Significant Dispatchable Load Facility (High Performance)	*Minor Dispatchable Load Facility* and *Non-Dispatchable Load Facility**** that includes a *non-dispatchable load* rated at 20 MVA or higher or is comprised of *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA (Medium Performance)
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	Less than 10 seconds from change in field monitored quantity
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	Less than 10 seconds from field status change
Data skew	Maximum:* 4 seconds	Not applicable
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds
IESO scan period for equipment status	Maximum:* 4 seconds	Minimum:** 4 seconds

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

*** Where directed by the *IESO* if *transmitter* data is not adequate.

Appendix 4.23 – IESO Monitoring Requirements: Embedded Load Consumers Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *embedded load consumers* designated pursuant to section 7.6.1 when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements. An *embedded load consumer* that is also a *generator* shall also comply with the requirements of Appendix 4.19.

FUNCTION	Major Dispatchable Load Facility and Significant Dispatchable Load Facility (High Performance)	*Minor Dispatchable Load Facility* and *Non-dispatchable Load Facility**** that includes a *non-dispatchable* load rated at 20 MVA or higher or is comprised of *non-dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA (Medium Performance)
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	1. Less than one minute from change in field monitored quantity; or 2. Less than 10 seconds from change in field monitored quantity if designated by the *IESO* as required to maintain *reliable* operation of the *IESO-controlled grid*.
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	1. Less than one minute from change in field monitored quantity; or 2. Less than 10 seconds from field status change if designated by the *IESO* as required to maintain *reliable* operation of the *IESO-controlled grid*.
Data skew	Maximum:* 4 seconds	Not applicable
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds
IESO scan period for equipment status	Maximum:* 4 seconds	Minimum:** 4 seconds

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

*** Where directed by *IESO* if *transmitter* or *distributor* data is not adequate.

Appendix 4.24 – IESO Monitoring Requirements: Electricity Storage Participants

The following information, as a minimum, shall be available on a continual basis to the *IESO* from:

(a) any *electricity storage participant* (i) whose *electricity storage facility* is connected to the *IESO-controlled grid*, or (ii) that is participating in the *IESO-administered markets*; and

(b) any *embedded electricity storage participant* (i) that is not a *market participant* or whose *embedded electricity storage facility* is not a *registered facility*; (ii) whose *embedded electricity storage facility* includes an *electricity storage unit* with an *electricity storage unit* size rated at greater than 20 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which exceeds 20 MVA; and (iii) that is designated by the *IESO* for the purposes of section 7.3.1 of this Chapter as being required to provide such data in order to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.

TYPE	INFORMATION REQUIREMENTS
Major electricity storage facility	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) injected or withdrawn a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the *IESO* as required for: (i) determination of operating *security limits*; (ii) to maintain *reliable* operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *electricity storage units* with an *electricity storage unit size* greater than or equal to 100 MVA, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *electricity storage units* with an *electricity storage unit size* of less than 100 MVA: (i) for a group of *electricity storage units* if those *electricity storage units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *electricity storage units*, and total *gross MW* and *gross MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or

TYPE	INFORMATION REQUIREMENTS
	(ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). d) For *electricity storage facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain *reliable* operation of the *IESO-controlled grid* or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). 2. State of Charge and Charge Limit a) For each *electricity storage unit* or *electricity storage facility*, the *state of charge* of the applicable *electricity storage unit* or *electricity storage facility* b) For each *electricity storage unit* or *electricity storage facility*, the economic maximum charge limit and the economic minimum charge limit expressed in MWh as per the applicable *market manual*. 3. Base point a) For each *electricity storage unit* or *electricity storage facility*, providing *regulation*, the basepoint, if applicable, of the *electricity storage unit* expressed in MW, according to the applicable *market manual*. 4. Dynamic Maximum and Minimum Power a) For each *electricity storage unit* or *electricity storage facility*, the economic maximum power mode and economic minimum power mode, expressed in MW. 5. Voltage: a) For each *electricity storage unit*, unit terminal voltage, except if *electricity storage units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *electricity storage units*. 6. Equipment Status a) Voltage Control status and stabilizer status (if applicable) for each *electricity storage unit* with an *electricity storage unit size* > 100 MVA. When applicable, stabilizer status reporting is only required if it can be switched off by electricity storage participant personnel remotely or at the facility. b) AGC status for each *electricity storage unit* providing *regulation*. c) Voltage control status and stabilizer status (if applicable) for each *electricity storage unit* with an *electricity storage unit size* < 100 MVA if the status of this equipment is designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the *IESO-controlled grid*. When applicable, stabilizer status reporting is only required if it can be switched on or off by market participant operating personnel remotely or at the *facility*. d) Synchronizing Breaker status for each *electricity storage unit*. Where a *electricity storage facility* is designed such that no low voltage synchronizing breaker is installed for each *electricity storage unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the electricity storage unit must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration.

TYPE	INFORMATION REQUIREMENTS
	e) Where a *electricity storage facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. f) *Remedial Action Scheme* status for each applicable *electricity storage unit*.
Significant electricity storage facility and minor electricity storage facility connected to IESO-controlled grid	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) injected or withdrawn: a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX* facility. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the IESO as required for: (i) determination of operating security limits; (ii) to maintain reliable operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating security limits. b) For *electricity storage facilities* that have not been aggregated pursuant to Chapter 7 section 2.3: (i) for a group of *electricity storage units* if those *electricity storage units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these electricity storage units, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the IESO as required using the criteria listed above in part a); (ii) if designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid or for compliance monitoring purposes, the standard requirement as defined in part a) for each electricity storage unit shall be provided, and gross MW and gross or net MX for each electricity storage unit shall be provided if designated by the IESO as required using the criteria listed above in part a). c) For *electricity storage facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the IESO as required using the criteria listed above in part a); or (ii) if so designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid or for dispatch compliance monitoring purposes, the standard requirement as defined in part a) for each electricity storage unit shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the IESO as required using the criteria listed above in part a). 2. Voltage: a) For *electricity storage units* that are VAR dispatchable, unit terminal voltage, except if the electricity storage units are connected to a common low voltage bus section, then the bus section voltage is adequate for those electricity storage units. 3. State of Charge and Charge Limit a) For each *electricity storage unit* or *electricity storage facility*, the *state of charge* of the applicable *electricity storage unit* or *electricity storage facility* b) For each *electricity storage unit* or *electricity storage facility*, the economic maximum charge limit and the economic minimum charge limit expressed in MWh as per the applicable *market manual*. 4. Dynamic Maximum and Minimum Power

TYPE	INFORMATION REQUIREMENTS
	a) For each *electricity storage unit* or *electricity storage facility*, the economic maximum power mode and economic minimum power mode, expressed in MW. 5. Base point a) For each *electricity storage unit* or *electricity storage facility*, providing *regulation*, the basepoint, if applicable, of the storage unit expressed in MW, according to the applicable *market manual*. 5. Equipment Status a) Automatic Voltage Control and stabilizer status (if applicable) for each *electricity storage unit* if the status of this equipment is designated by the IESO as required for determination of operating security limits or to maintain reliable operation of the IESO-controlled grid. When applicable, stablizer status reporting is only required if it can be switched on or off by the *market participant* operating personnel remotely or at the facility. b) Synchronizing Breaker Status for each *electricity storage unit*. Where an *electricity storage facility* is designed such that no low voltage synchronizing breaker is installed for each *electricity storage unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *electricity storage unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where an *electricity storage facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. c) *Remedial Action Scheme* status for each applicable *electricity storage unit*.
Self-scheduling electricity storage facility with a name-plate rating of less than 10 MW	Monitored Quantities 1. Active Power (MW) and Reactive Power (MX) injected or withdrawn: a) The standard requirement for active and reactive power is the provision of *net MW* and *net MX* or *gross MX*. *Gross MW* and *gross MX* or *net MX* are also to be provided, if designated by the IESO as required for: (i) determination of operating *security limits*; (ii) to maintain reliable operation of the *IESO-controlled grid*; (iii) for compliance monitoring purposes; or (iv) if provision of only the standard requirement values as defined above would have a negative impact on other *market participants* through reduced operating *security limits*. b) For *electricity storage facilities* that have not been aggregated pursuant to Chapter 7 section 2.3: (i) for a group of *electricity storage units* if those *electricity storage units* are similar in size and operating characteristics, the standard requirement as defined in part a) shall be provided as a total for these *electricity storage units*, and total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the *IESO* as required using the criteria listed above in part a); (ii) if designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for compliance monitoring purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). c) For *electricity storage facilities* that have been aggregated pursuant to Chapter 7 section 2.3: (i) the standard requirement as defined in part a) shall be provided as an aggregated total, and an aggregated total *gross MW* and *gross MX* or *net MX* shall be provided if designated by the IESO as required using the criteria listed above in part a); or (ii) if so designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid* or for *dispatch* compliance monitoring

TYPE	INFORMATION REQUIREMENTS
	purposes, the standard requirement as defined in part a) for each *electricity storage unit* shall be provided, and *gross MW* and *gross MX* or *net MX* for each *electricity storage unit* shall be provided if designated by the *IESO* as required using the criteria listed above in part a). 2. Voltage: a) For *electricity storage unit*s that are VAR dispatchable, unit terminal voltage, except if the *electricity storage units* are connected to a common low voltage bus section, then the bus section voltage is adequate for those *electricity storage units*. 3. State of Charge and Charge Limit a) For each electricity storage unit or electricity storage facility, the state of charge of the applicable *electricity storage unit* or *electricity storage facility* b) For each *electricity storage unit* or *electricity storage facility* the economic maximum charge limit, the economic minimum charge limit expressed in MWh 4. Dynamic Maximum and Minimum Power a) For each *electricity storage unit*, the economic maximum power mode and economic minimum power mode, expressed in MW. 5. Base point a) For each *electricity storage unit*, providing *regulation*, the basepoint of the applicable *electricity storage unit* expressed in MW according to the applicable *market manual*. 6. Equipment Status a) Automatic Voltage Control status and Stabilizer status (if applicable) for each *electricity storage unit* if the status of this equipment is designated by the *IESO* as required for determination of operating *security limits* or to maintain reliable operation of the *IESO-controlled grid*. When applicable, stablizer status reporting is only required if it can be switched on or off by *market participant* operating personnel remotely or at the *facility*. b) Synchronizing Breaker Status for each *electricity storage unit*. Where an *electricity storage facility* is designed such that no low voltage synchronizing breaker is installed for each *electricity storage unit*, the status of the appropriate HV breaker(s) and disconnect switch(es) normally used to isolate the *electricity storage unit* must be provided. Where this results in access to the majority of breakers on a bus, the status of the remainder of the breakers shall be provided to complete the bus configuration. Where an *electricity storage facility* is designed such that there are disconnect switches in parallel, or directly in series, with the synchronizing breaker, the status of those switches is also required. c) *Remedial Action Scheme* status for each applicable *electricity storage unit*.
Small electricity storage facility	None
Minor electricity storage facility that is embedded in a distribution system and registered as a dispatchable electricity storage participant	Monitored Quantities 1. Total active power (MW) output of the individual *electricity storage unit* or of the aggregated resource. a) Unit status if the *facility* is comprised of a single *electricity storage unit*. b) Aggregated resource status if the *facility* is comprised of aggregated resources, i.e. if at least one unit of the aggregated resource is synchronized, the aggregated resource is synchronized or if no unit in the aggregated resource is synchronized, the aggregated resource is not synchronized.

TYPE	INFORMATION REQUIREMENTS
	c) Reactive Power (MX) output, if requested by the *IESO* for reliable operation of the *IESO-controlled grid*, of individual *electricity storage units* or of the aggregated resource. d) Unit terminal voltage (kV) if requested by the IESO for reliable operation of the *IESO controlled grid* 2. State of Charge and Charge Limit a) For each electricity storage unit or electricity storage facility, the state of charge of the applicable electricity storage unit or electricity storage facility expressed as a percentage b) For each *electricity storage unit* or *electricity storage facility*, the economic maximum charge limit, the economic minimum charge limit expressed in MWh 3. Dynamic Maximum and Minimum Power a) For each *electricity storage unit* or *electricity storage facility*, the economic maximum power mode and economic minimum power mode, expressed in MW. 4. Base point a) For each *electricity storage unit* or *electricity storage facility*, providing *regulation*, the basepoint, if applicable, of the *electricity storage unit* expressed in MW according to the applicable *market manual*.

Appendix 4.25 – IESO Monitoring Requirements: Electricity Storage Performance Standards

The following performance standards, as a minimum, shall be achieved on a continual basis by all *electricity storage participants* referred to in section 7.3.A of this Chapter when monitored by the *IESO*. Needs of the state estimation process or other reasons may result in additional requirements. The direction of all real and reactive power flows shall be indicated measurements.

FUNCTION	*Major electricity storage facility* or *significant electricity storage facility* (High Performance)	*Minor electricity storage facility* and *self-scheduling electricity storage facility* (*electricity storage facility unit size* <10MW) (Medium Performance)	*Small electricity storage facility*
Data measurements available at the *IESO* communications interface	Less than 2 seconds from change in field monitored quantity	1. Less than 10 seconds from change in field monitored quantity or 2. If the *minor electricity storage facility* is embedded within a *distribution system,* less than one minute from change in field monitored quantity unless otherwise designated by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.	Not applicable

FUNCTION	*Major electricity storage facility* or *significant electricity storage facility* (High Performance)	*Minor electricity storage facility* and *self-scheduling electricity storage facility* (*electricity storage facility unit size* <10MW) (Medium Performance)	*Small electricity storage facility*
Equipment status change available at the *IESO* communications interface	Less than 2 seconds from field status change	1. Less than 10 seconds from field status change or 2. If the *minor electricity storage facility* is embedded within a *distribution system*, less than one minute from change in equipment status unless otherwise designated by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*.	Not applicable
IESO scan period for data measurements	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
IESO scan period for Equipment Status	Maximum:* 4 seconds	Minimum:** 4 seconds	Not applicable
Data Skew	Maximum: 4 seconds	Not applicable	Not applicable

* The *IESO* may scan more frequently than the maximum.

** The *IESO* may scan less frequently than the minimum.

Market Rules

Chapter 5
Power System Reliability

Connecting Today.
Powering Tomorrow.

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Table of Contents

1. Purposes, Interpretation and General Principles

1.1 Purposes of Chapter 5 and Interpretation

1.1.1 Pursuant to section 6 of the *Electricity Act, 1998*, one of the objects of the *IESO* is to maintain the *reliability* of the *IESO-controlled grid*. This Chapter of the *market rules* sets forth:

1.1.1.1 rules governing maintenance of the *reliability* of the *IESO-controlled grid*;

1.1.1.2 conditions under which the *IESO* shall have authority to intervene in the *IESO-administered markets* and issue directions to *market participants* so as to maintain the *reliability* of the *IESO-controlled grid* and of electricity service;

1.1.1.3 procedures to be used by the *IESO*, including the issuance of directions, in the event of an *emergency,* an *emergency operating state* or a *high-risk operating state;*

1.1.1.4 minimum requirements for communication and information exchange between the *IESO* and *market participants* relating to the *reliability* of the *IESO-controlled grid*; and

1.1.1.5 the *IESO's* reporting requirements associated with its responsibilities for maintaining the *reliability* of the *IESO-controlled grid*.

1.1.2 For the purposes of this Chapter, “maintaining” *reliability* shall include re-establishing or restoring *reliability* and “maintain” and “maintenance” shall be interpreted accordingly.

1.1.3 In the event of a contradiction or inconsistency between the provisions of this Chapter 5 and any other provision of the *market rules*, the provisions of this Chapter 5 shall govern. In performing any act, power, or duty under the *market rules*, the *IESO* shall have due regard to and, when necessary to ensure the *reliability* of the *IESO-controlled grid*, give precedence to the provisions of this Chapter 5.

1.2 General Principles

1.2.1 To the fullest extent possible consistent with maintaining the *reliability* of the *IESO-controlled grid*, the *IESO* shall apply the *market rules* relating to *reliability* so as to minimize the *IESO's* intervention into the operation of the *IESO-administered markets*. However, the maintenance of a *reliable IESO-controlled grid* shall be considered of paramount importance under these *market rules*, and the *IESO* shall have authority to intervene in the *IESO-administered markets* to the extent necessary to maintain the *reliability* of the *IESO-controlled grid*.

1.2.2 In all cases, except as otherwise noted in this Chapter, where the *IESO* takes action under this Chapter, it shall attempt to coordinate its actions with affected *market participants* unless, in the *IESO's* opinion, conditions dictate the need for immediate action.

1.2.3 Nothing in this Chapter is intended to prevent *market participants* from acting to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*, provided that any such actions that may affect the *reliability* of the *IESO-controlled grid* are coordinated with the *IESO* to the fullest extent practicable and are, in any event, reported or notified to the *IESO* where required by these *market rules* to be so reported or notified.

1.2.4 Section 7.5 of Chapter 1 does not apply to this Chapter and any action or event that is required to occur on or by a stipulated time or day under this Chapter, or under a direction, instruction or order of the *IESO* issued pursuant to this Chapter, shall occur on or by that time, whether or not a business hour, or on or by that day, whether or not a *business day*, unless otherwise specified in this Chapter.

1.2.5 Unless a direction, instruction or order of the *IESO* provides otherwise, wherever this Chapter specifies that an action is to be taken "promptly" or "immediately", such action shall be taken as soon as possible after receiving the direction, instruction or order from the *IESO* or after becoming aware that an action is to be taken or is required not to be taken but in all events within five minutes, subject only to delay necessitated to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*.

1.2.6 Subject to section 1.2.7, *reliability standards* established by a *standards authority* that have not otherwise been stayed or revoked and referred back to the *standards authority* for further consideration by the *Ontario Energy Board* shall be declared in force in Ontario upon the later date of:

1.2.6.1 the *reliability standards* being declared in force in the United States or, for *NPCC* reliability criteria, when declared in force by *NPCC*; and

1.2.6.2 the expiry of the period for initiating a review before the *Ontario Energy Board* and the conclusion of any such review;

and shall cease to be in force in Ontario when they cease to be in force in the United States, provided that where a *reliability standard* is being retired and replaced with a new or amended version, the previous version shall remain in effect in Ontario until the later of the completion of the conditions in sections 1.2.6.1 and 1.2.6.2.

1.2.7 Notwithstanding section 1.2.6, where a *reliability standard* approved by *NERC* failed to achieve approval by the *NERC* registered ballot body as specified in *NERC*'s Rules of Procedure, the *reliability standard* will not be in force in Ontario unless and until the *IESO* determines, in consultation with affected *market participants*, that all or part of the *reliability standard* is in force in Ontario. The *IESO* shall *publish* notice of its determination and where applicable, such *reliability standard* will come into effect in accordance with section 1.2.6.

2. IESO-Controlled Grid and Operating States

2.1 Scope of IESO-Controlled Grid

2.1.1 The specific *facilities* included within the *IESO-controlled grid* shall be identified in the *operating agreements* between the *IESO* and each *transmitter* that are entered into in accordance with the Electricity Act, 1998. To the extent the *IESO* concludes, on its own initiative or further to a request made by a *market participant*, that, in order to meet its obligations to *reliably* operate the *IESO-controlled grid* or administer the *IESO-administered markets*, additional *transmission systems* or distribution *facilities* should be included within the *IESO-controlled grid*, the *IESO* shall negotiate to amend the applicable *operating agreement* to include such *transmission systems or facilities* or to conclude an *operating agreement* with the *transmitter* or owner of such *facilities* with whom no *operating agreement* has yet been concluded, as the case may be.

2.1.2 Subject to the licence of the *IESO* or of the applicable *transmitter* or *distributor*, if the *IESO* and a *transmitter* or *distributor* are unable to reach agreement on the inclusion of *facilities* within the *IESO-controlled grid*, the matter shall be resolved using the dispute resolution procedures in the applicable *operating agreement* or, in the absence of same, the procedures set forth in Section 2 of Chapter 3.

2.2 Normal Operating State

2.2.1 The *IESO-controlled grid* shall be considered as being in a *normal operating state* when:

2.2.1.1 the voltage magnitudes at all energized busbars at any switchyard or substation of the *IESO-controlled grid* are within the ratings set by relevant *transmitters*;

2.2.1.2 the current flows on all transmission *facilities* of the *IESO-controlled grid* are within the equipment ratings established by the relevant *transmitters*;

2.2.1.3 all other electric plant forming part of, or having or likely to have a material impact on the operation of, the *IESO-controlled grid* is being operated within the equipment ratings defined by the relevant *transmitters*, *generators, electricity storage participants,* and *distributors*;

2.2.1.4 all *interconnected systems* having or likely to have a material impact on the operation of the *IESO-controlled grid* are being operated within the equipment ratings that are jointly established between the *IESO* and the relevant *transmitters*;

2.2.1.5 the configuration of the *IESO-controlled grid* is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and

2.2.1.6 conditions on the *IESO-controlled grid* are secure in accordance with the requirements set forth in Section 5.

2.3 Emergency Operating State

2.3.1 The *IESO-controlled grid* shall be considered as being in an *emergency operating state* when observance of *security limits* under a *normal operating state* will either:

2.3.1.1 require curtailment of *non-dispatchable load*; or

2.3.1.2 restrict transactions on *interconnected systems* during an *emergency* on the *IESO-controlled grid* or on a neighbouring *electricity system*.

2.3.2 The *IESO* shall not take any action or refrain from taking any action that will, in the *IESO*'s opinion, be reasonably likely to lead to an *emergency operating state*.

2.3.3 The *IESO* shall promptly inform *market participants* when an *emergency operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During an *emergency operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required to restore the *IESO-controlled grid* to a *normal operating state* and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

2.3.3A Without limiting the generality of section 2.3.3 and notwithstanding any other provision of the *market rules*, the *IESO* may, when the *IESO-controlled grid* is in an *emergency operating state*, acquire *emergency energy* in accordance with all applicable *reliability standards* and any applicable *interconnection agreement* in order to maintain the *reliability* of the *IESO-controlled grid.* The *IESO* shall not exercise this power where *market participants* have *offered* to provide sufficient quantities of *energy*, eligible for *dispatch* or scheduling, to enable the *IESO* to maintain the *reliability* of the *IESO-controlled grid*. The costs associated with the acquisition of such *emergency energy* paid by the *IESO* pursuant to the applicable *interconnection agreement* shall be recovered in accordance with section 4.8 of Chapter 9.

2.3.4 Further provisions relating to system and market operations during *emergency* conditions are set forth in Chapter 7.

2.4 High-Risk Operating State

2.4.1 The *IESO-controlled grid* shall be considered to be in a *high-risk operating state* when the observance of *security limits* under a *normal operating state* will expose the *integrated power system* to a significantly higher than normal probability of one or more *contingency events* and associated consequences, or of a condition that may lead to, but is not yet, an *emergency*. The conditions under which the *IESO-controlled grid* may be considered as entering into or exiting a *high-risk operating state* shall be defined in the *IESO*'s operating procedures, it being understood that, without limiting the generality of the foregoing, a *high-risk operating state* is normally associated with adverse or extreme weather conditions or equipment-related problems that could lead to a *contingency event* on the *IESO-controlled grid* that is not expected under a *normal operating state*.

2.4.2 The *IESO* shall not take any action or refrain from taking any action that will, in the opinion of the *IESO*, be reasonably likely to lead to a *high-risk operating state*.

2.4.3 The *IESO* shall promptly inform *market participants* when a *high-risk operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During a *high-risk operating state*, the *IESO* shall have the authority to modify *security limits* as necessary to manage conditions and increase *reliability* on the *IESO-controlled grid*, and to take such other action or refrain from taking such other action consistent with *good utility practice* as may be required and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

2.5 Conservative Operating State

2.5.1 The *IESO-controlled grid* shall be considered to be in a *conservative operating state* when the impact of a *contingency* event on the *IESO-controlled grid* could be more severe than under a *normal operating state*. Under a *conservative operating state* the *IESO-controlled grid* will be operated within equipment and *security limits* established for a *normal operating state*. The *IESO-controlled grid* will be in a heightened state of readiness due to anticipated, or actual, stresses on the grid itself, or due to the *IESO's* loss of ability to effectively monitor the *IESO-controlled grid*. Conditions that may require a *conservative operating state* are listed in the applicable *market manual*.

2.5.2 The *IESO* shall promptly inform *market participants* when a *conservative operating state* is anticipated or has been declared, and when it ceases to exist or to be anticipated. During a *conservative operating state*, the *IESO* shall have the authority to take such action or refrain from taking such action consistent with *good utility practice* as may be required and with as little disruption to electric service or adverse impact on the operation of the *IESO-administered markets* as is reasonably practicable in the circumstances.

3. Obligations and Responsibilities

3.1 Objectives

3.1.1 This section 3 sets forth the responsibilities, obligations and authorities of the *IESO* and each *market participant* in order to maintain the *reliability* of the *IESO-controlled grid*.

3.2 Obligations of the IESO

3.2.1 The *IESO* shall direct the operations of the *IESO-controlled grid* pursuant to the provisions of all applicable *operating agreements* and shall maintain the *reliability* of the *IESO-controlled grid*. The *IESO's* responsibilities in this regard shall include, but are not limited to, the monitoring of, and the issuing of orders, directions or instructions to *dispatch* generation*, electricity storage facilities, dispatchable loads*, distribution *facilities* and transmission *facilities* on the *IESO-controlled grid*.

3.2.2 The *IESO* shall carry out its obligations in accordance with all applicable *reliability standards.*

3.2.3 In order to meet its obligations under this Chapter and under other provisions of the *market rules*, the *IESO* shall maintain written operating procedures and instructions and shall make same available for inspection at all times by *market participants*. The *IESO Board* may *amend* the *market rules* to include any such operating procedures and instructions within the *market rules*.

3.2.4 [Intentionally left blank – section deleted]

Identification of Reliability Standards

3.2.5 The *IESO* shall maintain a mapping containing *reliability standards* applicable to each class of *market participants,* as per the applicability criteria, and provide *market participants* with the ability to retrieve those *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant*. The *IESO* may revise its applicability determination under this section at any time on notice to the *market participant*. If required, the *IESO* shall consult with *market participants* to finalize *reliability standards'* obligations or requirements that apply to a *market participant.*

3.2.6 The *IESO* shall inform *market participants* when an amendment to a *reliability standard* or a new *reliability standard* will come into effect in Ontario, and update the mapping containing *reliability standards* applicable to each class of *market participants* to provide *market participants* with the ability to retrieve the new or amended *reliability standards'* obligations or requirements that the *IESO* determines apply to that *market participant*. The *IESO* may revise its applicability determination under this section at any time on notice to the *market participant*.

3.2.7 A *market participant* may request the *IESO* review a determination under section 3.2.5 or 3.2.6 with respect to that *market participant*. The *IESO* shall, following consideration of any representations made by the *market participant,* determine whether the *reliability standards'* obligations or requirements apply to that *market participant*.

3.2A Technical Feasibility Exceptions

3.2A.1 The *IESO* may:

3.2A.1.1 [Intentionally left blank – section deleted]

3.2A.1.2 approve a *TFE application*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *TFE application*, in whole or in part with such approval or disapproval being a *reviewable decision*;

3.2A.1.3 upon the request of a *market participant* amend or transfer a *TFE*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2A.1.4 terminate or amend an approved *TFE*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate. Such termination or amendment is a *reviewable decision*.

3.2A.2 A *TFE applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *TFEs* by filing with the *IESO* a *TFE application* for each required *TFE*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *TFE applicant* may withdraw a *TFE application* at any time.

3.2A.3 Upon request by the *IESO*, a *TFE applicant* shall provide to the *IESO*:

3.2A.3.1 [Intentionally left blank – section deleted]

3.2A.3.2 any supporting documentation; and

3.2A.3.3 an executed agreement pursuant to which the *TFE applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in processing the *TFE application* and maintaining an approved *TFE* until such time as the *TFE* is no longer in effect.

3.2A.4 The *IESO* shall process a *TFE application* in accordance with Ontario-adapted *NERC* procedures for processing *TFE applications* as set out in the applicable *market manual*.

3.2A.5 Where applicable, for each *TFE application,* the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable, which is a *reviewable decision*, and which will form part of the executed agreement set out in section 3.2A.3.3 and will monitor expenditures against the processing costs of a *TFE application* and where that threshold is reached:

3.2A.5.1 the *IESO* shall advise the *TFE applicant* of the work and costs incurred to date;

3.2A.5.2 the *IESO* shall provide an estimate to the *TFE applicant* of the further work and costs necessary to complete the processing of the *TFE application*; and

3.2A.5.3 the *TFE applicant* may choose to continue with the processing of the *TFE application* or discontinue the processing of the *TFE application*. In the event that the *TFE applicant* chooses to discontinue the processing by withdrawing the *TFE application*, the *IESO* shall issue an *invoice* to the *TFE applicant* for the reasonable costs incurred by the *IESO* to that point.

3.2A.6 The *IESO* may utilize an independent third party to review a *TFE application* and any changes to an approved *TFE* submitted by a *TFE applicant*.

3.2A.7 The *IESO* may consult with *NERC* or *NPCC* in its assessment of a *TFE application* and any changes to an approved *TFE*.

3.2A.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *TFE* shall be a breach of the *market rules* and the *IESO* may terminate the approved *TFE* and require the *TFE applicant* to become compliant with the applicable *NERC reliability standard*.

3.2A.9 Subject to section 3.2A.4, all *TFE*s which remain in effect are subject to periodic review, in accordance with the applicable *market manual*, to verify continuing justification for the *TFE*.

3.2A.10 The *IESO* may submit *invoices* to the *TFE applicant* for costs and expenses incurred by the *IESO* in processing the *TFE* application and maintaining the approved *TFE* until such time as the *TFE* is no longer in effect, less in each case, the amount of any deposit paid pursuant to section 3.2A.2 not previously applied against the *IESO's* costs and expenses. The submission of *invoices* to the *TFE applicant* is a *reviewable decision*.

3.2A.11 A *TFE applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2A.5.3 or 3.2A.10, pay to the *IESO* the amount owing.

3.2B Bulk Electric System Exceptions

3.2B.1 A *BES exception applicant* may, in accordance with the applicable *market manual*, request the *IESO* approve, amend, transfer, or terminate one or more *BES exceptions* by filing with the *IESO* a *BES exception request* for each required *BES exception*, and shall, in accordance with the applicable *market manual* submit to the *IESO* an initial deposit. A *BES exception applicant* may withdraw a *BES exception request* at any time.

3.2B.2 The *IESO* may review, reject or accept a *BES exception request* in whole or in part.

3.2B.3 The *IESO* shall process a *BES exception request* in accordance with the Ontario-adapted *NERC* procedure for processing *BES exception requests* as set out in the applicable *market manual*.

3.2B.4 Upon request by the *IESO*, a *BES exception applicant* shall provide to the *IESO*:

3.2B.4.1 a substantive review deposit amount;

3.2B.4.2 any supporting documentation; and

3.2B.4.3 an executed agreement pursuant to which the *BES exception applicant* agrees to pay to the *IESO* an amount equal to all of the reasonable costs incurred by the *IESO* in processing the *BES exception request*.

3.2B.5 Where applicable, for each *BES exception request*, the *IESO* shall establish a cost threshold or subsequent cost thresholds which it considers to be reasonable and which will form part of the executed agreement set out in section 3.2B.4.3 and will monitor expenditures against the processing costs of a *BES exception request* and where that threshold is reached:

3.2B.5.1 the *IESO* shall advise the *BES exception applicant* of the work and costs incurred to date;

3.2B.5.2 the *IESO* shall provide an estimate to the *BES exception applicant* of the further work and costs necessary to complete the processing of the *BES exception request*; and

3.2B.5.3 the *BES exception applicant* may choose to continue with the processing of the *BES exception request* or discontinue the processing of the *BES exception request*. In the event that the *BES exception applicant* chooses to discontinue the processing by withdrawing the *BES exception request*, the *IESO* shall issue an *invoice* to the *BES exception applicant* for the reasonable costs incurred by the *IESO* to that point. The issuance of such an *invoice* is a *reviewable decision*.

3.2B.6 The *IESO* may utilize an independent third party to review a *BES exception request* submitted by a *BES exception applicant*.

3.2B.7 After receiving a recommendation from the *IESO* on a *BES exception request*, the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* may:

3.2B.7.2 approve or disapprove a *BES exception request*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate or disapprove a *BES exception request*, in whole or in part, with such approval or disapproval being a *reviewable decision*;

3.2B.7.3 upon the request of a *market participant* or a *connection applicant* amend or transfer a *BES exception*, in whole or in part, subject to and including any terms and conditions the *IESO* determines appropriate; or

3.2B.7.4 terminate or amend an approved *BES exception*, in whole or in part, subject to any terms and conditions the *IESO* determines appropriate. Such termination or amendment is a *reviewable decision*.

3.2B.8 A failure by a *market participant* or the *IESO* to meet any of the terms and conditions of an approved *BES exception* shall be a breach of the *market rules* and the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* may terminate the approved *BES exception* and require the *BES exception applicant* to become compliant with the applicable *NERC reliability standards*.

3.2B.9 All *BES exceptions* are subject to periodic review, in accordance with the applicable *market manu*al, to verify continuing justification for the *BES exception* and may be referred to the *IESO Board* or a panel of the *IESO Board* as determined by the Chair of the *IESO Board* in accordance with section 3.2B.7.

3.2B.10 The *IESO* shall submit an *invoice* to a *BES exception applicant* upon completion of the processing of that applicant's *BES exception request* in an amount equal to all of the *IESO's* costs and expenses relating to the processing of the *BES exception applicant's BES exception request* less the amount of any deposit paid pursuant to section 3.2B.4.1. The submission of an *invoice* to a *BES exemption applicant* is a *reviewable decision*.

3.2B.11 A *BES exception applicant* shall, within thirty days of the date of an *invoice* referred to in section 3.2B.5.3 or 3.2B.10, pay to the *IESO* the amount owing.

3.3 Reliability-Related Information

3.3.1 The *IESO* shall *publish* a list of the categories of *reliability*-related information that it shall provide to *market participants*, the time periods within which such information will be provided, and the manner in which such information will be provided. Such information shall include, but not be limited to, information designed to:

3.3.1.1 enable *market participants* to initiate procedures to manage the potential risk of any action taken by the *IESO* to maintain the *reliability* of the *IESO-controlled grid*;

3.3.1.2 assist *market participants* in meeting their obligations under this Chapter; and

3.3.1.3 notify *market participants* of any operating changes or decisions that may have an impact on their operations, *facilities* or equipment.

3.3.2 The *IESO* shall publish a catalogue of the *reliability*-related information that the *IESO* shall require from *market participants*, including the information referred to in section 14.1.3, the time periods within which such information will be provided and the manner in which such information will be provided. At the same time, the *IESO* shall *publish* initial monitoring indices that the *IESO* shall use in evaluating the information so provided.

3.3.3 *Market participants* shall provide the *IESO* with the information referred to in section 3.3.2 within the time and in the manner required.

3.3.4 Subject to the confidentiality provisions of Chapters 3 and 4, the *IESO* shall, if requested to do so by a *market participant*, provide to that *market participant reliability*-related information not contained in the list referred to in section 3.3.1, provided that the *IESO* shall be under no obligation to provide any information that, in the *IESO's* opinion, would provide the requesting *market participant* with an undue advantage in the *IESO-administered markets*. In order to prevent any such undue advantage, the *IESO* may provide *market participants* with notice of the request prior to providing such information and may make the information requested by a *market participant* simultaneously available to all *market participants*.

3.4 Obligations of Transmitters

3.4.1 Each *transmitter* shall operate and maintain its transmission *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.4.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.4.1.2 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.4.1.3 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment*;*

3.4.1.4 promptly informing the *IESO* of any change or anticipated change in the capability of its transmission *facilities* or the status of its equipment or *facilities* forming part of the *IESO-controlled grid*, and of any other change or anticipated change in its transmission *facilities* that could have a material effect on the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets;* and

3.4.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *transmission system* for *reliability* purposes, unless the *transmitter* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *transmitter* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above.

3.4.2 Each *transmitter* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.5 Obligations of Wholesale Customers

3.5.1 Each *connected wholesale customer* shall operate and maintain its *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.5.1.1 ensuring there are controls, monitoring, and secure communication systems to facilitate a manually initiated, rotational load-shedding and restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.5.1.2 promptly informing the *IESO* of any change or anticipated change in the status of any *facility* or equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets;*

3.5.1.3 promptly complying with the *IESO's* directions, including directions to *disconnect* equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *connected wholesale customer* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *connected wholesale customer* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.5.1.4 [Intentionally left blank]

3.5.1.5 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more; relative to the average weekday *demand* of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* that it operates and that has been specifically designated by the *IESO* for this purpose.

3.5.2 Each *wholesale consumer* that is an *embedded market participant* and that operates a *registered facility* that is not directly *connected* to the *IESO-controlled grid* shall provide, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

3.5.2.1 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any such *registered facility*, where such *planned outage*, closure, test or other similar operational event is expected to result in a change in *demand* of 20 MW or more relative to the average weekday *demand* of that *registered facility*; and

3.5.2.2 the timing and duration of any *planned outage*, closure, test or other similar operational event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of such *registered facility* that has been specifically designated by the *IESO* for this purpose.

3.5.3 Each *wholesale customer* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.6 Obligations of Generators (Embedded and Non-embedded)

3.6.1 Each *generator* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall operate and maintain its *generation facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities related to *reliability*. Such obligation shall include, but not be limited to, the following:

3.6.1.1 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.6.1.2 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment, as required by the *IESO* to *reliably* operate the *IESO-controlled grid*;

3.6.1.3 promptly informing the *IESO* of any change or anticipated change in the status of any *generation facility* or related equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *generation facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets.* Such change shall include, but not be limited to, any change in status that could affect the maximum output of a *generation unit*, the minimum load of a *generation unit*, the ability of a *generation unit* to operate with *automatic voltage regulation*, or the availability of a *generation unit* to provide *ancillary services* (unless no application has been made to provide *ancillary services* to the *IESO-administered markets* in respect of a given *generation unit);*

3.6.1.4 promptly informing the *IESO* if any of the *generation facilities* that it operates are unable for any reason to operate in accordance with the schedules determined pursuant to Chapter 7;

3.6.1.5 providing the *IESO* with current information showing the maximum unit capabilities of each of its *generation units* to facilitate *dispatch* in an *emergency operating state*. Such maximum unit capabilities shall consist of the maximum physical-rating of the *generation unit* and shall not be limited to the unit capabilities contained in the *offers* submitted for such *generation unit* pursuant to Chapter 7;

3.6.1.6 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *generator* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *generator* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.6.1.7 [Intentionally left blank]

3.6.2 Each *generator* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.7 Obligations of Distributors

3.7.1 Each *distributor* shall operate and maintain its distribution *facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-controlled grid* and shall assist the *IESO* in the discharge of its responsibilities relating to *reliability*. Such obligation shall include, but not be limited to, the following:

3.7.1.1 ensuring that systems and procedures for load-shedding in *emergencies* are provided for as specified in section 10;

3.7.1.2 promptly informing the *IESO* of any change or anticipated change in the capability of its equipment or distribution *facilities* connected to the *IESO-controlled grid* that could have a material effect on the *reliable* operation of the *IESO-controlled grid* or the operation of the *IESO-administered markets*;

3.7.1.3 promptly informing the *IESO* of any event or circumstance in its service territory that could have a material effect on the *reliability* of the *IESO-controlled grid;*

3.7.1.4 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for equipment and distribution *facilities* that are included within the *IESO-controlled grid*;

3.7.1.5 promptly complying with the *IESO's* directions, including directions to *disconnect facilities* or equipment from the *IESO-controlled grid* or its *distribution system* for *reliability* purposes, unless the *distributor* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *distributor* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above;

3.7.1.6 providing, no later than 14:00 EST on the last *trading day* of every second *trading week*, or more frequently if requested by the *IESO*, the following information:

a. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* which is not a *registered facility* that draws electrical *energy* from or injects electrical *energy* into its *distribution system*, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by that *facility* of 20 MW or more relative to the average weekday demand or supply of that *facility*; and

b. the timing and duration of any *planned outage*, closure, test or other event scheduled to commence or occur in the immediately succeeding four *trading weeks*, or during such longer period as may be requested by the *IESO*, in respect of any *facility* which is not a *registered facility* that draws electrical *energy* from or injects electrical *energy* into its *distribution system* and that has been specifically designated by the *IESO* for this purpose, where such *planned outage*, closure, test or other event is expected to result in a change in *demand* or supply by such *facility* relative to the average weekday *demand* or supply of that *facility*; and

3.7.1.7 [Intentionally left blank]

3.7.2 Each *distributor* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

3.8 Obligations of Electricity Storage Participants (Embedded and Non-embedded)

3.8.1 Each *electricity storage participant* that participates in the *IESO-administered markets* or that causes or permits electricity to be conveyed into, through or out of the *IESO-controlled grid* shall operate and maintain its *electricity storage facilities* and equipment in a manner that is consistent with the *reliable* operation of the *IESO-*

controlled grid and shall assist the *IESO* in the discharge of its responsibilities related to *reliability*. Such obligations shall include, but not be limited to, the following:

3.8.1.1 ensuring there are controls, monitoring and secure communication systems to facilitate a manually initiated restoration process in order to assist the *IESO* in the management of a prolonged, major shortage of electrical supply or an extreme disruption to or *emergency* on the *IESO-controlled grid*;

3.8.1.2 providing the *IESO* with functional descriptions, equipment ratings, and operating restrictions for its equipment, as required by the *IESO* to *reliably* operate the *IESO-controlled grid*;

3.8.1.3 promptly informing the *IESO* of any change or anticipated change in the status of any *electricity storage facility* or related equipment that it operates and that is under the *dispatch* control of the *IESO* as described in these *market rules* or of any other change or anticipated change in its *electricity storage facilities* or equipment that could have a material effect on the *IESO-controlled grid* or the operation of the *IESO-administered markets.* Such change shall include, but not be limited to, any change in status that could affect its range of injections and withdrawals of *energy*, *state of charge*, the ability of an *electricity storage unit* to operate with *automatic voltage regulation*, or the availability of an *electricity storage unit* to provide *ancillary services* (unless no application has been made to provide *ancillary services* to the *IESO-administered markets* in respect of a given *electricity storage unit);*

3.8.1.4 promptly informing the *IESO* if any of the *electricity storage facilities* that it operates are unable for any reason to operate in accordance with the schedules determined pursuant to Chapter 7;

3.8.1.5 providing the *IESO* with current information showing the maximum unit capabilities to inject electricity, for each of its *electricity storage units* to facilitate dispatch in an *emergency operating state.* Such maximum unit capabilities shall consist of the maximum amount in MWs that can be injected at that point in time, and for how long, and shall not be limited to the unit capabilities contained in the *offers* submitted for such *electricity storage unit* pursuant to Chapter 7;

3.8.1.6 promptly complying with the *IESO's* directions, including directions to disconnect equipment from the *IESO-controlled grid* for *reliability* purposes, unless the *electricity storage participant* reasonably believes that following the *IESO's* direction poses a real and substantial risk of endangering the safety of any person, damaging equipment, or violating any *applicable law*. In all cases where the *electricity storage participant* does not intend to follow the *IESO's* directions for any such reasons, it shall promptly notify the *IESO* of this fact and shall nonetheless comply with the *IESO's* directions to the fullest extent possible without causing the harms described above; and

3.8.1.7 providing the *IESO* with current information showing the maximum unit capabilities to withdraw energy, for each of its *electricity storage units* to facilitate dispatch in an *emergency operating state*. Such maximum unit capabilities shall consist of the maximum amount in MWs that can be withdrawn at that point in time, and for how long, and shall not be limited to the unit capabilities contained in the *bids* submitted for such *electricity storage unit* pursuant to Chapter 7;

3.8.2 Each *electricity storage participant* shall carry out its obligations under this Chapter in accordance with all applicable *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

4. System Reliability

4.1 Objectives

4.1.1 The objective of this section 4 is to set forth the requirements to ensure the availability of sufficient capacity and *ancillary services* to the *IESO-administered markets.*

4.2 Standards for Ancillary Services

4.2.1 The *IESO* shall operate the *IESO-administered markets* and contract for *ancillary services*, including by means or within the scope of an *operating agreement* or another agreement of similar nature, to ensure that sufficient *ancillary services* are available to ensure the *reliability* of the *IESO-controlled grid*. *Ancillary services* shall be procured by the *IESO* in accordance with this Chapter and Chapter 7.

4.2.2 The requirements for *ancillary services* shall be determined based on all applicable *reliability standards* and actual and expected conditions on the *IESO-controlled grid.* Requirements for *ancillary services* may be adjusted from time to time by the *IESO* to take into account, among other things, variations in *integrated power system* conditions, real-time *dispatch* constraints, *contingency events*, the prevailing level of system risks or vulnerability, and the results of assessments of the voltage and dynamic stability of the *integrated power system*.

4.2.3 The *IESO* shall, in accordance with the procedures set forth in section 4 of Chapter 3, periodically review the operation of the *IESO-administered markets* for *ancillary services* to determine whether any revision to the requirements and standards for *ancillary services* is required for *reliability* purposes. As a minimum, the *IESO* shall conduct such reviews to accommodate revisions to applicable criteria established by relevant *standards authorities*.

4.3 Generic Performance Requirements for Ancillary Services

4.3.1 *Ancillary services* may be provided to the *IESO* only by *registered facilities* as required by Chapter 7. *Ancillary services* may be offered to the *IESO* in its daily and hourly *physical markets* or provided to the *IESO* under *contracted ancillary service* contracts through the *IESO's ancillary services procurement markets* or by means or within the scope of *operating agreements* or another agreement of a similar nature. Prior to entering into a contract with any *ancillary service provider*, the *IESO* shall determine whether the *facilities* and procedures of such *ancillary service provider* meet the requirements for registration as a *registered facility* in respect of the *ancillary service(s)* to be provided and are otherwise in compliance with the technical requirements of this Chapter. The *IESO* shall not contract for *ancillary services* with an *ancillary services provider* whose *facilities* are not in compliance with such requirements.

4.3.2 In order to make the determination referred to in section 4.3.1, the *IESO* may require each *ancillary service provider* to demonstrate through physical tests or other appropriate means specified by the *IESO* that the *registered facilities* or equipment that will be used to provide the *ancillary service* meet the performance standards for each *ancillary service* set forth in Appendix 5.1 or in the applicable *market manual*.

4.3.3 [Intentionally left blank – section deleted]

4.3.4 [Intentionally left blank – section deleted]

4.4 Regulation

4.4.1 The *IESO* shall maintain sufficient *regulation* to allow the *IESO* to meet all applicable *reliability standards.*

4.4.2 The *IESO* shall determine the quantity of *regulation* capacity needed for each hour of the following day. As a minimum, the requirement shall be +/- 100 MW, with a ramp rate of 50 MW/min.

4.4.3 If the *IESO* is unable to comply with applicable *reliability standards*, it shall take corrective action to achieve compliance with applicable *reliability standards* within three months.

4.4.4 *Area control error (ACE)* shall be calculated by the *IESO* in accordance with section 4.4.5 and all applicable *reliability standards*. Control signals shall be sent from the *IESO* to *registered facilities* providing *regulation*, as required by the *IESO*.

4.4.5 The calculation of *ACE* shall occur at least every four seconds.

4.4A Assistance to Other Control Areas

4.4A.1 Notwithstanding any other provision of the *market rules*, when a *transmission system* in another *control area* is in a state identical or comparable to an *emergency operating state*, the *IESO* may, in accordance with all applicable *reliability standards* and any applicable *interconnection agreement*, provide *emergency energy* to the *control area* within which such other *transmission system* is located in order to maintain the *reliability* of such *transmission system.* The *IESO* shall only provide *emergency energy* to another *control area* in circumstances where *energy* could not be obtained by that *control area* using the *offer* and *bid* processes described in Chapter 7. The compensation associated with the provision of such *emergency energy* that is received by the *IESO* pursuant to the applicable *interconnection agreement* shall be distributed in accordance with section 4.8 of Chapter 9.

4.5 Operating Reserve

4.5.1 *Operating reserve* is capacity that, for any given operating interval or *dispatch interval*, is in excess to that required to meet anticipated requirements for *energy* for that operating interval or *dispatch interval*, and is available to the *integrated power system* for *dispatch* by the *IESO* within a specified time period, such as 10 minutes or 30 minutes. *Operating reserves* may be provided by *generation facilities,* dispatchable *electricity storage facilities, dispatchable loads* and *boundary entities* to the extent that each meets the applicable requirements to be a *registered facility* in respect of each category of *operating reserves*. Neighbouring *control areas* may also provide *operating reserve* through simultaneous activation of *operating reserve* and regional reserve sharing programs. *Operating reserve* is required to:

4.5.1.1 cover or offset unanticipated increases in load during a *dispatch day* or *dispatch hour*;

4.5.1.2 replace or offset capacity lost due to the *forced outage* of generation, electricity storage or transmission equipment; or

4.5.1.3 cover uncertainty associated with the performance of *generation facilities, electricity storage facilities* or *dispatchable loads* in responding to the *IESO's dispatch instructions*.

4.5.2 The *IESO* shall maintain sufficient *operating reserve* to meet all applicable *reliability standards.*

4.5.3 The *IESO* shall maintain, as a minimum, total *operating reserve* that is the sum of the *ten-minute operating reserve* requirement and the *thirty-minute operating reserve* requirement.

4.5.4 Part of the requirement for *ten-minute operating reserve* shall be synchronized with the *IESO-controlled grid* consistent with section 4.5.9.

4.5.5 The *IESO* shall ensure that *operating reserve* is distributed throughout the *IESO-controlled grid* such that sufficient *operating reserve* can be activated and delivered to any location on the *integrated power system*.

Simultaneous Activation of Reserve

4.5.6 The *IESO* may simultaneously activate with nearby systems its *ten-minute operating reserve* to respond to *contingency events* in accordance with agreements between the *IESO* and such systems. Similarly, such systems may activate their *operating reserve* when requested to meet *contingency events* in the *IESO control area* in accordance with agreements between the *IESO* and such systems. Such simultaneous activation of *operating reserve* is solely for the purpose of maintaining the *reliability* of *interconnection systems* and shall not alter the *operating reserve* requirements of the *IESO*.

Control Action Operating Reserve

4.5.6A The *IESO* may include voltage reductions, and reductions in the *thirty-minute operating reserve* requirements within allowable *reliability standards* as standing *offers* in the *operating reserve markets* subject to the following conditions:

4.5.6A.1 the *IESO* shall introduce such standing *offers* in increasing quantities;

4.5.6A.2 the quantities referred to in section 4.5.6A.1 and the prices therefore shall be determined by the *IESO Board* and such quantities and prices shall be *published* by the *IESO*;

4.5.6A.3 the *IESO Board* may specify the circumstances under which any one or more of the quantities may either be withdrawn or not introduced and the manner in which any such withdrawal will be effected and the *publishing* thereof;

4.5.6A.4 the *IESO* shall *publish* the times and quantities of the voltage reductions and reduction in *thirty-minute operating reserve* when these sources of *operating reserve* have been scheduled to provide *operating reserve;* and

4.5.6A.5 the prices and quantities of the standing *offers* set by the *IESO Board* in accordance with section 4.5.6A.2 shall be monitored by the *IESO* to assess their impacts and that any changes to the prices and quantities would be recommended to the *IESO Board* as necessary.

Regional Reserve Sharing

4.5.6B The *IESO* may participate in regional reserve sharing programs with neighbouring *control areas*. Subject to availability and deliverability of the associated *energy*, the *IESO* may count towards its *ten-minute operating reserve* requirement a contribution of up to 100 MW from neighbouring *control areas* in accordance with applicable regional reserve sharing programs and applicable *reliability standards.* The *IESO* shall activate *energy* from regional reserve sharing programs in accordance with applicable *reliability standards*.

Ten-Minute Operating Reserve

4.5.7 *Ten-minute operating reserve* is capacity that is available to the *integrated power system* in excess of anticipated requirements for *energy* and that can be made available and used within ten minutes. It includes resources that are either synchronized or non-synchronized with the *IESO-controlled grid*.

4.5.8 The *IESO* shall maintain sufficient *ten-minute operating reserve* to meet the requirements of all applicable *reliability standards.* This shall be at least equal to the largest first contingency loss sustainable on the *IESO-controlled grid*.

4.5.9 *Ten-minute operating reserve* shall be synchronized with the *IESO-controlled grid* to the extent required by all applicable *reliability standards*.

4.5.10 If, for any reason, there is a deficiency of *ten-minute operating reserve*, the *IESO* shall replace such *reserve* in accordance with the applicable *reliability standards* referenced in the *market manuals*.

4.5.11 The *IESO* shall, in accordance with Chapter 7, *publish* daily its estimates of the quantity of *ten-minute operating reserve* that is required for each hour of the following day.

4.5.12 A *registered facility* that is a *boundary entity* that is used as *ten-minute operating reserve* shall be treated as *operating reserve* that is non-synchronized with the *IESO-controlled grid*.

4.5.13 The reduction in load that can be effected by curtailing pumping hydroelectric *generation facilities* is eligible to be treated as *operating reserve* that is synchronized with the *IESO-controlled grid*.

4.5.13A [Intentionally left blank – section deleted]

4.5.13B The reduction in load that can be effected by curtailing withdrawals from *electricity storage facilities* is eligible to be treated as *operating reserve* that is synchronized with the *IESO-controlled grid*.

4.5.14 [Intentionally left blank]

4.5.15 [Intentionally left blank]

4.5.16 [Intentionally left blank]

4.5.17 [Intentionally left blank]

Thirty-Minute Operating Reserve

4.5.18 *Thirty-minute operating reserve* is capacity in excess of anticipated requirements for *energy* that can be made available and used within thirty-minutes and that is not included as *ten-minute operating reserve*.

4.5.19 Subject to section 4.5.20, the requirement for *thirty-minute operating reserve* shall be at least equal to one-half of the largest *second contingency loss* sustainable on the *IESO-controlled grid*. However, when a *generation unit* is commissioning and is one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall be at least equal to the *second contingency loss*.

4.5.20 If such a commissioning *generation unit* is not one of the two largest *contingency events*, the requirement for *thirty-minute operating reserve* shall be at least equal to the larger of one-half of the *second contingency loss* or the output of the commissioning *generation unit.*

4.5.21 The requirement for *thirty-minute operating reserve* shall be maintained in accordance with the applicable *reliability standards* referenced in *the market manuals*.

4.6 Reactive Support and Voltage Control

4.6.1 *Reactive support service and voltage control service* is the control and maintenance of prescribed voltages on the *IESO-controlled grid*. The devices that supply reactive power to the *integrated power system* include but are not limited to, capacitors, static VAR compensators, reactors, synchronous *generation facilities*, and synchronous condensers.

4.6.1A The *IESO* shall direct the operation of the *IESO-controlled grid* to meet all applicable *reliability standards* with respect to the *dispatch* of reactive power resources.

4.6.2 The *IESO* shall ensure that sufficient resources are available throughout the *IESO-controlled grid* to meet all applicable *reliability standards* for *reactive support service and voltage control service*. Voltage levels shall be maintained within acceptable levels within the *IESO-controlled grid*. As part of its assessment of system *adequacy* under the *market rules*, the *IESO* shall on a continual basis assess whether sufficient reactive resources are available to the *IESO*.

4.6.3 The *IESO* shall direct providers of *reactive support service and voltage control service* to take any actions necessary to maintain stable voltage levels in accordance with *reliability standards* and to prevent the collapse of voltages on the *IESO-controlled grid*.

4.6.4 [Intentionally left blank]

4.6.5 [Intentionally left blank]

4.6.6 [Intentionally left blank]

4.6.7 [Intentionally left blank]

4.6.8 [Intentionally left blank]

4.6.9 The *IESO* shall obtain reactive power resources to maintain *reactive support service* and *voltage control service* in accordance with all applicable *reliability standards*. *Reactive support service* and *voltage control service* shall be made available by *market participants* from, but not limited to, the following:

4.6.9.1 reactive resources produced from within the standard power factor range of a *generation facility* as described in Chapter 4*,* which shall be *dispatchable* by the *IESO*;

4.6.9.2 equipment owned by *market participants* (capacitors, SVCs, synchronous condensers and reactors) that is made available to the *IESO* pursuant to the *market rules* and any *operating agreement* between the *IESO* and a *market participant*; and

4.6.9.3 reactive resources produced outside the standard power factor range of a *generation facility* as required in Chapter 4 of the *market rules* (synchronous condensers or hydroelectric units in condense mode) as acquired by the *IESO* through *contracted ancillary services* contracts.

4.7 Black Start Service

4.7.1 [Intentionally left blank]

4.7.2 The *IESO* shall determine the required amounts and locations of *black start capability* across the *IESO-controlled grid*, as required to satisfy the requirements of the *Ontario power system restoration plan* and all applicable *reliability standards.* The *IESO* shall notify *market participants* of these requirements before entering into agreements for the provision of *certified black start facilities*.

4.7.3 *Ancillary service providers* providing *certified black start facilities* must also be *restoration participants*.

4.8 Reliability Must-Run Resources

4.8.1 The *IESO* may need to call on specific *registered facilities*, excluding *non-dispatchable load facilities*, to maintain the *reliability* of the *IESO-controlled grid* whenever sufficient resources for the provision of *physical services*, other than *contracted ancillary services*, are not otherwise offered in the *IESO-administered markets*. Such applicable *registered facilities* are referred to as *reliability must-run resources* and shall be procured either through *reliability must-run contracts* in accordance with this section 4.8 and sections 9.6 and 9.7 of Chapter 7 or by means of the process for directing the submission of *dispatch data* referred to in sections 3.3.10 to 3.3.17 of Chapter 7.

4.8.2 The *IESO* shall identify all *reliability must-run resources* in respect of which it wishes to conclude *reliability must-run contracts* and may enter into *reliability must-run contracts* with the *registered market participant* or prospective *registered market participant* for such *reliability must-run resources*. Where the *IESO* identifies such a *reliability must-run resource*, the *registered market participant* or prospective *registered market participant* for such *reliability must-run resource* shall, subject to section 9.6.4 of chapter 7, contract with the *IESO* to supply *physical services,* other than *contracted ancillary services,* to the *IESO-controlled grid* for *reliability* purposes in accordance with sections 9.6 and 9.7 of Chapter 7. Each such *reliability must-run contract* shall provide the *IESO* with the ability to call on the *reliability* *must-run resources* covered by the *reliability must-run contract* in accordance with section 9 of Chapter 7 and shall comply with Chapter 7.

4.8.3 [Intentionally left blank]

4.8.4 The provisions of this section 4.8 and of any *reliability must-run contracts* shall be consistent with the provisions of the *license* of the *IESO* that incorporate the terms of any directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the Ontario Energy Board Act, 1998 or that incorporate terms imposed by the *Ontario Energy Board* in furtherance of the exercise of its powers under subsection 70(5) of the Ontario Energy Board Act, 1998. In the event of any inconsistency between such terms and the provisions of this section 4.8 or of any *reliability must-run contracts*, such terms shall govern.

4.8A [Intentionally left blank – section deleted]

4.8A.1 [Intentionally left blank – section deleted]

4.8A.2 [Intentionally left blank – section deleted]

4.9 Auditing and Testing of Ancillary Services

4.9.1 The *IESO* shall test *facilities* that will or do provide *ancillary services* to the *IESO-controlled grid.* The *IESO* shall use such tests to determine whether to register each *facility* as a *registered facility* for the provision of *ancillary services* and to ensure that each applicable *registered facility* continues to meet the requirements for registration to provide the relevant *ancillary services.*

4.9.1.1 [Intentionally left blank]

4.9.1.2 [Intentionally left blank]

4.9.2 Tests of the *facilities* or *registered facilities* of *ancillary service providers* or of prospective *ancillary service providers* referred to in section 4.9.1 shall include, but not be limited to, testing in the manner set forth in this section 4.9.2, to determine whether the *ancillary service provider* can supply the *ancillary services* which it wishes to supply or has contracted or been registered to supply:

4.9.2.1 the *IESO* may test the synchronized *ten-minute operating reserve* capability of a *generation facility, dispatchable load* or an *electricity storage facility* by issuing unannounced *dispatch instructions* requiring the *generation facility, dispatchable load* or *electricity storage facility* to ramp up or reduce demand, in either case to its ten-minute capability;

4.9.2.2 the *IESO* may test the non-synchronized *ten-minute operating reserve* capability of a *generation facility, electricity storage facility* or *dispatchable load* by issuing unannounced *dispatch instructions* requiring the *generation facility*, *electricity storage facility* or *dispatchable load* to come on line and ramp up or to reduce *demand*, in either case to its ten-minute capability;

4.9.2.3 the IESO may test the *thirty-minute operating reserve* capability of a *generation facility, electricity storage facility* or *dispatchable load* by issuing unannounced dispatch instructions requiring the *generation facility*, *electricity storage facility* or *dispatchable load* to come on line and ramp up or to reduce *demand*, in either case to its thirty-minute capability;

4.9.2.4 a *certified black start facility* must perform tests on auxiliary and control equipment and alternate sources of power in accordance with and using the testing criteria and testing frequency requirements specified in the *Ontario power system restoration plan*;

4.9.2.4A a *certified black start facility* must pass the tests required for *certified black start facilities* in accordance with and using the testing criteria specified in the *Ontario power system restoration plan*;

4.9.2.4B the *IESO* may direct line energization tests of a *certified black start facility* to determine whether the *certified black start facility* can energize a transmission path specified by the *IESO*;

4.9.2.5 the *IESO* may test the *reactive support and voltage control* that has been contracted from a *registered facility* that is a *generation facility* or *electricity storage facility* by issuing unannounced *dispatch instructions* requiring the *generation facility* or *electricity storage facility* to provide such support within its contracted capability; and

4.9.2.6 the *IESO* shall at least annually test a *registered facility* providing *regulation* for compliance with the performance standards referred to in sections 1.1.3 and 1.1.4 of Appendix 5.1 in accordance with the testing procedures specified in the applicable *contracted ancillary services* contract.

4.9.3 The costs incurred by the *IESO* in conducting and evaluating any tests pursuant to section 4.9.1 or 4.9.2 shall be recovered by the *IESO* as part of the costs to the *IESO* of contracting for the applicable *ancillary service* in accordance with section 4.2 of Chapter 9.

4.9.4 Any costs incurred by the *ancillary service provider* in conducting any tests pursuant to section 4.9.1 or 4.9.2 shall be borne by the *ancillary service provider*.

4.10 Consequences of Failure to Pass a Test

4.10.1 If an *ancillary service provider's registered facility* fails a test performed pursuant to section 4.9.1 or 4.9.2 in respect of an *ancillary service*, the *IESO* shall not schedule such *ancillary services* from such *registered facility* until the *ancillary service provider* demonstrates that it can provide the relevant *ancillary service*.

4.10.2 Without prejudice to the application of section 4.10.1, an *ancillary service provider* whose *registered facility* fails a test performed pursuant to section 4.9.1 or 4.9.2:

4.10.2.1 in the case of an ancillary service provider providing a certified black start facility or regulation under a contracted ancillary service contract:

a. where there is sufficient information available to determine the date as of which the applicable *contracted ancillary service* was not provided, the *IESO* may require the *ancillary service provider* to refund the compensation it has received for such *contracted ancillary service* from such date to the date of the failed test; or

b. in all other cases, the *ancillary service provider* shall provide such refund of compensation, if any, as may be specified in its *contracted ancillary service* contract;

4.10.2.2 in the case of an *ancillary service provider* providing a *certified black start facility* or *regulation* under a *contracted ancillary service* contract, shall be subject to such penalties and sanctions as may be specified in its *contracted ancillary service* contract; and

4.10.2.3 in the case of any other *ancillary service provider*, shall be subject to financial penalties in accordance with section 6.6 of Chapter 3 and to such other sanctions as may be provided for in these *market rules*.

4.11 Emergency Conditions

4.11.1 Notwithstanding any other provision of the *market rules*, when the *IESO-controlled grid* is in an *emergency operating state*, the *IESO* may acquire *ancillary services* from any *market participant*, whether or not such *market participant* satisfies all of the standards and registration requirements applicable in respect of such *ancillary services*.

5. System Security

5.1 Objectives and General Obligations

5.1.1 The objective of this section is to detail the procedures necessary to enable the *IESO* to ensure the *security* of the *IESO-controlled grid* in accordance with all applicable *reliability standards.*

5.1.2 In order to maintain the *security* of the *IESO-controlled grid*, the *IESO* shall:

5.1.2.1 monitor the real-time operating status of the *IESO-controlled grid*;

5.1.2.2 establish and *publish security limits* for all *facilities* that are part of the *IESO-controlled grid*;

5.1.2.3 establish and *publish* criteria and margins to be used in the development of *security limits* and a process for reviewing and revising such criteria and margins;

5.1.2.4 establish available *transmission transfer capabilities* in accordance with all applicable *reliability standards* and manage the use of transmission in accordance with such *transmission transfer capabilities* and the *market rules*;

5.1.2.5 direct the operation of *facilities* that are part of the *IESO-controlled grid* within the appropriate *security limits* and in accordance with the applicable *operating agreements*;

5.1.2.6 direct any *market participant* to take or to refrain from taking any action necessary to maintain the *IESO-controlled grid* in a *normal operating state*;

5.1.2.7 act as the *control area operator* and as *security coordinator* for the province of Ontario and interact with other *control area operators*, *security coordinators* and *interconnected transmitters* as required to establish *security limits* and rules for interconnected operations including, but not limited to, entering into *interconnection agreements* with adjacent *control area operators*, *security coordinators* and *interconnected transmitters* that provide for interconnected operations, other than with respect to the physical *facility* and equipment requirements for *interconnections* which shall be the responsibility of *transmitters*. In the event of flows or exchanges of *physical services* across the *interconnections* or *interties* which are not directly attributable to the transactions of *market participants*, the *IESO* may provide for such exchanges through the sale or purchase of these *physical services* in the *IESO-administered markets*;

5.1.2.8 represent Ontario in the context of the work of *standards authorities* with respect to the *reliable* operation of the *IESO-controlled grid* and the *interconnected systems*, and the operation of the *IESO-administered markets*, other than with respect to the physical facility and equipment requirements for *reliability* of the *IESO-controlled grid* which shall be the responsibility of the relevant *transmitters*, *distributors* and *generators* as applicable;

5.1.2.9 investigate major operational incidents on the *IESO-controlled grid* and initiate plans to manage abnormal situations or significant deficiencies which, in the *IESO's* opinion, threaten the *reliability* of the *IESO-controlled grid*;

5.1.2.10 issue directions to market participants in order to manage high-risk operating states and emergency operating states; and

5.1.2.11 assess the future *reliability* of the *IESO-controlled grid*.

5.2 Security Limits

5.2.1 The *IESO* shall establish and *publish security limits* to prevent, contain and alleviate the effects of *contingency events*. Such *security limits* shall be as described in section 5.2.4 and shall be observed by the *IESO* in the minute-to-minute operation of the *IESO-controlled grid*.

5.2.2 The *IESO* shall calculate and *publish transmission transfer capabilities*.

5.2.3 *Market participants* shall immediately respond to directions from the *IESO* to alter their operations to stay within the *security limits* and *transmission transfer capabilities* established by the *IESO*.

5.2.4 Two types of *security limits* shall be established by the *IESO*:

5.2.4.1 *security limits* based on the dynamic response of the *IESO-controlled grid*, including transient stability limits, voltage stability limits, dynamic stability limits, and voltage decline limits; and

5.2.4.2 *security limits* based on the ratings of equipment, including the thermal ratings of lines and transmission equipment (e.g. the design characteristic of lines and equipment and weather conditions) and the short circuit capability of equipment.

5.2.5 Each *market participant* shall:

- establish thermal ratings for the equipment that it owns and that is part of the *IESO-controlled grid*, and
- provide such ratings (including continuous and limited time ratings) to the *IESO* in a form suitable for *IESO* monitoring

The *IESO* shall not deliberately operate or plan to operate equipment comprising the *IESO-controlled grid* in excess of the thermal rating for such equipment as communicated to the *IESO* by the relevant *market participants*.

5.2.6 The *IESO* shall respect all pre-and post-contingency *security* criteria that are used to establish *security limits*.

5.3 The Use of Tie-Lines and Associated Facilities

5.3.1 The *IESO-controlled grid* is interconnected with utilities in Canada and the United States via *tielines* such that *interconnected systems* can be used to help maintain the *security* of the *IESO-controlled grid*.

5.3.2 With respect to the use of *tielines*:

5.3.2.1 the *IESO* shall endeavour to conduct studies on a coordinated basis with adjacent *control areas* so that normal and emergency transfer limits on all *tielines* are established or reaffirmed at least annually;

5.3.2.2 the *IESO* shall endeavour to cooperate with other *control area operators* to determine and reaffirm total *transmission transfer capability* with other *control areas* at least annually;

5.3.2.3 the *IESO* shall operate the *IESO-controlled grid* so that there is no net transfer of reactive power, provided that reactive power may be exchanged or transferred from one system to another under contractual agreement with adjacent *control areas;*

5.3.2.4 the maximum net scheduled interchange across *tielines* shall not exceed the lower of the continuous rating of the *tielines* or the incremental transfer capability of the first *contingency event*;

5.3.2.5 for *interconnected systems* that are entirely controlled by phase-shifters, such as Manitoba and Minnesota, the *IESO* shall maintain MW flows at the scheduled transfer level;

5.3.2.6 unless there is prior agreement to that effect between *control areas*, the *IESO* shall not move phase shifters or make changes to fixed-tap positions; and

5.3.2.7 the *IESO* shall abide by all applicable *reliability standards* with respect to the management of *tielines*.

5.3.3 Each *market participant* shall comply with all relevant *reliability standards* relating to the *reliability* of *interconnections* and:

5.3.3.1 each *registered market participant* submitting an *energy offer* or an *energy bid* in respect of a *boundary entity* shall comply with the scheduling and notification procedures for the source or sink *control area*, as applicable, and any intervening *control areas* and with all other applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access;

5.3.3.2 each *registered market participant* submitting an offer to provide *operating reserve* in respect of a *boundary entity* shall comply with all applicable procedural and information requirements established by relevant *standards authorities* and other relevant entities for registering transactions and/or arranging transmission access; and

5.3.3.3 the notification of the activation of the *energy* associated with an *operating reserve offer* and the scheduling coordination shall be the responsibility of the *IESO*.

5.3.4 Where:

5.3.4.1 the quantity of a *physical service* delivered to or withdrawn from the *IESO-controlled grid* by a *registered market participant* is reduced relative to that *registered market participant's* most recent valid *bid* or *offer*; and

5.3.4.2 such reduction is initiated pursuant to *reliability standards* by an entity, other than the *IESO*, having authority under such *reliability standards*;

the *registered market participant* shall not be entitled to compensation for any financial loss suffered as a result of such action.

Where such reduction was initiated by the *IESO*, the *registered market participant* shall be entitled to compensation, which shall be calculated and paid in accordance with section 3.5 of Chapter 9.

5.4 Reliability Policy for Area Supply

5.4.1 In coordination with *transmitters*, the *IESO* may develop and apply specific *security* criteria in areas of the *IESO-controlled grid* where the consequences of *contingency events* are localized and do not have a significant adverse impact on the *reliability* of the *IESO-controlled grid* ("*local areas*").

5.4.2 The following criteria shall be used to assess the *security* of a *local area*, as determined at the delivery point demarcating the boundary between the *local area* and the remainder of the *IESO-controlled grid*, on the one hand, and individual and collective *connection points* of the *IESO-controlled grid*, on the other:

5.4.2.1 the extent to which severe *contingency events* are experienced; and

5.4.2.2 the *reliability* of transmission *facilities* which directly affect the exchange of electricity to the *local area*.

5.4.3 The *IESO* shall coordinate with *transmitters* to review the performance at *connection points* at least once annually in order that they can jointly assess the *reliability* of *local areas*.

5.5 Interconnection Assistance

5.5.1 The *IESO* shall use and support *interconnected systems* in accordance with agreements between the *IESO* and other *security coordinators, control area operators* or *interconnected transmitters* and to the extent necessary to maintain the *security* of the *IESO-controlled grid*.

5.5.1A Information provided to the *IESO* under an *interconnection agreement* by a *security coordinator, control area operator* or *interconnected transmitter* and identified by the person providing the information as confidential shall be *confidential information* and shall not be disclosed or made available without the prior written consent of the particular *security coordinator, control area operator* or *interconnected transmitter*.

5.5.2 In requesting assistance from *market participants* and from other *security coordinators*, the *IESO* shall take effective action in the *IESO control area* prior to, or concurrently with, similar action being taken by the *interconnected system* providing assistance.

5.5.3 All agreements entered into by the *IESO* and other *security coordinators* relating to *security* shall meet all applicable *reliability standards*.

5.6 Inadvertent Interchange

5.6.1 Inadvertent interchange is the difference between the scheduled interchange on a single *interconnection*, or the sum of scheduled interchanges with several *interconnected systems*, on the one hand, and the actual metered flow on the *interconnection* point(s), on the other.

5.6.2 Inadvertent interchange shall be addressed in any agreement relating to *security* between the *IESO* and other *security coordinators*. The means used to mitigate inadvertent interchange shall respect all applicable *reliability standards.*

5.7 The Management of Violations to Security Limits

5.7.1 When there is a violation of a *security limit* on the *IESO-controlled grid* while in a *normal operating state*, the sequence of control actions taken by the *IESO* shall be defined in its operating procedures and instructions.

5.7.2 The operating procedures and instructions of the *IESO* shall allow the use of market mechanisms to the maximum extent possible for purposes of responding to violations of *security limits*.

5.7.3 Where market mechanisms fail or are not sufficient to maintain the *security* of the *IESO-controlled grid*, the *IESO* may direct *market participants* to take actions to either prevent the loss of *non-dispatchable load* or to prepare for *contingency events*.

5.8 Operation Under an Emergency Operating State

5.8.1 Once an *emergency operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.8.1.1 [Intentionally left blank]

5.8.1.2 [Intentionally left blank]

5.8.1.3 [Intentionally left blank]

5.8.1.4 coordinating with other *security coordinators*;

5.8.1.5 issuing directions to *market participants* to reduce *demand* through voltage reductions and interruptions in accordance with section 10.3;

5.8.1.6 operate to those *security limits* appropriate for an *emergency operating state* to allow for increased power transfers; and

5.8.1.7 acquiring *emergency energy* in accordance with section 2.3.3A;

5.9 Operation Under a High-Risk Operating State

5.9.1 Once a *high-risk operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.9.1.1 [Intentionally left blank]

5.9.1.2 [Intentionally left blank]

5.9.1.3 [Intentionally left blank]

5.9.1.4 operating to *security limits* appropriate for a *high-risk operating state*;

5.9.1.5 coordinating with neighbouring *security coordinators*;

5.9.1.6 issuing directions to *market participants* to reduce *demand* through voltage reductions or interruptions in accordance with section 10.3; and

5.9.1.7 temporarily and selectively increase the level of *security* on the *IESO-controlled grid*.

5.9A Operation Under a Conservative Operating State

5.9A Once a *conservative operating state* has been declared by the *IESO*, the *IESO* may take such action as it determines appropriate including, but not limited to:

5.9A.1 coordinating with neighbouring *control area operators*; and

5.9A.2 requesting *market participants* to monitor the *IESO-controlled grid* on the *IESO's* behalf.

5.9A.3 direct *market participants* to suspend all non-urgent maintenance and switching activities on *facility* elements for which outages must be reported or involve elements that could impact the operations of the *IESO-controlled grid.*

5.10 Restoration of System Security Following a Contingency Event

5.10.1 *Market participants* shall be prepared for, shall be able to manage and shall take such actions as may be necessary to restore *security* of the *IESO-controlled grid* following a *contingency event,* as directed by the *IESO*.

5.10.2 The *IESO* shall establish:

5.10.2.1 procedures that identify the steps necessary to restore the operation of the *IESO-controlled grid* to an *emergency operating state* respecting corresponding *security limits*, within 30 minutes;

5.10.2.2 procedures to attempt to restore supply first to individual loads identified by *market participants* as critical in nature, once the minimum acceptable level of *security* on the *IESO-controlled grid* has been restored; and

5.10.2.3 in consultation with relevant *market participants*, procedures to restore the operation of the *IESO-controlled grid* and of *facilities connected* to a *transmission system* that forms part of the *IESO-controlled grid* following automatic *outages*.

6. Outage Coordination

6.1 Introduction

6.1.1 The objectives of this section 6 are to enable the *IESO* to review and assess the impact of *outage* schedules on the fulfillment by the *IESO* of its *reliability*-related responsibilities under the Electricity Act, 1998, its *license*, and the *market rules*, to require *market participants* to obtain the approval of the *IESO* in respect of *planned outage* schedules and to permit the *IESO* to reject, revoke *advance approval* of and recall *outages* that may have an impact on the *reliability* of the *IESO-controlled grid* or a material impact on the operation of the *IESO-administered markets*.

6.1.2 The *IESO* shall maintain a database of all submissions to the *outage* planning and scheduling process.

6.1.3 The *IESO* shall develop, and include in the applicable *market manual*, a full list of the equipment and *facilities* the *outage* of which must be reported to and scheduled with the *IESO* in accordance with this section 6. The *IESO* shall use as the basis for including *facilities* and equipment on this list that any change or anticipated change to the *facilities* or equipment could have a material effect on the value of an operating *security limit*, the *reliable* operation of *IESO-controlled grid* or operation of the *IESO-administered markets*, including, but not be limited to, the following:

6.1.3.1 *facilities* forming part of the *IESO-controlled grid*;

6.1.3.2 *generation facilities, electricity storage facilities* and auxiliary equipment connected to the *IESO-controlled grid* or in respect of which a *generator* or *electricity storage participant* is participating in the *real-time markets*;

6.1.3.3 protection systems; and

6.1.3.4 communication equipment, including related hardware and software systems.

6.1.4 [Intentionally left blank]

6.1.5 Nothing in this section 6 shall relieve a *market participant* from its responsibility for and arising from the performance of all work relating to any *outage* or test, whether in respect of energized or de-energized *facilities* or equipment, including, but not limited to, its responsibility in respect of worker safety.

6.1.6 No *market participant* shall remove equipment or *facilities* from service except in accordance with this section 6 unless such removal from service is necessary to ensure the safety of any person, prevent the damage of equipment, or prevent the violation of any *applicable law*. If any equipment or *facilities* are removed from service for these reasons, the *market participant* shall promptly notify the *IESO*.

6.1.7 The *IESO* shall coordinate *outages* with *market participants* except that, with respect to *outages* to any portion of the *transmission system* during a *normal operating state*, the applicable *transmitter* shall, pursuant to the Transmission System Code, coordinate the *outage* with affected *market participants* directly connected to that portion of the *transmission system* unless the *IESO* determines it necessary to coordinate such activities in order to maintain *reliability*.

6.2 Outage Planning

6.2.1 Each *market participant* shall inform the *IESO* of its long-term plans for *outages* in accordance with the provisions of this section 6.2.

6.2.2 Each *market participant* shall establish its *outage* planning process in such manner as will enable it to comply with its reporting and scheduling obligations under this section 6. Without limiting the generality of the foregoing, *market participants* shall be required to plan *outages* in advance of the anticipated date of the *planned outage* in accordance with the submission requirements of this section 6.

6.2.2A – 6.2.2J [Intentionally left blank – sections deleted]

Requests for Advance Approval

6.2.2K A *market participant* may request *quarterly advance approval*, *weekly advance approval*, *three-day advance approval* or *one-day advance approval* for a *planned outage* of equipment or *facility* in accordance with this section 6 and the applicable *market manual*.

IESO Obligation to Consider Planned Outages for Advance Approval

6.2.2L The *IESO* shall consider all *planned outages* submitted under section 6.2.2K for *advance approval* in accordance with this section 6 and the processes specified in the applicable *market manual*.

IESO Obligation to Include Planned Outages in Daily and Quarterly Assessments

6.2.3 The *IESO* shall include in the daily assessments referred to in section 7.3.1.4 all *outages* which have *advance approval* and are planned to occur in the immediately following 33 calendar days as reported or scheduled by *market participants*. The *IESO* shall include in the quarterly assessments referred to in section 7.3.1.2 all *outages* planned or scheduled to occur in the immediately following 18 months as reported or scheduled by *market participants*.

Transmitter Generator and Electricity Storage Participant Obligation to Provide Planned Outage Information for 18-Month Assessments

6.2.4 To support the 18-month assessments referred to in section 7.3.1.2, and subject to section 6.2.5, for those *facilities* and equipment on the list developed in accordance with section 6.1.3, *transmitters generators* and *electricity storage participants* shall, as frequently as may be necessary to maintain the accuracy of the information provided, report to the *IESO* the *outage* plans for transmission *facilities* forming part of the *IESO-controlled grid* and for *generation facilities*, or *electricity storage facilities* respectively, as follows:

6.2.4.1 for *outages* starting 3 months or more in the future, those with a scheduled duration of 5 days or more; and

6.2.4.2 for *outages* starting less than 3 months in the future, those with a scheduled duration of 4 hours or more.

Exclusions of Outages for Generation Facilities or Electricity Storage Facilities

6.2.5 Notwithstanding any other provision of section 6, *outages* to the following *generation facilities* or *electricity storage facilities* do not need to be reported to support the 18-month assessments referred to in section 7.3.1.2:

6.2.5.1 in the case of all *generators, generation facilities* having a *capacity* of less than 20 MW;

6.2.5.2 in the case of a *generator* whose total available capacity inside the *IESO control area* exceeds 4000 MW, *generation facilities* that represent less than 0.5 percent of the total *capacity* of such *generator,* unless the *generation facilities* have been identified by the *IESO* as affecting the *reliability* of the *IESO-controlled grid.* The *IESO* shall notify the relevant *generators* of any *generation facilities* so identified; or

6.2.5.3 in the case of all *electricity storage participants*, *electricity storage facilities* with an *electricity storage facility size* of less than 20 MW.

6.3 Outage Scheduling with the IESO

Planned Outages

6.3.1 Subject to section 6.1.3 and 6.4, each *market participant* shall submit its current schedule of all *planned outages*, regardless of duration, to the *IESO*.

6.3.2 A *planned outage* submitted by a *market participant* pursuant to section 6.3.1 shall represent the intent of the *market participant* to take the relevant equipment out of service at the scheduled time and to return the relevant equipment to service at the scheduled time.

6.3.3 [Intentionally left blank – section deleted]

Forced Outages

6.3.4 Each *market participant* shall to the maximum extent possible notify the *IESO* in advance of a *forced outage* and provide a brief description of the nature and causes of the *forced outage.* When such advance notice cannot be given, the *market participant* shall promptly notify the *IESO* of the occurrence of a *forced outage* and provide a brief description of the nature and causes of the *forced outage*.

6.3.5 Whenever, in the opinion of the *IESO*, a *forced outage* has had a significant impact on the *reliability* of the *IESO-controlled grid*, or gives rise to potential *reliability* concerns, the *IESO* may require the *market participant* experiencing the *forced outage* to provide a detailed description of the nature and causes of the *forced outage* to the *IESO*. Such description of the *forced outage* shall be provided as soon as practicable and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO* in any given case, following the start of the *forced outage.* The *IESO* may also require the *market participant* experiencing the *forced outage* to provide a detailed description of the steps that the *market participant* intends to take to prevent any recurrence of the circumstances that led to the *forced outage*. Such description shall also be provided as soon as practical and in any event within 48 hours, or within such longer period of time as may be agreed to by the *IESO*, following the start of the *forced outage*.

Replacement Energy to Support Planned Outages

6.3.6 A *generator* or *electricity storage participant* may, no later than the time specified in section 6.4.1, in requesting a *planned outage* in accordance with section 6.3.1, notify the *IESO* that the *generator* or *electricity storage participant* shall arrange replacement *energy offers* in the form of an import to support the *outage* request. A *generator* or *electricity storage participant* may, when requesting an extension to an *outage* under section 6.4.7 or resubmitting an *outage* under section 6.4.10, notify the *IESO* that the *generator* or *electricity storage participant* shall arrange replacement *energy offers* in the form of an import to support the *outage* extension or resubmission. For certainty, this section shall not under any circumstances impose any explicit or implicit obligation on either a *generator* or *electricity storage participant* to so notify the *IESO*, or if so notified, the *IESO* to approve or accept any such arrangement. Upon notice to the *IESO*, a *generator* or *electricity storage participant* may withdraw the arrangement for replacement *energy offers* at any time up to final approval of the *outage* or up to the final approval of the extension to or resubmitting of the *outage.*

6.3.7 The *generator* or *electricity storage participant* shall provide the following information to the *IESO* when in accordance with section 6.3.6 it either submits a *planned outage* request or requests the extension to or resubmission of an *outage*:

6.3.7.1 Subject to the approval of the *IESO*, the *intertie* zone or zones through which the replacement *energy* is intended to be scheduled; and,

6.3.7.2 The *registered market participant* associated with a *registered facility* that is a *boundary entity* that shall submit the *offers* and, pursuant to section 7.5.8A of Chapter 7, schedule the replacement *energy* if *dispatched* by the *IESO.*

6.3.8 The *IESO* may limit the number and aggregate size of *outages* supported by replacement *energy* and, where the number and aggregate size of *outages* is limited the *IESO* shall determine the priority of the *outages*, in accordance with sections 6.4.13 through 6.4.20.

6.3.9 The *IESO* may specify and inform the *generator* or *electricity storage participant* of the minimum amount of replacement *energy* in megawatts and the duration of *offers* necessary to support the *planned outage* request or the request for the extension to or rescheduling of the *outage*.

6.3.10 If the *registered market participant* associated with a *registered facility* that is a *boundary entity* referred to in section 6.3.7.2 fails to submit *offers* for the replacement *energy,* that have been arranged by the *generator* or *electricity storage participant*, the *generator* or *electricity storage participant* shall be subject to the financial penalties calculated in accordance with the provisions of section 6.6.8 of Chapter 3.

6.4 Submission of Outage Schedules and IESO Approval of Outage Schedules

6.4.1 In order to obtain *IESO* approval of a *planned outage*, a *market participant* shall submit a *planned outage* with the *IESO* under the timelines specified in sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E. At the time of the submission, the *market participant* shall:

6.4.1.1 provide information about the recall of the *planned outage*, including the time required to return the *facilities* or equipment to service and other applicable conditions of recall; and

6.4.1.2 [Intentionally left blank – section deleted]

6.4.1.3 confirm, if applicable and as specified in the applicable *market manual*, the request for *weekly advance approval* for the *planned outage*.

6.4.1A [Intentionally left blank – section deleted]

6.4.1B If requesting *quarterly advance approval* of a *planned outage*, the *market participant* shall submit the *planned outage* with the *IESO* no later than 00:00 EST on the first day of the month that is three months prior to the start of a six month period, beginning with the next calendar quarter, in which the *planned outage* is scheduled to start.

6.4.1C If requesting *weekly advance approval* of a *planned outage*, the *market participant* shall submit the *planned outage* with the *IESO* no later than 16:00 EST on the third Friday prior to the start of the week, starting Monday, in which the *planned outage* is scheduled to start, and confirm the request for *weekly advance approval* in accordance with section 6.4.1.3.

6.4.1D If requesting a *three-day advance approval* of a *planned outage*, the *market participant* shall submit the *planned outage* with the *IESO* no later than 16:00 EST on the fifth *business day* prior to the start date of a *planned outage*.

6.4.1E If requesting *one-day advance approval of a planned outage* the *market participant* shall submit the *planned outage* with the *IESO* no later than 16:00 EST on the second *business day* prior to the start date of the *planned outage*.

6.4.2 Where the scheduling of *planned outages* submitted by different *market participants* conflicts such that the *planned outages* cannot both or all be approved by the *IESO*, the *IESO* shall inform the affected *market participants* and request that they resolve the conflict. Should the conflict remain unresolved, the *IESO* shall determine which of the *planned outages* can be approved on the basis of the priority accorded to each *planned outage* pursuant to sections 6.4.13 to 6.4.20.

6.4.3 No *planned outage* shall occur or be permitted by a *market participant* to occur unless:

6.4.3.1 the *planned outage* has been submitted with the *IESO* in accordance with sections 6.4.1 or 6.4.6;

6.4.3.2 the *planned outage* has been approved by the *IESO* in accordance with this section 6.4;

6.4.3.3 immediately prior to the scheduled commencement of the *planned outage* or at a pre-arranged time specified by the *IESO* when providing the *advance approval* referred to in sections 6.4.4.4B, 6.4.4.4C, 6.4.4.5 and 6.4.4.5A, the *market participant* has requested from the *IESO* and has received the *IESO*'s final approval to the *planned outage*; and

6.4.3.4 the removal from service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4.4.6.

6.4.4 The *IESO* shall:

6.4.4.1 provide *advance approval* for a *planned outage* submitted to it pursuant to section 6.4.1 and shall provide its final approval to the *planned outage* pursuant to section 6.4.3.3 unless it determines, based primarily on the quarterly assessments referred to in section 7.3.1.2 and on the daily assessments referred to in section 7.3.1.4, that the *planned outage,* including but not limited to a *planned outage* identified by an *embedded generator,* will or is reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid* or as otherwise described in section 6.4.4A*;*

6.4.4.2 assess each *planned outage* submitted under section 6.4.1;

6.4.4.3 following receipt of an *outage* submission pursuant to section 6.2.1, 6.3.1, or 6.4.1, advise the relevant *market participant* of the existence of any conflict with a *planned outage* planned by another *market participant*;

6.4.4.4 if the *market participant* submitted the *planned outage* with the *IESO* under section 6.4.1, advise the relevant *market participant* of the expected outcome of the approval process;

6.4.4.4A [Intentionally left blank – section deleted]

6.4.4.4B if the *market participant* submitted its *planned outage* for *quarterly advance approval* under section 6.4.1B, advise the *market participant* whether or not *quarterly advance approval* of the *planned outage* has been granted no later than the end of the month that is one month prior to the start of the six month period, starting with the next calendar quarter, in which the *planned outage* is scheduled to start. Where the *IESO* does not grant *quarterly advance approval*, the *IESO* shall subsequently consider the *planned outage* for either *quarterly advance approval* in accordance with this section 6.4.4.4B, *weekly advance approval* in accordance with section 6.4.4.4C, or *three-day advance approval* in accordance with section 6.4.4.5, and as specified in the applicable *market manual*;

6.4.4.4C if the *market participant* submitted its *planned outage* for *weekly advance approval* under section 6.4.1C or if the *IESO* considered the *planned outage* for *weekly advance approval* in accordance with section 6.4.4.4B, and if the *market participant* confirmed the request for *weekly advance approval* in accordance with section 6.4.1.3, advise the *market participant* of the *weekly advance approval* or rejection of the *planned outage* no later than 16:00 EST on the second Friday prior to the week, starting Monday, in which the *planned outage* is scheduled to start.

6.4.4.5 if the *market participant* submitted its *planned outage* for *three-day advance approval* under section 6.4.1D, or if the *IESO* considered the *planned outage* for *three-day advance approval* in accordance with section 6.4.4.4B, advise the *market participant* of the *three-day advance approval* or rejection of the *planned outage* no later than 16:00 EST on the third *business day* prior to the day on which the *planned outage* is scheduled to commence;

6.4.4.5A if the *market participant* submitted its *planned outage* and request for *one-day advance approval* under section 6.4.1.E, advise the *market participant* of the *one-day advance approval* or rejection of the *planned outage* no later than 14:00 EST on the *business day* prior to the day on which the *planned outage* is scheduled to commence; and

6.4.4.6 when providing the final approval referred to in section 6.4.4.1, advise the *market participant* if the submitted *planned outage* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*. If it is known in advance, the *IESO* will advise the *market participant* of this requirement when providing the *advance approval* referred to in sections 6.4.4.4B, 6.4.4.4C, 6.4.4.5 or 6.4.4.5A or as soon as possible thereafter.

6.4.4A The *IESO* may refuse to provide *advance approval* to a *transmitter's planned outage* if:

6.4.4A.1 the *transmitter's planned outage* is to a *connection facility* that would prevent the delivery of electricity to the *IESO-controlled grid* from a *generation unit* or *electricity storage unit* that has committed capacity to an external *control area* in accordance with section 20.2 of Chapter 7;

6.4.4A.2 the *IESO* is advised by the *market participant* that has committed its capacity to an external *control area* in accordance with section 20.2 of Chapter 7, that the external *control area operator* has determined that a *transmitter's planned outage* would result in an unacceptable risk of an adequacy shortfall to the *external control area,* as may be specified in the applicable *capacity export agreement*; and

6.4.4A.3 the *market participant* that has committed its capacity to an external *control area* in accordance with section 20.2 of Chapter 7 has demonstrated to the *IESO* that it has made best efforts to reschedule the *planned outage* with the *transmitter*, as prescribed in the applicable *market manual*.

6.4.5 Where the *IESO* does not provide *advance approval* of a *planned outage* or does not give its final approval to a *planned outage* pursuant to section 6.4.4 or 6.4.4A, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the *reliable* operation of the *IESO-controlled grid.* Upon the resubmission of the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant.*

Requests for Late Submissions of Planned Outages

6.4.6 A *market participant* may make a request to the *IESO* for approval of a *planned outage* after the deadlines in sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E have expired, where the request represents an unexpected opportunity to accomplish work that would otherwise have been unable to proceed. The *IESO* may consider such late submissions where the opportunity presents a low risk to the *reliability* of the *IESO-controlled grid* and a low risk to the *IESO*.

Extensions

6.4.7 Each *market participant* shall notify the *IESO* if a *planned outage* which has been approved by the *IESO* will have a duration which exceeds the duration originally approved by the *IESO*, which notice shall include a request that the *IESO* approve the extension. Unless the extension is due to a *forced outage* condition, such notice shall be provided to the *IESO* in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E and will be treated as a new *outage* request.

6.4.8 If the *IESO* determines that an extension to the duration of a *planned outage* will or is reasonably likely to adversely affect the *reliability* of the *IESO-controlled grid* or will or is reasonably likely to require the re-scheduling of a *planned outage* submitted to the *IESO* pursuant to section 6.4.1 or the revoking of *advance approval*, or recall of a *planned outage* approved pursuant to section 6.4.4, the *IESO* shall reject such extension and the *market participant* shall use its reasonable best efforts to ensure that the duration of the *planned outage* does not exceed the duration originally approved by the *IESO* or such longer period as the *IESO* may advise in rejecting the extension requested.

Revoke Advance Approvals

6.4.9 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, or as provided in section 6.4.9.3, revoke an *advance approval* of a *planned outage*. Without limiting the generality of the foregoing, the *IESO* may revoke an *advance approval* if:

6.4.9.1 the *IESO* determines that a *conservative operating state,* an *emergency operating state* or a *high-risk operating state* is occurring or is reasonably likely to occur at the time at which the *planned outage* would otherwise take place;

6.4.9.2 necessary to avoid recalling a *planned outage* pursuant to section 6.4.11; or

6.4.9.3 the *transmitter's planned outage* is to a *connection facility* that would prevent the delivery to the *IESO-controlled grid* of electricity from a *generation unit* or *electricity storage unit* that has committed capacity to an external *control area* in accordance with section 20.2 of Chapter 7; and

6.4.9.3.1 the *IESO* is advised by the *market participant* that has committed its capacity to an external *control area* in accordance with section 20.2 of Chapter 7, that the external *control area operator* has determined that a *transmitter's planned outage* would result in an unacceptable risk of an adequacy shortfall to the *external control area,* as may be specified in the applicable *capacity export agreement*; and

6.4.9.3.2 the *market participant* that has committed its capacity to an external *control area* in accordance with section 20.2 of Chapter 7 has demonstrated to the *IESO* that it has made best efforts to reschedule the *planned outage* with the *transmitter*, as prescribed in the applicable *market manual*.

A *planned outage* that receives *advance approval* under section 6.4.4 but does not receive final approval pursuant to section 6.4.3.3 shall be considered to have had its *advance approval* revoked.

6.4.10 Where the *IESO* revokes *advance approval* of a *planned outage* pursuant to section 6.4.9, the *market participant* may elect either to resubmit or to cancel the *outage*. When the *market participant* elects to resubmit the *outage*, the *IESO* shall work with the relevant *market participant* to re-schedule the *planned outage* to a date and time at which the *planned outage* will not or is not reasonably likely to have an adverse impact on the reliable operation of the *IESO-controlled grid* and not pose an unacceptable risk to the adequacy of an external *control area* to which capacity has been committed. In re-scheduling the *planned outage*, the *IESO* shall where reasonably practicable take into account the date and time preferences of the *market participant*. A *planned outage* that is re-scheduled under this section must be resubmitted in accordance with the submission requirements in sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E. To maintain the priority date of the approved *planned outage* prior to the revocation of the *advance approval*; the *planned outage* must be resubmitted in accordance with section 6.4.16.

Recalls

6.4.11 The *IESO* may, where necessary to maintain the *reliability* of the *IESO-controlled grid*, recall a *planned outage* that has already commenced, having due regard to the time needed to return the *facilities* or equipment to service as identified by the relevant *market participant* pursuant to section 6.4.1.1 and shall so advise the relevant *market participant*. Such *market participant* shall arrange for the accelerated return to service of the *facilities* or equipment in accordance with the schedule identified by the *market participant* pursuant to section 6.4.1.1. The *IESO* shall not recall a *planned outage* unless further control action is required and it has revoked *advance approval* or rejected requests for approval of all other *planned outages* the revocation or rejection of which could eliminate the need to recall the *planned outage* that has already commenced.

Embedded Generators

6.4.12 Each *distributor* shall, in reporting to the *IESO* pursuant to sections 6.2 and 6.3, identify to the *IESO* any *outages* that potentially constrain an *embedded generator* or an *embedded electricity storage facility* that is connected to its *distribution system.*

Determining Outage Priority

6.4.13 The *IESO* shall assign a priority date to each *outage* submission received by the *IESO*. Where the *IESO* is required or permitted by this section 6 to approve, reject, revoke *advance approval* of or recall one or more *planned outages*, such *planned outages* shall:

6.4.13.1 be given advance or final approval in order of priority determined on the basis of sections 6.4.14A to 6.4.20; and

6.4.13.2 be rejected, be resubmitted, have *advance approval* revoked or be recalled in reverse order of priority determined on the basis of sections 6.4.14A to 6.4.20.

6.4.13A [Intentionally left blank – section deleted]

6.4.14 [Intentionally left blank – section deleted]

6.4.14A Where an *outage* is granted *advance approval* in accordance with sections 6.4.4.4B, 6.4.4.4C, 6.4.4.5 and 6.4.4.5A:

6.4.14A.1 *outages* granted *quarterly advance approval* take priority over *outages* granted *weekly advance approval*, *three-day advance approval* or *one-day advance approval*; and

6.4.14A.2 *outages* granted *weekly advance approval* take priority over *outages* granted *three-day advance approval* or *one-day advance approval*; and

6.4.14A.3 *outages* granted *three-day advance approval* take priority over *outages* granted *one-day advance approval*; and

6.4.14A.4 within *quarterly advance approval*, *weekly advance approval*, *three-day advance approval* and *one-day advance approval*, an *outage* with an earlier priority date takes priority over other *outages* granted the same level of *advance approval*.

6.4.15 Where a *market participant* gives notice of a change in the commencement, duration or nature of a *planned outage* relative to the most recent *outage* submission, the *IESO* shall revise the priority date with the time at which such notice was received by the *IESO.* The revised priority date shall be used by the *IESO* in determining the priority to be given to the *planned outage*. Where such notice reflects only a shortening in the duration of a *planned outage* relative to the most recent *outage* submission for that *planned outage*, the priority date associated with such previous *outage* submission shall be retained in determining the priority to be given to the *planned outage*.

6.4.15A [Intentionally left blank – section deleted]

6.4.16 Where:

6.4.16.1 the *IESO* revokes *advance approval* of a *planned outage* prior to the commencement thereof; and

6.4.16.2 the *market participant* subsequently re-submits the *planned outage* with the *IESO*, in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E, within five *business days* of the revocation;

6.4.16.3 [Intentionally left blank – section deleted]

the priority date of the approved *planned outage* prior to the revocation of *advance approval* shall be deemed to be the priority date of the re-submitted *planned outage* for purpose of determining the priority to be given to the *planned outage*.

6.4.17 Where:

6.4.17.1 the IESO rejects *advance approval* of a *planned outage* in accordance with section 6.4.4.4C, 6.4.4.5 or 6.4.4.5A;

6.4.17.2 the *market participant* resubmits the *planned outage* to the *IESO,* in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E, within five *business days* of the rejection; and

6.4.17.3 this was the first time the *planned outage* had been rejected, the priority date of the *planned outage* prior to the rejection will be deemed to be the priority date of the re-submitted *planned outage* for purposes of determining the priority to be given to the *planned outage*.

6.4.18 [Intentionally left blank – section deleted]

6.4.19 Where:

6.4.19.1 the *IESO* recalls a *planned outage* that has already commenced; and

6.4.19.2 the *market participant* resubmits the *planned outage* to the *IESO*, in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E within five *business days* of the recall,

the priority date of the *planned outage* prior to the recall will be deemed to be the priority date of the re-submitted *planned outage* for purposes of determining the priority to be given to the *planned outage*.

6.4.20 Where:

6.4.20.1 the *IESO* does not grant *quarterly advance approval* of a *planned outage* that was scheduled to start in the first three months of a six month period, starting with the next calendar quarter; and

6.4.20.2 the *market participant* re-submits the *planned outage* for *quarterly advance approval* no later than the start of the six month period, starting with the next calendar quarter, in which the *planned outage* that was not granted *quarterly advance approval* was scheduled to start; and

6.4.20.3 the scheduled start date of the re-submitted *outage* which was not granted *quarterly advance approval* is revised to a date which is after the first three months of the six month period, starting with the next calendar quarter;

the priority date of the *planned outage* which was not granted *quarterly advance approval* will be deemed to be the priority date of the re-submitted *planned outage* for purposes of determining the priority to be given to the *planned outage*.

6.4A Return of Equipment or Facilities to Service

6.4A.1 No *market participant* shall return to service any equipment or *facilities* that are undergoing a *planned outage* unless:

6.4A.1.1 immediately prior to its return to service, or at a pre-arranged time specified by the *IESO*, the *market participant* has requested and has received the *IESO's* approval to return the equipment or *facilities* to service; and

6.4A.1.2 the return to service of the relevant equipment or *facilities* is undertaken under the direction of the *IESO* where the *IESO* has made the determination referred to in section 6.4A.2.3.

6.4A.2 The *IESO* shall:

6.4A.2.1 approve the return to service of equipment or *facilities* that are undergoing a *planned outage* unless it determines that such return to service will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*;

6.4A.2.2 promptly notify the *market participant* if a determination is made that a return to service of equipment or *facilities* will or is reasonably likely to have an adverse impact on the *reliability* of the *IESO-controlled grid*; and

6.4A.2.3 when providing the approval referred to in section 6.4A.2.1, advise the *market participant* if the return to service of equipment or *facilities* is to be undertaken under the direction of the *IESO* where the *IESO* has made a determination that this is necessary to maintain the *reliability* of the *IESO-controlled grid*.

6.4A.3 Where the *IESO* does not approve the return to service of equipment or *facilities* pursuant to section 6.4A.2.1, the *IESO* shall, subject to final confirmation by the *IESO* pursuant to 6.4A.1, advise the *market participant* when the equipment or *facilities* may be returned to service.

6.4B Notification of Commencement and Completion of Planned Outages

6.4B.1 Each *market participant* shall notify the *IESO*:

6.4B.1.1 subject to section 6.4.3.3, of the commencement of a *planned outage* at the time the relevant equipment or *facilities* are removed from service; and

6.4B.1.2 subject to section 6.4A.1.1, of the completion of a *planned outage* at the time the relevant equipment or *facilities* are fully returned to service.

6.5 Information

6.5.1 Each *transmitter,* each *generator* and each *electricity storage participant* shall provide to the *IESO* such *outage* information as may be requested by the *IESO* to enable the *IESO* to review and schedule *outages*.

6.5.2 Subject to the confidentiality provisions of Chapter 3, the *IESO* shall *publish* the *planned outage* information provided to it pursuant to section 6.5.1.

6.5.3 Notwithstanding any other provision of these *market rules*, *planned outage* information that is provided to the *IESO* by *market participants* pursuant to this Chapter may be exchanged between the *IESO* and other *security coordinators, control area operators*, and *interconnected transmitters* who are signatories to the *NERC confidentiality agreement* or who are otherwise legally bound to withhold the information from any person competing with the *market participant* that provided the information.

6.5.4 [Intentionally left blank – section deleted]

6.5.5 The *IESO* shall *publish generator outage* information aggregated by fuel type based on information provided to it by *market participants* and may also *publish* the *outage* information for *electricity storage participants*.

6.6 Tests

6.6.1 A *market participant* who wishes to engage in a test that could affect the *reliability* of the *IESO-controlled grid* or the operation of the *IESO-administered markets* shall provide the information referred to in section 6.6.2 to the *IESO*.

6.6.2 As a minimum, the information referred to in section 6.6.1 shall identify:

6.6.2.1 the equipment involved;

6.6.2.2 the relevant details of contracts or agreements as they relate to the test activities;

6.6.2.3 preferred and alternative dates and times for the conduct of the test activities;

6.6.2.4 unusual system configurations or setup;

6.6.2.5 the expected impact of the test activities on power flows, voltage and frequency, and of any other dynamic that could interfere with the *reliability* of the *IESO-controlled grid*;

6.6.2.6 details of special readings or observations, as available; and

6.6.2.7 the names of and methods of communication with personnel who will be involved in the test activities and who may be contacted with respect thereto.

6.6.3 Tests covered by the requirements of this section 6.6 shall include, but are not limited to:

6.6.3.1 the deliberate application of short circuits;

6.6.3.2 stability tests of *generation facilities, electricity storage facilities* and transmission *facilities*;

6.6.3.3 planned actions which could cause abnormal voltage, frequency or overload; and

6.6.3.4 planned abnormal station or system configurations with inherent risk.

6.6.4 The *IESO* shall permit a test referred to in this section 6.6 to be performed if the *IESO* determines that the performance of the test will not have an adverse effect on the *reliability* of the *IESO-controlled grid* or on the operation of the *IESO-administered markets.*

6.6.5 In permitting a test to be performed, the *IESO* shall endeavour to permit the test to be performed at the time and on the date preferred as identified by the *market participant* pursuant to section 6.6.2.3.

6.6.6 This section 6.6 also applies to tests conducted pursuant to section 5 of Chapter 4.

6.6.7 During performance testing, a *market participant* shall keep the *IESO* informed of the expected operating capability of the *market participant's generation facility* or *electricity storage facility* using the outage management process as specified in the applicable *market manual*.

6.7 Compensation

Revoke Advance Approvals or Recalls

6.7.1 *Transmitters* whose *outages* are rejected or have *advance approvals* revoked or have *outages* recalled by the *IESO* shall not be entitled to compensation for any costs, losses or damage associated with such rejection, revocation or recall.

6.7.2 *Generators*, *electricity storage participants, distributors* or *wholesale consumers* whose *outages* have *advance approval* revoked or have *outages* recalled by the *IESO* shall, subject to the exceptions defined in sections 6.7.3A and 6.7.3B, be entitled to compensation for out-of-pocket expenses associated with such revocation or recall only if:

6.7.2.1 the *outage* was originally provided *advance approval* by the *IESO* pursuant to 6.4.4 and was submitted in accordance with sections 6.4.1B, 6.4.1C, 6.4.1D and 6.4.1E;

6.7.2.2 the *outage* was recalled or had *advance approval* revoked by reason of a material error in the *IESO's* demand forecast, a failure of *generation facilities* within the *IESO control area,* a failure of *facilities* forming part of the *IESO-controlled grid* or a failure of *interconnection facilities*; and

6.7.2.3 [Intentionally left blank – section deleted]

6.7.2.4 the out-of-pocket expenses exceed $1000.00.

6.7.3 [Intentionally left blank – section deleted]

6.7.3A A *market participant* shall not be entitled to compensation under section 6.7.2 with respect to a *planned outage* of its *generation facility* or *electricity storage facility* that received a *quarterly advance approval* or *weekly advance approval* and that *advance approval* was subsequently revoked by the *IESO* if:

6.7.3A.1 the *IESO* revoked the *advance approval* as a result of a *forced outage* of another *generation facility* or *electricity storage facility* with the same *registered market participant* as the *generation facility* or *electricity storage facility* that was the subject of the *planned outage* and the *forced outage* occurred before 16:00 E.S.T. on the third *business day* prior to the scheduled start of the *planned outage*; or

6.7.3A.2 the *advance approval* was revoked as a result of a delayed return to service from a *planned outage* or *forced outage* of another *generation facility* or *electricity storage facility* with the same *registered market participant* as, respectively, the *generation facility* or *electricity storage facility* that was the subject of the *planned outage*.

6.7.3B A *market participant* shall not be entitled to compensation under section 6.7.2 with respect to a *planned outage* that is granted *quarterly advance approval* and scheduled to start in the last three months of a six month period, starting with the current calendar quarter, and where the *quarterly advance approval* is subsequently revoked no later than one month prior to the start of the next calendar quarter.

6.7.4 The out-of-pocket expenses claimed by *generators*, *electricity storage participants, distributors* or *wholesale consumers* pursuant to section 6.7.2 shall be subject to verification and audit by the *IESO* and shall, where paid, be recovered by the *IESO* in accordance with section 4.8 of Chapter 9.

6.7.5 A *generator*, *electricity storage participant, distributor* or *wholesale consumer* shall not be entitled to compensation for any costs, expenses, losses or damage associated with an *outage* which has been rejected by the *IESO* provided that, in exceptional circumstances and where a *generator*, *electricity storage participant, distributor* or *wholesale consumer* has suffered substantial financial harm as a direct result of such rejection, the *generator*, *electricity storage participant, distributor* or *wholesale consumer* may request that an *arbitrator* be appointed pursuant to section 2 of Chapter 3 to determine whether and the amount of any compensation which the *generator*, *electricity storage participant, distributor* or *wholesale consumer* shall be entitled to recover as a result of the rejection of the *outage* by the *IESO.* In the case of *generators* or *electricity storage participants*, no such compensation shall be recoverable under this section 6.7.5 unless the *generator* or *electricity storage participant* demonstrates that the amount claimed cannot be recovered through *market prices*.

6.7.6 [Intentionally left blank – section deleted]

6.7.7 Each act of revocation or recall by the *IESO* shall be treated separately for compensation purposes.

7. Forecasts and Assessments

7.1 Forecasts Prepared by the IESO

7.1.1 The *IESO* shall produce and *publish* the following ongoing *demand* forecasts for Ontario or parts thereof:

7.1.1.1 [Intentionally left blank – section deleted]

7.1.1.2 on a daily basis, a forecast of *demand* for each of the 34 days following the current day, by hour; and

7.1.1.3 [Intentionally left blank – section deleted]

7.1.1.4 on a quarterly basis, a forecast of *demand* for the next 18 months, by week.

7.1.1.5 [Intentionally left blank – section deleted]

7.1.2 The forecasts referred to in section 7.1.1 shall be prepared by the *IESO* in such form as may be specified in the applicable *market manual,* shall be used in conducting the assessments referred to in section 7.3, and shall, in the case of the forecast referred to in section 7.1.1.4, be included in the reports referred to in section 7.3.1.2.

7.1.3 The *IESO* shall *publish* the method to be used to perform the forecasts described in section 7.1.1.

7.1.4 [Intentionally left blank – section deleted]

7.1.5 [Intentionally left blank – section deleted]

7.1.6 If required by the *IESO* for the purpose of enabling the *IESO* to produce the forecasts referred to in section 7.1.1, each *distributor, connected wholesale customer, electricity storage participant* or other load-serving entity shall provide to the *IESO* the load forecasts described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual*.

7.2 Basis for IESO Forecasts

7.2.1 The *IESO* shall develop forecasts of peak *demand* and *energy demand*, by area, that may be based in part on forecasts provided pursuant to section 7.1.6 if required.

7.3 Advance Assessments of System Reliability

7.3.1 The *IESO* shall prepare for the purposes referred to in section 7.4 and based on the information received pursuant to section 7.5.1 and such other information as the *IESO* considers appropriate, and *publish,* the following reports of its findings in relation to such *reliability* assessments:

7.3.1.1 [Intentionally left blank – section deleted]

7.3.1.2 on a quarterly basis and no later than 5 *business days* prior to the end of each calendar quarter, an assessment covering an eighteen-month period commencing with the following calendar month;

7.3.1.3 [Intentionally left blank – section deleted]

7.3.1.4 on a daily basis and not later than 17:00 EST on each day, an assessment covering a thirty-four-day period commencing on the following day; and

7.3.1.5 as required, an assessment of the *reliability* of the *IESO-controlled grid*.

7.3.2 Any information derived from the s*ecurity* and *adequacy* assessment process shall be used to provide a basis for informing *market participants* about expected conditions on the *IESO-controlled grid* and in the *IESO-administered markets*. It is expected that the information will trigger appropriate responses under other market processes, such as *outage* coordination, and transmission investment planning.

7.3A Liability

7.3A.1 Notwithstanding section 13.1.2 of Chapter 1, no *market participant* shall be entitled to compensation from the *IESO* for any costs, loss or damage sustained by the *market participant* as a result of any difference between:

7.3A.1.1 *demand* as forecasted pursuant to section 7.1.1 and actual *demand*;

7.3A.1.2 conditions on the *IESO-controlled grid* as forecasted in the assessments referred to in section 7.3.1 and actual conditions on the *IESO-controlled grid*; or

7.3A.1.3 information contained in succeeding forecasts *published* pursuant to section 7.1.1 or reports *published* pursuant to section 7.3.1 that cover in whole or in part the same time frame.

7.3B Succession of Forecasts and Reports

7.3B.1 Each forecast *published* pursuant to section 7.1.1 or report *published* pursuant to section 7.3.1 shall, to the extent that it covers in whole or in part the same time frame as that covered in a previous *published* forecast or report, supercede such previous *published* forecast or report.

7.4 Purpose of Assessments

7.4.1 [Intentionally left blank – section deleted]

7.4.1.1 [Intentionally left blank – section deleted]

7.4.1.2 [Intentionally left blank – section deleted]

7.4.1.3 [Intentionally left blank – section deleted]

7.4.1.4 [Intentionally left blank – section deleted]

7.4.2 The *IESO* shall conduct the quarterly assessments referred to in section 7.3.1.2 to:

7.4.2.1 provide forecasts, by month, of expected *demand*, *generation capacity, electricity storage capacity* and transmission capacity, *energy* capability of *generation facilities*, and *electricity storage facilities* and the possibility of any *security*-related events on the *IESO-controlled grid* that could require contingency planning by *market participants* or by the *IESO*;

7.4.2.2 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that could give rise to shortfalls in *generation capacity* and *electricity storage capacity* and thus provide information by which *market participants* could act to reschedule *outage* plans to avoid such projected shortfalls; and

7.4.2.3 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of the regional power systems to match generation and *demand*.

7.4.3 [Intentionally left blank – section deleted]

7.4.3.1 to 7.4.3.3 [Intentionally left blank – sections deleted]

7.4.4 The *IESO* shall conduct the daily assessments referred to in section 7.3.1.4 to:

7.4.4.1 provide forecasts of:

7.4.4.1.1 expected hourly *demand*, *generation capacity, electricity storage capacity, energy* capability of *generation facilities* and *electricity storage facilities*, exports and imports of *energy*, and *operating reserve* requirements;

7.4.4.1.2 expected transmission limits with all elements in-service; and

7.4.4.1.3 expected transmission limits with *outages*;

that may affect the *security* of the *IESO-controlled grid* or affect operational decisions to be taken by the *IESO* that must be made more than a day in advance;

7.4.4.2 allow the *IESO* to meet its obligations to relevant *standards authorities* so as to enable the latter organizations to assess the expected *reliability* of regional power systems to match generation and *demand*, on a daily and hourly basis, particularly in peak seasons and in peak hours; and

7.4.4.3 allow the *IESO* to identify exigencies potentially impacting on the coordination of *outages* that may give rise to shortfalls in *generation* *capacity* and thereby assist *market participants* in finalizing *outage* plans and submitting *outage* schedules to the *IESO*.

7.4.5 The *IESO* shall conduct the assessments referred to in section 7.3.1.5 to:

7.4.5.1 meet its obligations to maintain the *reliability* of the *IESO-controlled grid*;

7.4.5.2 meet the requirements of *standards authorities*; and

7.4.5.3 assist the *OEB* in meeting their objectives.

7.5 Information Requirements

7.5.1 Each *market participant* shall, for the purpose of enabling the *IESO* to perform the *reliability* assessments referred to in section 7.3.1, provide to the *IESO* the information described in the applicable *market manual* in such form, at such time and having such resolution as may be specified in such *market manual*.

7.6 The Reporting of Reliability Assessments

7.6.1 The reports referred to in section 7.3.1 shall be prepared by the *IESO* in such form and shall contain such information as may be specified in the applicable *market manual.*

7.6.2 [Intentionally left blank – section deleted]

7.7 Updated and Related Reports

7.7.1 [Intentionally left blank – section deleted]

7.7.2 [Intentionally left blank – section deleted]

7.7.3 [Intentionally left blank – section deleted]

7.7.4 [Intentionally left blank – section deleted]

Interim Updates

7.7.5 The *IESO* may *publish* additional updated versions of any of the assessment reports referred to in section 7.3.1 in the event of changes that, in the *IESO*'s opinion, are significant and should be communicated to *market participants*.

Related Reports

7.7.6 From the material and assessments in the assessment reports referred to in section 7.3.1, the *IESO* may produce additional related reports as required by relevant *standards authorities*, the *IESO Board*, the *OEB*, and the Government of Ontario.

Advisory Notices

7.7.7 The *IESO* may *publish* notifications in the event of changes that occur between scheduled *publication* times of the assessment reports referred to in section 7.3.1.4, in accordance with the applicable *market manual*. Where applicable, the corresponding information shall be included by the *IESO* in a subsequent *publication* of a scheduled report under section 7.3.1.4.

7.8 [Intentionally left blank – section deleted]

7.8.1 [Intentionally left blank – section deleted]

7.8.2 [Intentionally left blank – section deleted]

7.9 Provision of Information to Transmitters

7.9.1 [Intentionally left blank – section deleted]

7.9.2 Notwithstanding any other provision of these *market rules*, the *IESO* may, if necessary to enable *transmitters* to prepare plans for the expansion or modification of the *IESO-controlled grid*, provide to relevant *transmitters* information provided by *market participants* pursuant to this Chapter regarding their forecasts and plans. Any such information which is *confidential information* shall be provided to *transmitters* on a confidential basis and the receiving *transmitter* shall use all reasonable endeavours to protect such *confidential information* and shall use such *confidential information* solely for the purpose of preparing plans for the expansion or modification of the *IESO-controlled grid*.

7.9.3 Where the *IESO* intends to disclose to a *transmitter confidential information* pertaining to a *market participant* pursuant to section 7.9.2, the *IESO* shall provide the *market participant* with advance notice of such intention and shall provide the *market participant* with a reasonable opportunity to make representation as to why the *confidential information* should not be disclosed.

7.10 IESO Actions

Actions Within Next Twelve Months

7.10.1 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that requires action to be initiated within the next twelve months in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may:

- conduct and *publish* a *reliability* assessment in accordance with section 7.3.1.5; and
- take any additional steps necessary to ensure that the *reliability* of the *IESO-controlled grid is* maintained.

7.10.2 If the *IESO* does not believe that *market participants* have or will voluntarily put forward reasonable commitments for technically feasible options to alleviate the condition identified in section 7.10.1, the *IESO* may direct the *transmitter(s)* in the relevant location(s) to prepare a detailed proposal for the enhancement of the *IESO-controlled grid*. The *transmitter(s)* shall submit the proposal to the *OEB* and other governmental agencies having authority to approve the proposal, in the form of an application for approval of the enhancement. The *IESO* shall notify the *OEB* of its identification of the adverse condition.

Actions Beyond the Next Twelve Months

7.10.3 If the *IESO* identifies an adverse condition on the *IESO-controlled grid* that does not require action to be initiated within the next twelve months, the *IESO*:

- shall notify the *OEB* of its determination.

Actions Independent of IESO Recommendations

7.10.4 Nothing in this section 7.10 is intended to limit the ability of any *market participant* to file for approval a proposal to invest in *facilities* on the *integrated power system* that are not the subject of specific recommendations made by the *IESO*. A *market participant* interested in sponsoring a new or modified *connection* to the *IESO-controlled grid* may submit a *request for connection assessment* in accordance with section 6.1.6 of Chapter 4.

8. Remedial Action Schemes (RAS)

8.1 Objectives

8.1.1 *Remedial Action Schemes* ("RA*S*") have been installed in a number of locations on the *IESO-controlled grid* which automatically initiate one or more of the following control actions:

8.1.1.1 load rejection;

8.1.1.2 generation rejection;

8.1.1.3 generation runback;

8.1.1.4 shunt capacitor switching;

8.1.1.5 shunt reactor switching; and

8.1.1.6 cross-tripping.

For further certainty, any of the control actions listed above may be applied by the *IESO* to *electricity storage facilities* if and as applicable.

8.1.2 The *IESO* shall direct the arming of *RASs* installed on the *IESO-controlled grid* as necessary to:

8.1.2.1 increase the capability of power transfers on the *IESO-controlled grid;* or

8.1.2.2 provide additional *security* beyond that required to manage *contingency events* in a *normal operating state*.

8.1.3 New *RASs* shall be installed and utilized on the basis of agreements between and/or among the parties involved.

8.2 Responsibilities of the IESO

8.2.1 The *IESO* shall classify all *RASs* and obtain approval for their use in accordance with all applicable *reliability standards.*

8.2.2 The *IESO* shall determine the need for utilizing an *RAS* for *security* reasons.

8.2.2A The *IESO* shall direct the arming of all *RASs* installed on the *IESO-controlled grid* in accordance with applicable *reliability standards* and applicable agreements including those negotiated under section 8.4.3.

8.2.3 The *IESO* shall direct the arming of an *RAS* to mitigate the adverse effects of specific extreme *contingency events* and to mitigate congestion provided that there are no overriding concerns related to the *security* of the *IESO-controlled grid*.

8.2.4 The *IESO* shall establish and *publish* criteria for arming and activation of *RASs* in sufficient detail and precision to allow a *market participant* whose *facility* forms part of an *RAS* to understand the conditions under which that *RAS* would be armed and activated. Prior to establishing changes to such criteria, the *IESO* shall consult with, and, where practicable, gain the agreement of, the *market participant* whose *facility* is part of the *RAS* to the intended changes. In the event that agreement cannot be reached, the *IESO* may change the criteria for the *RAS* if necessary to maintain *reliable* operation of the *IESO-controlled grid*.

8.2.5 The *IESO* shall from time to time review or cause to be reviewed the performance of *RASs*.

8.2.6 In the event that a *market participant* applies to the *IESO* for compensation under section 8.4.1, the *IESO* shall, upon verification that the amount being claimed is correct, pay such compensation by crediting the *market participant's preliminary settlement statement* for the last day of the month in which the application for compensation was received.

8.3 Responsibilities of RAS Equipment Owners

8.3.1 Owners of *RAS* equipment shall:

8.3.1.1 maintain *RAS* equipment in accordance with all applicable *reliability standards*;

8.3.1.2 test and report operating statistics associated with an *RAS* to the *IESO* on an annual basis;

8.3.1.3 report the performance of an *RAS* when requested to do so by the *IESO*;

8.3.1.4 evaluate and notify the *IESO* of any request from affected *market participants* for permanent exemptions from *connection* to the *RAS*; and

8.3.1.5 provide written notice to the *IESO* of any proposal to install a new, or modify an existing, *RAS*, which notice shall be provided with sufficient lead time and in sufficient detail for the *IESO* to review and seek, if necessary, approval from the relevant *standards authorities* for such new or modified *RAS*; and

8.3.1.6 specify to the *IESO* and *market participants* whose *facilities* form part of an *RAS* the means used to arm the *RAS*.

8.4 Responsibilities of Market Participants Whose Facilities Form Part of an RAS

8.4.1 A *market participant* with a *dispatchable generation facility* or a *dispatchable electricity storage facility* that is not a *quick start facility* and that is part of an RA*S* may, in the time and manner specified in the applicable *market manual*, apply to the *IESO* for compensation, if that *facility* is tripped offline as a result of the activation of the *RAS*. The amount of compensation that may be claimed shall be determined in accordance with the applicable *market manual* and shall be the equivalent of up to the first two hours of constrained off congestion management *settlement* credit payments that would otherwise be calculated if the *facility* had been constrained down to zero and its circuit breaker had remained closed.

8.4.2 Section 8.4.1 shall apply only as long as section 3.5 of Chapter 9 is in effect.

8.4.3 *Market participants* whose *facilities* form part of an existing *RAS* or may form part of a new *RAS* may request notification and/or status annunciation of *RAS* arming, disarming and activation and may enter into agreements with the *RAS* equipment owner/operator and the *IESO* to determine the appropriate status annunciation and notification. The *market participant*, *RAS* equipment owner/operator and the *IESO* shall use the following criteria in determining and implementing the appropriate status annunciation and/or notification:

8.4.3.1 licensing/legal requirements of the *market participant* related to the operation of its *facility* that is part of the *RAS*;

8.4.3.2 practicality of status annunciation and/or notification;

8.4.3.3 cost-effectiveness of status annunciation and/or notification;

8.4.3.4 the status annunciation and/or notification does not adversely impact the intended use of the *RAS*; and

8.4.3.5 comparison to the notification and annunciation of *RAS* arming and activation provided to other *market participants* whose *facilities* form part of an *RAS.*

In the event that they cannot agree on the status annunciation and notification requirements and implementation, the *RAS* owner/operator, the *IESO* and the *market participant* shall use the dispute resolution provisions in section 2 of Chapter 3 to resolve the issue.

8.4.4 *Market participants* whose *facilities* form part of an *RAS* shall notify the *IESO* in accordance with the applicable *market manual* or applicable agreements including those negotiated under section 8.4.3 if the *facility* is unavailable for *RAS* arming.

8.4.5 If an *RAS* has been armed and the *market participant* whose *facility* forms part of the *RAS* reasonably believes that a subsequent activation of that *RAS* would endanger the safety of any person, damage equipment or violate any *applicable law*, the *market participant* whose *facility* is part of that *RAS* may take action in accordance with applicable agreements including those negotiated under section 8.4.3 or may request that the *IESO* disarm the *RAS*. Upon such a request, the *IESO* shall, as soon as the *IESO* can take action to maintain reliable operation of the *IESO-controlled grid*, disarm the *RAS*.

9. Voltage Control

9.1 General

9.1.1 No *market participant* shall make changes in equipment status or operations that could materially adversely affect the voltage profile of the *IESO-controlled grid* without the prior approval of the *IESO*. To this end, each *market participant* shall notify the *IESO* of the *market participant's* intention to make any such change. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid.*

9.2 Under Load Tap Changers

9.2.1 The *IESO* shall direct the operation of under loads tap changers installed on auto-transformers on the *IESO-controlled grid* to control the voltage profile of the *IESO-controlled grid* while ensuring that acceptable voltages at the *connections* to *IESO-controlled grid* are maintained. No *market participant* shall make any changes to such taps without the prior approval of the *IESO*. The *IESO* shall approve such changes unless it determines that such changes could affect the *IESO's* ability to control voltage on the *IESO-controlled grid*, that procedures for such changes cannot be adopted or both.

9.2A Under Load Tap Changers – Connection Transformers

9.2A.1 The *IESO* shall not direct the operation of under load tap changers on *connections* to the *IESO-controlled grid* unless, in the *IESO's* opinion, the operation of such equipment otherwise will or is likely to affect the *reliability* of the *IESO-controlled grid.*

9.3 Off Load Tap Changers

9.3.1 No *market participant* shall make any changes to off load taps of transformers on the *IESO-controlled grid* without the prior approval of the *IESO*. The *IESO* shall approve such change unless it determines that the change is reasonably likely to adversely affect the *reliability* and voltage profile of the *IESO-controlled grid.*

10. Demand Control

10.1 Introduction

10.1.1 This section 10 applies in situations on the *integrated power system* where there is insufficient capacity available to satisfy expected *demand*, where operating problems (such as frequency, voltage levels or thermal over-loads) exist which affect the ability to serve load, or where there is a breakdown on any part of the *IESO-controlled grid*. This section 10 identifies actions that the *IESO* may take or direct *market participants* to take to assist in achieving reductions in *demand* to either avoid or alleviate such situations.

10.1.2 Pursuant to Chapter 7, the *IESO* shall continuously inform *market participants* of conditions on the *IESO-controlled grid* that may require the *IESO* to initiate reductions in *demand* by *non-dispatchable loads*.

10.2 Demand Control Initiated by a Market Participant

10.2.1 *Market participants* shall notify the *IESO* of any action initiated by them to control *demand* in accordance with this section 10.2.

10.2.2 Each *market participant* that can intentionally and directly cut *dispatchable load* or the withdrawals by a dispatchable *electricity storage facility* shall provide the following information to the *IESO* :

10.2.2.1 the proposed date, time, and duration of the cuts by *connection point* on the *IESO-controlled grid*, by hour;

10.2.2.2 the proposed MW reduction of *demand* by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.2.3 the details of the actual decrease in *dispatchable load* or the withdrawals by a dispatchable *electricity storage facility* that was achieved.

10.2.3 Each *transmitter* and *distributor* that intends to initiate a voltage reduction shall:

10.2.3.1 by 10:00 EST each day, notify the *IESO* of all such planned voltage reductions and consequent reduction in load for the following day;

10.2.3.2 immediately notify the *IESO* of a voltage reduction that is planned after 10:00 EST for the following day;

10.2.3.3 the proposed date, time, and duration of the voltage reduction by connection point on the *IESO-controlled grid*, by hour;

10.2.3.4 the proposed MW reduction by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.3.5 details of the actual voltage reduction achieved, in MWs.

10.2.4 Each *distributor* or *transmitter* that intends to initiate a disconnection in load (including, but not limited to, interruptible loads and demand management activities) shall:

10.2.4.1 by 10:00 EST each day, notify the *IESO* of all such planned disconnections in load and consequent reduction in loads for the following day;

10.2.4.2 immediately notify the *IESO* of a disconnection in load that is planned after 10:00 EST for the following day;

10.2.4.3 the proposed date, time, and duration of the disconnection in load by *connection point* on the *IESO-controlled grid*, by hour;

10.2.4.4 the proposed reduction, in MWs, of loads by *connection point* on the *IESO-controlled grid*, by hour; and

10.2.4.5 details of the actual reduction in loads achieved, in MWs.

10.2.5 Each *distributor* and *transmitter* that has operational control over load shall:

10.2.5.1 make arrangements that enable it to *disconnect* load immediately under an *emergency operating state* declared by the *IESO*;

10.2.5.2 make arrangements that enable it to apply *disconnections* to load to individual or specific groups of *connection points* on the *IESO-controlled grid* as determined in a coordinated fashion by the *IESO* and *market participants*;

10.2.5.3 provide the *IESO* in writing, by week 24 in each calendar year, its total forecasted peak *demand* for the immediately following twelve-month period, by *connection point* on the *IESO-controlled grid*; and

10.2.5.4 provide the *IESO* in writing, by week 24 in each calendar year, the total forecasted peak *demand* for the immediately following twelve-month period that can be *disconnected* within the following time scales: immediately, 15 minutes, 1 hour and more than 1 hour. This information shall be provided by *connection point* on the *IESO-controlled grid.*

10.2.6 No *distributor* or *transmitter* that has *disconnected* load pursuant to section 10.2.4 shall reconnect the load until directions have been received from the *IESO* permitting it to do so. Such *distributor* or *transmitter* shall commence restoration of load immediately following receipt of such directions.

10.3 Demand Control Initiated by the IESO in an Emergency Operating State

10.3.1 When an *emergency operating state* has been declared by the *IESO*, the actions available to the *IESO* to safeguard the *security* of the *IESO-controlled grid* may include issuing directions to *market participants* to reduce *demand* for electricity.

10.3.2 Whenever possible, the *IESO* shall issue a warning by 16:00 EST on the previous day when requesting a reduction of *demand* through voltage reductions or interruptions.

10.3.3 Each *market participant* that receives a direction from the *IESO* to reduce *demand* shall achieve the reduction in *demand* within 5 minutes of receipt of the direction and shall notify the *IESO* that it has done so.

10.3.4 Each *market participant* may interchange customers to whom the *demand* reduction has been applied provided the necessary *demand* reduction required by the *IESO* is achieved by the interchange.

10.3.5 No *market participant* that has reduced *demand* pursuant to this section 10.3 shall restore *demand* until directions have been received from the *IESO* permitting it to do so. Such *market participant* shall commence restoration of *demand* immediately following receipt of such directions.

10.3.6 The *IESO* shall maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the *Ontario Electricity Emergency Plan* regarding exclusions to load management activities that are undertaken for the purpose of controlling *demand*.

10.3.7 The *IESO* shall release to all *market participants* an estimate of aggregate load *curtailed* as soon as practicable following the return to a *normal operating state*.

10.4 Under-Frequency Load Shedding

10.4.1 Automatic under-frequency load shedding shall be accomplished to maintain the frequency of the *IESO-controlled grid* and to restore the *IESO-controlled grid* to normal frequency following frequency deviations outside of the range established by the *IESO*.

10.4.2 Each *transmitter* shall, where possible and upon receipt of an under-frequency alarm or an indication of declining frequency and voltage, identify to the *IESO* frequency values for stations under its control.

10.4.3 Each *transmitter* shall undertake the following actions immediately and independently as pre-authorized by the *IESO* pursuant to the Operating Agreement between the *transmitter* and the *IESO*:

10.4.3.1 when frequency is between 58.5 and 59.0 Hz, take immediate independent action to shed 25% of controlled load. The block of load to be shed shall not include load connected to under-frequency load-shedding relays; or

10.4.3.2 when frequency is below 58.5 Hz, take immediate independent action to shed affected load until the frequency is restored to 59.0 Hz or, in the case of known island situations, to 60 Hz.

10.4.4 Each affected *transmitter* shall notify the *IESO* of the approximate amounts and locations of loads that were shed and of conditions on the *IESO-controlled grid*.

10.4.5 Once loads have been shed to maintain the frequency of the *IESO-controlled grid*, the *IESO* shall immediately report conditions on the *IESO-controlled grid* to affected *transmitters*.

10.4.6 Each *distributor* and *connected wholesale customer*, in conjunction with the relevant t*ransmitter*, shall make arrangements to enable the disconnection of automatic under-frequency *demand* of at least 30% of its total peak customer *demand*.

10.4.7 The *demand* of each *distributor* and *connected wholesale customer* that is subject to automatic under-frequency load shedding pursuant to section 10.4.6 shall be split into discrete MW blocks. The number, location, size and associated low frequency settings of these blocks shall be as specified by the *IESO*. Such specifications shall be established by the *IESO*, following consultations with the relevant *market participants*, by week 24 in each calendar year to cover the immediately following twelve-month period.

10.4.8 No *market participant* shall restore load that has been shed pursuant to this section 10.4 until directions have been received from the *IESO* permitting it to do so.

Such *market participant* shall commence the restoration of load immediately following receipt of such direction.

10.4.9 Each *distributor* and *connected wholesale customer* shall provide the *IESO* with an estimate of the *demand* reduction that has occurred as a result of *disconnecting* under-frequency *demand*.

10.4.10 The amount of load rejected by automatic under-frequency load shedding shall conform to the minimum requirements set forth in all applicable *reliability standards.*

10.4.11 The *IESO* shall, maintain, *publish* and revise as required, following appropriate consultations with *market participants*, the applicable *market manual* regarding exclusions to load management activities that are undertaken for the purpose of shedding load during under-frequency conditions.

10.5 Generator Obligations During Abnormal Frequency

10.5.1 Abnormal frequency excursions on the *IESO-controlled grid* may require immediate actions by *generators* to restore the frequency to an acceptable level.

10.5.2 A g*enerator* that observes a frequency excursion greater than 60.2 Hz or less than 59.8 Hz shall immediately report this condition to the *IESO* and shall carry out frequency restoration actions as directed by the *IESO*.

10.5.3 No *generator* shall be precluded by the restoration actions referred to in section 10.5.2 from taking action for the purpose of ensuring the safety of any person, preventing the damage of equipment, or preventing the violation of any *applicable law*. Any such directives shall be immediately reported to the *IESO.*

10.5A Electricity Storage Participant Obligations During Abnormal Frequency

10.5A.1 Abnormal frequency excursions on the *IESO-controlled grid* may require immediate actions by *electricity storage participants* to restore the frequency to an acceptable level.

10.5A.2 An *electricity storage participant* that observes a frequency excursion greater than 60.2 Hz or less than 59.8 Hz shall immediately report this condition to the *IESO* and shall carry out frequency restoration actions as directed by the *IESO*.

10.5A.3 No *electricity storage participant* shall be precluded by the restoration actions referred to in section 10.5A.2 from taking action for the purpose of ensuring the safety of any person, preventing the damage of equipment, or preventing the violation of any *applicable law*. Any such directives shall be immediately reported to the *IESO*.

11. Emergency Preparedness and System Restoration

11.1 Objective

11.1.1 The objective of this section 11 is to establish the means by which the *IESO* and *market participants* will fulfil their respective *emergency* preparedness and system restoration obligations, including regular and real-time testing; the preparation by the *IESO* of the *Ontario electricity emergency plan* and the *Ontario power system restoration plan*; the preparation by *market participants* of *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*; and the preparation of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan*. This objective will be met through co-operation and in consultation with all relevant *market participants.*

11.2 Emergency Preparedness Plans and Ontario Electricity Emergency Plan

11.2.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario electricity emergency plan* describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *electricity system,* having regard to the mitigation of the impact of an *emergency* on public health and safety as identified in each *market participant's emergency preparedness plan.*

11.2.2 The *IESO* shall file with the *Minister* the *Ontario electricity emergency plan* and such other emergency plans as the *Minister* may require pursuant to subsection 39(1) of the Electricity Act, 1998.

11.2.3 In order to assist the *IESO* in fulfilling its responsibilities under section 39 of the Electricity Act, 1998, each *market participant* shall prepare and submit to the *IESO* an *emergency preparedness plan* and such other *emergency* preparedness-related information as the *IESO* considers necessary. Each *market participant* shall ensure that its *emergency preparedness plan* complies with section 11.2.4 and is submitted to the *IESO* during registration to become a *market participant*, or at such later times as the *IESO* shall specify.

11.2.4 Each *market participant* shall ensure that its *emergency preparedness plan*:

11.2.4.1 describes such planning, testing, information, communication and other elements designated by the *IESO*;

11.2.4.2 complies with such *emergency* planning criteria as may be designated by the *IESO*;

11.2.4.3 complies with all relevant *reliability standards*;

11.2.4.4 is consistent with the *emergency* planning and preparedness procedures established by relevant government authorities;

11.2.4.5 indicates the manner in which the impact of an *emergency* on public health and safety will be mitigated;

11.2.4.6 indicates the manner in which the *market participant* will minimize the cutting and expedite the restoration of critical loads and priority loads during short and prolonged *emergencies*; and

11.2.4.7 is submitted with a statement certified by an officer or equivalent of the *market participant* stating that the *emergency preparedness plan* is a true and complete copy as at the date of the certification.

11.2.5 The *IESO* shall assist *market participants* in the development of *emergency preparedness plans* for the purpose of ultimately establishing *emergency preparedness plans* that support and are coordinated with the *Ontario electricity emergency plan*.

11.2.6 [Intentionally left blank]

11.3 Ontario Power System Restoration Plan and Restoration Participant Attachments

11.3.1 The *IESO* shall develop and maintain, in consultation with all relevant *market participants*, the *Ontario power system restoration plan* for restoring the *security* of the *IESO-controlled grid* following a major *contingency event* or *emergency* as required by all applicable *reliability standards* and considered prudent by the *IESO* for Ontario.

11.3.2 The *Ontario power system restoration plan* shall cover each of the planning, testing, information, load reduction, load restoration, communication and other elements described in section 10 and section 11 and such other elements as the *IESO* deems necessary to implement effective system restoration.

11.3.3 The *Ontario power system restoration plan* shall include, but not be limited to:

11.3.3.1 plans for managing major disturbances on the *IESO-controlled grid* that blackout all or a portion of the *IESO-controlled grid*;

11.3.3.2 plans for the testing and verification of *emergency* preparedness facilities and procedures; and

11.3.3.3 descriptions of the roles of the IESO and various restoration participants in the *Ontario power system restoration plan*.

11.3.4 The *IESO* shall file with the *Minister* the *Ontario power system restoration plan* and such other restoration documentation as the *Minister* may require under subsection 39(1) of the *Electricity Act, 1998*.

11.3.5 Each *restoration participant* shall prepare and submit to the *IESO* a *restoration participant attachment* to the *Ontario power system restoration plan* and such other system restoration-related information as the *IESO* considers necessary. Each *restoration participant* shall ensure that its *restoration participant attachment* complies with section 11.3.6 and is submitted to the *IESO* during registration to become a *market participant*, or at such later times as the *IESO* shall specify.

11.3.6 Each *restoration participant* shall ensure that its *restoration participant attachment*:

11.3.6.1 includes the elements described in section 11.3.7;

11.3.6.2 complies with such restoration planning criteria as may be designated by the *IESO*; and

11.3.6.3 complies with all relevant *reliability standards,* subject to the information reporting requirements specified in section 14.1.2.

11.3.7 Each *restoration participant* shall ensure that its *restoration participant attachment* includes:

11.3.7.1 a statement describing that the *restoration participant*: (i) has an operator training program in place, (ii) uses trained operating personnel, and (iii) maintains operator training records;

11.3.7.2 documentation detailing organizational responsibility for co-ordinating with the *IESO* the development of and participation in system restoration drills. Such development and participation shall be conducted by the *restoration participant* at its own expense;

11.3.7.3 a statement describing the program in place to test the *restoration participant's* equipment as may be designated in the *Ontario power* *system restoration plan*. Such testing shall be conducted by the *restoration participant* at its own expense;

11.3.7.4 a statement of policy and supporting documentation demonstrating how the *restoration participant* will minimize the cutting and expedite the restoration of critical loads and priority loads under system restoration conditions;

11.3.7.5 any other documentation that the *IESO* deems necessary to support or facilitate the successful implementation of the *Ontario power system restoration plan*; and

11.3.7.6 a statement certified by an officer or equivalent of the *market participant* stating that the *restoration participant attachment* is a true and complete copy as at the date of the certification.

11.3.8 [Intentionally left blank]

11.3.9 The *IESO* shall assist *restoration participants* in the development of *restoration participant attachments* that support and are coordinated with the *Ontario power system restoration plan* for the purpose of ultimately establishing one integrated restoration plan for Ontario.

11.3.10 Each *restoration participant* shall ensure that the guidelines and procedures applicable to it and set forth in the *Ontario power system restoration plan* are carried out by trained operating staff with sufficient authority to take any action that may be necessary to ensure that all relevant equipment is operated in a timely, stable and reliable manner.

11.3.11 The *IESO* shall direct *market participants* in restoring the *IESO-controlled grid* following major disturbances. Each such *market participant* shall be responsible for carrying out these *IESO* directions, in accordance with the provisions of the *Ontario power system restoration plan.*

11.4 Review and Audit

11.4.1 The *IESO* shall review each *emergency preparedness plan* and each *restoration participant attachment* submitted to it, in accordance with sections 11.2.3 and 11.4.3, and shall prepare and provide to the relevant *market participant* or *restoration participant* a record of review indicating the changes, if any, required to be made and the date by which the revised *emergency preparedness plan* or *restoration participant attachment* must be submitted with the *IESO*.

11.4.2 Each *market participant* shall make such changes to its *emergency preparedness plan* or *restoration participant attachment* as may be required by the record of review and shall submit to the *IESO* a revised *emergency preparedness plan* or *restoration participant attachment* within the time specified in the record of review or within such other period as may be agreed with the *IESO*.

11.4.3 Each *restoration participant* shall review its *emergency preparedness plan* and *restoration participant attachment* at least annually, or as required, and shall, following such review, submit to the *IESO*:

11.4.3.1 a statement certified by an officer or equivalent of the *restoration participant* confirming that the review has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.3.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the review, together with a statement certified by an officer or equivalent of the *restoration participant* identifying such amendments, as the case may be. Each *restoration participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.3 complies with section 11.2.4 or 11.3.6, respectively.

11.4.4 When directed by the *IESO*, the *market participant* shall have an independent audit of its *emergency preparedness plan* and/or *restoration participant attachment* conducted. The independent audit may be conducted by, without limitation, the *market participant's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of conducting such an audit shall be borne by the *market participant*. Each *market participant* shall, following such audit, submit to the *IESO* a copy of the audit report, together with:

11.4.4.1 a statement certified by an officer or equivalent of the *market participant* confirming that the audit has not required any change to be made to its *emergency preparedness plan* or its *restoration participant attachment*; or

11.4.4.2 a revised version of its *emergency preparedness plan* or *restoration participant attachment*, amended as may be required by the results of the audit, together with a statement certified by an officer or equivalent of the *market participant* identifying such amendments, as the case may be. Each *market participant* shall ensure that any revised *emergency preparedness plan* or *restoration participant attachment* prepared and submitted pursuant to this section 11.4.4 complies with section 11.2.4 or 11.3.6, respectively.

11.4.5 [Intentionally left blank – section deleted]

11.4.6 The *IESO* shall review its *emergency preparedness plan,* the *Ontario electricity emergency plan* and the *Ontario power system restoration plan* at least annually, or as required. When directed by the *Minister*, the *IESO* shall have an independent audit conducted of these plans. The independent audit may be conducted by, without limitation, the *IESO's* internal auditors or before a peer review team having diverse membership or industry *emergency preparedness* expertise. The cost of such an audit shall be borne by the *IESO*.

11.4.7 [Intentionally left blank – section deleted]

11.5 [Intentionally left blank]

11.6 Emergency Facilities

11.6.1 The *IESO* may evacuate its principal control centre in the event that a circumstance arises that poses a hazard to *IESO* personnel. During and following such evacuation, operation of the *IESO-controlled grid* shall be effected in accordance with this section 11.6.

11.6.2 The *IESO-administered markets* shall continue to operate during an evacuation of the *IESO*'s principal control centre unless conditions exist that would warrant a suspension of market operations as described in Chapter 7.

11.6.3 During the interval between the evacuation of the *IESO' s* principal control centre and the establishment of a backup control centre:

11.6.3.1 the *IESO* shall designate an interim emergency system coordinator to act in its stead, as required; and

11.6.3.2 all *generators, electricity storage participants* and *transmitters* shall manage their *facilities* and support the emergency system coordinator in the operation of the *IESO-controlled grid.*

11.6.4 The *IESO* shall test the backup control centre and associated procedures and facilities on a regular basis, and each *market participant* connected to the *IESO-controlled grid* shall, at its own expense and as directed by the *IESO*, support and actively participate in evacuation tests and simulations.

11.7 Testing

11.7.1 Each *market participant* shall ensure that the capability and reliability of its personnel, procedures, and equipment are maintained to the extent necessary to fulfill its obligations under its *emergency preparedness plan* and its *restoration participant attachment*.

11.7.2 The *IESO* shall develop, schedule, implement and conduct such tests as are provided for in the *Ontario electricity emergency plan* and the *Ontario power system restoration plan.*

11.7.3 [Intentionally left blank]

11.7.4 Each *market participant* shall support and actively participate, at its own expense and as directed by the *IESO*, in the implementation and testing of its *emergency preparedness plan*, its *restoration participant attachment*, the *Ontario electricity emergency plan,* the *Ontario power system restoration plan* and voice communications facilities.

11.7.5 The *IESO* shall schedule the tests referred to in section 11.7.4 at an appropriate time of the year and time of day, in consideration of the needs of *market participants* and of the desire to minimize their costs relating to such tests. To the extent practicable, such tests of the *restoration participant attachment* shall be scheduled in a manner consistent with the *outage* coordination process described in section 6.

11.8 Enforcement

11.8.1 Failure by a *market participant* to take any action required to be taken in, or to act in a manner consistent with, its *emergency preparedness plan*, its *restoration participant attachment* or its accountabilities within the *Ontario power system restoration plan* shall be deemed to constitute a breach of the *market rules.*

12. Communications

12.1 Communication Methods

12.1.1 Communication between the *IESO* and:

12.1.1.1 *market participants*;

12.1.1.2 *embedded generators* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both;

12.1.1.3 *embedded load consumers* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control or both; and

12.1.1.4 *embedded electricity storage participants* required by Appendix 2.2 of Chapter 2 to provide or install and maintain voice communication facilities, facilities relating to monitoring and control, or both;

shall take place through a combination of methods as identified in Appendix 2.2 of Chapter 2 and as directed by the *IESO* pursuant to section 12.2.3.2.

12.1.2 For the purposes of section 12.1.1 and with the exception of section 12.1.2A, the *IESO* shall provide and maintain, at its cost, a dedicated, real-time communication network from the *IESO's* facilities to the communication terminal point between such network and:

12.1.2.1 the monitoring and control devices; and

12.1.2.2 where applicable, the *dispatch workstation*

of the persons referred to in sections 12.1.1.1 to 12.1.1.3 to enable communication between the *IESO* and such persons.

12.1.2A Subject to section 12.1.6, for a *variable generator* that is a *registered market participant*, the *registered market participant* shall, if a dedicated communication network in accordance with section 12.1.2 is not already in place, provide and maintain, at its cost, a dedicated, internet based real-time communication network from the *IESO's* facilities to the communication terminal point between such network and a *dispatch workstation.* Any such internet based real-time communication network shall meet the applicable specifications and other requirements set forth in the *participant technical reference manual.*

12.1.3 The *IESO* shall provide real-time communication network channels to the persons referred to in sections 12.1.1.1 to 12.1.1.3 as follows:

12.1.3.1 one communication channel and, where available and justified for *reliable* operation of the *IESO-controlled grid* and efficient operation of the *IESO-administered markets*, a redundant physically diverse communication channel, for:

a. each *facility* to which the high performance information monitoring standard applies in accordance with Appendices 4.19 to 4.23 of Chapter 4, and

b. each *facility* that is providing monitoring information for two or more *facilities*;

12.1.3.2 one communication channel for each *facility* to which the medium performance information monitoring standard applies in accordance with Appendices 4.19 to 4.23 of Chapter 4.

12.1.3.3 [Intentionally left blank]

12.1.3.4 [Intentionally left blank]

12.1.3.5 [Intentionally left blank]

12.1.4 The *IESO* may, in respect of a given *facility*, provide additional real-time network communication channels in addition to those referred to in section 12.1.3 where the *IESO* considers, based on the size and location of the *facility*, and, where applicable, the number of *facilities* monitored at a single *facility*, that such additional channels are desirable for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.1.5 Where a *market participant* wishes to submit *dispatch data*, *physical bilateral contract data*, or *TR bids* in the *TR market* using private network dedicated communication links, all costs associated with such use, including but not limited to the cost of the provision and maintenance of the required communication channel, shall be borne by the *market participant*.

12.1.6 Where problems exist which require methods of communication other than those referred to in section 12.1.1 or 12.1.2A, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.2 Voice Communication

12.2.1 [Intentionally left blank]

12.2.2 [Intentionally left blank]

12.2.3 Each *market participant*, *embedded generator*, *embedded electricity storage participant* and *embedded load consumer* shall provide and maintain:

12.2.3.1 the applicable voice communication facilities required by Appendix 2.2 of Chapter 2 and that meet the requirements of that Appendix; and

12.2.3.2 such additional or other voice communication facilities as the *IESO* may direct in respect of *facilities* that the *IESO* considers to be significant for purposes of maintaining the *reliability* of the *IESO-controlled grid*.

12.2.4 Each person referred to in section 12.2.3 shall ensure that the overall mean time between failures of the voice communication facilities referred to in section 12.2.3 is no less than five years.

12.2.5 Each person referred to in section 12.2.3 shall respond to an outage of or defect in the voice communication facilities referred to in section 12.2.3:

12.2.5.1 immediately, in the case of an outage of or defect in a *high priority path facility*; and

a. [Intentionally left blank]
b. [Intentionally left blank]
c. [Intentionally left blank]
d. [Intentionally left blank]
e. [Intentionally left blank]
f. [Intentionally left blank]
g. [Intentionally left blank]

12.2.5.2 no later than the next day following the day on which the outage or defect is discovered, in the case of an outage of or defect in a *normal priority path facility*.

a. [Intentionally left blank]
b. [Intentionally left blank]
c. [Intentionally left blank]
d. [Intentionally left blank]
e. [Intentionally left blank]
f. [Intentionally left blank]

12.2.6 Each person referred to in section 12.2.3 shall ensure that the voice communication facilities referred to in section 12.2.3 are restored to a fully operational state following an *outage* of or defect in such facilities as follows:

12.2.6.1 in the case of the *high priority path facilities* referred to in section 12.2.5.1, within 24 hours of the time at which the *outage* or defect is discovered;

12.2.6.2 in the case of the *normal priority path facilities* referred to in section 12.2.5.2, within 48 hours of the time at which the *outage* or defect is discovered; and

12.2.6.3 in all other cases, within 14 days of the time at which the *outage* or defect is discovered.

12.2.7 The *IESO* may direct a person referred to in section 12.2.3 to respond and restore a voice communication facility to a fully operational state following an *outage* of or defect in such facility within such longer or shorter time periods than those referred to in sections 12.2.5 and 12.2.6 based on the immediate or short-term impact of the unavailability of the voice communication facility on the *reliable* operation of the *IESO-controlled grid*.

12.2.8 Each person referred to in section 12.2.3 shall notify the *IESO* of any *planned outage* of the voice communication facilities referred to in section 12.2.3 no less than four days prior to the *planned outage*.

12.2.9 The *IESO* shall:

12.2.9.1 maintain, at each of its principal control center and back-up control center, *high priority path facilities* and *normal priority path facilities* that meet the requirements of sections 1.1.7 and 1.1.8 of Appendix 2.2 of Chapter 2, respectively, for the purpose of voice communication with the persons referred to in section 12.2.3 and with neighbouring *security coordinators*; and

12.2.9.2 ensure that its voice communication facilities include facilities that permit telephone conference calls between six parties.

12.2.10 The *IESO* shall develop, in consultation with all relevant *market participants*, test plans and procedures for voice communication during an *emergency* on or a major disturbance of the *IESO-controlled grid*.

12.2.11 Each person referred to in section 12.2.3 shall, at its own expense, not less than annually or more frequently as may be directed by the *IESO*, monitor and test its voice communication facilities and shall, at its own expense and as directed by the *IESO*, support and actively participate in the testing of voice communication facilities.

12.2.12 Where problems exist which require methods of communication other than those referred to in section 12.2.3, such alternative communication capabilities as shall be selected by the *IESO*, including facsimile capability, shall be used.

12.3 Electronic Data

12.3.1 Energy management system (EMS) information shall be exchanged between the communication system of the *IESO* and the communication system of each *market participant* in order to support real-time functions such as:

12.3.1.1 the monitoring of the *IESO-controlled grid*;

12.3.1.2 the control and analysis of *generation facilities* and *electricity storage facilities*;

12.3.1.3 an analysis of the *security* of the *IESO-controlled grid*;

12.3.1.4 the scheduling of *generation facilities* and *electricity storage facilities*;

12.3.1.5 the monitoring of compliance with *dispatch instructions*; and

12.3.1.6 [Intentionally left blank]

12.3.1.7 reports.

12.3.2 The *IESO* and *market participants* shall exchange EMS information between their respective communication systems via dedicated data circuits.

12.3.3 For the exchange of schedules referred to in Chapter 7 and of *outage* and planning data between *market participants* and the *IESO*, a computer path distinct from the EMS path shall be used. Communications shall occur over separate data links using a different protocol than that used for EMS information. Real-time *dispatch instructions* for *generation facilities, electricity storage facilities,* transmission *facilities* and load shall be communicated electronically through the EMS path and shall be integrated with the EMS messaging system for logging purposes.

12.4 Voice Links and Other Communications

12.4.1 The *IESO* shall develop and notify all *market participants* of standard operating terms, abbreviations and definitions that shall be approved for use in communications between the *IESO* and *market participants*. Such approved, standard operating terms, abbreviations and definitions shall wherever possible be used by the *IESO* and *market participants* in their communications with one another.

12.4.2 All communications between a *market participant* and the *IESO* with respect to the *reliability* of the *IESO-controlled grid* shall be recorded and the records shall be retained by the *IESO* for 7 years.

12.4.3 The *IESO* shall maintain a log of activities related to the *reliable* operation of the *IESO-controlled grid.*

13. Prior Arrangements

13.1 Market Participant Review of Arrangements

13.1.1 Each *market participant* shall review any contractual or other arrangements relating to the *reliability* of the *IESO-controlled grid* which it may have with other *market participants* or with *interconnected systems* on the date of coming into force of this Chapter for the purpose of determining whether such arrangements are consistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter. Where such contractual or other arrangement is consistent with the requirements and obligations imposed on the *market participant* by this Chapter, no further action with respect to such contract or arrangement is required.

13.1.2 Where a *market participant* determines that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on the *market participant* by, this Chapter, the *market participant* shall:

13.1.2.1 negotiate an amendment to the contract or a modification to the arrangement which removes the inconsistency; or

13.1.2.2 report the inconsistency to the *technical panel*, which shall make a determination as to whether the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*.

13.1.3 Where the *technical panel* determines under section 13.1.2 or 13.1.4 that the inconsistency will or is reasonably likely to have an adverse effect on the *reliability* of the *IESO-controlled grid*, the *IESO* shall take appropriate actions to mitigate the effect of the inconsistency until the inconsistency is removed.

13.1.4 Where the *IESO* becomes aware that a contractual or other arrangement referred to in section 13.1.1 is inconsistent with the requirements of, or the obligations imposed on a *market participant* by, this Chapter, it may report the inconsistency to the *technical panel* notwithstanding that the inconsistency may not have been reported by the *market participant* and the *technical panel* shall make the determination referred to in section 13.1.2.2 in respect of that inconsistency.

14. Information and Reporting

Requirements

14.1.1 The *reliable* operation of the *IESO-controlled grid* requires the rapid and continuous flow of accurate information among the *IESO*, *market participants* and *interconnected systems*, with due regard for maintaining the confidentiality of information where appropriate. To that end, the *IESO* shall establish and periodically up-date and inform all *market participants* with respect to the specific information it requires from *market participants* for *reliability* purposes.

14.1.2 Each *market participant* shall provide the information referred to in section 14.1.1 to the *IESO* in the manner and within the time prescribed by the *IESO*. By submitting such information to the *IESO,* a *market participant* is considered to have fulfilled any requirement under a *reliability standard* to report such information to one or more *standards authorities*. The *IESO* shall provide such information to other *standards authorities,* as required.

14.1.3 The *IESO* shall establish a catalogue of reporting requirements listing the *reliability*-related information to be exchanged between the *IESO* and *market participants.* Such reporting requirements shall include, but not be limited to, the following:

14.1.3.1 each *market participant* shall report to the *IESO* the planned implementation of a change to a setting on a fixed-tap transformer. This information shall be reported to the *IESO* in writing one week prior to the date scheduled for implementation of such change, provided that where such change is effected on an unplanned, emergency basis, the information shall be reported to the *IESO* within one *business day* of implementation of the change;

14.1.3.2 each *market participant* shall report to the *IESO* any change in equipment and *facilities* to that which has been provided pursuant to Chapter 4;

14.1.3.3 each *market participant* shall report to the *IESO* a list of all of its equipment for which periodic maintenance has been performed on *remedial action schemes* in the previous 12 months, as required by relevant *standards authorities*. This information shall be reported no later than the first day of December in each year;

14.1.3.4 each *market participant* shall provide to the *IESO* a report describing any modification proposed to be made to protection on a primary relay. The report shall be delivered to the *IESO* within one week of the date on which the *IESO* approves such modification pursuant to section 6 of Chapter 4, or, where the modification is effected on an unplanned, emergency basis, within one week of the date of modification;

14.1.3.5 each *market participant* shall annually provide to the *IESO* a written summary of actions taken to control *demand* in the previous 12 months;

14.1.3.6 each *market participant* shall annually provide to the *IESO* a written summary of automatic under-frequency load shedding activities taken in the previous 12 months; and

14.1.3.7 each *market participant* shall annually provide to the *IESO* a report of *reliability*-related performance measures for transmission *facilities* and *connections* to the *IESO-controlled grid* in accordance with all applicable *reliability standards*.

14.1.4 Each *market participant* shall provide to the *IESO* such data as may be required by the *IESO* to enable it to satisfy a request by a *standards authority.*

14.1.5 The *IESO* shall file such reports including, but not limited to, disturbance reports, and participate in such discussions as may be required by relevant *standards authorities*. Each *market participant* shall provide to the *IESO* such information and reports as may be required by the *IESO* to facilitate preparation by the *IESO* of such disturbance reports.

Market Rules

Chapter 5
Power System Reliability - Appendices

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Appendix 5.1 – Performance Standards for Ancillary Services

1.1 Regulation

1.1.1 A *registered facility* providing *regulation* shall submit to the energy management system referred to in section 12 of Chapter 5 the monitoring and control information required to be provided pursuant to Chapter 4.

1.1.2 The telemetering between the energy management system referred to in section 12 of Chapter 5 and a *registered facility* providing *regulation* shall indicate:

1.1.2.1 whether the *registered facility* is synchronized to the *IESO-controlled grid,* connected to a *distribution system,* or connected to another *market participant's facility*;

1.1.2.2 whether the *registered facility* is providing *regulation* or not; and

1.1.2.3 the net injection or withdrawal of the *registered facility* as a whole.

1.1.3 A *registered facility* providing *regulation* must achieve at least the ramp rate specified in its *contracted ancillary services* contract for the full amount of *regulation* capacity offered in such contract.

1.1.4 A *registered facility* providing *regulation* must be able to adjust its output or consumption at least at the ramp rate specified in its *contracted ancillary services* contract to the maximum and minimum values specified in such contract.

1.1.5 No *registered facility* shall offer to provide *regulation* capacity that exceeds an amount equal to the *registered facility's* maximum ramp rate multiplied by ten minutes.

1.1.6 A *registered facility* providing *regulation* must be capable of receiving control signals sent from the *IESO* at the rate of at least one signal every two seconds. If the *regulation* control signals are received by a control centre, the control centre must forward these signals to the *registered facility* providing *regulation* within two seconds of having received the signal from the *IESO*.

1.1.7 All *registered facilities* providing *regulation* must meet, at a minimum, the performance requirements for off-nominal frequency, speed/frequency regulation and voltage ride through specified in Appendix 4.2. For greater certainty, the foregoing obligation applies to all *registered facilities* providing *regulation*, regardless of size, technology or connection location.

1.2 Operating Reserve

Ten-Minute Operating Reserve

1.2.1 An *ancillary service provider* offering *ten-minute operating reserve* shall ensure that the *registered facility*, or *registered facilities*, that it has scheduled to provide *ten-minute operating reserve* is available for *dispatch* as scheduled.

1.2.2 An *ancillary service provider* offering *ten-minute operating reserve* shall be capable of achieving at least the ramp rate stated in its *offer* for the full amount of *ten-minute operating reserve* offered.

1.2.3 When activated by the *IESO*, *ten-minute operating reserve* shall be available for dispatch for at least one hour.

Thirty-Minute Operating Reserve

1.2.4 An *ancillary service provider* offering *thirty-minute operating reserve* shall ensure that the *registered facility*, or *registered facilities*, that it has scheduled to provide *thirty-minute operating reserve* is available for *dispatch* as scheduled.

1.2.5 An *ancillary service provider* offering *thirty-minute operating reserve* shall be capable of achieving at least the ramp rate stated in its *offer* for the full amount of *thirty-minute operating reserve* offered.

1.2.6 When activated by the *IESO*, *thirty-minute operating reserve* shall be available for *dispatch* for at least one hour.

1.3 Reactive Support and Voltage Control – Generation Facilities and Electricity Storage Facilities

1.3.1 All *registered facilities* that are *generation facilities* or *electricity storage facilities* providing *reactive support service* and *voltage control service* must be capable of meeting the requirements specified in Chapter 4.

1.3.2 Subject to section 1.3.6, *automatic voltage regulators* shall be in service and in automatic mode as indicated in Chapter 4 unless the *registered* facility that is a *generation facility* or *electricity storage facility* is specifically directed by the *IESO* to operate the *AVRs* in manual mode.

1.3.3 Subject to section 1.3.4, *registered* facilities that are *generation facilities* or *electricity storage facilities* providing *reactive support service* and *voltage control service* shall be operated to within the standard power factor range described in Appendix 4.2 of Chapter 4.

1.3.4 The *IESO* may direct a *registered facility* that is a *generation facility* providing *reactive support service* and *voltage control service* to operate in an under- or over-excited state for a certain period of time in order to maintain prescribed voltages on the *IESO-controlled grid*. Such direction may require such *registered facility* to operate in the condense mode or to reduce active power output in order to increase its ability to provide reactive power.

1.3.4A The IESO may direct a *registered facility* that is an *electricity storage facility* to provide *reactive support service* and *voltage control service* to absorb reactive power or inject reactive power for a certain period of time in order to maintain the prescribed voltages on the *IESO-controlled grid*. If applicable and required, the IESO may direct such *registered facility* to reduce the withdrawal or injection of active power in order to increase its ability to provide reactive power.

1.3.5 Unless otherwise specified by the *IESO*, each *registered facility* that is a *generation facility* or *electricity storage facility* providing *reactive support service* and *voltage control service* shall respond to voltage or reactive power schedules immediately following receipt of the *IESO's* request. Where such *registered facility* cannot be *dispatched* as directed by the *IESO*, the *ancillary service provider* shall immediately provide the *IESO* with notice to this effect.

1.3.6 Each *ancillary service provider* shall:

1.3.6.1 notify the *IESO* immediately upon the *forced outage* of the *AVR* at its *registered facility* that is a *generation facility* or *electricity storage facility* being forced out of service; or

1.3.6.2 for *planned outages,* prior to the *AVR* being removed from its *registered facility* that is a *generation facility* or *electricity storage facility* for maintenance, follow the procedures outlined in section 6.

1.3.7 Following a *contingency event*, each *registered facility* that is a *generation facility* or an *electricity storage facility* shall automatically respond to provide or absorb the reactive power in accordance with the established maximum and minimum reactive power capabilities of such *registered facility*. Each *ancillary service provider* shall immediately notify the *IESO* whenever its *registered facility* that is a *generation facility* or an *electricity storage facility* cannot perform to the established maximum and minimum reactive power capabilities of such *registered facility.*

1.4 Reactive Support and Voltage Control – Facilities that are neither Generation nor Electricity Storage

1.4.1 Except for *forced outages* and *planned outages* coordinated with the *IESO* pursuant to these *market rules*, each *transmitter* shall keep its transmission assets in service at all times unless released from service by the *IESO* or directed by the *IESO* to be removed from service pursuant to this section 1.4.

1.4.2 The *IESO* may direct a *transmitter* to remove transmission assets from service to the extent necessary to maintain reactive support and voltage control.

1.4.3 Each *connected wholesale customer, transmitter* and *distributor connected* to the *IESO-controlled grid* providing *reactive support service* and *voltage control service* shall respond immediately following receipt of a direction from the *IESO* with respect to directions concerning but not limited to, static capacitors, static VAR compensators and reactors. For directions concerning synchronous condensers, the response time will be as soon as practicable recognizing the device characteristics and operating state of the device at the time of receipt of the *IESO's* direction. Each such *ancillary service provider* shall immediately notify the *IESO* whenever the devices referred to in this section 1.4.3 cannot be switched in accordance with the *IESO* direction.

1.5 Black Start

1.5.1 A *certified black start facility* will be tested and/or assessed for its ability to comply with the performance standards as specified in its *contracted ancillary services* contract for *certified black start facilities*.

1.5.2 Prior to registering a *generation facility* as a *certified black start facility,* the *IESO* shall be satisfied that the *generator* has demonstrated through completion of tests and assessments that the *generation facility* can provide sufficient MWs and MVARs to:

1.5.2.1 energize or assist in energizing the specified transmission path within the applicable time period referred to in section 1.5.7;

1.5.2.2 provide *energy* requirements along such transmission path, including the requirements of any load connected to the transmission path; and

1.5.2.3 provide start-up power to the *generation facility* as specified by the *IESO* which will meet the objectives and priorities of the *Ontario power system restoration plan*.

1.5.3 A *certified black start facility* will be tested and/or assessed for its ability to maintain voltage within emergency voltage limits over a range of loading from no external load to full external load in accordance with *reliability standards*.

1.5.4 A *certified black start facility* must be equipped with governors that are capable of operating in an isochronous mode.

1.5.5 Adequate transmission capacity shall be available to connect the *certified black start facility* to the source providing station services to other specified generation stations referred to in 1.5.8.

1.5.6 A *generator* operating a *certified black start facility* shall make efforts consistent with *good utility practice* to comply with a direction from the *IESO* to deliver power without assistance from the electrical system unless:

1.5.6.1 the *certified black start facility* is on an *outage*, which *outage* is not a removal of the *certified black start facility* from service caused by the de-energization of the electrical network to which the *certified black start facility* is connected, or

1.5.6.2 where to do so would endanger the safety of any person, damage equipment, or violate any *applicable law*, regulation, or operating limit.

1.5.7 A *certified black start facility* will be tested and/or assessed for its ability to start and energize the applicable transmission path specified in 1.5.2.1 as follows:

1.5.7.1 if the *certified black start facility* is comprised of a hydroelectric *generation unit* or a *generation unit* that generates using aero-derivative gas turbines, within 30 minutes of the initiation of the black start process;

1.5.7.2 if the *certified black start facility* is comprised of a *generation unit* that generates using industrial gas turbines, within 60 minutes of the initiation of the black start process;

1.5.7.3 if the *certified black start facility* is comprised of a *generation unit* that generates using hot, steam-driven turbines, within 2.5 hours of the initiation of the black start process; and

1.5.7.4 if the *certified black start facility* is in another operating state or is comprised of an unspecified technology, within such time as may be specified in its *contracted ancillary services* contract for *certified black start facilities*.

1.5.8 A *certified black start facility* will be tested and/or assessed for its ability to provide startup power for the period of time it takes to switch the applicable transmission path specified in section 1.5.2.1 into service and to complete the start-up process at the generating station specified in section 1.5.2.3.

1.5.9 A *certified black start facility*:

1.5.9.1 referred to in section 1.5.7.1, 1.5.7.2 or 1.5.7.3 will be tested and/or assessed for its ability to complete three successive starts within eight hours of the initiation of the black start process; or

1.5.9.2 referred to in section 1.5.7.4, will be tested and/or assessed for its ability to complete such number of successive starts within such period of time as may be specified in its *contracted ancillary services* contract for *certified black start facilities*.

1.5.10 A *certified black start facility* will be tested and/or assessed for its ability to produce the range of reactive power resources required by the *IESO-controlled grid* as described in Chapters 4, 5 and 7.

1.5.11 A *certified black start facility* must participate in the training activities and restoration drills referred to in sections 11.3.7.1 and 11.3.7.2, respectively.

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Market Rules

Chapter 6

Wholesale Metering

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1. Introduction

1.1 Application and Interpretation

1.1.1 This Chapter applies to the following:

1.1.1.1 the *IESO*;

1.1.1.2 *market participants*; and

1.1.1.3 *metering service providers*.

1.1.2 Nothing in this Chapter shall affect the obligation of any *market participant*, *metered market participant* or *metering service provider* to comply with all applicable *federal metering requirements* provided that, where this Chapter or a policy or standard established by the *IESO* pursuant to this Chapter prescribes a higher standard than that prescribed by *federal metering requirements*, the relevant *market participant*, *metered market participant* or *metering service provider* shall, for purposes of this Chapter, comply with such higher standard.

1.1.3 This Chapter does not apply to an *intertie metering point*.

1.1.4 This Chapter does not apply to a *metering installation* that is not used or required by these *market rules* to be used for *settlement* purposes in the *IESO-administered markets*.

1.2 Purpose

1.2.1 The purpose of this Chapter is to set out the rights and obligations of *market participants, metered market participants* and the *IESO*, and the rights, obligations and qualifications of *metering service providers* associated with the measurement of *energy*; the registration, provision, installation, commissioning, maintenance, repair, replacement, inspection, testing and audit of *metering installations;* and the provision, security and accuracy of *metering data* relating to the *real-time markets* or the *procurement markets.*

1.2.2 Nothing in this Chapter shall preclude a *metered market participant* from applying, or from permitting a *metering service provider* to apply, evolving technologies and processes relating to *metering* as they become available provided that such application is effected in accordance with section 12.1.1.

2. Requirements for Metering Installations

2.1.1 Subject to section 2.1.5, the *IESO* shall not permit a person to participate in the *real-time markets* or the *procurement markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of a *connection point*, other than an *interconnection*, or in respect of an *embedded connection point* unless the *IESO* is satisfied that:

2.1.1.1 the *connection point* or *embedded connection point* has an associated *metering installation* that, subject to section 4.4, complies with the requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter. A single *metering installation* may be associated with more than one *connection point* or *embedded connection point*;

2.1.1.2 if the person is or will be the *metered market participant* for the *metering installation* referred to in section 2.1.1.1:

a. the person has entered into an agreement under section 3.1.2.2(a) in relation to the *metering installation* or is a *metering service provider*; and

b. if the person is also an *embedded market participant*, has advised the relevant *distributor* or *transmitter* of the entering into of the agreement referred to in section 2.1.1.2(a); and

2.1.1.3 either

a. such *metering installation* has been and continues to be registered with the *IESO* in accordance with the procedures referred to in section 6.1.2., or

b. such *metering installation* has been registered with the *IESO* in accordance with the procedures referred to in section 6.1.2 and the registration has expired provided that the *IESO* determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*.

2.1.2 The *IESO* shall refuse to permit a person to participate in the *real-time markets* or the *procurement markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* in respect of any *connection point*, other than an *interconnection*, or an *embedded connection point* if the conditions set forth in section 2.1.1 are not satisfied. Such refusal is a *reviewable decision*.

2.1.3 [Intentionally left blank – section deleted]

2.1.4 This Chapter applies in respect of a *metering installation* that measures the consumption of *energy* in accordance with section 2.1A.1 of Chapter 9.

Temporary Withdrawal of Electricity without a Registered Wholesale Meter

2.1.5 The *IESO* may permit a *market participant* to withdraw electricity temporarily from the *IESO-controlled grid* at a *connection point* without a *metering installation* being registered with the *IESO* for that *connection point* under the conditions specified in the applicable *market manual*.

3. Metered Market Participants

3.1 General Obligations

3.1.1 Each *metered market participant* shall:

3.1.1.1 ensure that, subject to section 4.4, each *metering installation* in respect of which it is the *metered market participant* complies with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

3.1.1.2 comply with the obligations imposed on *metered market participants* in Appendix 6.1 and in any policy or standard established by the *IESO* pursuant to this Chapter; and

3.1.1.3 coordinate electronic access, by persons other than the *IESO*, to each *metering installation* in respect of which it is the *metered market participant* so as to prevent such persons from accessing the *metering installation* at a time or in a manner that may adversely affect the ability of the *IESO* to access the *metering data* in that *metering* *installation* in accordance with the notice given pursuant to section 8.1.7.

3.1.2 Each *metered market participant* shall:

3.1.2.1 if registered as a *metering service provider*:

a. subject to section 4.4, register, provide, install, commission, maintain, repair, replace, inspect and test each *metering installation* in respect of which it is the *metered market participant* in accordance with the provisions of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter;

b. comply with all of the obligations imposed on *metering service providers* in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

c. provide to the *IESO* the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and update such information as required to maintain such information current; and

d. where the *metering installation* is associated with more than one *connection point*, *defined meter point* or *facility*, on a timely basis review and update the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and provide it to the *IESO*:

i. annually; and

ii. when material changes are made to the *IESO-controlled grid* downstream of the *metering installation* including the application by another *metered market participant* to register a different *metering installation* downstream of the *metering installation*; or

3.1.2.2 if not registered as a *metering service provider*:

a. enter into an agreement with a *metering service provider* for the registration, provision, installation, commissioning, maintenance, repair, replacement, inspection and testing by that *metering service provider* of each *metering installation* in respect of which it is the *metered market participant*;

b. ensure that its *metering service provider* provides the *IESO* with the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and updates such information as required to maintain that information current;

c. where the *metering installation* is associated with more than one *connection point*, *defined meter point* or *facility*, on a timely basis ensure that its *metering service provider* reviews and updates the information referred to in sections 1.2 and 1.3 of Appendix 6.5 and provide it to the *IESO*:

   i. annually; and

   ii. when material changes are made to the *IESO-controlled grid* downstream of the *metering installation* including the application by another *metered market participant* to register a different *metering installation* downstream of the *metering installation*; and

d. be liable to the imposition of financial penalties and other sanctions, in accordance with Chapter 3, in respect of the failure by each *metering service provider* that acts as a *metering service provider* for a *metering installation* in respect of which it is the *metered market participant* to comply with the obligations imposed on *metering service providers* in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

3.1.3 Nothing in section 3.1.2 shall prevent a *metered market participant* from entering into an agreement with one *metering service provider* for the provision, installation and commissioning of a *metering installation* and entering into a separate agreement with another *metering service provider* under which that other *metering service provider* assumes responsibility for all subsequent maintenance, repair, replacement, inspection and testing of that *metering installation.*

3.1.4 Each *metered market participant* shall bear all costs and expenses associated with:

3.1.4.1 the registration, provision, installation, commissioning, maintenance, repair, replacement and inspection of each *metering installation* for which it is the *metered market participant*;

3.1.4.2 the routine testing, as described in section 7.1.1, of each *metering installation* in respect of which it is the *metered market participant*;

3.1.4.3 the testing, other than the routine testing referred to in section 3.1.4.2, and audit of each *metering installation* in respect of which it is the *metered market participant* where such costs and expenses are required to be borne by the *metered market participant* pursuant to section 7.3.1;

3.1.4.4 the security and accuracy of all *metering data* recorded in each *metering installation* for which it is the *metered market participant* and the transfer of such *metering data* to the communication interface of the *metering database*; and

3.1.4.5 gaining its own access to the *metering registry*, the *metering database* and the *metering data* recorded in each *metering installation* for which it is the *metered market participant*.

3.1.5 Nothing in section 3.1.4 shall prevent a *metered market participant* from entering into an agreement with a person pursuant to which agreement such person agrees to indemnify the *metered market participant* in respect of some or all of the costs and expenses referred to in section 3.1.4.

3.2 Transitional Arrangements

3.2.1 Notwithstanding any other provision of this Chapter, a person that owns a *metering installation* that is in service on the date of coming into force of this section 3.2 or that is brought into service between the date of coming into force of this section 3.2 and the *market commencement date* shall, unless an election is made by such person pursuant to section 3.2.2, apply for registration as a *metering service provider* and shall act as the *metering service provider* in respect of such *metering installation* from the *market commencement date* until the earliest expiry date of any seal period of any *meter* forming part of such *metering installation*. Once such seal period expires, the *metered market participant* for the *metering installation* shall make such alternative arrangements as may be necessary to comply with the provisions of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter.

3.2.2 A person that owns a *metering installation* that is in service on the date of coming into force of this section 3.2 may elect to enter into an agreement with a *metering service provider* pursuant to which that *metering service provider* acts as the *metering service provider* in respect of such *metering installation*.

3.2.3 Notwithstanding section 3.1.2.2(c), a *metering service provider* designated as such pursuant to section 3.2.1 or 3.2.2, shall, in addition or in lieu of any liability that may be imposed on a *metered market participant* pursuant to section 3.1.2.2(c), be liable to the imposition of financial penalties and other sanctions, in accordance with the enforcement provisions of Chapter 3, in respect of a failure by the *metering service provider* to comply with the obligations imposed on *metering service providers* in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter, and for such purposes, *metering service providers* shall be deemed as *market participants*. Such *metering service providers* shall only be subject to such liability in respect of *metering installations* for which they are designated as *metering service providers* pursuant to section 3.2.1 or 3.2.2 and only until the earliest expiry date of any seal period of any *meter* forming part of the *metering installation*.

4. Metering Installation

4.1 Metering Installation Standards

4.1.1 Subject to sections 4.1.2, 4.4, and 4.6, each *metering installation* shall:

4.1.1.1 contain *meters* that are of a type that are described on the list of conforming *meters* established by the *IESO*;

4.1.1.2 be comprised of two *meters*, at least one of which shall be a *revenue meter* that meets or exceeds the 0.2% accuracy class of ANSI standard C12.20*;*

4.1.1.3 have *instrument transformers* whose current transformers and voltage transformers meet or exceed the 0.3% accuracy class of ANSI standard C57.13;

4.1.1.4 meet the accuracy requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.1.5 meet the security requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.1.6 subject to section 10.3.2, be capable of collating *metering data* into *dispatch intervals*;

4.1.1.7 be capable of separately registering and recording flows in each direction where bi-directional active *energy* flows may occur;

4.1.1.8 be capable of allowing remote access to the *metering data* contained in the *metering installation* in the manner set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.1.9 be capable of storing *metering data* for at least 35 days; and

4.1.1.10 comply with all other requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.1.2 A *metering installation* may exceed the level of accuracy and other requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.1.3 No *metering installation* shall be placed into service unless:

4.1.3.1 it has been commissioned in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter;

4.1.3.2 the communication equipment forming part of the *metering installation* has successfully passed an end-to-end test; and

4.1.3.3 it has been registered with the *IESO* in accordance with the procedures described in section 6.1.2.

4.1.4 The *IESO* shall, upon request by a *metered market participant* or a *metering service provider*, review conceptual drawings for a metering installation proposed to be installed by the *metered market participant* or the *metering service provider*.

4.1.5 A *metered market participant* or a *market participant,* with the agreement of the relevant *metered market participant*, may arrange for a *metering installation* to contain features in addition to those specified in section 4.1.1 and in the requirements, policies or standards referred to in that section.

4.1.6 Subject to section 4.1.7, where a *metering installation* is intended to be used for a purpose in addition to the collection, recording and storage of *metering data* and the transfer of *metering data* to the *IESO,* the *metered market participant* for the *metering installation* shall:

4.1.6.1 ensure that such use shall not interfere with the ability of the *metering installation* to perform or function in accordance with section 4.1.1 and the requirements, policies and standards referred to in that section;

4.1.6.2 obtain the prior approval of the *IESO* for such use and shall co-ordinate with any person that uses the *metering installation* for such other purposes to ensure that such use does not interfere with the ability of the *metering installation* to perform or function in accordance with section 4.1.1 and with the requirements, policies and standards referred to in that section; and

4.1.6.3 ensure that such use complies with all applicable *federal metering requirements*.

4.1.7 Each *metered market participant* shall ensure that any *instrument transformer* forming part of a *metering installation* in respect of which it is the *metered market participant* is not used for a purpose other than the measurement of *energy* for *settlement* purposes unless:

4.1.7.1 the instrument transformer is part of a *main/alternate metering installation*;

4.1.7.2 the *instrument transformer* is not connected to the *revenue meter* that has been designated by the *metered market participant* as the main *revenue meter* as reflected in the registration information pertaining to the *main/alternate metering installation*; and

4.1.7.3 the *instrument transformer* is operated within the rated burden limits for the accuracy class referred to in section 4.1.1.4.

or

4.1.7.4 the *metering installation* is registered under section 4.6 and the *IESO* has approved the placing of additional loads on the *instrument transformer* under section 4.6.6.

4.1A Metering Installations for Segregated Mode of Operation

4.1A.1 Subject to section 4.4, no *metered market participant* may operate a *registered facility* in a *segregated mode of operation* unless the *metering installation* for that *registered facility* generates *metering data* that reads zero, or is capable of such adjustment as may be required to ensure that such *metering data* reads zero, when the *registered facility* is operating in a *segregated mode of operation*.

4.2 Defined Meter Point and Error Correction Factors

4.2.1 Subject to section 4.4, each *metered market participant* shall ensure, in respect of each *metering installation* for which it is the *metered market participant*, that:

4.2.1.1 subject to sections 4.2.2 and 4.2.2A, the *meter point* is located at the *defined meter point* for the *facility* to which the *metering installation* relates and otherwise complies with all requirements for *meter points* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.2.1.2 [Intentionally left blank – section deleted]

4.2.2 The *IESO* shall permit a *metering installation* to be registered in respect of a *facility* notwithstanding that the *meter point* is not located at the *defined meter point* provided that all transfers of *energy* at any points of supply or consumption for the *facility* to which the *metering installation* relates are separately *metered* in a manner satisfactory to the *IESO*.

Metering Installation Associated with More than One Defined Meter Point and/or Facility

4.2.2A The *IESO* shall permit a *metering installation* to be associated with more than one *facility* notwithstanding that the *meter point* is not located at the *defined meter points* for the *facilities,* provided that all transfers of *energy* at any points of supply or consumption for the *facilities* to which the *metering installation* are associated, are determined in a manner satisfactory to the *IESO*.

Where a *metered market participant* intends that such a *metering installation* is to be used for determining *settlement amounts* instead of one or more pre-existing downstream *metering installations,* the *IESO* shall not permit the use of the upstream *metering installation* for determining *settlement amounts* unless the *metered market participant* demonstrates, to the satisfaction of the *IESO* in accordance with the applicable *market manual*, the accuracy of the *energy* transfer measurements of the upstream *metering installation* relative to the downstream *metering installations*.

4.2.2B When developing the conditions of satisfaction referred to in section 4.2.2A, the *IESO* shall be guided by the principle that all *market participants* are to be held financially whole by the use of the upstream *metering installation*.

4.2.3 The *IESO* shall, in respect of *metering data* recorded in the *metering database* that was obtained from a *metering installation* whose *meter point* is not located at the *defined meter point* for a *facility* to which the *metering installation* relates, adjust the *metering data* on the basis of the site-specific loss adjustments referred to in section 4.2.4 or 4.2.5.1 and, where applicable, on the basis of the loss adjustments provided pursuant to section 4.2.5.2.

4.2.4 Where the *defined meter point* in respect of a *facility* is a *connection point* and the *meter point* of the *metering installation* for that *facility* is located other than at the *defined meter point*, the *metering service provider* for the relevant *metering installation* shall provide to the *IESO*, at the time of registration of the *metering installation*, in accordance with section 4.2.6, the parameters for site specific loss adjustments required to reflect losses between the *meter point* and the *defined meter point*.

4.2.5 Where the *defined meter point* in respect of a *facility* is an *embedded connection point* and the *meter point* is not located at the *defined meter point*, the *metering service provider* for the relevant *metering installation* shall provide to the *IESO*, at the time of registration of the *metering installation*:

4.2.5.1 the parameters for site specific loss adjustments to reflect losses between the *meter point* and the *embedded connection point*, in accordance with section 4.2.6; and

4.2.5.2 the loss adjustments required to reflect losses between the *defined meter point* for the *primary RWM* associated with the *facility* and the *defined meter point* for the *embedded RWM* associated with the *facility*, obtained where applicable from the relevant *transmitter* or *distributor*, as the case may be depending on the owner of the *facilities* to which the *facility* to which the *meter point* relates is connected.

4.2.6 The parameters for site specific loss adjustments referred to in sections 4.2.4 and 4.2.5.1 shall comply with the requirements of any site specific loss adjustment policy or standard established by the *IESO* and shall be updated by each *metering service provider* as may be required by the *IESO*.

4.2.7 Each *metering service provider* shall provide to the *IESO* measurement error correction factors for each *metering installation* in respect of which it acts as a *metering service provider* in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter.

4.3 Use of Metering Data and Metering Data Collection

4.3.1 *Metering data* shall be used by the *IESO* for *settlement* purposes following completion of the validation and, where applicable, substitution and estimation processes, in the manner set forth in Chapter 9.

4.3.2 Each *metering installation* shall:

4.3.2.1 have a communication link to the relevant telecommunication network, and, where required, isolation equipment approved under applicable telecommunications laws and regulations; and

4.3.2.2 be capable of remote communication by electronic means from the site of the *metering installation* to the communication interface of the *metering database*.

4.3.3 Each *metered market participant* shall ensure that all *metering data* contained in each *metering installation* for which it is the *metered market participant* is made available and transferred to the communication interface of the *metering database* in accordance with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter. The *IESO* may use *data collection systems* operated by meter data management agencies for the purpose of the transfer of *metering data* to the *metering database*.

4.3.4 Each *metered market participant* shall ensure that all *metering data* in each *metering installation* for which it is the *metered market participant* is transferred to the communication interface of the *metering database* in a manner that preserves the security from access and the accuracy of such *metering data* as described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.3.5 The *IESO* shall ensure that all *metering data* that has been transferred to the communication interface of the *metering database* is transferred from such communication interface to the *metering database* in a manner that preserves the security of access and the accuracy of such *metering data* as described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

4.3.6 No *metered market participant* shall use a protocol or data format in respect of the transfer of *metering data* from a *metering installation* to a *data collection system* unless that protocol or data format has been approved by the *IESO*.

4.3.7 Each *metered market participant* shall ensure that *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* that is transferred to the communication interface of the *metering database* is in a data format that is compatible with the data format used by the *IESO* for the retrieval of *metering data* from such communication interface.

4.4 Alternative Metering Installation Standards

Obligations of Metered Market Participants

4.4.1 A *metered market participant* with a *metering installation* registered under section 4.4.3, shall ensure that the *metering installation* meets the requirements set forth in the alternative standards specified in Appendix 6.2.

Registration Under the Alternative Metering Installation Standard

4.4.2 A *metering service provider* applying to register a *metering installation* under the alternative standards specified in Appendix 6.2 shall submit to the *IESO*:

4.4.2.1 an application for registration specifying the alternative *metering installation* standard(s) for which registration is sought;

4.4.2.2 applicable supporting information as specified in Appendix 6.2; and

4.4.2.3 information otherwise required by Chapter 6 or the applicable *market manual*.

4.4.3 The *IESO* shall register the *metering installation* provided that, in the opinion of the *IESO,* the *metering service provider* meets the requirements of section 4.4.2. Where the *IESO* is not satisfied that the requirements of section 4.4.2 have been met, it shall refuse to register the *metering installation*. The *IESO* shall so notify the applicant, together with the reasons for refusal. Such a refusal is a *reviewable decision*.

Expiry and Revocation of Registration

4.4.4 Registration granted under section 4.4.3, in respect of a particular alternative standard, shall expire on the earlier of:

4.4.4.1 the date specified in Appendix 6.2 for that alternative standard; and

4.4.4.2 the date on which registration is revoked by the *IESO* under section 4.4.6.

4.4.5 Subject to section 4.4.8, prior to the expiry of registration of a *metering installation* under the alternative standard, the *metered market participant* for that *metering installation* shall ensure that the *metering installation* is brought into full compliance with the applicable requirements set forth in this Chapter and in any policy or standard established by the *IESO* under this Chapter.

4.4.6 The *IESO* may revoke registration granted under section 4.4.3 in the circumstances described in Appendix 6.2.

4.4.7 If the *IESO* revokes the registration for a *metering installation* under section 4.4.6, the *metered market participant* for that *metering installation* shall ensure that the *metering installation* is brought into full compliance with the applicable requirements of this Chapter within the time specified in Appendix 6.2 and shall so notify the *IESO*.

Retaining Registration Under the Alternative Standard

4.4.8 Prior to the expiry of registration of a *metering installation* under the alternative standards specified in sections 1.2, 1.6, 1.7, 1.8, 1.9, 1.11, 1.12, and 1.13 of Appendix 6.2, the *metered market participant* may apply to the *IESO* to retain registration under those sections. The *IESO* shall grant the *metered market participant* the right to retain registration if, in the opinion of the *IESO,* the changes required for the *metering installation* meet the criteria specified in the applicable *market manual*. The *IESO* shall recover the cost of processing the application from the *metered market participant* in accordance with the applicable *market manual*.

Estimation of Metering Data for Settlement Purposes

4.4.9 Where a *metered market participant* fails to comply with section 4.4.5 or 4.4.7, the *IESO* shall take such action with respect to the estimation of *metering data* for *settlement* purposes as specified in section 1.14 of Appendix 6.2.

4.5 Alternative Metering Installation Standards for Embedded Generation Facilities

4.5.1 A *transmission customer* that has an *embedded generation facility* that:

4.5.1.1 registers that *generation facility* for the purpose of determining transmission charges;

4.5.1.2 is rated less than 20 MW; and

4.5.1.3 meets the applicable Ontario Uniform Transmission Rate Schedule requirements with respect to the transmission *delivery point* through which the *generation facility* is connected to the *transmission system* and attracts Line or Transformation Connection Service charges;

4.5.1.4 [Intentionally left blank – section deleted]

shall either comply with the *metering installation* standards specified elsewhere in this Chapter 6 or with the alternative *metering installation* standards specified in this section 4.5 for that *embedded generation facility*.

4.5.2 A *transmission customer* that chooses to meet the alternative *metering installation* standards of this section 4.5 for an *embedded generation facility* shall, in accordance with the applicable *market manual*, have their *metering service provider*:

4.5.2.1 register with the *IESO* a *metering point* for that *embedded generation facility.*

4.5.2.2 [Intentionally left blank – section deleted]

4.5.3 Within three months of the calendar year end, the *transmission customer* shall, for each *embedded generation facility* for which a *metering point* has been registered under the alternative *metering installation standards* of this section 4.5, in the manner specified in the applicable *market manual*:

4.5.3.1 determine the annual adjustment dollar value for the applicable *transmission services charges* based on the impact of the actual output of the *embedded generation facility*;

4.5.3.2 obtain agreement of the *transmitter* as to this adjustment amount; and

4.5.3.3 submit this information to the *IESO*.

4.5.4 In the event that the *IESO* does not receive the information specified in section 4.5.3 within the time specified in section 4.5.3, the *IESO* shall use the *maximum continuous rating* for the *embedded generation facility*, provided to the *IESO* at the time of the *meter point* registration referred to in section 4.5.2.

4.5.5 The *IESO* shall adjust the applicable *transmission service charge settlement amounts* by any such amount, submitted in accordance with section 4.5.3 or by the amount determined under section 4.5.4, for the *transmission customer* and the *transmitter*. The *IESO* shall make this adjustment on the applicable *settlement statement* for the last day of the month in which the adjustment information is received or the last day of the month in which the *IESO* determines the adjustment amount, whichever is applicable.

4.6 Metering Installation Standards for Embedded Generation Facilities Under 2 MVA or Injecting Less than 17 GWh Per Annum

4.6.1 A *market participant* that has a registered *minor generation facility* embedded within a *distribution system* and which either injects less that 17 gigaWatt-hours per annum or has a nameplate rating less than 2 MVA shall be eligible to register with the *IESO* a *metering installation* for that *generation facility* comprised of a standalone *meter.*

4.6.2 The standalone *meter* shall be either a main *meter* or an alternate *meter* from the *IESO's* conforming *meter* list.

4.6.3 The *metering service provider* for the *metering installation* registered under section 4.6.1 shall not be required to submit an emergency *instrument transformer* restoration plan otherwise required under section 1.3.2.17 of Appendix 6.5.

4.6.4 If there is a failure of an *instrument transformer* at a *metering installation* registered in accordance with this section, the *IESO* shall estimate the *metering data* from the *metering installation* for *settlement* purposes in accordance with section 11.1.4A of Chapter 6 for the duration of the failure.

4.6.5 The *metered market participant* for a *meter* registered in accordance with this section shall not be required to meet the testing requirements specified in section 1.2 of Appendix 6.3.

4.6.6 The *metered market participant* for a *metering installation* registered in accordance with this section shall, subject to *IESO* approval, be permitted to place additional loads on its *instrument transformer*.

4.6.7 Within three months from the date of notification by the *IESO*, a *metered market participant* shall make a *metering installation* fully compliant with the *metering installation* standards specified elsewhere in Chapter 6 if the *energy* threshold recorded by the standalone *meter* exceeds 17 gigaWatt-hours per annum.

5. Metering Service Providers

5.1 Registration

5.1.1 No person may perform the activities required by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter to be performed by a *metering service provider* unless that person has been registered by the *IESO* as a *metering service provider.*

5.1.2 No person shall be registered by the *IESO* as a *metering service provider* unless the person demonstrates to the satisfaction of the *IESO* that the person has the qualifications described in Appendix 6.4.

5.1.3 Any person including, but not limited to, a *market participant* or a *metered market participant*, that wishes to be registered by the *IESO* as a *metering service provider* shall file with the *IESO*:

5.1.3.1 a completed application for registration as a *metering service provider* in such form as shall be established by the *IESO*;

5.1.3.2 an executed agreement, in such form as shall be established by the *IESO*, pursuant to which the person agrees, among other matters, to be bound by and comply with the provisions of the *market rules* applicable to *metering service providers*; and

5.1.3.3 the application fee established from time to time by the *IESO*, and approved by the *OEB*, to defray the costs of processing the application, conducting the systems and procedures tests and audits referred to in section 5.1.6 and conducting the review referred to in section 5.1.13.

5.1.4 The *IESO* shall, within ten *business days* of receiving an application for registration as a *metering service provider* or within such longer period of time as may be agreed between the *IESO* and the applicant, notify the applicant of any further information or clarification that is required in support of its application if, in the *IESO's* opinion, the application is:

5.1.4.1 incomplete; or

5.1.4.2 contains information with respect to which the *IESO* requires clarification.

5.1.5 If the further information or clarification which is requested by the *IESO* pursuant to section 5.1.4 is not provided to the *IESO's* satisfaction within fifteen *business days* of the request or within such longer period of time as may be agreed between the *IESO* and the applicant, the applicant shall be deemed to have withdrawn its application for registration as a *metering service provider*.

5.1.6 The *IESO* may, if the applicant does not have ISO 9000 certification, conduct such audits or tests of the applicant's systems and procedures as the *IESO* determines appropriate.

5.1.7 The *IESO* shall, within twenty *business days* of:

5.1.7.1 receipt of the application for registration as a *metering service provider*;

5.1.7.2 receipt of the further information or clarification requested under section 5.1.4; or

5.1.7.3 the conduct of any audits or tests referred to in section 5.1.6,

whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, notify the applicant that the *IESO* intends to register the person as a *metering service provider* upon completion of the review referred to in section 5.1.13, on such terms and conditions as the *IESO* considers appropriate, if the applicant has demonstrated to the *IESO*'s satisfaction that it has the qualifications set forth in Appendix 6.4. If the applicant has ISO 9000 certification, the *IESO* shall, together with the notice of intention to register the applicant, refund that portion of the application fee referred to in section 5.1.3.3 that is attributable to the costs of conducting the systems and procedures tests and audits referred to in section 5.1.6.

5.1.8 If the *IESO* is not satisfied that the applicant has demonstrated that it has the qualifications set forth in Appendix 6.4, the *IESO* shall, within twenty *business days* of receipt of the application for registration as a *metering service provider*, of receipt of the further information or clarification requested under section 5.1.4 or of any audits or tests referred to in section 5.1.6, whichever is the later, or within such longer period of time as may be agreed between the *IESO* and the applicant, notify the applicant that the *IESO* intends to deny its application for registration as a *metering service provider*. Such notice shall identify the deficiency in the applicant's qualifications that formed the grounds for the issuance of the notice.

5.1.9 An applicant to whom a notice is issued in accordance with section 5.1.8 shall have 20 *business days* from the date of receipt of such notice, or such longer period of time as may be agreed between the *IESO* and the applicant, in which to rectify the deficiency in its qualifications identified in such notice and to notify the *IESO* of such rectification.

5.1.10 Where the *IESO* is satisfied that, with the rectification described in section 5.1.9, the applicant has demonstrated that it meets the qualifications set forth in Appendix 6.4, the *IESO* shall notify the applicant that the *IESO* intends to register the person as a *metering service provider* upon completion of the review referred to in section 5.1.13, on such terms and conditions as the *IESO* considers appropriate.

5.1.11 Where:

5.1.11.1 an applicant to whom a notice is issued in accordance with section 5.1.8 fails to rectify the deficiency in its qualifications within the time specified in that section; or

5.1.11.2 the rectification described in section 5.1.9 is not such as to satisfy the *IESO* that the applicant meets the qualifications set forth in Appendix 6.6,

the *IESO* shall:

5.1.11.3 notify the applicant in writing that its application for registration as a *metering service provider* has been denied;

5.1.11.4 if the *IESO* has not conducted the systems and procedures tests and audits referred to in section 5.1.6, return to the applicant that portion of the application fee referred to in section 5.1.3.3 that is attributable to the costs of conducting such tests and audits; and

5.1.11.5 return to the applicant that portion of the application fee referred to in section 5.1.3.3 that is attributable to the costs of conducting the review described in section 5.1.13.

5.1.12 Denial by the *IESO* of an application for registration as a *metering service provider* is a *reviewable decision*.

5.1.13 The *IESO* shall review with each applicant referred to in sections 5.1.7 and 5.1.10:

5.1.13.1 the procedures for the registration of *metering installations* described in this Chapter and in the procedures established by the *IESO* pursuant to section 6.1.2 of this Chapter; and

5.1.13.2 the performance standards for *metering service providers* set forth in the applicable *market manual*.

5.1.14 The *IESO* shall, within five *business days* of completion of the review referred to in section 5.1.13, register the person as a *metering service provider*, on such terms and conditions as the *IESO* considers appropriate, and shall notify the applicant accordingly.

5.1.15 Each applicant for registration as a *metering service provider* and each *metering service provider* shall forthwith notify the *IESO* of any circumstances that result or are likely to result in a change in the information provided in the person's application for registration as a *metering service provider* or any updates thereto.

5.1.16 The *IESO* shall establish, maintain, update and *publish*:

5.1.16.1 a list of all persons that have been registered as *metering service providers*; and

5.1.16.2 a list of each *metering service provider* whose registration as a *metering service provider* has been revoked pursuant to section 5.3.

5.2 Activities and Standards for Metering Service Providers

5.2.1 The activities described in section 1.3 of Appendix 6.1 shall be performed by a *metering service provider*.

5.2.2 Each *metering service provider* shall comply with all of the obligations imposed on *metering service providers* in Appendix 6.1 and in any policy or standard established by the *IESO* pursuant to this Chapter.

5.2.3 Each *metering service provider* shall meet all performance standards as set forth in the applicable *market manual*.

5.2.4 Where the provision of written meter-related materials or of post-registration familiarization and competency updating or upgrading to a metering service *provider* imposes a significant expense on the *IESO*, such documentation, assistance or training may be provided upon payment by the *metering service provider* of a reasonable fee.

5.3 Revocation of Registration of Metering Service Providers

5.3.1 The *IESO* may revoke the registration of a *metering service provider* where the *metering service provider*:

5.3.1.1 has been found to be in breach of the *market rules* applicable to *metering service providers* on a persistent basis;

5.3.1.2 fails to meet the performance standards set forth in the applicable *market manual* on a consistent basis;

5.3.1.3 has been found to be in breach of a material provision of the agreement referred to in section 5.1.3.2; or

5.3.1.4 ceases to satisfy any material qualification for registration as a *metering service provider* or any material requirement imposed upon it as a condition of registration as a *metering service provider*.

5.3.2 Where the *IESO* intends to revoke the registration of a *metering service provider*, the *IESO* shall give notice to the *metering service provider* and to all *metered market participants* for whom the *metering service provider* is, to the *IESO's* knowledge, acting as *metering service provider*. The notice shall specify:

5.3.2.1 the grounds upon which the *metering service provider's* registration is proposed to be revoked and details of any evidence on which the *IESO* is relying in support of its intention to revoke such registration;

5.3.2.2 that the *metering service provider* may within 10 *business days* make written representations as to why its registration should not be revoked; and

5.3.2.3. the right of the *metering service provider* to request a hearing before the *IESO Board* or a committee of the *IESO Board* established for such purpose to show cause why its registration should not be revoked.

5.3.3 Following expiry of the time noted in section 5.3.2.2, and after consideration of any representations made by the *metering service provider* pursuant to that section, the *IESO* may:

5.3.3.1 subject to section 5.3.4, revoke the *metering service provider's* registration; or

5.3.3.2 make such order as the *IESO* determines appropriate, including but not limited to an order:

a. directing the *metering service provider* to do, within a specified period, such things as may be necessary to comply with the *market rules* applicable to *metering service providers*;

b. directing the *metering service provider* to cease, within a specified period, the act, activity or practice constituting a breach of the *market rules* or a breach of a material provision of the agreement referred to in section 5.1.3.2; and

c. imposing additional or more stringent terms and conditions in respect of the continued registration of the *metering service provider*.

5.3.4 Where the *metering service provider* has requested a hearing pursuant to section 5.3.2.3, the *IESO Board* or a committee of the *IESO Board* established for such purpose shall conduct a hearing providing the *metering service provider* with a reasonable opportunity to show cause as to why its registration should not be revoked by the *IESO*. In such case, the *IESO* shall not revoke the *metering service provider's* registration under section 5.3.3.1 until such hearing has been held.

5.3.5 All rights of a *metered service provider* to perform the activities of a *metering service provider* under this Chapter shall be terminated upon revocation of the *metering service provider's* registration.

5.3.6 The *IESO* shall, immediately upon revoking the registration of a *metering service provider*, notify each *metered market participant* for whom the *metering service provider* was, to the *IESO's* knowledge, acting as *metering service provider* at the time of revocation, of the revocation of the *metering service provider's* registration.

5.3.7 A *metering service provider* whose registration has been revoked by the *IESO* remains subject to and liable for all of its liabilities and financial obligations as a *metering service provider* which were incurred or arose under the *market rules* prior to the date on which it's registration is revoked regardless of the date on which any claim relating thereto may be made.

5.3.8 A *metering service provider* whose registration has been revoked and that wishes to be re-registered a *metering service provider* shall be required to re-apply for registration in accordance with section 5.1. The *IESO* may impose such terms and conditions on the registration of the *metering service provider* as the *IESO* determines appropriate in the circumstances, whether or not such terms and conditions are otherwise applicable to other *metering service providers*.

5.3.9 A decision by the *IESO* to revoke the registration of a *metering service provider* is a *reviewable decision* and shall be without prejudice to the right of the *IESO* to impose upon the *metered market participant* for whom the *metering service provider* is acting as *metering service provider* sanctions or financial penalties in accordance with Chapter 3 in respect of any breach of the *market rules* that formed the grounds for revocation of the *metering service provider's* registration.

6. Registration of Metering Installations and Metering Registry

6.1 Registration of Metering Installations

6.1.1 Subject to section 6.1.1A, no person shall use a *metering installation* for the measurement of *energy* for *settlement* purposes relating to the *real-time markets* or the *procurement markets* unless the *metering installation* has been registered by the *IESO* in accordance with this section 6.1 and that registration has not expired.

6.1.1.A A person may only use a *metering installation* for the measurement of *energy* for *settlement* purposes relating to the *real-time markets* or the *procurement markets* if the *metering installation* has been registered by the *IESO* in accordance with this section 6.1 and the registration has expired provided that the *IESO* determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*.

6.1.2 The *IESO* shall establish in the applicable *market manual* the procedures to be followed by *metering service providers* for the registration of *metering installations*. Such procedures shall include, but not be limited to, an identification of:

6.1.2.1 the information and documentation required to be submitted by a *metering service provider* in support of the registration of a *metering installation* including, but not limited to, the information described in sections 1.2, 1.3 and, where applicable, 1.3A of Appendix 6.5; and

6.1.2.2 the tests required to be conducted in respect of a *metering installation* prior to registration.

6.1.2A Each *metered market participant* for a *metering installation* that will be used for the purpose of the calculation and collection by the *IESO* of charges for *transmission service* shall, request the *metering service provider* for that *metering installation* to submit the *meter point* documentation for that *metering installation* and any updates thereto, to the *transmitter* identified by the *metered market participant* for the purpose of soliciting the written confirmation of that *transmitter's* approval referred to in section 1.3A of Appendix 6.5.

6.1.2B Each *metering service provider* to whom a request has been made pursuant to section 6.1.2A shall as soon as practicable submit the relevant *meter point* documentation or update referred to in that section to each *transmitter* identified in such request.

6.1.3 The *IESO* shall refuse to register a *metering installation*:

6.1.3.1 where the *metering installation* does not comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter; or

6.1.3.2 where the *metering installation* will be used for the calculation and collection of charges for *transmission service*, the relevant portion of the *meter point* documentation submitted in support of the application to register the *metering installation* is not accompanied by such confirmation of each applicable *transmitter* referred to in section 1.3A of Appendix 6.5.

6.1.4 Where the *IESO* refuses to register a *metering installation* pursuant to section 6.1.3, the *IESO* shall so notify the *metering service provider*, together with reasons for the refusal.

6.1.5 Refusal by the *IESO* to register a *metering installation* is a *reviewable decision*.

6.1.6 Each *metering service provider* shall, at the request of the *metered market participant* for a *metering installation*, provide that *metered market participant* with copies of all information, including but not limited to *meter point* documentation and data, submitted by the *metering service provider* in support of the application to register the *metering installation*, and of all updates to such information submitted to the *IESO* by the *metering service provider*.

6.1.7 Each *metering service provider* shall, at the request of a *transmitter* that has given confirmation of its approval of a portion of the applicable *meter point* documentation or any update thereto referred to in section 1.3A of Appendix 6.5, as may be applicable, provide that *transmitter* with copies of such *meter point* documentation submitted by the *metering service provider* in support of the application to register the *metering installation* and of all updates thereto submitted to the *IESO* by the *metering service provider*.

6.1.8 No *metering service provider* to whom a request has been made pursuant to section 6.1.2A has been made shall submit to the *IESO* any updates to any *meter point* documentation for a *metering installation* that will be used for the purpose of the calculation and collection by the *IESO* of charges for *transmission service* unless such updates are accompanied by the confirmation of the approval of each applicable *transmitter* referred to in section 1.3A of Appendix 6.5.

6.2 Metering Registry

6.2.1 The *IESO* shall establish and maintain a *metering registry* containing the information specified in Appendix 6.5 in respect of each *metering installation* that provides *metering data* used by the *IESO* for *settlement* purposes.

6.2.2 The *IESO* shall record in the *metering registry* the results of all tests provided to it pursuant to section 7.1.2, the results of any tests conducted pursuant to section 7.2.5 and any changes confirmed to it pursuant to section 9.3.1.3.

6.2.3 The data recorded in the *metering registry* in respect of a registered *metering installation* shall be available to:

6.2.3.1 the *metered market participant* for that *metering installation* and an authorized agent of such *metered market participant*;

6.2.3.2 the metering service provider for that *metering installation*;

6.2.3.3 any *market participant* whose *settlement statement* is determined on the basis of the *metering data* recorded in that *metering installation* and an authorized agent of such *market participant;* and

6.2.3.4 any *transmitter* or *distributor* to whose system a *facility* in respect of the *metering installation* relates is connected.

6.2.4 Data recorded in the *metering registry* is *confidential information* and the *IESO* shall ensure that such data is not accessible by or disclosed by the *IESO* to any person other than the *IESO* and the persons referred to in sections 6.2.3.1 to 6.2.3.4 or as otherwise permitted by section 5 of Chapter 3 or any policy of the *IESO* established pursuant to that section.

7. Testing and Auditing of Metering Installations

7.1 Testing and Auditing

7.1.1 Each *metered market participant* shall ensure that each *metering installation* in respect of which it is the *metered market participant* is inspected and tested by its *metering service provider* in accordance with the requirements set forth in Appendix 6.3.

7.1.2 Each *metered market participant* shall ensure that its *metering service provider* provides to the *IESO* the results of each test referred to in section 7.1.1.

7.1.3 The *IESO* shall review the results of all tests provided to it pursuant to section 7.1.2.

7.1.4 Where, following the review referred to in section 7.1.3, the *IESO* determines that an audit of a *metering installation* is required to assess the compliance of the *metering installation* with the requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter, the *IESO* shall arrange for the audit of the *metering installation*. The *metered market participant* for the *metering installation* shall ensure that the *IESO's* auditor is provided with unrestricted access to such *metering installation* for the purpose of such audit provided that the *IESO* has given the *metered market participant* notice of the audit no less than 5 *business days* in advance. *Metered market participant* shall carry out any additional testing the *IESO*'s auditor may require within 30 days of being requested to do so, or within such other time as the *metered market participant* and the IESO's auditor may agree. Notice of the audit shall specify:

7.1.4.1 the name of the person that will be conducting the audit; and

7.1.4.2 the date of the audit and the time at which the audit is expected to commence and conclude.

7.1.5 The *IESO* may carry out periodic, random and unannounced audits of a *metering installation* for the purpose of ascertaining whether the *metering installation* complies with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter. The *metered market participant* for the *metering installation* shall ensure that the *IESO's* auditor is provided with unrestricted access to the *metering installation* for the purpose of such audit.

7.1.6 The *IESO* shall, as soon as practicable, make the results of any audit conducted pursuant to section 7.1.4 or 7.1.5 available to the *metered market participant* for the *metering installation* to which the audit relates.

7.1.7 Each *metered market participant* shall, as soon as practicable, make the results of all tests conducted pursuant to section 7.1.1 and of all audits conducted pursuant to sections 7.1.4 and 7.1.5 available to the *distributor* or *transmitter* to whose system the *facility* to which the *metering installation* relates is connected.

7.2 Tests and Audits of Metering Data

7.2.1 A *market participant* may request the *IESO* to conduct an audit to determine the consistency between the *metering data* recorded in the *metering database* and the *metering data* recorded in the *metering installation* whose *meter point* is used to determine that *market participant's settlement statement*.

7.2.2 The *IESO* shall give the *metered market participant* in respect of the *metering installation* that will be the subject of an audit pursuant to section 7.2.1 notice of the audit no less than 5 *business days* in advance. Notice of the audit shall specify:

7.2.2.1 the name of the person that will be conducting the audit; and

7.2.2.2 the date of the audit and the time at which the audit is expected to commence and conclude.

7.2.3 The *IESO* shall conduct the audit referred to in section 7.2.1 and the *metered market participant* for the *metering installation* referred to in section 7.2.1 shall, provided that notice has been given in accordance with section 7.2.2, ensure that the *IESO's* auditor is provided with unrestricted access to the *metering installation* for the purpose of such audit.

7.2.4 The *IESO* shall, as soon as practicable, make the results of an audit conducted pursuant to section 7.2.1 available to the *market participant* that requested the audit and, if such *market participant* is not the *metered market participant* for the *metering installation*, to such *metered market participant.*

7.2.5 Provided that the *metering service provider* for a *metering installation* has provided to the *IESO* the necessary *meter* register dial readings pursuant to section 1.2.4 of Appendix 6.3 or such dial readings are available in the manner described in section 7.2.6, the *IESO* shall, no less than:

7.2.5.1 twice in each successive twelve-month period following the date of registration of a *metering installation* that is not a *main/alternate metering installation* and that is associated with a *facility* that has a minimum rated transformer or circuit capacity of less than 10 MW; or

7.2.5.2 four times in each successive twelve-month period following the date of registration of a *metering installation* that is not a *main/alternate metering installation* and that is associated with a *facility* that has a minimum rated transformer or circuit capacity of 10 MW or more, compare the *metering data* recorded in such *metering installation* over a given period of time with the *metering data* recorded in the *metering database* from that *metering installation* for the same period. The *IESO* shall, as soon as practicable, make the results of the comparison effected pursuant to this section available to the *metered market participant* for the *metering installation*.

7.2.6 The procedure referred to in section 7.2.5 may be executed during the transfer of the *metering data* to the *metering database* if the *meter* within the *metering installation* is capable of transmitting the necessary *meter* register dial readings.

7.2.7 An error detected as a result of the procedure referred to in section 7.2.5 that exceeds one multiplier, calculated as the current transformer ratio times the voltage transformer ratio times the *meter* register multiplier, shall be recorded by the *IESO* as an *outage* or defect, and the *IESO* shall so notify the *metered market participant* and issue a trouble call to the *metering service provider* in accordance with section 11.1.3.1.

7.2.8 If an audit conducted pursuant to section 7.2.1 or a comparison performed pursuant to section 7.2.5 reveals a discrepancy between the *metering data* recorded in a *metering installation* and the *metering data* recorded in the *metering database*, the *metering data* in the *metering installation* shall govern for *settlement* purposes.

7.3 Costs of Tests and Audits

7.3.1 The costs and expenses associated with the inspection and testing of a *metering installation* referred to in section 7.1.1 shall be paid by the *metered market participant* responsible for that *metering installation*, and the costs and expenses of review of such tests referred to in section 7.1.3 shall be paid by the *IESO*.

7.3.2 The costs and expenses associated with the audit of a *metering installation* referred to in section 7.1.4, the periodic, random and unannounced audits referred to in section 7.1.5, the security audits referred to in section 9.1.3, or the *connection station service* audit referred to in Chapter 9 section 2.1A.3, shall be paid as follows:

7.3.2.1 the *IESO* shall pay all of its costs as described in the applicable *market manual*; and

7.3.2.2 the *metered market participant* responsible for that *metering installation* shall pay all costs incurred by any of the *metered market participant, metering service provider*, and *facility* owner as described in the applicable *market manual*.

Where the *metering installation* is shown by the test or audit not to comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, thereby requiring for any reason a re-test or additional inspection or re-audit or any additional work by the *IESO*, the *metered market participant* responsible for that *metering installation* shall bear the costs of that re-test, inspection, audit and remedial work, including but not limited to any and all costs incurred by the *IESO*.

7.3.3 The costs and expenses associated with the *metering data* audit referred to in section 7.2.1 shall be paid as follows:

7.3.3.1 the *IESO* shall pay all of its costs for the purposes of the *metering data* audit as described in the applicable *market manual*; and

7.3.3.2 the *market participant* who requested the *IESO* to conduct the audit shall pay all costs incurred by the *metered market participant*, *metering service provider* and *facility* owner as described in the applicable *market manual*.

Where the *metering installation* is shown by the *metering data* audit not to comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, the *metered market participant* responsible for that *metering installation* shall bear the costs incurred for any re-audit or remedial work, including reimbursement of all costs incurred by the *market participant* who requested the *IESO* to conduct the *metering data* audit which demonstrated the non-compliance.

7.3.4 The costs and expenses associated with the *metering data* audit referred to in section 7.2.5 shall be paid as follows:

7.3.4.1 the *IESO* shall pay all of its costs for the purposes of the *metering data* audit as described in the applicable *market manual*; and

7.3.4.2 the *metered market participant* responsible for that *metering installation* shall pay all costs incurred by any of the *metered market participant, metering service provider*, and *facility* owner costs as described in the applicable *market manual*.

Where the *metering installation* is shown by the *metering data* audit not to comply with the requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, thereby requiring for any reason a retest or an additional inspection or re-audit or any additional work by the *IESO*, the *metered market participant* responsible for that *metering installation* shall bear the costs of any such re-test, inspection, audit and remedial work, including but not limited to any and all *IESO* costs.

7.3.5 The costs and expenses associated with the implementation of the safety requirements and practices referred to in section 7.4.1, including but not limited to the costs associated with training the *IESO's* auditor in respect of such requirements or practices and of accompanying the *IESO's* auditor during an audit referred to in sections 7.1.4, 7.1.5, 7.2.3 and 9.1.3 and section 2.1A.3 of Chapter 9, shall be borne by the *metered market participant* for the *metering installation* that is undergoing the audit.

7.4 Safety Requirements and Practices During Audits

7.4.1 The *IESO* shall use reasonable endeavours to ensure that, in performing an audit referred to in section 7.1.4, 7.1.5 or 7.2.3, the *IESO's* auditor complies with such reasonable and *bona fide* safety requirements and practices of:

7.4.1.1 the owner of the *metering installation*; or

7.4.1.2 the owner of the *facility* within which the *metering installation* is located,

or both, as may be applicable, as may be made known to the *IESO's* auditor.

7.4.2 The *metered market participant* for a *metering installation* shall, subject to section 7.4.3, ensure that the *IESO's* auditor is, at all times while conducting an audit referred to in section 7.1.4, 7.1.5 or 7.2.3, accompanied by a qualified representative of:

7.4.2.1 the owner of the *metering installation*; or

7.4.2.2 the owner of the *facility* within which the *metering installation* is located,

or both, as may be applicable, responsible for ensuring the safety of the *IESO's* auditor during the audit.

7.4.3 A *metered market participant* for a *metering installation* that is undergoing an audit referred to in section 7.1.4, 7.1.5 or 7.2.3 shall not be required to ensure the accompaniment of the *IESO's* auditor referred to in section 7.4.2 if the *metered market participant* has, prior to the date of the audit, provided the *IESO's* auditor with adequate information pertaining to hazards on the site and sufficient technical and safety training so as to ensure that the *IESO's* auditor may safely conduct the audit unaccompanied having regard to the *bona fide* safety requirements and practices of:

7.4.3.1 the owner of the *metering installation*; or

7.4.3.2 the owner of the *facility* within which the *metering installation* is located,

or both, as may be applicable, in effect on the date of the audit.

7.4.4 The *IESO* auditor shall have successfully completed safety training in general industry safety practice, such a vehicle parking and electrical safety awareness, from an entity recognized by the *IESO* for such purpose, including but not limited to the Electrical & Utilities Safety Association of Ontario, the former Ontario Hydro and corporations referred to in subsection 48(2) of the *Electricity Act, 1998*.

7.4.5 An *IESO* auditor who will be working on, or testing, the *metering installations* shall have successfully completed, in addition to the training referred to in section 7.4.4, specific training in inspection and testing of *meter installations* from an entity recognized by the *IESO* for such purpose, including but not limited to the Electrical & Utilities Safety Association of Ontario, the former Ontario Hydro and corporations referred to in subsection 48(2) of the *Electricity Act, 1998*.

8. Ownership of and Rights of Access to Data

8.1.1 The *metering data* in a *metering installation* shall be owned by the *metered market participant* for that *metering installation* and the *metered market participant* shall at all times have access to such *metering data*, subject only to sections 8.1.6 and 8.1.7.

8.1.2 Subject to sections 8.1.6 and 8.1.7, a *metered market participant* may at any time extract real-time information, billing data and spin-off data directly from a *metering installation* for which it is the *metered market participant*.

8.1.3 Unless otherwise permitted by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter, no *metered market participant* shall in any manner modify a *meter* within a *metering installation* in respect of which it is the *metered market participant,* any *metering data* recorded in the *metering installation* or the clock time of a *meter* within the *metering installation*.

8.1.4 Each *metered market participant* shall ensure that no person referred to in sections 8.1.5.1 to 8.1.5.4 modifies a *meter* within a *metering installation* in respect of which it is the *metered market participant,* any *metering data* recorded in the *metering installation* or the clock time of any *meter* within the *metering installation* unless otherwise permitted by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter.

8.1.5 Each *metered market participant* shall ensure that the persons entitled to have either direct or remote access to *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* are limited to the following:

8.1.5.1 a *market participant* whose *settlement statement* relates to *energy* flowing through that *metering installation* and an authorized agent of such *market participant*;

8.1.5.2 a *metering service provider* that provides services in respect of the *metering installation* under the terms of an agreement with the *metered market participant,* to the extent necessary to permit work authorized under the agreement or otherwise by the *metered market participant*;

8.1.5.3 the *transmitter* or *distributor* to whose system the *registered facility* in respect of the *metering installation* is connected;

8.1.5.4 an authorized agent of the *metered market participant*; and

8.1.5.5 the *IESO*.

8.1.6 Each *metered market participant* shall ensure that electronic access to *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* shall only be provided where passwords in accordance with section 9.2 have been allocated. Otherwise, access to *metering data* shall be allowed only from the *metering database* and only by the *metered market participant* and the persons described in sections 8.1.5.1 to 8.1.5.5.

8.1.7 The *IESO* shall notify the *metered market participant* in respect of a *metering installation* of the time period within which it intends to initiate routine access to *metering data* recorded in that *metering installation*. The *metered market participant* shall ensure that no person other than the *IESO* accesses such *metering data* at a time or in a manner that may adversely affect the ability of the *IESO* to access the *metering data* during such time period.

8.1.8 The *IESO* may initiate access to *metering data* recorded in a *metering installation* at a time other than the time referred to in section 8.1.7 where such access is necessary for the performance by the *IESO* of its responsibilities under these *market rules,* and shall make reasonable efforts to notify the *metered market participant* or the *metering service provider* for such *metering installation* of its intention to initiate such access.

9. Security of Metering Installations and Data

9.1 Security of Metering Equipment

9.1.1 Each *metered market participant* shall ensure that:

9.1.1.1 each *metering installation* in respect of which it is the *metered market participant* is secure from access by persons other than the *IESO*, the person that acts as *metering service provider* in respect of such *metering installation* and, for the purpose of section 4.1A.1, the *metered market participant*;

9.1.1.2 all associated links, circuits and information storage and processing systems are secured by means of seals or other devices approved by the *IESO;*

9.1.1.3 the *meter* box is physically secure, locked and sealed by means of devices approved by the *IESO* so as to enable detection of access by persons other than the *IESO*, the person that acts as *metering service provider* in respect of such *metering installation* and, for the purposes of section 4.1A.1, the *metered market participant;*

9.1.1.4 the data connections to the *meter's* communication ports are secure from access by persons other than persons authorized by it to have access to such data connections; and

9.1.1.5 the *metering installation* meets all of the requirements pertaining to the security of *metering installations* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

9.1.2 Subject to any limitations prescribed by *federal metering requirements*, the *IESO* may override any of the security devices fitted to a *metering installation* without prior notice to the *metered market participant* or the *metering service provider* for such *metering installation*.

9.1.3 The *IESO* may audit the security measures applied to each registered *metering installation* from time to time as determined appropriate by the *IESO*.

9.2 Security Controls

9.2.1 Each *metered market participant* shall ensure that the *metering data* recorded in each *metering installation* in respect of which it is the *metered market participant* is:

9.2.1.1 protected from direct local or remote electronic access, including during the transfer of such *metering data* to the communication interface of the *metering database,* by persons other than itself and those persons described in sections 8.1.5.1 to 8.1.5.5, by ensuring that its *metering service provider* implements suitable password and other security controls in accordance with the requirements of this section 9.2; and

9.2.1.2 during delivery of the *metering data* to the *IESO* other than by electronic means, protected from access by persons other than itself and those persons described in sections 8.1.5.1 to 8.1.5.5 regardless of the medium, including but not limited to diskette, magnetic tape, electronic cartridge and paper, on or in which such *metering data* is transcribed, transferred or stored for purposes of such delivery.

9.2.2 Each *metering service provider* shall, except as otherwise permitted by this section 9.2, keep all records of passwords for electronic access to *metering data* confidential.

9.2.3 Subject to section 9.2.4, each *metering service provider* shall provide, in respect of each *metering installation* in respect of which it is the *metering service provider*, 'read-only' passwords to the *IESO,* to the *metered market participant* for the *metering installation*, to any *market participant* whose *settlement statement* is determined on the basis of the *metering installation's meter point*, and to any relevant *transmitter* or *distributor,* as the case may be depending upon the owner of the *facilities* to which the *facility* to which the *metering installation* relates is connected. Each *metering service provider* shall provide the *IESO* with a password allowing 'read plus synchronize time' access to the *meter* in each *metering installation* for which it is the *metering service provider*.

9.2.4 Where separate 'read-only' and 'read plus synchronize time' passwords are not available, the *metering service provider* shall provide the password for each *metering installation* only to the *IESO*.

9.2.5 Each *metering service provider* shall hold 'read-only', 'read plus synchronize time' and 'read plus write' passwords for each *metering installation* for which it is the *metering service provider*, where available, and shall forward a copy of such passwords to the *IESO*.

9.2.6 A *metering service provider* may, and at the request of the *IESO* shall, change one or more of the passwords relating to a *metering installation* in respect of which it is the *metering service provider* and shall provide the changed password to any person to whom the previous password was provided in accordance with section 9.2.3.

9.2.7 The *IESO* may reveal the passwords referred to in sections 9.2.3, 9.2.5 and 9.2.6 to a *metering service provider* that has assumed responsibility as a *metering service provider* for a *metering installation* in the event that the passwords cannot be obtained on a timely basis by that *metering service provider* by any other means.

9.3 Changes to Metering Equipment, Parameters and Settings

9.3.1 Each *metered market participant* shall ensure that changes to equipment, parameters or settings within a *metering installation* in respect of which it is the *metered market participant* that may affect the collection, security or accuracy of any *metering data* recorded in that *metering installation* shall be:

9.3.1.1 authorised by the *IESO* prior to the change being made;

9.3.1.2 implemented by a *metering service provider* who shall obtain an end reading, ensure that the *metering data* recorded in the *metering installation* is transferred to the *metering database* prior to the change and obtain a start reading once the change has been completed; and

9.3.1.3 confirmed to the *IESO* within 1 *business day* after the change has been made.

9.3.2 Each *metered market participant* shall ensure that the *IESO* is provided with alternative *metering data* acceptable to the *IESO* while changes to equipment, parameters or settings within a *metering installation* in respect of which it is the *metered market participant* are being made.

9.3.2A An adjustment required to be made to a *metering installation* to enable it to generate *metering data* that reads zero while the *registered facility* to which such *metering installation* relates is operating in a *segregated mode of operation* shall:

9.3.2A.1 be deemed not to be a change to equipment, parameters or settings for the purposes of sections 9.3.1 and 9.3.2 and of section 1.3.2.22 of Appendix 6.1; and

9.3.2A.2 shall be effected while at all times maintaining the security of the *metering installation* in accordance with the requirements pertaining to the security of *metering installations* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

9.3.3 The *IESO* shall, upon request by a *metered market participant* or a *metering service provider*, review conceptual drawings for any change to equipment, parameters or settings within a *metering installation* proposed to be made by the *metering market participant* or the *metering service provider.*

9.4 Changes to Metering Data

9.4.1 Each *metered market participant* shall ensure that no alterations to the original *metering data* recorded in a *metering installation* in respect of which it is the *metered market participant* are effected. Each *metered market participant* shall ensure that no on-site testing of a *metering installation* in respect of which it is the *metered market participant* that might cause the *meter* to register false data is performed until such time as the *metering data* has been transferred to the *metering database*.

10. Processing of Metering Data for Settlement Purposes

10.1 Metering Database

10.1.1 The *IESO* shall establish and maintain a *metering database* containing *metering data* transferred from each *metering installation* registered with the *IESO* and each *metering installation* whose registration has expired but whose continued use has been determined by the *IESO* to be necessary for the efficient operation of the *IESO-administered markets.*

10.1.2 The *IESO* may use the databases of meter data management agencies to form part of the *metering database.*

10.1.3 The *metering data* recorded in the *metering database* in respect of a registered *metering installation* shall be accessible by electronic means by:

10.1.3.1 the *metered market participant* for that *metering installation* and an authorized agent of such *metered market participant*;

10.1.3.2 the *metering service provider* for that *metering installation*;

10.1.3.3 any *market participant* whose *settlement statement* is determined on the basis of the *metering data* recorded in that *metering installation* and an authorized agent of such *market participant;* and

10.1.3.4 any *transmitter* or *distributor* to whose system a *facility* in respect of which the *metering installation* relates is connected.

10.1.3A [Intentionally left blank.]

10.1.4 *Metering data* recorded in the *metering database* is *confidential information* and the *IESO* shall ensure that such *metering data* is not accessible by or disclosed by the *IESO* to any person other than the *IESO* and the persons referred to in sections 10.1.3.1 to 10.1.3.4, or as otherwise permitted by section 5 of Chapter 3 or any policy of the *IESO* established pursuant to that section.

10.1.5 The *metering database* shall include:

10.1.5.1 original *energy* readings, substitutions, estimations and calculated values;

10.1.5.2 *energy* readings, both loss adjusted and totalized, to their respective *delivery points* for the purposes of the *IESO-administered markets*; and

10.1.5.3 *energy* readings, both loss adjusted and totalized, to their respective *delivery points* defined for the purposes of *transmission services charges* as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

10.2 Remote Acquisition of Data

10.2.1 The *IESO* shall initiate the remote acquisition of *metering data* recorded in a *metering installation* and shall store the *metering data* so acquired in the *metering database* for *settlement* purposes.

10.2.2 If remote acquisition from a *metering installation* becomes unavailable, the *IESO* shall arrange, in consultation with the *metered market participant* or the *metering service provider* for that *metering installation*, an alternative means of transferring the relevant *metering data* from the *metering installation* to the communication interface of the *metering database* or to the *metering database,* as the case may be.

10.3 Periodic Energy Metering

10.3.1 Subject to section 10.3.2, *metering data* relating to the amount of active *energy* and, where relevant, reactive *energy* passing through a *metering installation* shall be collated by *dispatch intervals*.

10.3.2 *Metering data* may be collated into 5 or 15 minute intervals by a *metering installation* that was in service on the date of coming into force of this section 10.3.2 and that is used in respect of a *non-dispatchable load facility*, a *self-scheduling generation facility* with a name-plate rating of less than 10 MW, a *transitional scheduling generator* or an *intermittent generator*.

10.3.2.1 [Intentionally left blank]

10.3.2.2 [Intentionally left blank]

10.4 Errors Relating to Metering Installations and Metering Data

10.4.1 If a test, review, inspection or audit, carried out in accordance with section 7, of a *metering installation* or of *metering data* demonstrates errors in excess of those prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter and the *IESO is* not aware of the time at which that error arose, the error shall be deemed to have occurred at a time which is half way between (i) the time of the most recent test, review, inspection or audit which demonstrated that the *metering installation* complied with the relevant measurement standard and (ii) the time when the error was detected.

10.4.2 If a *metered market participant* becomes aware of an error in excess of those prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, the *metered market participant* shall provide notice to the *IESO* of such error within two *business days* of becoming aware of such error and such notice shall include a general description of the error.

10.4.3 As soon as reasonably practicable after either receiving a notice from a *metered market participant* in accordance with section 10.4.2, or after the *IESO* otherwise becomes aware of an error in excess of those prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, the *IESO* shall determine the scope of the issue and the necessary corrections, if any. The *IESO* shall use the information provided in and with a notice issued by the *metered market participant* in accordance with section 10.4.2 and any other information available to the *IESO*, including conducting an audit of the relevant *metering installations* in accordance with section 7, to determine the scope of the issue and the necessary corrections, if any.

10.4.4 Following the *IESO*'s determination pursuant to section 10.4.3, the *IESO* shall inform the *metered market participant* of the *IESO*'s determination, provide the *metered market participant* the opportunity to respond within ten *business days*, and, after considering any such response, take one of the following actions:

10.4.4.1 if the *IESO* concludes that no error has occurred or such error is within acceptable parameters prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, it shall take no further action; or

10.4.4.2 subject to section 10.4.7, if the *IESO* concludes that an error has occurred outside of the acceptable parameters prescribed in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter, it shall:

(a) make appropriate corrections to *metering data* contained in the *metering database* to effect a correction for that error in respect of the period since the error occurred or was deemed to have occurred in accordance with section 10.4.1; and

(b) if the *IESO* concludes that an adjustment or correction is required to a *final settlement statement* or a *recalculated settlement statement*, shall make the adjustment on one or more of the next scheduled *recalculated settlement statements*.

10.4.5 If the *IESO* does not make a determination pursuant to section 10.4.3 before the date for issuing a *settlement statement*, the *IESO* shall issue such *settlement statement* without taking into account the error.

10.4.6 Any changes required to be made to a *final settlement statement* or *recalculated settlement statement* as a result of the process described in this section 10.4 shall be included as a debit or credit in the *recalculated settlement statements* issued for each affected *metered market participant* as an *adjustment period allocation*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *metered market participant*, such amounts shall then be included as a *current period adjustment* to a subsequent *preliminary settlement statement*.

10.4.7 Commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date*, the *IESO* shall not make any correction under section 10.4.4.2 in regards to any *settlement amounts* which were invoiced, or should have been invoiced, more than 23 months before the day on which the *IESO* issues the *settlement statement* referred to in section 10.4.4.2. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, the *IESO* shall not make any correction under section 10.4.4.2 in regards to any *settlement amount* beyond the limitation period, if any, provided pursuant to *applicable law*. Additionally, where a *metering service provider* fails to conduct a review, test, or audit, in accordance with section 1.3.2.3 of Appendix 6.1, section 1.4.3 of Appendix 6.3, or section 1.5.3 of Appendix 6.3, as the case may be, the *IESO* shall not take any action under section 10.4.4.2 in regards to any *settlement amount* pertaining to the *metering installation* and/or *meter point* documentation which was not tested, reviewed, or audited that arose prior to the date on which the *metering service provider* failed to conduct the applicable test, review or audit.

10.4.8 If a *metered market participant* disagrees with the *IESO*'s determination and action taken in accordance with section 10.4.4 or the *IESO* has not made its determination prior to earlier of either the date referred to in section 10.4.7 or twelve months after the date of the notice referred to in section 10.4.2, the *metered market participant* may pursue their disagreement through the dispute resolution process outlined in section 2 of Chapter 3.

11. Performance of Metering Installation

11.1.1 Each *metering service provider* shall ensure that *metering data* from each *metering installation* in respect of which it acts as *metering service provider* is made available to the *IESO* for each *dispatch interval* or, where permitted by section 10.3.2, for each *dispatch hour,* in accordance with the requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter and in accordance with the following:

11.1.1.1 95 percent or more of the *metering data* shall be available to the *IESO* on the first *business day* following the day on which the *dispatch interval* occurs; and

11.1.1.2 95 percent of the attempts by the *IESO* to initiate access to the *metering data* must be successful on the first attempt.

11.1.2 Where either a *metered market participant* or a *metering service provider* becomes aware that a *metering installation* in respect of which it is the *metered market participant* or the *metering service provider* has gone out of service, is defective or malfunctions, it shall notify the *IESO* of the *outage,* defect or malfunction within 1 *business day* of becoming aware of same. In addition, the *metered market participant* shall:

11.1.2.1 where the *outage,* defect or malfunction relates to any portion of the *metering installation* other than an *instrument transformer*, ensure that the *metering installation* or the defective portion thereof is replaced or repairs are made to the *metering installation* as soon as practicable and in any event within 2 *business days* of the date of the notice referred to in section 11.1.2 or within such longer period of time as may be agreed by the *IESO;* and

11.1.2.2 where the *outage,* defect or malfunction relates to an *instrument transformer*:

a. ensure that the *instrument transformer* is replaced as soon as practicable and in any event within 12 weeks of the date of the notice referred to in section 11.1.2 or within such longer period of time as may be agreed by the *IESO*; and

b. subject to section 4.6, ensure that the emergency restoration plan referred to in section 1.3.2.17 of Appendix 6.5 is implemented within 2 *business days* of the date of the notice referred to in section 11.1.2 and remains in effect until such time as the *instrument transformer* has been replaced.

11.1.3 Where the *IESO* becomes aware, other than by means of the notice referred to in section 11.1.2, that a *metering installation* has gone out of service, is defective or malfunctions, the *IESO* shall:

11.1.3.1 promptly notify the *metered market participant* for that *metering installation* of the *outage*, defect or malfunction and issue a trouble call to the *metering service provider* for that *metering installation*;

11.1.3.2 where the *outage,* defect or malfunction relates to any portion of the *metering installation* other than an *instrument transformer*, direct the *metered market participant* to ensure that the *metering installation* or the defective portion thereof is replaced or that repairs are made to the *metering installation* as soon as practicable and in any event within 2 *business days* of the date of the notice referred to in section 11.1.3.1 or within such longer period of time as may be specified by the *IESO*; and

11.1.3.3 where the *outage,* defect or malfunction relates to an *instrument transformer*, direct the *metered market participant* to:

a. ensure that the *instrument transformer* is replaced as soon as practicable and in any event within 12 weeks of the date of the notice referred to in section 11.1.3.1 or within such longer period of time as may be specified by the *IESO*; and

b. ensure that the emergency restoration plan referred to in section 1.3.2.17 of Appendix 6.5 is implemented within 2 *business days* of the date of the notice referred to in section 11.1.3.1 and remains in effect until the *instrument transformer* has been replaced.

11.1.4 Where an *outage* or malfunction of or the defect in a *metering installation* is not rectified in accordance with and within the time period specified in section 11.1.2.1, 11.1.2.2, 11.1.3.2 or 11.1.3.3 and is, in the *IESO's* opinion, likely to have a significant impact on one or more *market participants* other than the *metered market participant* for that *metering installation*, the *IESO* shall so notify the *metered market participant* for that *metering installation*. Within one *business* *day* of receipt of such notice, the *metered market participant* shall notify the *IESO* as to the:

11.1.4.1 [Intentionally left blank]

11.1.4.2 [Intentionally left blank]

11.1.4.3 corrective action taken or arranged by the *metered market participant* to rectify the *outage* or malfunction of or the defect in the *metering installation*.

The *IESO* shall estimate the *metering data* for *settlement* purposes in accordance with section 11.1.4A from the date referred to in section 11.1.5 until the date on which the *outage* or malfunction of or defect in the *metering installation* is rectified.

11.1.4A For the purposes of sections 11.1.4.3 and 11.1.4B.2, estimation of *metering data* shall be based on the following:

11.1.4A.1 in the case of a *metering installation* for a *generation facility*, production shall be estimated at zero;

11.1.4A.2 in the case of a *metering installation* for a load, withdrawal for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that load during the twelve-month period preceding the date of the notice referred to in section 11.1.2 or 11.1.3.1, as the case may be; or

11.1.4A.3 in the case of a *metering installation* for an *electricity storage facility*, the injections shall be estimated at zero and the withdraws for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that load during the twelve-month period preceding the date of the notice referred to in section 11.1.2 or 11.1.3.1 as the case may be.

11.1.4B Where a *metered market participant* fails to notify the *IESO* pursuant to section 11.1.4 as to the action that it wishes to take or to have taken, the *IESO* shall:

11.1.4B.1 [Intentionally left blank]

11.1.4B.2 estimate the *metering data* for *settlement* purposes in accordance with section 11.1.4A from the second *business day* after the date on which notice was given to the *metered market participant* pursuant to section 11.1.4 until the date on which the *outage* or malfunction of or defect in the *metering installation* is rectified.

11.1.5 The *IESO* shall not commence to estimate *metering data* pursuant to section 11.1.4.3:

11.1.5.1 where the *outage*, defect or malfunction relates to any portion of the *metering installation* other than an *instrument transformer*, until 3 *business days* have elapsed from the date on which the notice was given to the *metered market participant* pursuant to section 11.1.4; and

11.1.5.2 where the *outage*, defect or malfunction relates to an *instrument transformer* and the emergency restoration plan referred to in section 1.3.2.17 of Appendix 6.5:

a. has been implemented within the time required by section 11.1.2.2(b) or 11.1.3.3(b), as the case may be, until the expiry of the period referred to in section 11.1.2.2(a) or 11.1.3.3(a), as the case may be; or

b. has not been implemented within the time required by section 11.1.2.2(b) or 11.1.3.3(b), until 3 *business days* have elapsed from the date on which the notice was given to the *metered market participant* pursuant to section 11.1.4, provided that where such emergency restoration plan is thereafter implemented, the *IESO* shall cease the estimation of *metering data* until the expiry of the period referred to in section 11.1.2.2(a) or 11.1.3.3(a), as the case may be.

11.1.6 Where the *IESO* becomes aware that *metering data* from a *metering installation* reads other than zero in respect of a time during which the *registered facility* to which such *metering installation* relates was operating in a *segregated mode of operation,* the *IESO* shall for *settlement* purposes deem such *metering data* to have read zero during such time.

11.2 Meter Time

11.2.1 Each *metering installation* and the *metering database* shall be referenced to eastern standard time in the Province of Ontario.

11.2.2 The *IESO* shall synchronize each *meter* clock to within ±5 seconds of eastern standard time in the Province of Ontario, or to such greater standard of accuracy as can be reasonably achieved by the *IESO*, at the time of commissioning of a *metering installation* and thereafter whenever it reads a *meter*.

12. Evolving Technologies and Processes and Development of the Market

12.1.1 Subject to any restrictions imposed by *federal metering requirements*, a *metered market participant* may use or permit the use of evolving technologies or processes that:

12.1.1.1 meet or exceed the performance and functional requirements set forth in this Chapter or in any policy or standard established by the *IESO* pursuant to this Chapter; or

12.1.1.2 facilitate the efficient development of the *IESO-administered markets*,

if agreed between the *metered market participant*, the relevant *transmitter* or *distributor,* as the case may be depending on the owner of the *facilities* to which the *facility* in respect of the relevant *metering* installation is connected, and the *IESO*.

13. Responsibilities of the IESO

13.1.1 The *IESO* shall:

13.1.1.1 establish and administer a process for the registration of *metering service providers*;

13.1.1.2 maintain and operate facilities necessary for *settlement* in accordance with this Chapter and Chapter 9;

13.1.1.3 provide a communication interface for the *metering database* and ensure that *metering data* is transferred from such communication interface to the *metering database* and stored in the *metering database* in a reliable, secure and accurate manner;

13.1.1.4 ensure that *metering data* is stored in the *metering database* for 13 months in accessible format and for an additional 6 years in archive;

13.1.1.5 establish *metering*-related policies and standards including, but not limited to, policies or standards for *metering installations*; site specific loss adjustments; transfers of *metering data* to the *metering database*; *metering data* security requirements; and the inspection, testing and audit of *metering installations*; the security of *metering installations* and measurement error correction;

13.1.1.6 audit *metering installations* in accordance with this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter;

13.1.1.7 where necessary, issue trouble calls to *metering service providers, metered market participants* or both and monitor the status of each trouble call, the response time and the resolution of the trouble call;

13.1.1.8 monitor the performance of *metering service providers* against the performance standards set forth in the applicable *market manual*;

13.1.1.9 establish such *metering*-related familiarization and competency updating or upgrading programs for *metering service providers* and *metered market participants* as the *IESO* determines appropriate;

13.1.1.10 initiate and perform any end-to-end testing required prior to registration of a *metering installation*;

13.1.1.11 periodically monitor the registration status of each *metering service provider* and of each *metering installation;*

13.1.1.12 carry out the *metering data* summation process; and

13.1.1.13 prevent access to information recorded in the *metering database* or the *metering registry* in respect of each *metering installation* by any person other than the persons entitled to such access in respect of a given *metering installation* pursuant to section 6.2.3 or 10.1.3, respectively.

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Market Rules

Chapter 6
Wholesale Metering - Appendices

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Table of Contents

Appendix 6.1 – Metering Obligations

1.1 Introduction

1.1.1 This Appendix sets forth certain obligations of *metered market participants* and *metering service providers* in respect of *metering*.

1.2 Obligations of Metered Market Participants

1.2.1 Each *metered market participant* shall:

1.2.1.1 ensure that its contracts relating to each *metering installation* in respect of which it is the *metered market participant* contain such terms and conditions related to the *metering installation* as may be required for compliance with the *market rules*;

1.2.1.2 ensure that every *meter* and *instrument transformer* used in a *metering installation* in respect of which it is the *metered market participant* that may be used for *settlement* purposes has been approved for use by Measurement Canada and has been obtained from a manufacturer that:

a. has obtained approval of type from Measurement Canada, which approval shall, in the case of a *meter*, be evidenced by the time-limited seal placed on the *meter* by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada); and

b. agrees to provide, upon request, the approval number to the *metered market participant's metering service provider* and to the *IESO*;

1.2.1.3 ensure that each *meter* forming part of a *metering installation* in respect of which it is the *metered market participant* that may be used for *settlement* purposes has been shop tested, verified and/or re-verified for accuracy in accordance with the requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter sealed and/or re-sealed in accordance with all applicable *federal metering requirements* by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada);

1.2.1.4 ensure that sealed *meters* are provided to its *metering service provider* by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) in accordance with the schedule agreed between the *metered market participant* and such person;

1.2.1.5 ensure that records required by *federal metering requirements* or requested by its *metering service provider* are provided to its *metering service provider* by any accredited meter verifier providing any of the services referred to in sections 1.2.1.2 to 1.2.1.4 in respect of the *metering installation*;

1.2.1.6 ensure that any person that provides any of the services referred to in sections 1.2.1.2 to 1.2.1.5 agrees to:

a. provide it with copies of any test results or certificates within 30 days of being requested to do so; and

b. carry out any additional testing required for the resolution of a *metering*-related disputes within 30 days of being requested to do so; and

1.2.1.7 ensure that, when a *registered facility* to which a *metering installation* in respect of which it is the *metered market participant* relates is operating in a *segregated mode of operation*, the *metering installation* generates *metering data* that reads zero for the period of time during which such *registered facility* operated in a *segregated mode of operation*.

1.3 Metering Service Providers

1.3.1 The following activities shall be performed by *metering service providers* in accordance with the requirements of this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter*:*

1.3.1.1 the provision, installation, commissioning, maintenance, repair, replacement, inspection and testing of *metering installations*;

1.3.1.2 the registration of *metering installations* with the *IESO* and the preparation of all *meter point* documentation and other documentation, other than the written confirmation referred to in section 1.3A.1 of Appendix 6.5, required to be submitted in support of the application for registration; and

1.3.1.3 the resolution of trouble calls relating to *metering installations* and *metering data* in accordance with sections 1.3.2.14 and 1.3.2.15 of this Appendix.

1.3.2 Each *metering service provider* shall, in respect of each *metering installation* in respect of which it is the *metering service provider*:

1.3.2.1 conduct routine testing and maintenance of the *metering installation* in accordance with Appendix 6.3;

1.3.2.2 prepare the *meter point* documentation referred to in Appendix 6.5 in accordance with that Appendix, ensure that such *meter point* documentation and all other documentation referred to in section 1.3.1.2 of this Appendix is maintained up to date and provide the *IESO* with any updates to such *meter point* documentation and other documentation, and make such *meter point* documentation available to the *metered market participant* for the *metering installation* upon request;

1.3.2.3 conduct an annual review of all documentation pertaining to the *metering installation*; and *meter point* documentation provided to the *IESO* in accordance with Appendix 6.5 and within two *business days* of becoming aware of an error, notify the *IESO* of such errors pertaining to the *metering installation* or within such *meter point* documentation.

1.3.2.4 provide technical assistance at the site of the *metering installation* with respect to access to *metering data* by persons authorized by this Chapter to have such access;

1.3.2.5 provide such support for investigations, audits, tests and the resolution of disputes relating to the *metering installation*, including the provision of complete and accurate documentation, as may be requested by the *IESO*;

1.3.2.6 replace equipment sealed by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) before the expiry of the seal period;

1.3.2.7 ensure, by means of the placement of sufficient seals on test links, fuses and the *meter* box or otherwise in accordance with any policy or standard established by the *IESO* pursuant to this Chapter, that access to the *metering installation* by a person not authorized by this Chapter to have such access can be detected;

1.3.2.8 advise the *IESO* of any error messages or equipment failures detected and repair or replace any failed equipment in accordance with section 11 of this Chapter;

1.3.2.9 provide *meter* readings to the *IESO* as may be required under this Chapter, under any policy or standard established by the *IESO* pursuant to this Chapter or as may be requested by the *IESO*;

1.3.2.10 maintain such records of all inspections, tests, audits and activities that may affect the collection, security or accuracy of *metering data* contained in, and of any changes made to, the *metering installation* and provide such records to the *IESO* as may be requested by the *IESO* or required pursuant to this Chapter or any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.11 maintain all records required to be maintained by owners of *metering installation* pursuant to *federal metering requirements,* whether or not the *metering service provider* is the owner of the *metering installation*;

1.3.2.12 assist with end-to-end testing of the *metering installation* as may be required under this Chapter or any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.13 submit to the *IESO* the information required by this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter to be submitted for storage in the *metering registry* or the *metering database* using the software designated by the *IESO,* and in such data format as may be approved by the *IESO,* for such purpose;

1.3.2.14 establish, maintain and operate a trouble call service and acknowledge receipt of each trouble call issued by the *IESO* by 3:00 pm on the next *business day* following the date of issuance of the trouble call;

1.3.2.15 promptly respond to all trouble calls issued by the *IESO*;

1.3.2.16 attend to the repair or replacement of a *metering installation* within the time prescribed in section 11 of this Chapter;

1.3.2.17 maintain and implement effective procedures to ensure that *metering data* is not compromised during the maintenance, repair, replacement, inspection or testing of the *metering installation* or during the retrieval or storage of *metering data* or the transfer of the *metering data* to the communication interface with the *metering database*;

1.3.2.18 ensure that information submitted to the *IESO* in support of a request for an adjustment to *metering data* is correct, accurate and auditable;

1.3.2.19 ensure that all portable testing equipment is fit for its intended purpose and calibrated with devices traceable to federal measurement standards so as to create an audit trail for calibration;

1.3.2.20 establish procedures for the transfer of *metering data* to the *metering database* when the *metering data* cannot be made available to the *IESO* by means of remote access;

1.3.2.21 maintain spare stock sufficient to repair or replace failed *metering installations* within the time limits specified in section 11 of this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.22 obtain the prior approval of the *IESO* prior to carrying out procedures or effecting any changes to the equipment, parameters or settings of a *metering installation* that may affect the collection, security or accuracy of any *metering data* stored in the *metering installation*;

1.3.2.23 ensure that each *metering installation* is sealed with uniquely numbered seals and maintain a register of such numbers;

1.3.2.24 implement appropriate recovery processes to enable the recovery of any lost or destroyed records that are required to be kept pursuant to this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter;

1.3.2.25 attend any post-registration familiarization and competency updating or upgrading sessions as may be required by the *IESO*;

1.3.2.26 handle *meters* in accordance with the requirements of the accredited meter verifier, within the meaning of the *Electricity and Gas Inspection Act* (Canada), that sealed the *meters;* and

1.3.2.27 ensure that the *metering installation* is suitable for the range of operating conditions to which it will be exposed and that all equipment within the *metering installation* operates within the limits established for such equipment in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

1.3.3 Each *metering service provider* shall ensure that all members of its personnel that may be entering or may have cause to enter a *facility* owned by a person other than the *metering service provider* for the performance of the *metering service provider's* obligations pursuant to:

1.3.3.1 this Chapter 6;

1.3.3.2 any policy or standard established by the *IESO* pursuant to this Chapter 6; or

1.3.3.3 the agreement referred to in section 5.1.3.2 of this Chapter 6,

are familiar with and adhere to the safety requirements and practices of the owner of such *facility*.

Appendix 6.2 – Alternative Metering Installation Standards

1.1 Introduction

1.1.1 This appendix applies to *metering installations*:

- in service on April 17, 2000; or
- that are the subject of an application for registration filed prior to the *market commencement date* and in respect of which the major components were ordered or procured on or before May 17, 2000.

1.1.2 This Appendix sets forth:

1.1.2.1 the alternative standards and accompanying conditions that must be met in respect of a *metering installation* registered under Chapter 6, section 4.4.3;

1.1.2.2 the information that must be submitted by a *metering service provider* in support of an application referred to in Chapter 6, section 4.4.2;

1.1.2.3 the circumstances in which the *IESO* may revoke the registration granted pursuant to Chapter 6, section 4.4.3; and

1.1.2.4 the time at which registration granted by the *IESO* under Chapter 6, section 4.4.3 expires. Where the time at which registration expires is specified to be the earliest expiry date of the seal period of any *meter* within the *metering installation*, that date shall be the earliest expiry date of the seal period of any *meter* within the *metering installation* as of the *market commencement date*.

1.1A Metering Installation Not Comprised of Two Meters

1.1A.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the dual *meter* requirement referred to in section 4.1.1.2 of Chapter 6 shall meet the following conditions:

1.1A.1.1 the *meter* within the *metering installation* is one in respect of which Measurement Canada has granted approval of type;

1.1A.1.2 a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) has verified and sealed the *meter* within the *metering installation*;

1.1A.1.3 the seal period for the *meter*, including the seal period for the *data logger* if sealed separately from the remainder of the *meter*, within the *metering installation* has not expired;

1.1A.1.4 the *metering installation* shall, subject to section 1.1A.1.5, be capable of collating *metering data* into *dispatch intervals*;

1.1A.1.5 the *metering installation* shall, if used in respect of a *non-dispatchable load facility*, a *self-scheduling generation facility* with a name-plate rating of less than 10 MW, a *self-scheduling electricity storage facility* with an *electricity storage facility size* of less than 10 MW, a *transitional scheduling generator* or an *intermittent generator*, be capable of collating *metering data* into 5 or 15 minute intervals; and

1.1A.1.6 the *meter* contained in the *metering installation* shall be capable of time synchronization by the *IESO* to eastern standard time.

1.1A.1.7 [Intentionally left blank]

1.1A.2 Registration of a *metering installation* that meets the conditions set out in section 1.1A.1 shall expire on the earliest expiry date of the seal period of the *meter* within the *metering installation*, including the expiry date of the seal period of the *data logger* if sealed separately from the remainder of the *meter*. Registration of a *metering installation* shall not expire in instances where there are multiple *metering installations* served by a single *data logger* whose seal expires.

1.2 Compliance with Blondel's Theorem

1.2.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with Blondel's theorem shall:

1.2.1.1 comply with rulings issued by Measurement Canada on two and one-half element *metering*; and

1.2.1.2 have a magnitude of maximum error satisfactory to the *IESO*.

1.2.2 The *metering service provider* shall provide to the *IESO* the magnitude of maximum error for both active power and reactive power for a *metering installation* that does not comply with Blondel's theorem.

1.2.3 Where the magnitude of maximum error referred to in section 1.2.2 is less than or equal to 0.2%, no correction factor shall be applicable.

1.2.4 Where the magnitude of maximum error referred to in section 1.2.2 exceeds 0.2%, the *IESO* shall apply to the *metering data* a fixed correction factor based on the actual maximum error figure submitted by the *metering service provider*, subject to the following:

1.2.4.1 *energy flows* in respect of injections shall not be increased; and

1.2.4.2 *energy flows* in respect of withdrawals shall not be decreased.

1.2.5 Where the magnitude of maximum error referred to in section 1.2.2 exceeds 3.0%, registration relating thereto shall expire.

1.2.5.1 [Intentionally left blank]

1.2.5.2 [Intentionally left blank]

1.3 [Intentionally left blank – section deleted]

1.3.1 [Intentionally left blank – section deleted]

1.3.1.1 [Intentionally left blank – section deleted]

1.3.1.2 [Intentionally left blank – section deleted]

1.3.2 [Intentionally left blank – section deleted]

1.3.3 [Intentionally left blank – section deleted]

1.3.4 [Intentionally left blank – section deleted]

1.4 Accuracy

1.4.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the accuracy requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.4.1.1 the *meters* within the *metering installation* are ones in respect of which Measurement Canada has granted approval of type;

1.4.1.2 a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act*, (Canada) has verified and sealed the *meters* within the *metering installation*; and

1.4.1.3 the seal period for the *meters* within the *metering installation* have not expired.

1.4.2 Registration of a *metering installation* that meets the conditions set out in section 1.4.1 shall expire on the earliest expiry date of the seal period of any *meter* within the *metering installation*.

1.5 Functional Requirements

1.5.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the functional requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.5.1.1 the *meters* within the *metering installation* are ones in respect of which Measurement Canada has granted approval of type;

1.5.1.2 a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) has verified and sealed the *meters* within the *metering installation*;

1.5.1.3 the seal periods for the *meters* within the *metering installation* have not expired;

1.5.1.4 the *metering installation* shall, subject to section 1.5.1.5, be capable of collating *metering data* into *dispatch intervals*;

1.5.1.5 the *metering installation* shall, if used in respect of a *non-dispatchable load facility*, a *self-scheduling generation facility with* a name-plate rating of less than 10 MW, a *self-scheduling electricity storage facility* with an *electricity storage facility size* of less than 10 MW, a *transitional scheduling generator* or an *intermittent generator*, be capable of collating *metering data* into 5 or 15 minute intervals; and

1.5.1.6 the *meters* contained in the *metering installation* shall be capable of time synchronization by the *IESO* to eastern standard time.

1.5.2 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that met conditions set out in section 1.5.1 if the *metering installation* fails to comply with the requirements of any of sections 1.5.1.4 to 1.5.1.6, in which case the *metered market participant* shall ensure that the *meters* within the *metering installation* are replaced with *meters* that comply with the functional requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 2 *business days* of the date of notice of such revocation.

1.5.3 Registration of a *metering installation* that meets the conditions set out in section 1.5.1 shall expire on the earliest expiry date of the seal period of any *meter* within the *metering installation*.

1.6 Instrument Transformers – Power Switching

1.6.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the power system switching requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.6.1.1 all switching devices that may affect the accuracy of any *metering data* recorded in the *metering installation* shall be identified to the *IESO*;

1.6.1.2 an alternate source of *metering data* is provided;

1.6.1.3 correction factors have been provided to and approved by the *IESO* in accordance with this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter; and

1.6.1.4 loss adjustment factors have been provided to and approved by the *IESO* in accordance with this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter.

1.6.2 *Metering data* from a *metering installation* in respect of which registration has been granted under Chapter 6, section 4.4.3 that met the conditions set out in section 1.6.1 shall be the subject of adjustment by the correction and loss adjustment factors referred to in sections 1.6.1.3 and 1.6.1.4 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.6.3 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that met the conditions set out in section 1.6.1 if the conditions set forth in any one of sections 1.6.1.1 to 1.6.1.4 are not met or if the *metered market participant* fails to:

1.6.3.1 notify the *IESO*, in the manner set forth in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter, of the duration of any power switching operation relating to the *metering installation* no later than 24 hours after the operation has taken place; or

1.6.3.2 install additional or corrected *metering installations* in circumstances where power switching operations affect the *metering data* in the existing *metering installation* more than twice in any twelve-month period,

in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the power switching requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.6.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.6.1 shall expire on the date that the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.7 Instrument Transformers – Accuracy Requirements

1.7.1 Subject to section 1.7.1A, each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the 0.3% accuracy requirements of ANSI standard C57.13, as evidenced by factory test cards complete with serial numbers, for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.7.1.1 the *instrument transformer* shall be of a type approved for use by Measurement Canada;

1.7.1.2 the *instrument transformer* shall:

a. [Intentionally left blank]

b. be tested on-site for accuracy in the manner described in, and meet the accuracy test point requirements of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter with correction factors approved by the *IESO* in the manner described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter; or

c. be demonstrated, to the satisfaction of the *IESO,* by means of the provision to the *IESO* of copies of the manufacturer's records, to be identical to an *instrument transformer* that has been tested on-site for accuracy, provided that installation or other documents have been provided to the *IESO* demonstrating that the applied burden for the *instrument transformer* is either identical to that of the tested *instrument transformer* or within the correction factors applied to that *instrument transformer*; and

1.7.1.3 the *instrument transformer* complies with the security requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

1.7.1A Notwithstanding section 1.7.1.2, the *IESO* shall accept the following as proof of accuracy of *instrument transformers*:

1.7.1A.1 *instrument transformer* nameplate data, where the nameplate contains the required ANSI accuracy information and is affixed to the *instrument transformer*; and

1.7.1A.2 Measurement Canada-type approval information, where such approval contains the required ANSI accuracy information.

1.7.2 *Metering data* from a *metering installation* for which registration has been granted under Chapter 6, section 4.4.3 that met the conditions set out in section 1.7.1 shall be the subject of adjustment by the correction factors referred to in section 1.7.1.2(b) in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.7.3 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that met the conditions set out in section 1.7.1 if the conditions set forth in any one of sections 1.7.1.1 to 1.7.1.3 are not met, in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the accuracy requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.7.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that met the conditions set out in section 1.7.1 shall expire on the date that the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.8 Instrument Transformers – Secondary Cabling

1.8.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the secondary cabling requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.8.1.1 each *meter* shall be connected to the *instrument transformer* in the manner described in the *meter point* documentation submitted in support of the application for registration of the *metering installation*;

1.8.1.2 fixtures, including but not limited to AC outlets and voltage test points, that may allow access to the *instrument transformer* secondaries by persons not authorized by this Chapter to have such access shall be removed, if possible, or disabled or made inaccessible by a sealed cover;

1.8.1.3 the secondary cabling otherwise complies with as many of the requirements described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter as is practicable and any requirements not so complied with have been identified to the *IESO*;

1.8.1.4 where the secondary cabling does not meet all of the requirements described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter, measurement error correction factors have been provided to and approved by the *IESO* in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter; and

1.8.1.5 where the error introduced by the secondary cabling exceeds 0.02%, correction factors have been provided to and approved by the *IESO*.

1.8.2 *Metering data* from a *metering installation* in respect of which registration has been granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.8.1 shall be the subject of adjustment by the correction factors referred to in sections 1.8.1.4 and 1.8.1.5 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.8.3 The *IESO* may, by notice to the *metered market participant* in respect of the *metering installation* to which the registration relates, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.8.1 if the conditions set forth in any one of sections 1.8.1.1 to 1.8.1.5 are not met, in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the secondary cabling requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.8.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.8.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.9 Parallel Current Transformer Secondaries

1.9.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the prohibition on parallel current transformer secondaries set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.9.1.1 current transformers shall have the same nominal ratio and the same secondary ampere rating;

1.9.1.2 paralleled secondaries shall be connected to the same phase;

1.9.1.3 phasing shall be consistent on both primary and secondary circuits;

1.9.1.4 paralleling of secondaries shall be done at the test links directly connected to the *meter*;

1.9.1.5 each *meter point* shall have its own current test links;

1.9.1.6 paralleled secondaries shall be used to sum currents from no more than two *meter points*;

1.9.1.7 a common point shall exist at the primary voltage to which each of the measured flows is connected;

1.9.1.8 the primaries of the voltage transformers for the paralleled installation must be connected to the common point referred to in section 1.9.1.7;

1.9.1.9 the burden on any current transformer shall not exceed the rated burden;

1.9.1.10 the burden shall be kept as low as practicable and shall take into account the effects of common secondary leads and worst-case unbalance as described in section 1.9.1.11;

1.9.1.11 worst-case unbalance shall include operation of secondary fusing or single phase primary power;

1.9.1.12 the *meter* shall be rated at twice the secondary rating of one current transformer;

1.9.1.13 current transformers shall not operate below 10% of the secondary ampere rating under normal or expected operating conditions;

1.9.1.14 the primaries of the current transformers shall not be paralleled;

1.9.1.15 where a switching device exists between the primary connection point of the current transformers, the *IESO* shall be notified whenever the paralleled current transformers are operated with the switching device open;

1.9.1.16 the *metered market participant* shall identify the time, date and duration, and current and voltage readings for both *meter points* before, after, and at regular intervals during any period of disconnection; and

1.9.1.17 correction factors shall be provided to and approved by the *IESO* in accordance with this Chapter and with any policy or standard established by the *IESO* pursuant to this Chapter.

1.9.2 *Metering data* from a *metering installation* in respect of which registration has been granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.9.1 shall be the subject of adjustment by the correction factors referred to in section 1.9.1.17 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.9.3 The *IESO* may, by notice to the *metered market participant* in respect of the *metering installation* to which the registration relates, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.9.1 if the conditions set forth in any one of sections 1.9.1.1 to 1.9.1.17 are not met, in which case the *metered market participant* shall ensure that each parallel current transformer secondary within the *metering installation* is removed within 8 weeks of the date of notice of such revocation.

1.9.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.9.1 shall expire on the date on which work or upgrading that is, in the *IESO's* opinion, substantial is carried out at the *metering installation's meter point*.

1.10 Meter Installation Enclosures

1.10.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the enclosure requirements for *metering installations* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.10.1.1 the *metering installation* is, in the *IESO's* opinion, secure; and

1.10.1.2 the *metering installation* complies with as many of the enclosure requirements described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter as is practicable and any requirements not so complied with have been identified to the *IESO*.

1.10.2 The *IESO* may, by notice to the *metered market participant*, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.10.1 if the conditions set forth in any one of sections 1.10.1.1 or 1.10.1.2 are not met, in which case the *metered market participant* shall ensure that each *metering installation* complies with the enclosure requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 2 *business days* of the date of notice of such revocation.

1.10.3 Registration of a *metering installation* that meets the conditions set out in section 1.10.1 shall expire on the earliest expiry date of the seal period of any *meter* within the *metering installation*.

1.11 Instrument Transformers – Primary Connection Point

1.11.1 Each *metering installation* for which registration is being sought under Chapter 6, section 4.4.2 that does not comply with the primary connection point proximity requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall meet the following conditions:

1.11.1.1 in the case of a *metering installation* relating to a *load facility,* or an *electricity storage facility*:

a. the *metering installation* shall minimize the voltage drop between the voltage transformer and the current transformer;

b. the *metering installation* shall minimize the leakage of current between the voltage transformer and the current transformer; and

c. where the maximum error introduced by any physical separation of the primaries of the voltage transformer and the current transformer exceeds 0.02% for either active or reactive power flows, a constant correction factor has been provided to and approved by the *IESO* in the manner described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter; or

1.11.1.2 in the case of a *metering installation* relating to a *generation facility*:

a. the *metering installation* shall, where a current transformer is located on the grounded of the *generation facility*, minimize the leakage of current between the voltage transformer and the current transformer; and

b. where the maximum error introduced by leakage current between the location of the current transformer and the location of the corresponding voltage transformer exceeds 0.02% for either active or reactive power flows, a constant correction factor has been provided to and approved by the *IESO* in the manner described in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter.

1.11.2 *Metering data* from a *metering installation* in respect of which registration has been granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.11.1 shall be the subject of adjustment by the correction factors referred to in section 1.11.1.1 or 1.11.1.2, as the case may be, in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.11.3 The *IESO* may, by notice to the *metered market participant* in respect of the *metering installation* to which the registration relates, revoke registration of a *metering installation* granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.11.1 if the conditions set forth in section 1.11.1.1 or 1.11.1.2 are not met, in which case the *metered market participant* shall ensure that each *instrument transformer* within the *metering installation* is replaced with an *instrument transformer* that complies with the primary connection point proximity requirements set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter within 8 weeks of the date of notice of such revocation.

1.11.4 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.11.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.12 Instrument Transformer – Primary Cable

1.12.1 A *metering service provider* that seeks to register a *metering installation* under Chapter 6, section 4.4.2 that does not comply with the permissible primary cable error factor requirements for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall provide to the *IESO*, for the *IESO*'s approval, a constant correction factor.

1.12.2 *Metering data* from a *metering installation* in respect of which registration has been granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.12.1 shall be the subject of adjustment by the correction factor referred to in section 1.12.1 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.12.3 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.12.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.13 Instrument Transformers – Burdens

1.13.1 A *metering service provider* that seeks to register a *metering installation* under Chapter 6, section 4.4.2 that does not comply with the prohibition against errors resulting from calculated burdens for *instrument transformers* set forth in this Chapter and in any policy or standard established by the *IESO* pursuant to this Chapter shall provide to the *IESO*, for the *IESO*'s approval, a correction factor.

1.13.2 *Metering data* from a *metering installation* in respect of which registration has been granted under Chapter 6, section 4.4.3 that meets the conditions set out in section 1.13.1 shall be the subject of adjustment by the correction factor referred to in section 1.13.1 in the manner described in the wholesale revenue metering standard established by the *IESO* pursuant to this Chapter.

1.13.3 If the *IESO* does not grant the *metered market participant* the right to retain registration under section 4.4.8 of Chapter 6, the registration of a *metering installation* that meets the conditions set out in section 1.13.1 shall expire on the date on which the *metering installation* or the *facility* to which such *metering installation* relates undergoes upgrading or refurbishment that is, in the *IESO's* opinion, substantial.

1.14 Estimation Pending Rectification

1.14.1 Where registration has been revoked or expires pursuant to any section of this Appendix, the *IESO* may for *settlement* purposes estimate the *metering data* recorded in the *metering installation* in the manner described in section 1.14.2 with effect:

1.14.1.1 [Intentionally left blank]

1.14.1.2 in the case of revocation from the date specified in the notice of revocation issued by the *IESO*; or

1.14.1.3 in the case of expiry, from the date of expiry,

to the date on which the *IESO* is satisfied that the corrective action referred to in the relevant section of this Appendix has been taken.

1.14.2 For the purposes of section 1.14.1, estimation of *metering data* shall be based on the following:

1.14.2.1 in the case of a *metering installation* for a *generation facility*, production shall be estimated at zero;

1.14.2.2 in the case of a *metering installation* for a load, withdrawal for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that load during the twelve-month period preceding the applicable date referred to in section 1.14.1.2 or 1.14.1.3; or

1.14.2.3 in the case of a *metering installation* for an *electricity storage unit*, the injections shall be estimated at zero and the withdraws for each hour shall be estimated at 1.80 times the self-cooled rating of the power transformer or, if none exists, the highest hourly level of withdrawal of *energy* recorded for that load during the twelve-month period preceding the applicable date referred to in section 1.14.1.2 or 1.14.1.3

Appendix 6.3 – Inspecting and Testing Requirements

1.1 Routine Testing

1.1.1 The routine tests referred to in sections 1.2 to 1.4 of this Appendix shall be carried out by a *metering service provider* in accordance with section 1.5 of this Appendix.

1.2 On-Site Reconciliation and Meter Register Dial Readings

1.2.1 Subject to section 4.6.5 of Chapter 6 and section 1.2.3, on-site reconciliation shall be conducted to confirm whether the *energy* measured by a *meter* over a given period of time was accurately transmitted to the *meter's data logger* within the *meter*.

1.2.2 Each *metering service provider* shall record an error detected as a result of the procedure referred to in section 1.2.1 that exceeds one multiplier, calculated as the current transformer ratio times the voltage transformer ratio times the *meter* register multiplier, as an *outage* or defect and shall report the error as such to the *IESO* in accordance with section 11.1.2 of this Chapter.

1.2.3 On-site reconciliation shall not be required if the *meter's data logger* is built into the *meter* and both the *meter* and the *meter's data logger* are enclosed in a single housing.

1.2.4 Where a *meter* within a *metering installation* is not capable of transmitting *meter* register dial readings during the remote acquisition of *metering data* as described in section 7.2.6 of this Chapter, the *metering service provider* shall provide such readings to the *IESO* so as to enable the *IESO* to perform the comparison described in section 7.2.5 of this Chapter.

1.3 Spot Check of Meter Operation

1.3.1 The active and reactive demand recorded by a *meter* shall be compared with the active and reactive demand measured by a high-accuracy test set installed in parallel with the *meter* or by such other means as may be acceptable to the *IESO*.

1.3.2 Each *metering service provider* shall record an error detected as a result of the procedure referred to in section 1.3.1 that exceeds ± 0.5% on kW and ± 1% on kVAR as an *outage* or defect and shall report the error as such to the *IESO* in accordance with section 11.1.2 of this Chapter.

1.3.3 Each *metering service provider* shall ensure that any *meter* in respect of which an error that exceeds the thresholds referred to in section 1.3.2 is bench tested by a person that is an accredited meter verifier within the meaning of the *Electricity and Gas Inspection Act* (Canada) and shall make the results of such bench test available to the *IESO,* to the *metered market participant* for the *metering installation* of which the *meter* forms part, and to the *distributor* or *transmitter* to whose system the *facility* to which the *metering installation* relates is connected.

1.3.4 No *metering service provider* or *metered market participant* shall dispose of a *meter* in respect of which an error that exceeds the thresholds referred to in section 1.3.2 without the prior approval of the *IESO*.

1.4 Instrument Transformer Checks

1.4.1 The testing of currents and voltages applied to a *meter*, supported by independent confirmation of primary current and voltage, shall be used to test the correct operation of all *instrument transformers*.

1.4.2 The procedure referred to in section 1.4.1 may be conducted by a *metering service provider* by remote means if the *meter* is capable of transmitting the applied currents and voltages and if primary current and voltage can be independently confirmed by remote access.

1.4.3 Each *metering service provider* shall conduct the procedure referred to in section 1.4.1 in respect of each *metering installation* for which it acts as a *metering service provider* at the commissioning of any new *metering installation* and for all existing *metering installations* at the earliest of the following:

a. as per the *instrument transformer's* manufacturer's recommended maintenance schedule;

b. when the *IESO* has evidence that the *instrument transformer's* accuracy has been compromised; and

c. in any event, no less than once every eighteen months. For greater clarity, the first instrument transformer check after *RSS commencement date* will be earlier of (a) six years after the last instrument transformer check; and (b) the date that is eighteen months after *RSS commencement date*.

1.5 Frequency of Routine Testing

1.5.1 Each *metering service provider* shall conduct the routine tests referred to in sections 1.2 to 1.3 of this Appendix in respect of each *metering installation* for which it acts as a *metering service provider,* that is not a *main/alternate metering installation* and that is associated with a *facility* that has an average annual maximum monthly load of less than 10 MW as follows:

1.5.1.1 once every six months following the date of registration of the *metering installation*, in the case of the procedure referred to in section 1.2.1; and

1.5.1.2 once every twelve months following the date of registration of the *metering installation*, in the case of each of the procedures referred to in sections 1.3.1.

1.5.2 Each *metering service provider* shall conduct the routine tests referred to in sections 1.2 to 1.3 of this Appendix in respect of each *metering installation* for which it acts as a *metering service provider,* that is not a *main/alternate metering installation* and that is associated with a *facility* that has an average annual maximum monthly load of 10 MW or more as follows:

1.5.2.1 once every 3 months following the date of registration of the *metering installation*, in the case of the procedure referred to in section 1.2.1; and

1.5.2.2 once every six months following the date of registration of the *metering installation*, in the case of each of the procedures referred to in sections 1.3.1.

1.5.3 Each *metering service provider* shall conduct the routine tests specified in section 1.3.1, for each *metering installation* that is registered under section 4.6 of Chapter 6 for which it acts as a *metering service provider*, once every eighteen months following the date of registration of the *metering installation*. For greater clarity, the first routine test after *RSS commencement date* will be earlier of (a) three years after the last routine test; and (b) the date that is eighteen months after *RSS commencement date*.

1.5.4 Each *metering service provider* shall test the currents and voltages applied to a *meter*, for each *metering installation* that is comprised of an alternate *meter* and that is registered under section 4.6 of Chapter 6 for which it acts as a *metering service provider,* once every 6 months following the date of registration of the *metering installation*. This test may be conducted by remote means if the *meter* is capable of transmitting the applied currents and voltages.

1.6 Non-Routine Tests

1.6.1 Each *metered market participant* shall ensure that tests to determine *instrument transformer* burden and error correction, and ratiometer, megger, oil analysis, partial discharge and dielectric tests are conducted from time to time as may be determined appropriate by the *metered market participant* or its *metering service provider* or as may be required by the *IESO*.

Appendix 6.4 – Metering Service Provider Qualifications

1.1 Qualifications

1.1.1 Each person that wishes to be registered by the *IESO* as a *metering service provider* shall demonstrate to the satisfaction of the *IESO* that it has:

1.1.1.1 an adequate number of personnel having the qualifications described in sections 1.1.1.2 to 1.1.1.7 to permit it to perform all of the functions and obligations of a *metering service provider* under this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter and to meet the performance standards set forth in Appendix 6.6;

1.1.1.2 personnel that has successfully completed a metering training program relating to *metering installations* provided by an entity recognized by the *IESO* for such purpose, including but not limited to the Municipal Electric Association, the former Ontario Hydro and the corporations referred to in subsection 48(2) of the *Electricity Act, 1998*;

1.1.1.3 personnel that has recent training in procedures pertaining to the provision, installation, commissioning, repair, maintenance, replacement, inspection and testing of *metering installations*, in the preparation of *metering*-related documentation, in the calculation of site specific loss adjustments and error correction factors and in the resolution of trouble calls;

1.1.1.4 personnel that has successfully completed electrical safety training provided by an entity recognized by the *IESO* for such purpose, including but not limited to the Electrical & Utilities Safety Association of Ontario, the former Ontario Hydro and the corporations referred to in subsection 48(2) of the *Electricity Act, 1998*;

1.1.1.5 personnel that has demonstrated experience with *federal metering requirements*;

1.1.1.6 personnel that has demonstrated experience with the investigation and reporting of incidences of tampering with *metering installations* and *metering data*;

1.1.1.7 personnel that has demonstrated experience with procedures for maintaining the security, validity and integrity of *metering data*, including the collection of static and dynamic *metering data* and the reading of *metering data* prior to and after the repair or replacement of *metering installations*;

1.1.1.8 the necessary equipment, materials, systems and procedures to enable it to perform all of the functions and obligations of a *metering service provider* under this Chapter and any policy or standard established by the *IESO* pursuant to this Chapter and to meet the performance standards set forth in Appendix 6.6; and

1.1.1.9 all licences and other authorizations required by *applicable law*, all of which are valid and in good standing.

Appendix 6.5 – Metering Registry and Meter Point Documentation

1.1 Introduction

1.1.1 This Appendix sets forth certain of the information that is required to be contained in the *metering registry* and describes the *meter point* documentation that each *metered market participant* must provide to the *IESO* in support of an application to register a *metering installation*.

1.2 Metering Registry Information

1.2.1 The *IESO* shall ensure that the *metering registry* contains the following information respecting each registered *metering installation* and such other information as the *IESO* considers appropriate, including information respecting *metering installations* whose registration has expired but whose continued use has been determined by the *IESO* to be necessary for the efficient operation of the *IESO-administered markets*:

1.2.1.1 the *defined meter point* for the *connection point* associated with the *metering installation*;

1.2.1.2 where applicable, the *defined meter point* for the *embedded connection point* associated with the *metering installation*;

1.2.1.3 identification and name of the *metered market participant* for the *metering installation*;

1.2.1.4 identification and name of the *metering service provider* for the *metering installation*;

1.2.1.5 contacts for purposes of communicating with the *metering service provider*; and

1.2.1.6 those portions of the *meter point* documentation referred to in sections 1.3.2.2, 1.3.2.3, 1.3.2.4, 1.3.2.5, 1.3.2.6, 1.3.2.8, 1.3.2.12, 1.3.2.13 and 1.3.2.16.

1.2.2 The information referred to in section 1.2.1 relating to each *metering installation* shall be the information as provided to the *IESO* by the *metering service provider* for that *metering installation* in support of its application to register the *metering installation*. Where the *metering service provider* gives notice to the *IESO* of a change in any of the information referred to section 1.2.1, the *IESO* shall update the *metering registry* accordingly.

1.3 Meter Point Documentation

1.3.1 *Meter point* documentation that:

1.3.1.1 complies with the provisions of this section 1.3, of this Chapter and of any policy or standard established by the *IESO* pursuant to this Chapter; and

1.3.1.2 that is in such form as may be required by this Chapter or by any policy or standard established by the *IESO* pursuant to this Chapter or as may otherwise be established by the *IESO*,

shall be provided to the *IESO* by the relevant *metering service provider* in support of an application for registration of a *metering installation* and shall be updated by the *metering service provider* such as to maintain the *meter point* documentation current.

1.3.2 The *meter point* documentation referred to in section 1.3.1 shall be a package containing the following and such other documentation and information as the *IESO* may require in respect of each *metering installation*:

1.3.2.1 a single line drawing showing the electrical location of the *metering installation* and of each *meter* within the *metering installation*;

1.3.2.2 a totalization table indicating:

a. the *meters* to be summed for a single *market participant* and the sign of summation; and

b. information pertaining to each data channel comprising each point of summation in sufficient detail to permit summation, site specific loss adjustments and measurement error correction;

1.3.2.3 the unique identifier assigned by the *IESO* to the *metering installation* for purposes of the *metering database*, cross-referenced to the location of the *metering installation*;

1.3.2.4 the unit of measurement used to measure *energy* flowing through the *metering installation*;

1.3.2.5 the name and operating designation of the transformer station, distribution station and feeder normally supplying the *meter point*;

1.3.2.6 the site-specific loss adjustment and measurement error correction factors to be applied, including the sign of the loss adjustment;

1.3.2.7 data supporting loss adjustment and measurement error correction factors, including engineering calculations and power flow studies;

1.3.2.8 [Intentionally left blank – section deleted]

1.3.2.9 a written description of the location of the *meter point* of the *metering installation*;

1.3.2.10 the location and address of the *defined meter point* of the *metering installation*;

1.3.2.11 the location and address of the *meter point* of the *metering installation*, if the *meter point* is not located at the *defined meter point*;

1.3.2.12 the pulse multiplier and *meter* multiplier for the *metering installation*;

1.3.2.13 details of the *data logger* of the *meter* within the *metering installation* and of the modem speed;

1.3.2.14 the burdens connected to each *instrument transformer* contained within the *metering installation*;

1.3.2.15 the *instrument transformer* ratios available and in use;

1.3.2.16 the unique internal *meter* identifier, the telephone number, the passwords and the protocol translation program name for the *metering installation*; and

1.3.2.17 the emergency restoration plan required in respect of the *outage* or malfunction of or a defect in an *instrument transformer*.

1.3.3 The documentation relating to loss adjustment and measurement error correction factors and the documentation relating to *instrument transformer* burdens required by section 1.3.2 to form part of the *meter point* documentation for a *metering installation* shall be stamped by a registered professional engineer.

1.3.4 The *metering service provider* for a *metering installation* that measures the consumption of *energy* referred to in section 2.1A.1.1 of Chapter 9 or that measures the consumption of *station service* shall provide to the *IESO*, in support of the application to register the *metering installation*, the proportions referred to in section 2.1A.4.1(a) or 2.1A.4.2(a), as may be applicable, to the extent that such proportions have been agreed in the manner specified in those sections and in such form as may be required by the applicable *market manuals*.

1.3A Transmitter Confirmation of Meter Point Documentation

1.3A.1 No *metering service provider* to whom a request has been made pursuant to section 6.1.2A of Chapter 6 shall submit to the *IESO* the *meter point* documentation referred to in section 1.3 in respect of a *metering installation* that will be used for the calculation and collection of charges for *transmission service* unless the relevant portion of the *meter point* documentation is accompanied by the confirmation of the approval of each applicable *transmitter* referred to in sections 3.1.3, 5.1.3, 6.1.3 or 6A.1.2.2 of Chapter 10, as may be applicable.

1.4 Other

1.4.1 The *IESO* shall ensure that the *metering registry* contains, in respect of each registered *metering installation* and *metering installations* whose registration has expired but whose continued use has been determined by the *IESO* to be necessary for the efficient operation of the *IESO-administered markets*, the identification number assigned by the *IESO* to the *defined meter point* for that *metering installation*.

Appendix 6.6

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Market Rules

Chapter 7

System Operations and Physical Markets

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Table of Contents

1. Introductory Rules

1.1 Purpose

1.1.1 This Chapter sets forth rules governing the real-time operations of the *electricity system*, and the market-clearing and pricing process in the *physical markets*.

1.2 Application

1.2.1 The rules in this Chapter apply to:

1.2.1.1 the *IESO*;

1.2.1.2 any person who causes or permits electricity or any *physical service* to be conveyed into, through or out of the *integrated power system*;

1.2.1.3 any registered market participant that submits dispatch data with respect to any registered facility; and

1.2.1.4 transmitters.

1.2.2 The rules in this Chapter apply to both the 60 Hz and the 25 Hz portions of the *electricity system*.

1.2.3 In this Chapter, a reference to the term "area" in the context of *operating reserve* shall be construed as a reference to a portion of the *IESO control area* designated as such by the *IESO* and within which the *IESO* may impose limits on the amount of *ten-minute operating reserve* that can be scheduled from *registered facilities* located within that portion for the purpose of meeting the total requirement for *ten-minute operating reserve* within the *IESO control area*.

1.3 Scope of the Physical Markets

1.3.1 The *IESO* shall administer two types of *physical markets*: the *real-time markets* and the *procurement markets*.

1.3.2 The *IESO* shall administer, in accordance with sections 3 to 8 the following *real-time markets* in an integrated fashion:

1.3.2.1 a market in *energy*, measured in MWh; and

1.3.2.2 a market in several classes of *operating reserve*, measured in MW.

1.3.2.3 [Intentionally left blank- section deleted]

1.3.3 The *IESO* shall administer, in accordance with section 9, the following *procurement markets* to procure certain *physical services* required for *reliable* operation of the *electricity system*:

1.3.3.1 markets for contracted ancillary services, including regulation, reactive support service and voltage control service, and black-start capability; and

1.3.3.2 a market for reliability must-run contracts.

1.4 Co-ordination with Control Areas Outside the IESO Control Area

1.4.1 The *IESO* shall, where required or appropriate under duly constituted regional *reliability* agreements with one or more other *control areas*, and subject to any confidentiality agreements entered into with *market participants* or as part of such *reliability* agreements, share with other *control area operators* all relevant information concerning physical system operations in relation to the *electricity system*.

1.5 Delivery in Respect of Extra-provincial Intertie Transactions

1.5.1 Where *energy* or an *ancillary service* is being conveyed:

1.5.1.1 into the *IESO-controlled grid* from an *intertie zone* outside the Province of Ontario; or

1.5.1.2 out of the *IESO-controlled grid* to an *intertie zone* outside the Province of Ontario,

delivery of such *energy* or *ancillary service* to or from, as the case may be, the *boundary entity* shall, for all purposes under these *market rules*, be deemed to occur on the Ontario portion of the applicable *intertie*.

1.6 Planned Outages for Maintenance and Upgrades of IESO-Administered Markets Software, Hardware and Communication Systems

1.6.1 The *IESO* may, from time to time, undertake *planned outages* on *IESO-administered markets* software, hardware or communication systems for the purpose of maintenance and/or upgrades to those systems. These *planned outages* may result in temporary disruptions to some market activities, including but not limited to submission of *dispatch data*, scheduling, pricing, issuing of *dispatch instructions* and *IESO* report *publishing*.

1.6.2 The *IESO* shall, in respect of a *planned outage* referred to in section 1.6.1:

1.6.2.1 Notify all *market participants*, as far in advance as reasonably practicable, of the timing and duration of the *planned outage*;

1.6.2.2 Maintain normal market operations during the *planned outage* to the greatest extent practicable; and

1.6.2.3 Limit the impact and duration of the *planned outage*, and any resulting disruption to market operations to the greatest extent practicable.

1.6.3 If a *planned outage* referred to in section 1.6.1 is expected to result in a disruption to normal market operations, the *IESO* shall notify all *market participants* of the expected disruption and shall specify any required alternative procedures that will be in effect for the duration of the disruption. These alternative procedures shall be designed so as to permit normal market operations to the greatest extent practicable. These alternative procedures may include, but are not limited to:

1.6.3.1 Submission of *dispatch data* by an alternate means and/or in an alternative form pursuant to section 3.2.2; and

1.6.3.2 Establishment of *administrative prices* pursuant to section 8.4A.

1.6.4 *Market participants* shall comply with the alternative procedures specified by the *IESO* in section 1.6.3.

1.7 IESO Authorities and Obligations Regarding the Operation of the Day-Ahead Commitment Process Functions

1.7.1 The Chief Executive Officer of the *IESO* shall determine when the day-ahead commitment process shall first be used.

1.7.2 [Intentionally left blank – section deleted]

1.7.3 The *IESO* shall notify *market participants* at least five *business days* in advance of the day the day-ahead commitment process will first be used.

1.7.4 The *IESO* shall cancel the day-ahead commitment process for a given *dispatch day* when process or software failures prevent one or more hourly day-ahead commitment process runs from meeting the minimum criteria for a minimum acceptable DACP run, as defined in the applicable *market manual.*

1.7.5 In accordance with the applicable *market manual*, if the *IESO* cancels the day-ahead commitment process for a given *dispatch day*, the *IESO* shall:

- inform *market participants* of the cancellation;
- inform *market participants* as to whether the day-ahead commitment process will resume for the subsequent *dispatch day*.

2. Registration for Physical Operations

2.1 Requirements for Operating on the Grid

2.1.1 No person shall participate in the *real-time markets* or cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* unless:

2.1.1.1 that person is authorised to be a *market participant* in accordance with Chapter 2;

2.1.1.2 the *facility* to or from which the electricity or *physical service* is to be so conveyed or the *boundary entity* to which the electricity or *physical service* relates has either been registered by the *IESO* as a *registered facility* pursuant to section 2.2 or section 2.2A, as the case may be, or is exempt from registration under section 2.1.3; and

2.1.1.3 subject to section 2.1.1A, where such *registered facility* is a *generation facility* that is connected electrically to a neighbouring *control area,* and the electricity or *physical service* is to be conveyed out of the *integrated power system* over a *radial intertie*:

a. the person complies with the requirements of Appendix 7.7;

b. the person has entered into a *connection agreement;*

c. the *IESO* has entered into an *interconnection agreement* with the *control area operator, security coordinator* or *interconnected transmitter* for the relevant *radial intertie;* and

d. the *interconnection agreement* referred to in section 2.1.1.3(c) supports the implementation of the requirements of Appendix 7.7.

2.1.1A Section 2.1.1.3 shall not apply in respect of:

2.1.1A.1 the delivery of electricity or a *physical service* out of the *integrated power system* over a *radial intertie* where such delivery is required to provide support in the case of an *emergency* in a *control area*;

2.1.1A.2 the delivery of electricity or a *physical service* out of the *integrated power system* over a *radial intertie* where such delivery is required to provide support in the case of an *outage* in a *control area*; or

2.1.1A.3 the delivery of electricity or a *physical service* out of the *integrated power system* over an *intertie* that is configured as a *radial intertie* following and as a result of a *contingency event.*

2.1.2 A *market participant* shall not submit, and the *IESO* shall not accept, any *dispatch data* with respect to a *facility* or *boundary entity* unless:

2.1.2.1 that facility or boundary entity is a registered facility for the provision of the physical service(s) to which the dispatch data relate;

2.1.2.2 that market participant is the registered market participant for that registered facility; and

2.1.2.3 the *dispatch data* are consistent with: (i) the registration information defining the capabilities of the *registered facility*; (ii) the *market participant's* reasonable expectations of the current actual capabilities of the *registered facility*; and (iii) any revision in registration information requested by the *IESO* under section 7.5.6.2 or other provision of these *market rules*.

2.1.3 Subject to sections 2.3 and 10.2.6, no person that intends to participate in the *IESO-administered markets* or to cause or permit *electricity* or any *physical service* to be conveyed into, through or out of the *integrated power system* shall be required to register the *facility* to or from which the *electricity* or *physical service* is to be so conveyed as a *registered facility* if such *facility* is embedded within a *distribution system*, a load *facility,* a *generation facility* or an *electricity storage facility* and that:

2.1.3.1 in the case of a *generation facility*, has a maximum rated *generation capacity,* net of auxiliary requirements, of less than 1 MW;

2.1.3.2 in the case of a *load facility*, has a maximum load capacity of less than 1 MW;

2.1.3.3 in the case of a *distribution system*, has a maximum load capacity of less than 1 MW; or

2.1.3.4 in the case of an *electricity storage facility*, has a maximum capacity for *energy* for each of injections and withdrawals, net of auxiliary requirements, of less than 1 MW.

2.2 Registered Facilities

2.2.1 The *IESO* shall establish a process for registering a *facility* or *boundary entity* as a *registered facility* and for registering a *market participant* as a *registered market participant*. Such process shall include, but not be limited to, the certifications referred to in sections 2.2.3.3 and 2.2.3.4 and the testing and inspection referred to in section 2.2.3.5.

2.2.1A [Intentionally left blank – section deleted]

2.2.2 A market participant may apply to register a facility or boundary entity as a registered facility:

2.2.2.1 for the delivery or withdrawal of specific *physical services* pursuant to the provisions of this section 2.2.

2.2.2.2 [Intentionally left blank – section deleted]

2.2.3 The *IESO* shall approve an application for registration of a *facility* or *boundary entity* as a *registered facility* if:

2.2.3.1 the applying *market participant* submits:

a. the registration information required by this section 2.2;

b. in the case of a *facility connected* to the *IESO-controlled grid*, a copy of the *connection agreement* pertaining to the *facility* and entered into with the applicable *transmitter*; and

c. in the case of a *generation facility,* an *electricity storage facility*, or a *dispatchable load facility* embedded within a *distribution system*, a copy of the *connection agreement* pertaining to the *facility* and entered into with the applicable *distributor*;

2.2.3.2 the *IESO* is satisfied on reasonable grounds that the *facility* is capable of operating as described in the registration information or as otherwise provided by the *market rules* in respect of the relevant *physical service*;

2.2.3.3 the applying *market participant* certifies to the *IESO* that all of the facilities and equipment to which its application for registration relates comply with all applicable technical requirements, other than those referred to in section 6.2 of Chapter 2, set forth in these *market rules* applicable to all *market participants*, the class of *market participant* of which the applying *market participant* forms part and the *IESO-administered market* in which the applying *market participant* wishes to participate;

2.2.3.4 the applying *market participant* certifies to the *IESO* that it has adequate qualified employees or other personnel and organizational and other arrangements that are sufficient to enable the applying *market participant* to perform all of the functions and obligations applicable to *market participants*, the class of *market participant* of which the applying *market participant* forms part and the *IESO-administered market* in which the applying *market participant* wishes to participate in respect of all of the facilities and equipment to which its application for registration relates;

2.2.3.5 the applying *market participant* successfully completes such testing and permits such inspection as the *IESO* may require for the purposes of testing or inspecting whether all of the facilities and equipment to which its application for registration relates meet all applicable technical requirements, other than those referred to in section 6.2 of Chapter 2, set forth in these *market rules* applicable to all *market participants*, the class of *market participant* of which the applying *market participant* forms part and the *IESO-administered market* in which the applying *market participant* wishes to participate;

2.2.3.6 the applying *market participant* certifies to the *IESO* in writing that all of the *facilities* and equipment to which its application for registration relates complies with the requirements identified in any applicable *preliminary assessment* or *system impact assessment* associated with that *market participant's facilities* or equipment; and

2.2.3.7 the applying *market participant* certifies to the *IESO* that all of the *facilities* and equipment to which its application for registration relates does not differ materially from the configuration or technical parameters that were used by the *IESO* as the basis for which it issued any applicable approvals for such new or modified *connection* in accordance with section 6.1.14 to 6.1.18 of Chapter 4, unless the applicable *market participant* or *connection applicant* has obtained the approval of the *IESO* for the change in configuration or technical parameter in accordance with section 6.1.22 of Chapter 4.

2.2.3.8 [Intentionally left blank – section deleted]

2.2.3A [Intentionally left blank – section deleted]

2.2.3B [Intentionally left blank – section deleted]

2.2.4 The *market participant* designated in the registration information as the *market participant* authorised to submit *dispatch data* with respect to a *registered facility* shall be the *registered market participant* for that *registered facility*. The *registered market participant* designated for a *registered facility* may not be changed without the prior approval of the *IESO*.

2.2.5 The *IESO* shall define the form and content of information required for registration as a *registered facility* in accordance with sections 2.2.6 to 2.2.8.

2.2.6 Where the *facility* sought to be registered is within the *IESO control area*, the information required for registration as a *registered facility* shall, subject to any lesser requirements that may be *published* by the *IESO* in respect of the information required for registration of a given class or size of *facility*, include, but not be limited to:

2.2.6.1 the identity of the owner and the operator of the *facility*;

2.2.6.2 the identity of the *market participant* authorised to submit *dispatch data* with respect to the *facility*;

2.2.6.3 for a *connected facility*, information demonstrating that the *facility* has met the *connection* requirements set forth in Chapter 4;

2.2.6.4 information demonstrating that the *market participant* designated as the *registered market participant* for the *facility* has the operational control necessary to assure delivery or withdrawal of the relevant *physical services* as described in the registration information;

2.2.6.5 for a *connected facility*, the location of the *facility* and the identity of the *primary RWM* that will measure the flow of *energy* between the *facility* and the *IESO-controlled grid*;

2.2.6.6 for a *facility* embedded within a *distribution system* or within a *connected facility* within the *IESO control area* that is *connected* to the *IESO-controlled grid*, the location of that *facility*, the identity of the *primary RWM(s)* through which *energy* will flow between that *facility* and the *IESO-controlled grid* and information demonstrating that *energy* can flow to and from the identified *primary RWM*(s) with allocations and loss factors specified in the registration information;

2.2.6.7 standing technical data defining the ability of the *facility* to deliver or withdraw each *physical service* for which registration is sought including, where relevant, the trade-off functions among *energy* and *operating reserves;*

2.2.6.8 for a *facility* that will be subject to the *IESO's dispatch instructions*, certification that the *facility* has a minimum rated *generation capacity*, net of auxiliary requirements, or a minimum *dispatchable load* capacity, of 1 MW, or for an *electricity storage facility* an ability to inject a minimum of 1 MW and withdraw a minimum of 1 MW. Individual *facilities* or units may be aggregated to meet this minimum capacity requirement if they meet the aggregation requirements of section 2.3; and

2.2.6.9 [Intentionally left blank – section deleted]

2.2.6.10 for a cogeneration facility or enhanced combined cycle facility choosing to be either a dispatchable or self-scheduling generation facility, and the registered market participant wishes the compliance bands used to determine whether or not the facility is in compliance with its dispatch instructions or its current schedule, information as outlined in the applicable market manual concerning the impact that the production or supply of the other forms of useful energy within the facility has on energy production. The IESO may audit this information, which is to be used to determine appropriate compliance bands as outlined in section 3.3.8, at any time.

2.2.6A A *registered market participant* for a *generation facility* may submit the following *facility* specific information: forbidden regions; and period of steady operation. If the information regarding forbidden regions is submitted, the *market participant* shall respect such information when submitting *dispatch data* for the *real-time market*. If the *dispatch data* submitted does not respect such information the *IESO* shall reject the *dispatch data* submission for the affected resource and for the corresponding *dispatch hour* or *dispatch hours* and shall advise the submitting *registered market participant* accordingly.

2.2.6B A *registered market participant* for a *dispatchable generation facility* shall submit to the *IESO* the *minimum loading point*, the *minimum generation block run-time*, and the *minimum run-time* for the *generation facility* if the *minimum loading point* for the *facility* is greater than zero MW and if the *minimum generation block run-time* for the *facility* is greater than one hour.

2.2.6B.1 [Intentionally left blank – section deleted]

2.2.6B.2 [Intentionally left blank – section deleted]

2.2.6B.3 [Intentionally left blank – section deleted]

2.2.6C [Intentionally left blank – section deleted]

2.2.6D The *IESO* may request, and the *registered market participant* for a *dispatchable generation facility* or a dispatchable *electricity storage facility* shall submit to the *IESO*, the following information for that *facility*:

- *start-up time*; and
- *minimum shut-down time*.

2.2.6E If no *facility* specific data is submitted to the *IESO* for the *generation facility's minimum loading point*, *forbidden regions*, or *period of steady operation* in accordance with sections 2.2.6A, and 2.2.6B, the *IESO* shall assign default values of zero for that data.

2.2.6F If *facility* specific data is submitted to the *IESO* in accordance with sections 2.2.6A, 2.2.6B, 2.2.6G or 2.2.6J the *IESO* shall respect the data as submitted in its determination of the *real-time schedule* in accordance with section 6 and day-ahead schedule in accordance with section 5.

2.2.6G In accordance with the applicable *market manuals*, a *registered market participant* that operates a combined cycle facility that is not aggregated under section 2.3 shall submit to the *IESO* the required data for that combined cycle facility, and for those *registered market participants* that wish to designate their non-aggregated combined cycle *facility* as a *pseudo-unit* in the day-ahead commitment process set out in section 5.8, the required data for that *pseudo-unit*.

2.2.6H A *registered market participant* for a *dispatchable* hydroelectric *generation facility* shall submit to the *IESO* where applicable the *daily cascading* hydroelectric dependency for that *generation facility*.

2.2.6I Subject to section 2.2.6G, the *IESO* shall determine, in accordance with the applicable *market manual*, the *pseudo-unit* technical parameters based on the *facility* specific data submitted under section 2.2.6J.

2.2.6J A *registered market participant* for a *dispatchable generation facility* that is not a quick-start facility may submit on a daily basis the *minimum loading point*, the *minimum generation block run-time*, the maximum number of starts per day and the *minimum generation block down time*, and, for facilities designated as a *pseudo-unit* under section 2.2.6G, the combustion turbine single cycle mode, and the *IESO* shall use this data in the day-ahead commitment process set out in section 5.8.

2.2.6K A *registered market participant* for a *dispatchable generation facility* shall submit to the *IESO* the elapsed time to *dispatch* for the *generation facility*.

2.2.7 Where a *boundary entity* is sought to be registered, a valid *interconnection agreement* over the relevant *interconnection* must have been entered into prior to the approval of the application. In addition, the information required for registration of the *boundary entity* as a *registered facility* shall include, but not be limited to:

2.2.7.1 identification of the *intertie RWM*(s) through which the *physical services* will be delivered to or withdrawn from the *IESO-controlled grid*, which shall determine the *intertie zone* within which the *boundary entity* is deemed to be located;

2.2.7.2 information confirming that the *market participant* authorized to submit *dispatch data* with respect to the *boundary entity* holds all licences, permits or other authorizations that may be required to permit such *market participant* to deliver or withdraw the *physical* *services* to or from the *intertie zone* within which the *boundary entity* is deemed to be located;

2.2.7.3 information demonstrating compliance with applicable requirements of all relevant *standards authorities* and completion of the necessary transmission service arrangements with affected *control areas*;

2.2.7.4 the identity of the *market participant* authorized to submit *dispatch data* with respect to the *boundary entity*; and

2.2.7.5 information defining the maximum quantities of each *physical service* that the *market participant* authorized to submit *dispatch data* in respect of the *boundary entity* is entitled to inject into or withdraw from the *IESO-controlled grid* in respect of the *boundary entity* including, where relevant, the trade-off functions among *energy* and *operating reserves.*

2.2.8 In addition to the information required by section 2.2.6 or 2.2.7, as the case may be, the registration information for a *facility* or *boundary entity* that will provide *operating reserves* shall include information in a form approved by the *IESO* demonstrating in the case of a *facility*, the ability of the *facility* or, in the case of a *boundary entity*, the ability of the resources comprising the *boundary entity*, to:

2.2.8.1 provide *energy* and *operating reserves* according to the trade-off functions described in, and with the response times indicated in, the registration information; and

2.2.8.2 deliver, when the *facility* or *boundary entity* is called upon to do so by the *IESO*, *energy* at the specified rate (in MWh/hour or MW) in accordance with its *operating reserve offer* for at least one hour.

2.2.9 A *market participant* may apply to *register* as a *self-scheduling generation facility* any *generation facility*:

2.2.9.1 with a name-plate rating of 1 MW or more but less than 10 MW;

2.2.9.2 that is a *commissioning generation facility* of any name-plate rating and that is sought to be registered pursuant to section 2.2A.1; or

2.2.9.3 that is a *cogeneration facility* or *enhanced combined cycle facility* with a name plate rating of 10 MW or more provided that the *IESO* determines that there are no adverse impacts on the *reliable* operation of the *IESO-controlled grid* of the *facility* being registered as a *self-scheduling generation facility*.

2.2.9A Except as the *IESO* may authorize under section 21.3.2, a *market participant* may apply to register a *facility* as a *self-scheduling electricity storage facility* only if it:

2.2.9A.1 has an *electricity storage facility size* of 1 MW or more but less than 10 MW and meets the condition of section 2.1.3.4; or

2.2.9A.2 is a *commissioning electricity storage facility* of any capacity and that is sought to be registered pursuant to section 2.2D.

2.2.10 A *self-scheduling generation facility* may be registered:

- to provide *energy* and *reactive support service* and *voltage control service*; and
- as a *certified black start facility*.

2.2.11 The *IESO* shall approve an application for registration as a *self-scheduling generation facility* or a *self-scheduling electricity storage facility* if the information required by this section 2.2 is provided and the *IESO* determines that *self-scheduling* of the *facility* will not have a material adverse effect on power system *security*.

2.2.12 A *self-scheduling generation facility* or a *self-scheduling electricity storage facility* whose application for *facility* registration has been approved by the *IESO* is a *registered facility*.

2.2.13 A *market participant* may apply to register an *intermittent generator* if it has a name-plate rating of not less than 1 MW.

2.2.14 An *intermittent generator* may not be registered to provide any physical service other than *energy* and *reactive support service* and *voltage control service*.

2.2.15 The *IESO* shall approve an application for registration as an *intermittent generator* if the information required by this section 2.2 is provided and the *IESO* determines that intermittent operation of the *facility* will not have a material adverse impact on power system *security*.

2.2.16 An *intermittent generator* whose application for *facility* registration has been approved by the *IESO* is a *registered facility*.

2.2.17 For the purposes of this Chapter, a *distribution system* connected to the *IESO-controlled grid* must be a *registered facility*.

2.2.18 The *IESO* shall develop procedures and requirements for registering a *distribution system* as a *registered facility*. Such procedures shall include, but not be limited to, the certifications referred to in sections 2.2.3.3 and 2.2.3.4 and the testing and inspection referred to in section 2.2.3.5.

2.2.19 A *market participant* may apply to register a *transitional scheduling generator* if it has a nameplate rating of not less than 1MW.

2.2.20 A *transitional scheduling generator* may be registered:

- to provide *energy* and *reactive support service* and *voltage control service* and
- as a *certified black start facility*.

2.2.21 The *IESO* shall approve an application for registration as a *transitional scheduling generator* if the information required by this section 2.2 is provided, and the *generator* is under contract with *OEFC* and will participate in the *real-time market* for *energy*.

2.2.22 A *transitional scheduling generator* whose application for *facility* registration has been approved by the *IESO* is a *registered facility*.

2.2.23 Within one month of the coming into effect of the amendments to the contract with *OEFC* required as a result of electricity industry restructuring in Ontario in respect of a *transitional scheduling generator*, the *registered market participant* for the *transitional scheduling generator* shall change registration for the applicable *generation facility* to one of the other *generation facility* registrations.

2.2.24 [Intentionally left blank – section deleted]

2.2A Registration of Commissioning Generation Facilities

2.2A.1 A *market participant* may apply to register a *commissioning generation facility* as a *self-scheduling generation facility*, in accordance with section 2.2, for the purpose of being permitted to convey electricity or a *physical service* into, through or out of the *integrated power system* or of participating in the *real-time markets* during the period in which the *commissioning generation facility* is undergoing the commissioning tests referred to in section 2.2A.4.

2.2A.2 The *IESO* shall approve an application for *facility* registration of a *commissioning generation facility* as a *self-scheduling facility* if it is satisfied that the requirements of section 2.2 have been met. Any such registration shall expire upon completion by the *commissioning generation unit* of the final commissioning test submitted to and approved by the *IESO* pursuant to section 2.2A.4.

2.2A.3 Upon expiry of the registration referred to in section 2.2A.2, a *market participant* shall not participate in the *real-time markets* nor cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* in respect of a former *commissioning generation facility* unless such former *commissioning generation facility* has been registered as a *generation facility*, other than pursuant to this section 2.2A, in accordance with section 2.2.

2.2A.4 Where a *commissioning generation facility* has been registered by the *IESO* pursuant to section 2.2A.2, the *market participant* for that *commissioning generation facility* shall, while such registration is in effect:

2.2A.4.1 ensure that the commissioning generation facility:

a. complies with all of the provisions of these *market rules* applicable to *self-scheduling generation facilities*; and

b. where it will seek to be registered, other than pursuant to this section 2.2A, in accordance with section 2.2 as other than a *self-scheduling generation facility*, complies with all of the applicable requirements of section 7.3 of Chapter 4; and

2.2A.4.2 submit to the *IESO*, for approval and in accordance with section 2.2A.5, information detailing the commissioning test plans for the *commissioning generation facility*.

2.2A.5 The detailed commissioning test plans, referred to in section 2.2A.4.2 shall be submitted to the *IESO* for approval and shall be scheduled in accordance with the procedures applicable to the *outage* coordination process described in section 6 of Chapter 5 and with any applicable *market manual* and shall include, but not be limited to:

2.2A.5.1 the time required for the *commissioning generation facility* to synchronize to and de-synchronize from the *IESO-controlled grid*;

2.2A.5.2 *energy* and reactive output levels;

2.2A.5.3 the timing of and ramp rates associated with changes in *energy* and reactive output levels; and

2.2A.5.4 run-back or trip tests for the *commissioning generation facility*.

2.2A.6 Except as otherwise provided in this section 2.2A, where a *commissioning generation facility* has been registered by the *IESO* pursuant to section 2.2A.2, the *IESO* shall, while such registration is in effect, treat the *commissioning generation facility* as a *self-scheduling generation facility* for all purposes under these *market rules* including, but not limited to, the submission of *dispatch data* and *settlement*.

2.2B Generation Facility Eligibility for the Real-Time Generation Cost Guarantee

2.2B.1 A *registered market participant* for a *generation facility* shall be eligible for the guarantee of certain elements of its costs, calculated in accordance with section 4.7B of Chapter 9, provided the following criteria are met:

2.2B.1.1 the facility is not a quick-start facility;

2.2B.1.2 the facility is a dispatchable generation facility; and

2.2B.1.3 [Intentionally left blank – section deleted];

2.2B.1.4 the *registered market participant* has submitted to the *IESO* the following data for the *generation facility*, in accordance with the applicable *market manual*, and the *IESO* accepts the data as reasonable:

2.2B.1.4A the minimum run-time, minimum loading point, and minimum generation block run-time;

2.2B.1.4B the incremental fuel costs and incremental operating and maintenance costs determined in accordance with sections 2.2B.4, 2.2B.5 and 2.2B.6; and

2.2B.1.4C any other data, as reasonably requested by the *IESO* that is relevant to determine eligible costs in accordance with section 2.2B.4, from the *registered market participant*, any *affiliate*, service provider or contractual counter-party.

2.2B.2 The *IESO* may, at any time, audit the data submitted in accordance with section 2.2B.1.4, and the *registered market participant* shall provide the requested audit information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that the audit information provided does not support the submitted data, including, without limitation, that the *IESO* does not accept the data as reasonable, the *IESO* shall recover any resulting over-payments made to the *market participant.* Notwithstanding the foregoing sentence, where the *registered market participant* has submitted data in accordance with this section 2.2B and sections 10A.1 and 11.2.1 of Chapter 1, the *IESO* shall not retroactively revise pre-approved cost values determined in accordance with section 2.2B.5 when calculating any amount to be recovered from that *registered market participant*.

2.2B.3 For purposes of sections 2.2B.1.4 and 2.2B.2, the *registered market participant* shall retain supporting documentation related to cost submissions, including data that may be required by the *IESO* to determine pre-approved cost values and methodologies, in accordance with the applicable *market manual*, for a period of 7 years from the date when a cost is paid.

Submitted Eligible Costs

2.2B.4 Submitted eligible costs pursuant to section 2.2B.1 shall be limited to:

2.2B.4.1 incremental fuel costs, incremental operating and maintenance costs resulting from *wear and tear* caused by the operation of a *facility*; and

2.2B.4.2 all other incremental operating and maintenance costs as set out in section 4.7B.5.2 of Chapter 9;

from either the point of ignition or synchronization to the *IESO-controlled grid* as applicable, until the *facility* reaches its *minimum loading point*, where that *facility* has met the eligibility criteria specified in sections 2.2B.1, 5.7 and 6.3A, as specified and further detailed in the applicable *market manual*.

2.2B.5 Subject to section 2.2B.6, for each cost specified in section 2.2B.4, the *IESO* shall determine pre-approved cost values and methodologies that are either universal or *facility*-specific, and calculate the submitted eligible costs in accordance with section 4.7B.5 of Chapter 9. The pre-approved cost values and methodologies shall remain in effect until revised by the *IESO*. The *IESO* shall review the pre-approved cost values and methodologies at least once every 3 years. The first review shall be completed no later than 3 years from the effective date of this section.

2.2B.6 In circumstances where pre-approved cost values and methodologies are not established under section 2.2B.5, the *IESO* may at its sole discretion allow a *registered market participant* to submit the incremental fuel costs and incremental operating and maintenance costs for each *facility* under section 2.2B.1.4B, in accordance with the applicable *market manual*.

2.2C Generation Facility Eligibility for the Day-Ahead Production Cost Guarantee

2.2C.1 A *registered market participant* for a *generation facility* shall be eligible for the guarantee of certain elements of the *facility's* costs, calculated in accordance with section 4.7D of Chapter 9, provided the following criteria are met:

2.2C.1.1 the facility is not a quick-start facility;

2.2C.1.2 the *facility* is a *dispatchable generation facility* with a elapsed time to *dispatch* greater than one hour;

2.2C.1.3 [Intentionally left blank – section deleted];

2.2C.1.4 the *registered market participant* has, according to the timelines and in the form specified in the applicable *market manual*, submitted to the *IESO* the following information for the *generation facility*: the start-up costs; and the speed no-load costs; and

2.2C1.5 the *registered market participant* has, according to the timelines and in the form specified in the applicable *market manual*, submitted to the *IESO* the following information for the *generation facility*: the *minimum loading point*; and the *minimum generation block run-time* and the *IESO* accepts all such information as reasonable.

2.2C.2 [Intentionally left blank – section deleted]

2.2D Registration of Commissioning Electricity Storage Facilities

2.2D.1 A *market participant* may apply to register a *commissioning electricity storage facility* as a *self-scheduling electricity storage facility*, in accordance with section 2.2, for the purpose of being permitted to convey electricity or a *physical service* into, through or out of the *integrated power system* or of participating in the *real-time markets* during the period in which the *commissioning electricity storage facility* is undergoing the commissioning tests referred to in section 2.2D.4.

2.2D.2 The *IESO* shall approve an application for *facility* registration of a *commissioning electricity storage facility* as a *self-scheduling facility* if it is satisfied that the requirements of section 2.2 have been met. Any such registration shall expire upon completion by the *commissioning electricity storage unit* of the final commissioning test submitted to and approved by the *IESO* pursuant to section 2.2D.4.

2.2D.3 Upon expiry of the registration referred to in section 2.2D.2, a *market participant* shall not participate in the *real-time markets* nor cause or permit electricity or any *physical service* to be conveyed into, through or out of the *integrated power system* in respect of a former *commissioning electricity storage facility* unless such former *commissioning electricity storage facility* has been registered as an *electricity storage facility*, other than pursuant to this section 2.2D, in accordance with section 2.2.

2.2D.4 Where a *commissioning electricity storage facility* has been registered by the *IESO* pursuant to section 2.2D.2, the *market participant* for that *commissioning electricity storage facility* shall, while such registration is in effect:

2.2D.4.1 ensure that the commissioning electricity storage facility:

a. complies with all of the provisions of these *market rules* applicable to *self-scheduling electricity storage facilities*; and

b. where it will seek to be registered, other than pursuant to this section 2.2D, in accordance with section 2.2 as other than a *self-scheduling electricity storage facility*, complies with all of the applicable requirements of section 7.3 of Chapter 4; and

2.2D.4.2 submit to the *IESO*, for approval and in accordance with section 2.2D.5, information detailing the commissioning test plans for the *commissioning electricity storage facility*.

2.2D.5 The detailed commissioning test plans, referred to in section 2.2D.4.2 shall be submitted to the *IESO* for approval and shall be scheduled in accordance with the procedures applicable to the *outage* coordination process described in section 6 of Chapter 5 and with any applicable *market manual* and shall include, but not be limited to:

2.2D.5.1 the time required for the *commissioning electricity storage facility* to synchronize to and de-synchronize from the *IESO-controlled grid*;

2.2D.5.2 *energy* and reactive output levels;

2.2D.5.3 the timing of and ramp rates associated with changes in *energy* and reactive output levels; and

2.2D.5.4 run-back or trip tests for the commissioning electricity storage facility.

2.2D.6 Except as otherwise provided in this section 2.2D, where a *commissioning electricity storage facility* has been registered by the *IESO* pursuant to section 2.2D.2, the *IESO* shall, while such registration is in effect, treat the *commissioning electricity storage facility* as a *self-scheduling electricity storage facility* for all purposes under these *market rules* including, but not limited to, the submission of *dispatch data* and *settlement*.

2.3 Aggregated Registered Facilities

2.3.1 A *market participant* may apply to the *IESO* to aggregate several *facilities* for the purpose of delivering or withdrawing one or more *physical services* in the *real-time energy market*, the *procurement markets* or both. Upon *IESO* approval, the aggregated *facilities* shall, except as specifically stated in the registration information or the *IESO*'s approval of the aggregation, be treated as a single *registered facility* for the provision or withdrawal of the approved *physical services*:

2.3.1.1 by the *registered market participant* for purposes of the submission of *dispatch data*; and

2.3.1.2 by the *IESO*, for purposes of the scheduling and *dispatch* processes described in this Chapter.

2.3.1A [Intentionally left blank – section deleted]

2.3.1A.1 [Intentionally left blank – section deleted]

2.3.1A.2 [Intentionally left blank – section deleted]

2.3.2 The *IESO* shall approve an application for the aggregation of *facilities* into a single *registered facility* unless:

2.3.2.1 the registration information for the *facilities* proposed to be aggregated fails to satisfy the conditions of section 2.2;

2.3.2.2 the registration information fails to demonstrate one or more of the following in respect of the *facilities* proposed to be aggregated;

a. that they are all located within the *IESO control area*;

b. subject to section 2.3.2A, that they are all *connected* to the *IESO-controlled grid* at the same *connection point*;

c. that they are all under the operational control of a single *market participant* and that such *market participant* is authorized to submit *dispatch data* for all of them;

d. that operational communication between each of them and the *IESO* meets all applicable standards and protocols; or

e. that they all have relevant metering systems to be used for *settlements* purposes that satisfy the requirements of Chapter 6; or

2.3.2.3 one or more of the facilities proposed to be aggregated is or includes a *generation unit*, an *electricity storage unit*, or a *load facility* :

a. whose *offer* or *bid* information or whose in service or out of service status affects the numerical value of operating *security limits* in any manner;

b. whose *offer* or *bid* information or whose in service or out of service status is information required by the *IESO* for conducting detailed *security* and resource adequacy assessment;

c. whose *offer* or *bid* information or whose in service or out of service status is information required to be submitted to the *market assessment unit* or the *market surveillance panel* in furtherance of their respective functions and obligations under the *Electricity Act, 1998* the *Ontario Energy Board Act, 1998* and these *market rules*; or

d. whose *offer* or *bid* information, in service or out of service status or other information is required by *applicable law*, by *license*, by the *Ontario Energy Board* or by a *standards authority* to be submitted to or obtained by the *IESO*.

2.3.2.4 the applying *market participant* fails to provide the certification referred to in section 2.2.3.3 in respect of any of the *facilities*;

2.3.2.5 the applying *market participant* fails to provide the certification referred to in section 2.2.3.4 in respect of any of the *facilities*; or

2.3.2.6 the applying *market participant* fails to successfully complete the testing or to permit the inspection referred to in section 2.2.3.5 in respect of any of the *facilities.*

2.3.2A Notwithstanding section 2.3.2.2b, the *IESO* may approve an application for the aggregation of *facilities* into a single *registered facility* that are not all *connected* to the *IESO-controlled grid* at the same *connection point*, provided that, in the sole judgement of the *IESO*, they can be represented as a single point of injection or withdrawal without compromising the *reliability* of the *IESO-controlled grid*. Aggregation for the purposes of calculating *transmission service charges* is specified in the then current *Ontario Energy Board* Transmission Rate Order.

2.3.3 If a proposed aggregation of *facilities* meets one or more of the above conditions, the *IESO:*

2.3.3.1 shall provide to the *market participant* whose application is denied the reasons for such denial.

2.3.3.2 [Intentionally left blank]

2.3.3.3 [Intentionally left blank]

2.3.4 Approval of the aggregation of *facilities* shall be withdrawn by the *IESO* where, for any reason, one or more of the aggregation *facilities* commences to meet any one or more of the conditions described in section 2.3.2. The *IESO* shall give notice of the withdrawal to the *market participant* authorized to submit *dispatch data* in respect of the aggregated *facilities* and shall cease to treat those *facilities* as a single *registered facility* as of the date and time specified in the notice for such purpose. The date and time so specified shall not be less than 2 days from the date and time at which the notice of withdrawal is given to the *market participant*. If the *market participant* subsequently wishes to thereafter re-aggregate the *facilities*, it shall be required to re-apply to the *IESO* for approval of the aggregation in accordance with section 2.3.1.

2.3.5 A *market participant* authorized to submit *dispatch data* for aggregated *facilities* may give notice to the *IESO* that it no longer wishes to aggregate those *facilities*. The *IESO* shall acknowledge receipt of the *market participant's* notice and shall cease to treat those *facilities* as a single *registered facility* as of the date and time specified in the acknowledgement of receipt for that purpose. The date and time so specified shall be as soon as reasonably practicable following the date of receipt by the *IESO* of the *market participant's* notice. If the *market participant* subsequently wishes to re-aggregate the *facilities*, it shall be required to re-apply to the *IESO* for approval of the aggregation in accordance with section 2.3.1.

2.4 De-registration of Facilities

2.4.1 A *market participant* that wishes to de-register a *registered facility*, other than a *boundary entity*, which is being removed from service shall file with the *IESO* a notice of request to de-register in such form as may be specified by the *IESO;* provided, however, that a *market participant* shall not be entitled to file such a notice if it is no longer the beneficial owner of the *registered facility*.

2.4.2 Within ten *business days* of the date of receipt of the notice referred to in section 2.4.1, the *IESO* shall notify the *market participant* and the *transmitter* to whose *transmission system* the *registered facility* is *connected* as to whether the *IESO* requires a technical assessment of the impact of the removal from service of the *registered facility* on the *reliability* of the *IESO-controlled grid* and, if so, of the expected date of completion of such assessment. Such date shall not be more than 45 days from the date of issuance by the *IESO* of such notice or such later date as may be agreed between the *IESO* and the *market participant*.

2.4.3 Where the notice issued by the *IESO* pursuant to section 2.4.2 indicates that the *IESO* does not require a technical assessment or where the *IESO* conducts a technical assessment and concludes the removal from service of the *registered facility* will not or is not likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid*, the *market participant* shall file with the *IESO* a notice setting forth the date upon which the *market participant* wishes the *IESO* to de-register the *registered facility*. Such date shall not be less than five *business days* from the date of receipt by the *market participant* of the notice issued by the *IESO* pursuant to section 2.4.2 and, as applicable, shall be subject to the date on which the *registered facility* has been *disconnected* as confirmed by the relevant *transmitter* to the *IESO*.

2.4.4 Where section 2.4.3 applies, the *IESO* shall:

2.4.4.1 if the *registered facility* is not *connected* to the *IESO-controlled grid*, de-register the *registered facility* promptly upon completion of the technical assessment if applicable, or as of the date specified in the notice filed by the *market participant* pursuant to section 2.4.3, whichever is the later, and shall so notify the *market participant*, the *metering service provider* for the *metering installation* that relates to the *registered facility,* and any *market participant* within which the *registered facility* is embedded; or

2.4.4.2 if the registered facility is connected to the IESO-controlled grid:

a. issue to the relevant *transmitter* a *disconnection order* directing the relevant *transmitter* to *disconnect* the *registered facility* from the *IESO-controlled grid* on the date specified in the *disconnection order* which shall be no earlier than the date specified in the notice filed by the *market participant* pursuant to section 2.4.3; and

b. de-register the *registered facility* as of the date on which the relevant *transmitter* confirms to the *IESO* that the *registered facility* has been *disconnected* from the *IESO-controlled grid*.

and shall notify the *market participant* accordingly.

2.4.5 Where the *IESO* conducts the technical assessment referred to in section 2.4.2 and concludes that the removal from service of the *registered facility* will or is likely to have an unacceptable impact on the *reliability* of the *IESO-controlled grid,* the *IESO* and the *market participant* shall commence the process described in sections 9.6 and 9.7 and in section 4.8 of Chapter 5 with a view to concluding a *reliability must-run contract* for that *registered facility*. The *registered facility* shall not be removed from service during the course of such process.

2.4.6 [Intentionally left blank – section deleted]

2.4.6.1 [Intentionally left blank – section deleted]

2.4.6.2 [Intentionally left blank – section deleted]

2.4.7 A *transmitter* that receives a *disconnection order* from the *IESO* pursuant to section 2.4.4.2(a) shall:

2.4.7.1 subject only to section 3.4.1.5 of Chapter 5 and to the completion of any operating and decommissioning procedures contemplated in the *connection agreement* applicable to the *registered facility*, *disconnect* the *registered facility* from the *IESO-controlled grid* on the date and at the time specified in the *disconnection order*; and

2.4.7.2 promptly inform the *IESO* once the *registered facility* has been *disconnected* from the *IESO-controlled grid.*

Planned Retirements of Generation and Electricity Storage Facilities

2.4.8 Each *generator* shall provide the *IESO* not less than six months advance notice of the commencement of the planned retirement of any one of its *generation facilities* that are *registered facilities*, including notification of any plans the *generator* may have to construct replacement *facilities* for those being retired.

2.4.9 Each *electricity storage participant* shall provide the *IESO* not less than six months advance notice of the commencement of the planned retirement of any one of its *electricity storage facilities* that are *registered facilities*, including notification of any plans the *electricity storage participant* may have to construct replacement *facilities* for those being retired.

2.5 Transfer of Registration of Facilities

2.5.1 A *market participant* that wishes to transfer the registration of a *registered facility*, other than a *boundary entity*, as a result of the proposed transfer of the *registered facility* to another person by sale, assignment, lease, transfer of control or other means of disposition shall, not less than 10 *business days* prior to the date on which the transfer is proposed to take effect, file with the *IESO* and the relevant *transmitter* or *distributor*, a notice of request to transfer the registration of the *registered facility* in such form as may be specified by the *IESO*. Such notice shall specify:

2.5.1.1 the identity of the transferee and whether the transferee is or intends to be a *market participant*; and

2.5.1.2 the date upon which the transfer is proposed to take effect,

and shall be accompanied by a written declaration by the proposed transferee that it is willing and able to assume control of the *registered facility* and to comply with all provisions of these *market rules* and of any *reliability must-run contract* or *contracted ancillary services* contract applicable to such *registered facility.*

2.5.2 If the proposed transferee satisfies or is capable of satisfying the requirements of section 2.2, the *IESO* shall approve a request to transfer the registration of a *registered facility* unless the proposed transferee is a *suspended market participant* or is otherwise ineligible under these *market rules* to be a *market participant*.

2.5.3 Where the *IESO* approves a request to transfer the registration of a *registered facility*, the *IESO* shall transfer the registration of the *registered facility* to the proposed transferee:

2.5.3.1 on the date referred to in section 2.5.1.2, provided that the proposed transferee was a *market participant* at the time of filing of the notice referred to in section 2.5.1 and remains a *market participant* on such date; or

2.5.3.2 on such later date as may reasonably be required to permit the *IESO* to effect the transfer following the later of the date of authorization of the proposed transferee as a *market participant* and the date on which the proposed transferee meets the requirements of section 2.2.

2.5.4 Upon completion of the transfer of the *registered facility*, the proposed transferee will have to post with the *IESO prudential support* or *capacity prudential support* as applicable, equal to the proposed transferee's *prudential support obligation* or *capacity prudential support obligation*. Until the proposed transferee has done so, the transferring *market participant* shall continue to be liable for the obligations of the proposed transferee in the *IESO-administered markets*. Such obligations shall include, without limitation, the cost of electricity withdrawn from the *IESO-controlled grid* by the proposed transferee and related charges as determined by the *IESO* in accordance with Chapter 9. The *prudential support obligation* and/or *capacity prudential support obligation* as applicable of the transferring *market participant* shall include all such amounts whether or not the transferring *market participant* has complied with the provisions of this section 2.5.

3. Data Submissions for the Real-Time Markets

3.1 Applicability of this Section

3.1.1 A *registered market participant* that intends one or more of its *registered facilities* to be eligible for *dispatch* by the *IESO* for a given *dispatch hour* of a *dispatch day* shall submit to the *IESO dispatch data* for each such *registered facility* for such *dispatch hour* in accordance with this section 3.

3.1.2 *Dispatch data* that are revised after initial submission as allowed under the provisions of this section 3 must satisfy all of the requirements that apply to initial *dispatch data* and shall be *dispatch data*.

3.1.3 [Intentionally left blank – section deleted]

3.2 The Data Submission Process

3.2.1 Each *registered market participant* shall submit its *dispatch data* to the *IESO* through the *electronic information system* or, when not available, by such alternative means and/or in such alternative simplified form as may be specified by the *IESO* pursuant to section 3.2.2.3.

3.2.2 The *IESO* shall:

3.2.2.1 stamp all *dispatch data* with the time that it was received by the *IESO*;

3.2.2.2 within five minutes, confirm receipt of all such *dispatch data* through the *electronic information system*; and

3.2.2.3 specify alternative means and/or an alternative simplified form of submitting and confirming *dispatch data* when the *electronic information system* is unavailable.

3.2.3 The *IESO* shall reject any *dispatch data* that does not comply with the rules set forth in this section 3 and shall provide to the *registered market participant* submitting such rejected *dispatch data* the reasons for such rejection.

3.2.4 A *registered market participant* that does not receive from the *IESO* confirmation of receipt of *dispatch data* in accordance with section 3.2.2.2 shall immediately contact the *IESO* by telephone or facsimile seeking confirmation of receipt.

3.2.5 A *registered market participant* shall, if requested by the *IESO*, resubmit *dispatch data* by such means as may be specified by the *IESO* in the request.

3.3 Dispatch Data Submissions

3.3.1 Subject to sections 3.3.9 and 3.3A, a *registered market participant* that submits or is required to submit *dispatch data* for the initial *pre-dispatch schedule,* shall submit initial *dispatch data* for each *dispatch hour* of the *dispatch day* after 06:00 EST but before 10:00 EST of each *pre-dispatch day.* Such initial *dispatch data* may thereafter be revised as permitted by this section 3.3.

3.3.2 Subject to section 3.3A.6, the *IESO* shall use the initial *dispatch data* submitted by *registered market participants* to determine and *publish* the initial *pre-dispatch schedule* in accordance with section 5.

3.3.3 Subject to section 3.3A.8, a *registered market participant* may submit revised *dispatch data* with respect to any *dispatch hour* without restriction until 2 hours prior to the beginning of that *dispatch hour*.

3.3.4 [Intentionally left blank – section deleted]

3.3.4A [Intentionally left blank – section deleted]

Replacement Energy Offers

3.3.4B A registered market participant for a hydroelectric generation facility, a combined cycle generation facility, an enhanced combined cycle facility or a cogeneration facility that experiences a forced outage may submit revised dispatch data for a related generation facility, with respect to any dispatch hour up until 10 minutes prior to the beginning of that dispatch hour. If the revised dispatch data is submitted less than 10 minutes prior to the beginning of that dispatch hour, the revised dispatch data will apply to the subsequent dispatch hour. This section is subject to the following conditions:

- The submission of revised *dispatch data* takes place no later than one hour after the *generation facility* experiences the *forced outage* and is limited to the MW amount on *forced outage.*
- The *registered market participant* whose *generation facility* experienced a *forced outage* notifies the *IESO,* in accordance with the applicable *market manual*, of its intention to submit revised *dispatch data* for the related *generation facility* for the next available *dispatch hour* and of its intention to provide replacement *energy* from the related *generation facility.*
- Where the related *generation facility* is not synchronized, the *registered market participant* notifies the *IESO* of its intention to synchronize the related *generation facility* and the *IESO* determines synchronization will have no adverse impact on the *reliability* of the *IESO-controlled grid.*
- The related *generation facility* and the *generation facility* experiencing the *forced outage* have the same *registered market participant*.
- The related *generation facility* and the *generation facility* experiencing the *forced outage* have the same *metered market participant*.

Related *generation facilities* are *generation facilities* that, in the case of a hydroelectric *generation facility*, can utilize the water of the *generation facility* experiencing the *forced outage* without delay. In the case of combined cycle *facilities, enhanced combined cycle facilities* or *cogeneration facilities,* related *generation facilities* are *generation facilities* that can make up the loss in steam production to the steam turbine unit that would otherwise have been produced by the gas turbine unit experiencing the *forced outage.*

3.3.4C In the period after the notification and before the market tools process the revised *dispatch data,* the *IESO* shall accept replacement *energy* from the related *generation facility*, provided there is no adverse impact on the *reliability* of the *IESO-controlled grid.* The replacement *energy* delivered shall be limited to the amount of *energy* originally scheduled for the *generating facility* experiencing the *forced outage.* The *market participant* may choose to provide replacement *energy* from a related *generation facility* without submitting revised *dispatch data* for the current *dispatch hour* or, if within 10 minutes of the next *dispatch hour*, the current and subsequent *dispatch hour*.

3.3.5 Except as permitted by sections 3.3.4B, 3.3.8, 3.3.9.2, 3.3.11, and 21.6 no *registered market participant* may, without the approval of the *IESO*, submit revised *dispatch data* with respect to any *dispatch hour* within 2 hours of that *dispatch hour*.

IESO Approvals of Revised Dispatch Data

3.3.6 Where pursuant to section 3.3.5, the approval of the *IESO* is required for the submission of revised *dispatch data*, the *IESO* shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, approve the submission of revised *dispatch data* where:

3.3.6.1 [Intentionally left blank – section deleted]

3.3.6.2 [Intentionally left blank – section deleted]

3.3.6.3 the *registered market participant* indicates, at the time of the submission of the revised *dispatch data*, that the revision is required in order to reflect a proposed change in the operational status of the *registered facility* designed solely to prevent the *registered facility* from operating in a manner that would endanger the safety of any person, damage equipment, or violate any *applicable law*.

The *IESO* may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

3.3.7 *Dispatch data* submitted during the *dispatch day* to which it applies need refer only to the remaining *dispatch hours* of that *dispatch day*.

3.3.8 Notwithstanding any other provision of this section 3.3 and with the exception of testing specified in section 6.6 of Chapter 5, a *registered market participant* shall as soon as practical submit to the *IESO* revised *dispatch data* for any *registered facility* in respect of which it is the *registered market participant* if, for any *dispatch hour* in the current *pre-dispatch schedule,* the quantity of any *physical service* scheduled for that *registered facility* differs from the quantity the *registered market participant* reasonably expects to be delivered or withdrawn by more than the greater of:

(i) 2 percent;

(ii) such absolute amount as may be determined by the *IESO* based on considerations of *reliability* and *facility* specific characteristics;

(iii) in the case of a *cogeneration facility* that is either a *dispatchable* or *self-scheduling generation facility*, such amount based on the impact that the production of the other forms of useful energy within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10, and the *IESO*; and

(iv) in the case of an *enhanced combined cycle facility* that is either a *dispatchable* or *self-scheduling generation facility*, such amount based on the impact that the recovery of waste heat from an industrial process/processes within the *facility* has on *energy* production based on the information outlined in section 2.2.6.10;

and the *IESO*:

3.3.8.1 shall, unless the change in quantity poses risks in relation to the *reliability* or *security* of the *electricity system*, include such change as an input in respect of any subsequent *market schedules* determined following receipt of the change; and

3.3.8.2 may refer such changes or revision of *dispatch data* to the *market surveillance panel*.

Standing Dispatch Data

3.3.9 If the dispatch data for a registered facility for a given trading day of a trading week will not change from trading week to trading week, the registered market participant for that registered facility may, as and for its dispatch data described in section 3.3.1, submit standing dispatch data for that registered facility. Such standing dispatch data shall:

3.3.9.1 define the *dispatch data* for each *dispatch hour* of each *dispatch day*;

3.3.9.1A in respect of each *dispatch day* for which it is in effect, be deemed for the purposes of this section 3.3 to be initial *dispatch data* at 06:00 EST on the *pre-dispatch day*; and

3.3.9.2 remain in effect until the expiration date specified in the standing *dispatch data* unless earlier withdrawn or earlier revised by the *registered market participant*:

a. as standing *dispatch data* prior to 06:00 EST on the *pre-dispatch day*; or

b. in accordance with sections 3.3.3 to 3.3.8.

IESO Authorities to Direct Submission or Revision of Dispatch Data

3.3.10 Notwithstanding sections 3.3.3, 3.3.4, 3.3.4B, 3.3.5 and 3.3.8, where the *IESO* determines, on the basis of the initial *pre-dispatch schedule* or any subsequent *pre-dispatch schedule* determined in accordance with section 5, that a revision to *dispatch data* will not allow it to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* may, subject to sections 3.3.15 and 3.3.16:

3.3.10.1 refuse to accept a revision to the quantity element of *dispatch data* submitted by a *registered market participant*; or

3.3.10.2 direct a *registered market participant* to submit or to resubmit a revision to the quantity element of its *dispatch data*, or both. The *IESO* shall notify the *registered market participant* of a refusal referred to in section 3.3.10.1 and shall include in any direction issued pursuant to section 3.3.10.2 a description of the revised *dispatch data* to be submitted or resubmitted by the *registered market participant*.

3.3.10A A *registered market participant* in respect of a *transitional scheduling generator* may treat a direction referred to in section 3.3.10.2 that means an increase in the quantity element of its *dispatch data* as a request and shall confirm with the *IESO* its intention to comply or not comply with the request issued. If the *registered market participant* indicates its intentions are not to comply with the direction, the *registered market participant* shall provide the reasons for non-compliance to the *IESO*.

3.3.11 A *registered market participant* to which a direction has been issued pursuant to section 3.3.10.2 shall submit revised *dispatch data* to the *IESO* in accordance with the terms of the direction within 2 hours of the time of receipt of the direction.

3.3.12 If the *IESO* determines, on the basis of the initial *pre-dispatch schedule* or any subsequent *pre-dispatch schedule* determined in accordance with section 5, that it requires the supply of *energy, ancillary services*, other than *contracted ancillary services*, or both from additional *registered facilities* in order to maintain the *reliability* of the *IESO-controlled grid*, the *IESO* shall determine if there are additional *registered facilities* that have not submitted *dispatch data* and that can, to the *IESO's* knowledge, be made available within the time required in order to help maintain the *reliability* of the *IESO-controlled grid*.

3.3.13 Subject to sections 3.3.14 to 3.3.16, the *IESO* may direct the *registered market participant* for an additional *registered facility* identified pursuant to section 3.3.12 to submit *dispatch data*, and shall include in such direction a description of the *dispatch data* to be submitted by the *registered market participant*.

3.3.14 A *registered market participant* to which a direction is issued pursuant to section 3.3.13 shall submit *dispatch data* to the *IESO* in accordance with the terms of the direction within 2 hours of the time of receipt of the direction.

3.3.15 The *IESO* shall not issue a direction pursuant to section 3.3.10 or 3.3.13 for the purposes of addressing a lack of overall *adequacy* of the *IESO-controlled grid*.

3.3.16 Where a *registered facility* to which a direction issued pursuant to section 3.3.10.2 or 3.3.13 relates has a *reliability must-run contract* with the *IESO*, any such direction shall, subject to the time period for the submission of *dispatch data* referred to in sections 3.3.11 and 3.3.14, be consistent with the terms of such *reliability must-run contract*.

3.3.17 Nothing in sections 3.3.10 to 3.3.16 shall preclude the application of the provisions of sections 7.3.2.3 or of Appendix 7.6 in respect of *dispatch data* that is revised or submitted in accordance with sections 3.3.10 to 3.3.16.

3.3.18 A *registered market participant* may, for any one or more of its *registered facilities* that is a *dispatchable load*, identify all or a portion of the consumption at such *registered facilities* as *non-dispatchable load* by submitting *dispatch data* in accordance with the applicable *market manual*.

3.3A Dispatch Data Submissions for the Day-Ahead Commitment Process

3.3A.1 Subject to section 1.7, defining when the day-ahead commitment process shall function, this section 3.3A shall be in effect.

3.3A.2 Subject to the standing *dispatch data* provisions of section 3.3.9, each *registered market participant* that intends its *dispatchable generation facility*, including a *generation facility* that intends to operate in *segregated mode of operation* in real-time, *dispatchable load facility*, dispatchable *electricity storage facility*, or *hourly demand response* resource to be eligible for *dispatch* by the *IESO* for a given *dispatch hour* of a *dispatch day* shall, after 06:00 EST but before 10:00 EST of the *pre-dispatch day,* submit *dispatch data* for those *dispatch hours* of the *dispatch* day including, where applicable, the daily *energy* limit for the *facility* for the *dispatch day*. The *registered market participant* may then only revise such initial *dispatch data* as permitted by this section 3.3A.

3.3A.3 If a *registered market participant* for a *dispatchable generation facility* or a dispatchable *electricity storage facility* does not provide *dispatch data* in accordance with section 3.3A.2 the *facility* shall not operate in real-time without the approval of the *IESO* under section 3.3A.12.

3.3A.4 A *registered market participant* for a *dispatchable load facility* may, in the *dispatch data* submitted under section 3.3A.2, identify all or a portion of the consumption at such *registered facility* as *non-dispatchable load* in accordance with the applicable *market manual*.

3.3A.5 A *registered market participant* for a *boundary entity* may submit, between 6:00 EST and 10:00 EST of the *pre-dispatch day,* an import *offer* or export *bid* for the next *dispatch day* with a valid NERC tag identifier. If the import *offer* is included in the s*chedule of record* determined under section 5.8, the *registered market participant* will receive the day-ahead *intertie* offer guarantee determined under section 3.8A of Chapter 9.

3.3A.6 R*egistered market participants* that submitted *offers* or *bids* in accordance with either section 3.3A.2 or section 3.3A.5 shall require *IESO* approval to modify those *offers* or *bids* between 10:00 EST and 14:00 EST except for *registered market participants* for:

a. *dispatchable* hydroelectric *generation facilities* which submitted a *daily cascading hydroelectric dependency* in accordance with section 2.2.6K and which are designated by the *IESO* as eligible *energy* limited resources, and

b. physical generation units associated with a *pseudo-unit* designated in accordance with section 2.2.6G.

3.3A.7 [Intentionally left blank – section deleted]

Market Participant Revisions to Dispatch Data

3.3A.8 Subject to sections 3.3A.9, 3.3A.10 and 3.3A.14, after 14:00 EST a *registered market participant* may submit revised *dispatch data* with respect to any *dispatch hour* without restriction until 2 hours prior to the beginning of that *dispatch hour*.

3.3A.9 Subject to sections 3.3A.10 and 3.3A.14, a *registered market participant* for a *dispatchable generation facility* or a dispatchable *electricity storage facility* who did submit *dispatch data* under section 3.3A.2 may revise its *offer* in real-time provided the revised *dispatch data* does not increase the number of hours offered or the offered quantity in any hour relative to the *dispatch data* submitted under section 3.3A.2. Revised *offers* which represent increases to the number of hours offered or increases to the offered quantity relative to the *dispatch data* submitted under section 3.3A.2 will require *IESO* approval. Changes to daily *energy* limits will not require *IESO* approval.

3.3A.10 A *registered market participant* for a *dispatchable generation facility* who was deemed to have accepted the day-ahead production cost guarantee in accordance with section 5.8.4 shall not increase the *offer* price associated with the *minimum loading point* of the *facility*.

3.3A.11 *A registered market participant* for a *dispatchable load facility* that declared its intent for all or a portion of its consumption to be non-*dispatchable* under sections 3.3A.2 and 3.3A.4 will require *IESO* approval to increase its declared *bid* quantity and *bid* that consumption in real-time as *dispatchable load*.

3.3A.12 The *IESO* shall approve increases to declared availability of a *dispatchable facility* if that *generation facility, electricity storage facility* or *dispatchable load facility* returns from outage earlier than planned, or if the *IESO* has solicited additional *offers* and *bids*, or if such increases will avoid an *emergency operating state* or *high-risk operating state*, or as permitted under section 3.3.6.3.

3.3A.13 A *registered market participant* for a *boundary entity* who is eligible to receive a day-ahead *intertie offer* guarantee for an import transaction in accordance with section 3.3A.5 shall not revise the submitted *dispatch data* to link that import transaction to an export transaction as described in section 3.5.8.2 of Chapter 7. If the *IESO* determines that the *dispatch data* was revised by the *registered market participant* in the manner described above, the *IESO* shall recover from the *registered market participant* any day-ahead *intertie offer* guarantee payment for that import transaction and shall redistribute the payment in accordance with chapter 9, section 4.8.2.11.

3.3A.14 A *registered market participant* for a *dispatchable generation facility* who was deemed to have accepted the day-ahead production cost guarantee in accordance with section 5.8.4 shall be subject to a withdrawal charge as per section 3.8F of Chapter 9 if the *registered market participant* withdraws the *offer* for the *facility.*

3.4 The Form of Dispatch Data

3.4.1 *Dispatch data* shall relate to a specified *dispatch hour* of the *dispatch day* and to a specified *registered facility*, shall comply with the applicable provisions of this section and sections 3.5 to 3.9 and shall take one of the following forms:

3.4.1.1 for a *dispatchable generation facility*, or a dispatchable *electricity storage facility* proposing to inject *energy* an *offer* to provide a *physical service* to the appropriate *real-time market*. *Offers* accepted result in sales in the *real-time market* only to the extent that, for the *registered market participant* submitting such *offers*, the total value of the *physical services* provided to the *real-time markets* is greater than the total value of the *physical bilateral contract quantities* notified to the *IESO* in respect of that *registered market participant* pursuant to Chapter 8;

3.4.1.1.1 for a *dispatchable generation facility* that is classified as v*ariable generation,* an offer to provide a *physical service* to the appropriate *real-time market* reflecting its *generation facility's* full capacity available for production, determined in accordance with the applicable *market manual.*

3.4.1.2 for a *dispatchable load facility*, or a dispatchable *electricity storage facility* proposing to withdraw *energy* a *bid* to take *energy* from the *energy market*. *Bids* accepted result in purchases in the *real-time market* only to the extent that, for the *registered market participant* submitting such *bids*, the total value of the *physical services* taken from the *real-time markets* is greater than the total value of *physical bilateral contract quantities* notified to the *IESO* in respect of that *registered market participant* pursuant to Chapter 8;

3.4.1.2A [Intentionally left blank – section deleted]

3.4.1.3 for a self-scheduling generation facility or a *self-scheduling electricity storage facility*, a self-schedule for the provision of energy to the energy market. Energy actually provided by a *self-scheduling facility* results in sales in the real-time market only to the extent that, for the registered market participant designated for that *self-scheduling facility*, the total value of energy provided to the real-time market is greater than the total value of physical bilateral contract quantities notified to the IESO in respect of that registered market participant pursuant to Chapter 8;

3.4.1.4 for an *intermittent generator*, a forecast of *energy* expected to be provided to the *energy market*. *Energy* actually provided by an *intermittent generator* results in sales in the *real-time market* only to the extent that, for the *registered market participant* designated for such *intermittent generator*, the total value of *energy* provided to the *real-time market* is greater than the total value of *physical bilateral contract quantities* notified to the *IESO* by that *registered market participant* pursuant to Chapter 8;

3.4.1.4A for a *transitional scheduling generator*, a forecast schedule for the provision of *energy to the energy market*; and

3.4.1.4B [Intentionally left blank – section deleted]

3.4.1.5 [Intentionally left blank – section deleted]

3.4.1.6 for a capacity market participant with an hourly demand response resource, a demand response energy bid to reduce its energy consumption during a specified availability window and obligation period in accordance with the applicable market manual.

3.4.2 Each *transmitter* shall submit to the *IESO* information on the status of its *transmission system* as described in section 3.9.

3.4.3 Each *offer* or *bid* for any *physical service* shall contain prices, each with an associated quantity. A price and the associated quantity in an *offer* or *bid* is a *price-quantity pair* and shall comply with sections 3.5 and 3.6 and the following:

3.4.3.1 the quantity in any *price-quantity pair*, other than in the first *price-quantity pair*, shall be a cumulative quantity representing the maximum quantity the *registered market participant* is offering to sell or bidding to buy, respectively, at the associated price in the *price-quantity pair*;

3.4.3.1A [Intentionally left blank – section deleted]

3.4.3.2 in any *offer*, the price in each *price-quantity pair* must not decrease as the associated quantity increases; and

3.4.3.3 in any *bid*, the price in each *price-quantity pair* must not increase as the associated quantity increases.

3.4.4 The *market price* of *energy*, in $/MWh, at and below which the *IESO* may instruct a *generation facility* to reduce its *energy* output to zero shall be:

3.4.4.1 [Intentionally left blank]

3.4.4.2 in the case of a *generation facility* other than a *self-scheduling generation facility* or an *intermittent generator*, the lowest price in any *price-quantity pair* submitted with respect to such *facility*.

Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.4A Every submission of *dispatch data* with respect to a *self-scheduling generation facility* or an *intermittent generator* shall specify a price, in $/MWh, at and below which the applicable *registered market participant* reasonably expects to reduce the *energy* output of such *self-scheduling generation facility* or *intermittent generator* to zero. Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.4B The *market price* of *energy*, in $/MWh, at and below which the *IESO* may instruct an *electricity storage facility* to reduce its injections of *energy* to zero shall be:

3.4.4B.1 in the case of an *electricity storage facility* other than a *self-scheduling electricity storage facility* the lowest price in any *price-quantity pair* submitted with respect to such *facility*.

Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.4C Every submission of *dispatch data* with respect to a *self-scheduling electricity storage facility* shall specify a price, in $/MWh, at and below which the applicable *registered market participant* reasonably expects to reduce the injections of *energy* from *self-scheduling electricity storage facility* to zero. Such price may be zero or negative but may not be less than negative *MMCP*.

3.4.5 Every submission of *dispatch data* with respect to a *dispatchable load facility* or a dispatchable *electricity storage facility* proposing to withdraw *energy* shall specify a *market price* of *energy*, in $/MWh, at and above which the *IESO* may instruct the *facility* to reduce its *energy* withdrawals to zero. Such price shall not be greater than *MMCP*.

3.5 Energy Offers and Energy Bids

3.5.1 A registered market participant may submit no more than one energy offer or one energy bid with respect to a given registered facility for any dispatch hour.

3.5.2 All *energy offers* and *energy bids* shall be submitted using such forms as may be specified by the *IESO*, which forms shall require, at a minimum, provision of all of the information specified in Appendices 7.1 and 7.2, respectively, except where the *IESO* specifies an alternative means and/or an alternative simplified form pursuant to section 3.2.2.3.

3.5.3 Each *energy offer* or *energy bid* must contain at least 2 and, may contain up to 20 *price-quantity pairs* for each *dispatch hour*. The price in each such *price-quantity pair* shall be not more than the *Maximum Market Clearing Price* or *MMCP* and not less than the negative *Maximum Market Clearing Price* or negative *MMCP* and shall be expressed in dollars and whole cents per MWh. The quantity in each such *price-quantity pair* shall:

3.5.3.1 in the case of a *registered facility* other than a *boundary entity*, be expressed in MW (or MWh/hour) to one decimal place and shall not be less than 0.0 MW (or 0.0 MWh/hour); or

3.5.3.2 in the case of a *registered facility* that is a *boundary entity*, be expressed in whole MW (or MWh/hour) and shall not be less than 0 MW (or 0 MWh/hour).

The quantity in the first *price-quantity pair* shall be 0.0 MW (or 0.0 MWh/hour) or 0 MW (or 0 MWh/hour) as applicable. The price in the second *price-quantity pair* shall be the same as the price in the first *price-quantity pair*.

3.5.4 Prices in *energy offers* and *energy bids* may be negative and such negative price shall imply:

3.5.4.1 when in an *energy offer*, that the *registered market participant* is willing to pay up to that price for each MWh of *energy* it injects rather than reduce its output; and

3.5.4.2 when in an *energy bid*, that the *registered market participant* is willing to take or dispose of excess *energy*, but only if paid at least that price for each excess MWh taken or disposed of.

3.5.4A The IESO Board shall establish floor prices for energy offers from variable generators that are registered market participants and for energy offers from flexible nuclear generators for flexible nuclear generation, in accordance with the applicable market manual. The prices in each energy offer submitted by the variable generator or by a flexible nuclear generator in respect of flexible nuclear generation for each dispatch hour shall not be less than the floor prices specified in the applicable market manual.

3.5.5 Each *energy offer* or *energy bid* shall contain up to 5 sets of ramp quantity and ramp up/ramp down values for each *dispatch hour*. The ramp quantity in each such set shall be the maximum MW quantity at which the corresponding ramp rate values apply, shall be expressed in MW to one decimal place and shall be greater than 0.0 MW. The ramp up and ramp down values in each such set shall be expressed in MW/minute to one decimal place and shall be greater than 0.0 MW/min. The laminations corresponding to such sets may be different from those of the *price-quantity pairs* contained in each *energy bid* or *energy offer*.

3.5.6 The largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.6.1 the maximum output of *energy* in an hour indicated in the registration information for the relevant *registered facility*;

3.5.6.2 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *registered facility*, as estimated by the *registered market participant* for that *registered facility*; or

3.5.6.3 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

3.5.6.3.1 the capacity of any radial line connecting the *registered facility* to the *connection point*;

3.5.6.3.2 the maximum injection or withdrawal as specified in the *connection agreement* applicable to the *registered facility*; or

3.5.6.3.3 the maximum injection or withdrawal otherwise permitted by the relevant *transmitter*.

3.5.6A Where one or more *electricity storage facilities* and one or more other *generation facilities* are all:

3.5.6A.1 connected at the same *connection point*;

3.5.6A.2 registered to the same *registered market participant,* and

3.5.6A.3 none of the *facilities* are providing *contracted ancillary services* or participating in the *operating reserve market;*

section 3.5.6 shall not apply. Instead, the largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* for each *facility* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.6A.4 the maximum output of *energy* in an hour indicated in the registration information for the relevant *registered facility*;

3.5.6A.5 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *registered facility*, as estimated by the *registered market participant* for that *registered facility*; or

3.5.6A.6 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

3.5.6A.6.1 the capacity of any radial line connecting the *registered facility* to the *connection point*; or

3.5.6A.6.2 the maximum injection or withdrawal as specified in the *connection agreements* applicable to the *registered facilities* or to the maximum injection or withdrawal otherwise permitted by the relevant *transmitter,* calculated as the total net injections and withdrawals for all *generation facilities* and *electricity storage facilities* registered to the same *registered market participant* at the same *connection point*.

3.5.6B Where one or more *electricity storage facilities* and one or more other *generation facilities* are all:

3.5.6B.1 connected at the same *connection point*;

3.5.6B.2 registered to the same *registered market participant, and*

3.5.6B.3 any of the *facilities* are providing *contracted ancillary services* or participating in the *operating reserve market;*

sections 3.5.6 and 3.5.6A shall not apply. Instead, the largest quantity in any *energy offer* or *energy bid* for any *dispatch hour* for each *facility* must be at least 1.0 MWh but shall not exceed the lesser of:

3.5.6B.4 the maximum output of *energy* in an hour indicated in the registration information for the relevant *registered facility*;

3.5.6B.5 the maximum quantity of *energy* that can be supplied (for an *energy offer*) or taken (for an *energy bid*) in that *dispatch hour* by the *registered facility*, as estimated by the *registered market participant* for that *registered facility*; or

3.5.6B.6 the maximum allowed injection (for an *energy offer*) or withdrawal (for an *energy bid*) in that *dispatch hour* through the relevant *connection point*, as limited by the lesser of:

3.5.6B.6.1 the capacity of any radial line connecting the *registered facility* to the *connection point*; or

3.5.6B.6.2 the maximum injection or withdrawal as specified in the *connection agreement* applicable to the *registered facility* or the maximum injection or withdrawal otherwise permitted by the relevant *transmitter,* and the sum of all *energy* offers or the sum of all *energy* bids from all *facilities* shall not exceed these limits.

3.5.7 A *registered market participant offering energy* from a specified *registered facility* may submit *dispatch data* specifying a maximum amount of *energy* that can be scheduled by the *IESO* for that *registered facility* over a *dispatch day*. Such a limit shall be used only in the *pre-dispatch schedule* described in section 5, and only for the purpose of providing information that the *registered market participant* may use as a basis to revise its *energy offers* in subsequent submissions.

3.5.8 All wheeling through transactions shall consist of:

3.5.8.1 an individual *energy* offer from a *boundary entity* injecting *energy* into the *IESO-controlled grid* and an *energy* bid from a *boundary entity* withdrawing *energy* from the *IESO-controlled grid*; or

3.5.8.2 an individual *energy offer* from a *boundary entity* injecting *energy* into the *IESO-controlled grid* and an *energy bid* from a *boundary entity* withdrawing *energy* from the *IESO-controlled grid,* and an identification of the desire for these to be linked, in accordance with the applicable *market manual*. The *IESO* shall assess so identified *offers* separately from their associated *bids*. The *IESO* shall schedule and *dispatch* the linked *offers* and *bids* such that both are equal to the lower of the *offer* or *bid* that would otherwise be scheduled and *dispatched*.

3.5.9 An *energy bid* submitted by a *registered market participant* for a *boundary entity* in respect of the withdrawal from the *IESO-controlled grid* of *energy* destined for an *intertie zone* in the United States of America shall constitute a declaration by a *registered market participant* for the *boundary entity* of an intention to export *energy* in the circumstances described in paragraphs 1(b) to 1(d) of Part V of Schedule VI of the *Excise Tax Act* (Canada).

3.6 Operating Reserve Offers

3.6.1 A *registered market participant* may not submit, for any *registered facility*, more than one *offer* to provide each class of operating reserve in any *dispatch hour*.

3.6.2 Each *offer* to provide *operating reserve* must contain at least 2 and may contain up to 5 *price-quantity pairs* for each class of *operating reserve* for each *dispatch hour*. The price in each such *price-quantity pair* shall be not more than the *Maximum Operating Reserve Price* or *MORP* and not less than zero and shall be expressed in dollars and whole cents per MW. The quantity in each such *price-quantity pair* shall:

3.6.2.1 in the case of a *registered facility* other than a *boundary entity*, be expressed in MW to one decimal place and shall not be less than 0.0 MW; or

3.6.2.2 in the case of a *registered facility* that is a *boundary entity*, be expressed in whole MW and shall not be less than 0 MW.

The quantity in the first *price-quantity pair* shall be 0.0 MW (or 0.0 MWh/hour) or 0 MW (or 0 MWh/hour) as applicable. The price in the second *price-quantity pair* shall be the same as the price in the first *price-quantity pair*.

3.6.3 Each *offer* to provide *operating reserve* shall be accompanied by a corresponding *energy offer* or *energy bid* that covers the same MW range.

3.6.4 *Offers* to supply *operating reserve* shall be submitted in such form as may be specified by the *IESO*, which form shall require, at a minimum, provision of all of the information specified in Appendix 7.3, except where the *IESO* specifies an alternative means and/or an alternative simplified form pursuant to section 3.2.2.3.

3.7 Self-Scheduling Generators

3.7.1 A registered market participant for a self-scheduling generation facility shall submit dispatch data indicating the amount of energy that the registered market participant reasonably expects to be provided by that self-scheduling generation facility in each dispatch hour. Such dispatch data shall:

3.7.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, including provision of the applicable information specified in Appendix 7.1; and

3.7.1.2 comply with section 3.4.4A.

3.7A Self-Scheduling Electricity Storage

3.7A.1 A registered market participant for a self-scheduling electricity storage facility shall submit dispatch data indicating the amount of energy that the registered market participant reasonably expects to be injected by that self-scheduling electricity storage facility in each dispatch hour. Such dispatch data shall:

3.7A.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, including provision of the applicable information specified in Appendix 7.1; and

3.7A.1.2 comply with section 3.4.4C

3.7A.2 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is a *self-scheduling electricity storage facility* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* in accordance with section 3.7A.1.

3.7.2 A *registered market participant* for a self-scheduling *cogeneration facility* or self-scheduling *enhanced combined cycle facility* shall ensure its *facility* operates in accordance with its *dispatch data* within the tolerances for updating *dispatch data* outlined in section 3.3.8.

3.7.3 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is a *self-scheduling generation facility* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* in accordance with section 3.7.1.

3.8 Intermittent Generators

3.8.1 A *registered market participant* for an *intermittent generator* shall submit *dispatch data* indicating its best forecast of the amount of *energy* that the *intermittent generator* will inject in each *dispatch hour*. Such *dispatch data* shall:

3.8.1.1 be submitted to the *IESO* in such form as may be specified by the *IESO*, including provision of the applicable information specified in Appendix 7.1; and

3.8.1.2 comply with section 3.4.4A.

3.8.2 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is an *intermittent generator* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* indicating its best forecast of the amount of energy that the *intermittent generator* will inject in each *dispatch hour* of the next *dispatch day* in accordance with section 3.8.1.

3.8A Transitional Scheduling Generators

3.8A.1 A registered market participant for a registered facility that is a transitional scheduling generator shall submit dispatch data indicating its forecast of the amount of energy that the transitional scheduling generator will inject in each dispatch hour of the dispatch day. Such dispatch data shall be submitted to the IESO for the initial pre-dispatch schedule in accordance with section 3.3.1 and in such form as may be specified by the IESO.

3.8A.2 Subject to section 1.7 defining when the day-ahead commitment process shall function, a *registered market participant* for a *registered facility* that is a *transitional scheduling generator* shall submit *dispatch data* after 6:00 EST but before 10:00 EST of the *pre-dispatch day* indicating its forecast of the amount of *energy* that the *transitional scheduling generator* will inject in each *dispatch hour* of the next *dispatch day* in accordance with section 3.8A.1.

3.9 Transmission System Information

3.9.1 Each *transmitter* whose *transmission system* is part of the *IESO-controlled grid* shall provide the *IESO* with the *transmission system* information described in Appendix 7.4 in such form as the *IESO* may specify.

3.9.2 Each *transmitter* referred to in section 3.9.1 shall update the information described in Appendix 7.4 so that it is current at:

3.9.2.1 15:00 EST on the day which is two days prior to the relevant *dispatch day*;

3.9.2.2 05:00 EST on the *pre-dispatch day*;

3.9.2.3 10:00 EST on the *pre-dispatch day*; and

3.9.2.4 any time subsequent to 10:00 EST on the *pre-dispatch day* up to the beginning of the relevant *dispatch hour* if there is a material change in the information required by this section.

4. The Dispatch Algorithm

4.1 Purpose of the Dispatch Algorithm

4.1.1 The *IESO* shall determine the various schedules and prices required by this Chapter to be developed by it using a *dispatch algorithm* based on the mathematical techniques of constrained optimisation. The form and use of this *dispatch algorithm* are summarised in this section 4 and detailed in Appendix 7.5.

4.2 Uses of the Dispatch Algorithm

4.2.1 The *IESO* may use different numerical values in, or different computerised versions of, the *dispatch algorithm* for each of the several purposes described in this Chapter, but shall keep the objective, mathematical formulation and solution procedures the same, except as specifically noted.

4.2.2 The *IESO* shall, as far as practical, use the outputs of the *dispatch algorithm* to determine the *dispatch instructions* that guide actual physical operations of the *electricity system*. However, because any *dispatch algorithm* is only an approximation of a complex physical reality and may sometimes malfunction, the *IESO* may modify or override the results of the *dispatch algorithm* when issuing *dispatch instructions* pursuant to section 7.

4.2.3 The *IESO* shall no less than once in each calendar month, *publish* a report listing and giving reasons for all significant differences between *dispatch instructions* issued and the results of the *dispatch algorithm*.

4.2.4 Unless otherwise directed by the *IESO Board*, the *IESO* shall no less than once every two calendar years, commission and *publish* the results of an independent review of the operation and application of the *dispatch algorithm* and the related *dispatch* processes and procedures. The *IESO* shall use the results of such review to determine the need or otherwise for improvements in the related *dispatch* processes and procedures in meeting the objectives of the *market rules* and/or the mathematical representation of the *electricity system* or the solution procedures which form part of the market clearing logic. The first such review shall be completed no later than May 1, 2004.

4.3 The Optimisation Objective

4.3.1 The *dispatch algorithm* shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as defined in section 4.3.2.

4.3.2 The economic gain from trade shall be defined as the difference between the value of the electricity produced (as indicated by the *energy demand* from *non-dispatchable loads* and the *energy bids* from *dispatchable loads*) and the cost of producing that electricity (as indicated by the *offers* to supply the *energy* and *operating reserves* necessary to *reliably* deliver that electricity to loads).

4.3.3 Maximising the economic gain from trade will determine quantities and prices that "clear the market," in the sense that, given the market-clearing prices and the *dispatch data*, no *market participant* would be economically better off (in terms of the *dispatch data* it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any *physical service*.

4.4 Inputs to the Dispatch Algorithm

4.4.1 The *IESO* shall use as inputs to the *dispatch algorithm* the data and information outlined in section 4.4 and described in more detail in Appendix 7.5.

4.4.1A [Intentionally left blank]

4.4.2 The cost to suppliers of *energy* and *operating reserves* and the value to *dispatchable loads* of delivered electricity shall be based on the most recent valid *offers* and *bids* (including standing *dispatch data*) submitted by *registered market participants* with respect to *dispatchable generation facilities,* dispatchable *electricity storage facilities* and *dispatchable load facilities*.

4.4.3 Subject to section 4.4.3A, the price-insensitive load to be met shall be the sum of:

4.4.3.1 the net energy injections (injections minus withdrawals) by all non-dispatchable load facilities, self-scheduling generation facilities, *self-scheduling electricity storage facilities* and intermittent generators and transitional scheduling generators; and

4.4.3.2 any net amount by which the actual net injections (injections minus withdrawals) by all *dispatchable generation facilities,* dispatchable *electricity storage facilities* and *dispatchable load facilities* is less than the net amount implied by the *IESO's dispatch instructions* to such *facilities*.

4.4.3A Until such time that locational pricing is implemented in the *IESO-administered markets*, the price-insensitive load to be met shall be determined solely on the basis of the net *energy* injections referred to in section 4.4.3.1.

4.4.4 Limits on *intertie* flows between the *integrated power system* and neighbouring *transmission systems* shall be based on:

4.4.4.1 a simple model that assumes that each *intertie meter* is *connected* to an isolated *intertie zone* by a single transmission line;

4.4.4.2 the *IESO's* best estimate of the maximum flow on the single transmission line to each *intertie zone*, given the status of the neighbouring *transmission systems* and expected or actual unscheduled flows (including as unscheduled flows any flows planned by the *IESO* to balance interchange accounts with other *control area operators*). The *IESO's* best estimate of the maximum flow on the single transmission line to an *intertie zone* may reflect the *integrated power system's* limited capability to supply and export *energy* to an *intertie zone* and applicable neighbouring *transmission system* without scheduling imported *energy* to supply the exported *energy*; and

4.4.4.3 a net *interchange schedule* limit to represent the *integrated power system's* ability to respond to hourly *interchange schedule* deviations and maintain the *reliability* of the *IESO-controlled grid*.

4.4.5 Constraints on the use of the *IESO-controlled grid* shall be determined on the basis of such system *security* requirements as the *IESO* may determine necessary to maintain *reliable* system operations, which requirements shall include, at a minimum, the following:

4.4.5.1 the largest applicable *contingency events* and any increments above these required to satisfy applicable *reliability standards*;

4.4.5.2 *security* constraints on identified *facilities*;

4.4.5.3 minimum requirements for each class of *operating reserve*;

4.4.5.4 the IESO's commitments to neighbouring transmission systems for operating reserves and regulation;

4.4.5.5 the availability and need for contracted *ancillary services* and *reliability must-run resources*; and

4.4.5.6 *reliability* constraints associated with *interchange schedules* as referred to in section 4.4.4.3.

4.4.6 The following basic parameters of the *dispatch algorithm* shall be as specified from time to time by the *IESO Board:*

4.4.6.1 the *maximum market clearing price* or *MMCP* that defines the maximum allowable price for *energy*, and the negative of which defines the minimum allowable price for *energy;*

4.4.6.1A the *maximum operating reserve price* or *MORP* that defines the maximum allowable price for any class of *operating reserve*; and

4.4.6.2 the penalty functions for the violation of *dispatch algorithm* constraints.

If the output of the *dispatch algorithm* fails to satisfy *non-dispatchable demand* or the *operating reserve requirements* for any class of *operating reserve* then, subject to section 8.2.2, the penalty functions referred to in section 4.4.6.2 may influence the calculation of *market prices* for *energy* and *operating reserve* in a similar fashion to *offers* and *bids.*

4.4.7 *Interchange schedule data* shall be input as a constant value for the given *dispatch hour* unless otherwise specified by the *IESO* and shall be derived in accordance with the outputs of the *dispatch algorithm* for each *dispatch hour* as determined under section 4.6.

4.5 The Constrained and Unconstrained IESO-Controlled Grids

4.5.1 The *dispatch algorithm* shall be used to determine both operating schedules that reflect the realities of the *integrated power system* and uniform prices within the *IESO control area* that ignore *transmission system* constraints. Thus, the *dispatch algorithm* shall be capable of using the following two different models for the *integrated power system:*

4.5.1.1 an *unconstrained IESO-controlled grid model*, which, other than as set out in Section 4.4.4 of Chapter 7 and Section 7.5.1 of Appendix 7.5, ignores transmission and other *security* constraints on the *IESO-controlled grid* including *interties* and assumes, in effect, that all *physical services* are provided and consumed at a single, undesignated location *connected* to several isolated *intertie zones* by single transmission lines; and

4.5.1.2 a *constrained IESO-controlled grid model*, which includes a full (but necessarily approximate) mathematical representation of the *integrated power system*, with *interconnections* modelled as single transmission lines to isolated *intertie zones* or as proportionately allocated to *intertie zones.*

4.6 Outputs of the Dispatch Algorithm

4.6.1 The *IESO* shall use the *dispatch algorithm* to determine the quantities and prices summarised in this section 4.6 and detailed in Appendix 7.5.

4.6.2 The *dispatch algorithm* shall be used with the *constrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and to each *dispatch interval*, operating schedules and their associated costs and shadow prices. The principal outputs, for each *dispatch hour* or *dispatch interval,* as the case may be, shall be the following:

4.6.2.1 the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) scheduled to be provided to the *integrated power system* by each *registered facility*;

4.6.2.2 the amounts of *energy* (in MW or MWh/hour) scheduled to be withdrawn from the *integrated power system* by each *registered facility*;

4.6.2.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* scheduled to be provided by *registered facilities*;

4.6.2.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads* and any constraint violations;

4.6.2.5 power flows and *energy* losses on transmission lines;

4.6.2.6 the prices of providing *energy* at each set of transmission nodes identified by the *IESO* for this purpose and, subject to section 4.6.2B, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose.

4.6.2A [Intentionally left blank]

4.6.2B Until the date that is the first day of the fourth 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, the prices of each class of *operating reserve* in each reserve area referred to in section 4.6.2.6 shall not be included as a principal output of the *dispatch algorithm*.

4.6.3 The *dispatch algorithm* shall be used with the *unconstrained IESO-controlled grid model* to determine, prior to each *dispatch hour* and at several times after each *dispatch interval*, *market schedules* and the corresponding uniform prices within the *IESO control area*. The principal outputs of this process are the following:

4.6.3.1 the *market schedule* indicating the amounts of *energy* (in MW or MWh/hour) and of each class of *operating reserve* (in MW) that would be provided to the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid*;

4.6.3.2 the amounts of *energy* (in MW or MWh/hour) that would be withdrawn from the *integrated power system* by each *registered facility* if transmission were totally unconstrained on the *IESO-controlled grid;*

4.6.3.3 the deemed total cost, as defined by the prices in *offers*, of the total amounts of *energy* and *operating reserve* in the *market schedule*;

4.6.3.4 the deemed total cost, as defined by the prices in *energy bids*, the *MMCP* and the penalty functions in the *dispatch algorithm*, of any *dispatchable load* reductions, any failure to meet *non-dispatchable loads*, and any constraint violations that would occur if transmission were totally unconstrained on the *IESO-controlled grid*; and

4.6.3.5 the prices of providing *energy* and each class of *operating reserve* at any point within the *IESO control area* if transmission were totally unconstrained on the *IESO-controlled grid.* As provided in Chapter 9, the unconstrained prices for each *dispatch interval* shall be used for *settlement* purposes, except for *non-dispatchable loads*, who shall pay a uniform *hourly Ontario energy price* (HOEP) determined as described in section 8.3.1.

4.6.4 The *dispatch algorithm* shall be used with the constrained *IESO-controlled grid model* to determine, prior to each *dispatch hour*, *interchange schedules* and their associated costs. The *interchange schedule* for each *dispatch hour* shall be constant for the *dispatch hour* and used as inputs into the *dispatch algorithm* in accordance with section 4.4.

5. The Pre-dispatch Scheduling Process

5.1 Purpose and Timing of Pre-dispatch Schedules

5.1.1 The *IESO* shall determine *pre-dispatch schedules* in order to provide itself and *market participants* with advance information and projections necessary to plan the physical operation of the *electricity system*.

5.1.2 The *IESO* shall determine an initial *pre-dispatch schedule* for the 24 *dispatch hour*s of each *dispatch day* no later than 16:00 EST on the *pre-dispatch day*.

5.1.3 The *IESO* shall prepare a revised *pre-dispatch schedule* for each *dispatch day* whenever the *IESO* determines that changed circumstances have made the previous *pre-dispatch schedule* materially incorrect. A revised *pre-dispatch schedule* shall be determined only for *dispatch hours* following the changes that make it necessary.

5.1.4 Each time the *IESO* determines a *pre-dispatch schedule*, it shall also determine the associated projected *market prices* for *energy* and *operating reserve* and the associated projected *market schedule*.

5.1.5 The *IESO* shall *publish* and release to *market participants* each *pre-dispatch schedule* as provided in section 5.5. The most recently *published pre-dispatch schedule* shall supersede all previous *pre-dispatch schedules* for the same *dispatch hours*.

5.2 Information Used to Determine Pre-dispatch Schedules

5.2.1 The *IESO* shall use the following information for determining and updating the *pre-dispatch schedule* in accordance with section 5.3, using in each case the most current valid information:

5.2.1.1 dispatch data submitted by registered market participants;

5.2.1.2 the IESO's own forecasts of non-dispatchable load, and of generation by intermittent generators, transitional scheduling generators and self-scheduling generation facilities with name-plate ratings of less than 10 MW and *self-scheduling electricity storage facilities* with an *electricity storage facility size* of less than 10 MW;

5.2.1.3 the *transmission system* information provided by each *transmitter* pursuant to section 3.9;

5.2.1.4 the amount and location of *contracted ancillary services* under contract to the *IESO*;

5.2.1.5 the expected initial loading of each generator, *electricity storage facility* and *dispatchable load*, as determined based on the most current *pre-dispatch schedule* or, if applicable, *real-time schedule*; and

5.2.1.6 such other available information as the *IESO* determines appropriate including the *interchange schedule data* which are a result of the applicable *interchange schedule* protocol as defined in the applicable *market manual* and which may result in setting an upper limit for *energy* quantities scheduled in subsequent *pre-dispatch schedules*.

5.3 Determining the Pre-dispatch Schedule

5.3.1 The *IESO* shall use the information described in section 5.2 and the *dispatch algorithm* to determine a *pre-dispatch schedule* as follows:

5.3.1.1 the constrained *IESO-controlled grid* model shall be used;

5.3.1.2 the parameters defining the condition of the *integrated power system*, and any unscheduled flows between the *integrated power system* and neighbouring *control areas or* neighbouring *transmission systems*, shall be represented at their expected values in each *dispatch hour* of the *dispatch day*;

5.3.1.3 a *pre-dispatch schedule* shall be determined for each of the 24 *dispatch hours* of the *dispatch day* in sequence, with each *dispatch hour* assumed to be independent of the others except that the loading of each generator, *electricity storage facility* and *dispatchable load* for each *dispatch hour* shall be set equal to its value at the end of the preceding *dispatch hour*; and

5.3.1.4 for a *registered facility* that has specified a daily *energy* limit pursuant to section 3.5.7, hourly production amounts shall be cumulated until the first *dispatch hour* in which the *energy* limit is reached or exceeded, and the *energy* production of that *registered facility* shall be set to zero for all subsequent *dispatch hours* in that *dispatch day.*

5.3.2 If conditions or projections change materially during the *pre-dispatch day* or the *dispatch day*, the *IESO* shall use the *dispatch algorithm* with revised inputs reflecting the changes in conditions or projections to determine a revised *pre-dispatch schedule* for the remaining *dispatch hours* in the *dispatch day*.

5.4 Projected Market Schedules and Market Prices

5.4.1 Subject to section 5.4.2, the *IESO* shall, immediately after determining any *pre-dispatch schedule*, determine projected *market schedules* and projected *market* *prices* for each of the *dispatch hours* in that *pre-dispatch schedule*. For this purpose, the *IESO* shall use the same information and data used for determining the *pre-dispatch schedule* for those *dispatch hours*, except that:

5.4.1.1 the unconstrained *IESO-controlled grid* model shall be used;

5.4.1.2 the initial conditions to be used for any *dispatch hour* in the *market schedule* shall be the final conditions of the *market schedule* for the preceding *dispatch hour*;

5.4.1.3 the total demand (including losses) to be satisfied within a *dispatch hour* in the *market schedule* shall be the same as the total demand identified in the *pre-dispatch schedule* for that *dispatch hour*; and

5.4.1.4 total system *energy* losses determined in the *pre-dispatch schedule* shall be represented as an increase in *non-dispatchable load* within the *IESO control area.*

5.4.2 Where the transmission transfer capability of an interconnection is zero for a given dispatch hour by reason of the outage of that interconnection, the projected market prices for energy and operating reserve for the intertie zone associated with such interconnection shall be equal to the projected uniform market prices for energy and operating reserve for the IESO control area for that dispatch hour.

5.4.3 The *IESO* may use other available information for the purposes of determining *market schedules* including *interchange schedule data* which is the outcome of those protocols identified in section 5.2.1.6 which may result in the setting of an upper limit for *energy* quantities scheduled in subsequent *market schedules*.

5.5 Release of Pre-dispatch Schedule Information

5.5.1 The *IESO* shall release the initial *pre-dispatch schedule* and associated projections of *market schedules* and shall publish *market prices* by 16:00 EST of each *pre-dispatch day*, and shall release any revised *pre-dispatch schedules* and projections of *market schedules* and shall publish *market prices* as soon as practical after they are determined. The information to be released to *market participants* is described in this section 5.5.

5.5.2 For each registered facility that is a boundary entity, a dispatchable load facility, a dispatchable generation facility, a dispatchable *electricity storage facility*, or an hourly demand response resource in respect of which a valid bid or offer for at least one dispatch hour of the applicable dispatch day has been submitted, the IESO shall release the following information only to the registered market participant for that registered facility:

5.5.2.1 the pre-dispatch schedule for that registered facility;

5.5.2.2 the projected market schedule for that *registered facility*; and

5.5.2.3 [Intentionally left blank]

5.5.2.4 any requirement of that *registered facility* to submit an *offer* or *bid* under a *reliability must-run contract* and the expected scheduled use of that *registered facility* under *contracted ancillary service* contracts.

5.5.3 The *IESO* shall release to all *market participants* the following information for each *dispatch hour*:

5.5.3.1 total system load and total system losses;

5.5.3.2 area *operating reserve* requirements;

5.5.3.3 [Intentionally left blank]

5.5.3.4 projected hourly *energy* shortfalls;

5.5.3.5 aggregate *reliability must-run resources* being directed to submit *offers* or *bids*;

5.5.3.6 any area *operating reserve* shortfalls;

5.5.3.7 a list of the network constraints and *security* constraints that affect the *pre-dispatch schedule*;

5.5.3.8 [Intentionally left blank – section deleted]

5.5.3.9 the projected uniform market prices of *energy* and *operating reserves* in the *IESO control area*; and

5.5.3.10 the projected market prices of energy and operating reserves in each intertie zone outside the *IESO control area*.

5.5.3A Until the date that is the first day of the fourth 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, the *IESO* shall not be required to release the prices of each class of *operating reserve* referred to in section 5.5.3B.2.

5.5.3B Where the *IESO* determines and releases a *pre-dispatch schedule*, the *IESO* shall include in such *pre-dispatch schedule*, for information purposes only:

5.5.3B.1 the projected *energy prices* at each set of transmission nodes identified by the *IESO* for this purpose; and

5.5.3B.2 subject to section 5.5.3A, the projected prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose,

for the *dispatch hour* immediately following the hour in which such *pre-dispatch schedule* is determined and released.

5.5.4 If the *IESO* determines that release of specific types of information in the *pre-dispatch schedule* may facilitate anti-competitive behaviour, the *IESO* may limit the release of such information through an *urgent amendment* to these *market rules*. The *IESO* shall advise the *market surveillance panel* of the matter. The *IESO Board* may request the advice of the *market surveillance panel* of the need or otherwise for the *urgent amendment* to remain in effect.

5.6 [Intentionally left blank – section deleted]

5.6.1 [Intentionally left blank – section deleted]

5.6.2 [Intentionally left blank – section deleted]

5.7 Pre-Dispatch Scheduling of Generation Facilities Eligible for the Generation Cost Guarantee

5.7.1 A *generation facility* shall be eligible on a voluntary basis for the generation cost guarantee on a *per-start* basis for a given *dispatch hour*, provided that:

5.7.1.1 the criteria specified in section 2.2B have been met:

5.7.1.2 subject to section 5.7.2, the *offer* price in the submitted *price-quantity pair* corresponding to the *minimum loading point* for that *generation facility* for all hours of the *minimum generation block run-time* must be the same until after the *IESO* has constrained on the *generation facility* as specified in section 6.3A.2;

5.7.1.3 the *generation facility* is scheduled in any *pre-dispatch schedule* determined within 3 hours ahead of the *dispatch hour:*

a. for the *dispatch hour*; and

b. for at least half of *minimum generation block run-time*, rounded up, at *minimum loading point* or higher, during the period from *dispatch hour* until the earlier of:

- the end of the period representing *minimum generation block run-time*; or
- the end of the period representing *minimum run-time*;

Any schedule resulting from either a constraint associated with a day-ahead commitment or a manual constraint applied by the *IESO* at the *generator's* request shall be excluded from the eligibility test in this section 5.7.1.3;

5.7.1.4 the registered market participant for the generation facility does not increase the offer prices in its submitted price-quantity pairs corresponding to the generation facility's minimum loading point for the minimum generation block run-time after notifying the IESO of its intention to synchronize under section 5.7.1.6 or after the IESO has applied a manual constraint under section 6.3A.4;

5.7.1.5 the *generation facility* is not already synchronized at the time of the publication of the applicable *pre-dispatch schedule* referred to in section 5.7.1.3;

5.7.1.6 the *registered market participant* for the *generation facility* notifies the *IESO* of its intention to synchronize and then run for at least the *minimum generation block run-time* in accordance with applicable *market manual*; and

5.7.1.7 at the time of notification of intention to synchronize made in accordance with section 5.7.1.4, the *registered market participant* for the *generation facility* also notifies the *IESO* of its intention to qualify for the generation cost guarantee.

5.7.2 The *offer* price corresponding to *minimum loading point* in the *minimum generation block run-time* hours which contain a constraint associated with a day-ahead commitment will be excluded from the eligibility test in section 5.7.1.2.

5.8 The Day-Ahead Commitment Scheduling Process

5.8.1 Starting from 10:00 EST the *IESO* may in accordance with Appendix 7.5A determine the *schedule of record*.

5.8.2 Where the *IESO* determines the *schedule of record* in accordance with Section 5.8.1, it will be released by the *IESO* no later than 15:00 EST in accordance with the applicable *market manual*.

5.8.3 [Intentionally left blank – section deleted]

5.8.4 A *registered market participant* whose *facility* is eligible under section 2.2C for the day-ahead production cost guarantee and whose *facility* is included in the *schedule of record* is deemed to have accepted the guarantee for its *facility*.

5.8.5 Subject to sections 5.8.4 and 5.8.6, the *IESO* shall ensure that the scheduled output for a *facility* will meet or exceed its *minimum loading point* for all hours that it was included in the *schedule of record* in future iterations of the *pre-dispatch schedule* and in the *real-time schedule.*

5.8.6 The *IESO* may, to maintain the reliable operation of the *IESO-controlled grid*, require a *generation facility* that was included in the *schedule of record* to either de-synchronize from the *IESO-controlled grid* or to not synchronize to the *IESO-controlled grid*.

5.8.7 When determining the *schedule of record* applicable to the first hour of the next *dispatch day*, the *IESO* may disregard the net *intertie* scheduling limit.

5.8.8 [Intentionally left blank – section deleted]

6. The Real-Time Scheduling Process

6.1 Purpose and Timing of Real-Time Schedules

6.1.1 The *IESO* shall determine *real-time schedules* and use these as the primary determinant of the *dispatch instructions* the *IESO* issues to *market participants* regarding physical operation of *registered facilities* other than *boundary entities*.

6.1.2 The *IESO* shall determine, for *registered facilities* other than *boundary entities*, a *real-time schedule* for every *dispatch interval* two minutes before the *dispatch interval* to which it applies.

6.1.3 The *IESO* shall determine, for *registered facilities* that are *boundary entities*, a *real-time schedule* consisting of an *interchange schedule* for each *dispatch hour* using the outcome of the *pre-dispatch schedule* determined as at the preceding *dispatch hour* and modified as required by the *IESO*.

6.2 Information Used to Determine Real-Time Schedules

6.2.1 The *IESO* shall determine each *real-time schedule* in accordance with section 6.3 using the same type of information used for determining *pre-dispatch schedules* as described in section 5.2, updated to reflect the most recent valid *dispatch data* submitted by *registered market participants*, real-time system measurements, and the most recent projections of forecast data and other information pertaining to the *electricity system* which relates to future periods of time, as are available to the *IESO*.

6.3 Determining the Real-Time Schedule

6.3.1 The *IESO* shall use the information described in section 6.2 and the *dispatch algorithm* to determine a *real-time schedule* for each *dispatch interval* as follows:

6.3.1.1 the constrained *IESO-controlled grid* model shall be used;

6.3.1.2 *intertie* flows at the beginning of each *dispatch interval* shall be set at the *IESO's* best estimate of their actual values, as determined from real-time system data or applicable *interchange schedules* to reflect actual unscheduled flows;

6.3.1.3 *intertie* flows at the end of each *dispatch interval* shall be set at the value ascribed to such flows in the relevant *interchange schedule*;

6.3.1.4 the output level of each generator, and each *electricity storage facility*, and the withdrawal levels of each *dispatchable load, non-dispatchable load,* and *electricity storage facility* at the beginning of the *dispatch interval* shall be set at the *IESO's* best estimate of their actual values, as determined from real-time system data or the *real-time schedule* for the preceding *dispatch interval*; and

6.3.1.5 no daily *energy* limit specified for a *registered facility* pursuant to section 3.5.7 shall be taken into account in determining *real-time schedules*.

6.3A Real-Time Scheduling of Generation Facilities Eligible for the Generation Cost Guarantee

6.3A.1 After the *registered market participant* for a *generation facility* eligible for the generation cost guarantee notifies the *IESO* of its intent to synchronize pursuant to section 5.7 of Chapter 7, that *generation facility* shall synchronize, unless otherwise agreed to by the *IESO*, before the end of the specified *dispatch hour* and, subject to section 6.3A.3, run until the end of the *minimum generation block run-time*.

6.3A.2 The *IESO* shall, unless there is an adverse impact on the *reliable* operation of the *IESO-controlled grid*, if necessary to respect the *minimum generation block run-time* submitted by the *market participant* for the *generation facility*, constrain on the *facility* at its *minimum loading point* for the specified *minimum generation block run-time*.

6.3A.3 If the *IESO*, for reasons of *reliability*, constrains off the *generation facility* such that the *generation facility* has to de-synchronize before the end of its *minimum generation block run-time*, the *generation facility* shall remain eligible for the generation cost guarantee.

6.3A.4 In consultation with the *registered market participant*, the *IESO* may, for *reliability* reasons, during the time period from the release of the *pre-dispatch schedule* until the *dispatch hour*, manually apply a constraint to a *generation facility* that submitted *offers* into the *pre-dispatch schedule* to ensure that the output from that *generation facility* is scheduled for at least its *minimum generation block run time*. If the *IESO* applies that manual constraint, the *generator* will be deemed to have accepted the generation cost guarantee provided that:

- the criteria specified in sections 5.7.1.1 and 5.7.1.4 are satisfied; and
- the *generation facility* is not synchronized at the time the manual constraint is applied.

6.3B Real-Time Scheduling of Generation Facilities Eligible for the Day-Ahead Production Cost Guarantee

6.3B.1 If the *IESO*, for reasons of reliability, requires a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C to either de-synchronize from the *IESO-controlled grid* or to not synchronize to the *IESO-controlled grid* such that the *generation facility* does not comply with its *schedule of record*, the *generation facility* shall remain eligible for the day-ahead production cost guarantee. The *registered market participant* for the *generation facility* may also apply to the *IESO* for additional compensation under section 4.7E.1 of Chapter 9.

6.3B.2 If a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C does not close its breaker by the start of the first interval of the first hour of its *schedule of record* due to reasons not specified in sections 6.3B.1or 6.3B.3 then the *generation facility* shall not remain eligible for the day-ahead production cost guarantee associated with that start determined in accordance with section 5.8 nor shall the *registered market participant* for the *generation facility* be eligible to apply to the *IESO* for additional compensation under section 4.7E.1 of Chapter 9.

6.3B.3 If a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C does not comply with its *schedule of record* due to reasons specified in section 1.2.3 of Chapter 5 then the *facility* shall remain eligible for a pro-rated day-ahead production cost guarantee determined in accordance with section 4.7D of Chapter 9.

6.3B.4 If the *registered market participant* for a *generation facility* that was eligible for the day-ahead production cost guarantee under section 2.2C does not comply with its *schedule of record* by withdrawing the *dispatch data* for the *generation facility* the *facility* may not remain eligible for a day-ahead production cost guarantee and may be subject to a withdrawal charge as determined in accordance with section 3.8F of Chapter 9.

6.4 Market Schedules and Market Prices

6.4.1 Subject to section 8.4A the *IESO* shall, within five minutes after the end of each *dispatch interval*, use the *dispatch algorithm* to determine a *market schedule* and *market prices* for that *dispatch interval* based on the most recent *real-time schedule* for such *dispatch interval.*

6.4.2 Subject to section 8.4A for the purpose of determining the *market schedule* and *market prices* for any *dispatch interval*, the *IESO* 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 *IESO-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 *market schedule* shall be the final conditions of the *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 *market schedule* shall be set at the *IESO'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 *IESO 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 *IESO 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;

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*;

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;*

6.4.2.9A for a *variable generator* that is a *registered market participant,* if the *registered facility* is issued a *dispatch instruction* by the *IESO* in accordance with section 7.1*,* the quantity of *energy* scheduled for injection in the *market schedule* for the applicable *dispatch intervals* shall be limited to reflect the least of the maximum MW *energy* level associated with *energy offers* submitted for the *registered facility,* the *registered facility's* full capacity less submitted *outages, and the* forecast of *energy* produced by the *forecasting entity* for the *registered facility*; and

6.4.2.9B for a *variable generator* that is a *registered market participant,* if the *registered facility* is issued a *release notification* by the *IESO* in accordance with section 7.1, which remains in effect for any *dispatch interval*, the quantity of *energy* scheduled for injection in the *market schedule* for the applicable *dispatch intervals* shall be limited to reflect the least of the maximum MW *energy* level associated with *energy offers* submitted for the *registered facility*, the *registered facility's* full capacity less submitted *outages*, and the instantaneous *energy* output of the *registered facility,* as represented by its *operating result* for that *facility,* recorded at the end of each applicable *dispatch interval* as referred to in this section.

6.4.2A Until such time that locational pricing is implemented in the *IESO-administered markets*, in determining the *market schedule* and *market prices* for any *dispatch interval,* the *IESO* 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.

6.4.3 The *IESO* shall determine for *registered facilities* that are *boundary entities* a *market schedule* for each *dispatch hour* using the outcome of the projected *market schedule* determined as at the preceding *dispatch ho*ur and modified as required by the *IESO*.

6.5 Publication of Real-Time Schedule Information

6.5.1 For each *registered facility* that is a *dispatchable load facility* or a *dispatchable generation facility* in respect of which a valid *bid* or *offer* has been submitted for the applicable *dispatch hour*, the *IESO* shall, as soon as practical but no later than the start of the *dispatch interval* to which it relates, release the following information for each such *registered facility* only to the *registered market participant* for that *registered facility*:

6.5.1.1 the real-time schedule for that *registered facility*; and

6.5.1.2 [Intentionally left blank]

6.5.1.3 the scheduled use of that *registered facility* under *contracted ancillary service* contracts.

6.5.1.4 [Intentionally left blank]

6.5.1A Subject to section 8.4A, for each *registered facility* that is a *dispatchable load facility* or a *dispatchable generation facility* in respect of which a valid *bid* or *offer* has been submitted for the applicable *dispatch hour*, the *IESO* shall, within one hour after each *dispatch hour*, release to each *registered market participant* the *market schedule* for their *registered facilities* for each *dispatch interval* of that *dispatch hour.*

6.5.2 Subject to section 8.4A the *IESO* shall, in the five minute period after the end of each *dispatch interval*, release to all *market participants* the uniform *market prices* of *energy* and *operating reserves* related to that *dispatch interval*.

6.5.3 The *IESO* shall, within one hour after each *dispatch hour,* release to all *market participants* the following information for each *dispatch interval* of that *dispatch hour*:

6.5.3.1 total system load and total system losses;

6.5.3.2 area *operating reserve* requirements;

6.5.3.3 for information purposes only, *energy* prices at each set of transmission nodes identified by the *IESO* for this purpose, decomposed as far as practical into an *energy* component, a loss component and a component for all other transmission and system constraints and, subject to section 6.5.3A, the prices of each class of *operating reserve* in each reserve area identified by the *IESO* for this purpose;

6.5.3.4 [Intentionally left blank]

6.5.3.5 [Intentionally left blank]

6.5.3.6 any area *operating reserve* shortfalls; and

6.5.3.7 a list of network and *security* constraints that affected the *real-time schedule*.

6.5.3A Until the date that is the first day of the fourth 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, the *IESO* shall not be required to release the prices of each class of *operating reserve* referred to in section 6.5.3.3.

6.5.4 Subject to section 8.4A, for each *registered facility* that is a *boundary entity* in respect of which the *dispatch instructions* for a given *dispatch hour* provides for the *dispatch* of more than 0 MW or for a reduction to 0 MW relative to the previous *dispatch hour*, the *IESO* shall*,* as soon as practical and consistent with relevant *reliability standards,* but no later than the start of the *dispatch hour* to which it relates, release the following information for each such *registered facility* only to the *registered market participant* for that *registered facility:*

6.5.4.1 the interchange schedule for that *registered facility*;

6.5.4.2 [Intentionally left blank]

6.5.4.3 any request of that *registered facility* to submit an offer or bid under a *reliability must-run contract* and the scheduled use of that *registered facility* under contracted *ancillary service* contracts; and

6.5.4.4 the projected market schedule for that *registered facility*.

7. IESO Dispatch Instructions

7.1 Purpose and Timing of Dispatch Instructions

7.1.1 The *IESO* shall determine *dispatch instructions* for each *registered facility* as described in this section 7, as the primary means of co-ordinating the real-time operation of the *electricity system*.

7.1.1A The *IESO* shall only issue *dispatch instructions* for a *physical service* to a *registered facility* other than a *boundary entity* for a given *dispatch interval* when there is a change in the quantity of a *physical service* to be scheduled from that *registered facility* during that *dispatch interval* relative to the last *dispatch instruction* issued to the *registered facility* and with which the *registered market participant* has confirmed compliance in accordance with section 7.1.2 and 7.1.2A.

7.1.1B Where the *IESO*:

7.1.1B.1 is not required to issue a *dispatch instruction* at a *registered facility* other than a *boundary entity* for a given *dispatch interval* by virtue of section 7.1.1A; or

7.1.1B.2 for any reason fails to issue a dispatch instruction to a *registered facility* other than a *boundary entity* for a given *dispatch interval*,

subject to section 7.1.1B1, the last *dispatch instruction* issued to the *registered facility* and with which the *registered market participant* has confirmed compliance in accordance with sections 7.1.2 and 7.1.2A shall, for all purposes under these *market rules* but subject to section 7.1.4 and 7.4.3, be deemed to be the *dispatch instruction* issued for that *dispatch interval* for that *registered facility*.

7.1.1B1 For a *variable generator* that is a *registered market participant*, section 7.1.1B shall apply until the *registered facility* is issued a *release notification*.

7.1.1C Notwithstanding the identification of a portion of the consumption at a *registered facility* under section 3.3.18 as *non-dispatchable load,* the *IESO* shall issue *dispatch instructions* in accordance with the applicable *market manual* to that *registered facility* including that portion that has been identified pursuant to section 3.3.18 as *non-dispatchable load*.

7.1.2 Subject to section 7.1.1A, the *IESO* shall issue *dispatch instructions* for each *registered facility*, other than a *boundary entity*, for which a *dispatch instruction* is required no later than the start of each *dispatch interval* or, where section 7.1.4 or 7.4.3 applies, within a *dispatch interval*. The *IESO* shall:

7.1.2.1 [Intentionally left blank]

7.1.2.2 issue such *dispatch instructions* using the systems and protocols defined in the applicable *market manual*; and

7.1.2.3 record and time-stamp all such *dispatch instructions*, store such records for at least seven years and make such records available for purposes of audit and dispute resolution in accordance with these *market rules*.

7.1.2A Each registered market participant shall:

7.1.2A.1 acknowledge receipt of; and

7.1.2A.2 confirm its intention to comply or not to comply with,

each *dispatch instruction* issued to it in accordance with section 7.1.2 in respect of each of its *registered facilities*, other than a *boundary entity*, using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.2A1 The *IESO* shall issue a *release notification* to a *variable generator* that is a *registered market participant* if the *registered facility* is not required to be at or below forecasted output. Each *variable generator* shall acknowledge receipt of each *release notification* using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.2B Confirmation by a *registered market participant* of its intention not to comply with a *dispatch instruction* pursuant to section 7.1.2A shall constitute non-compliance with the *dispatch instruction* by the *registered market participant* for all purposes under these *market rules*, including but not limited to section 7.5.

7.1.2C Where a *registered market participant* has for a *registered facility* that is a *dispatchable load* identified pursuant to section 3.3.18 all or a portion of that *registered facility's* consumption as *non-dispatchable load* and the *IESO* has issued a *dispatch instruction* requiring a reduction of such non-dispatchable consumption pursuant to section 7.1.1C, the *registered market participant* shall confirm its intention not to comply with each such *dispatch instruction* in accordance with section 7.1.2A and the applicable *market manual*.

7.1.2D Confirmation by a *registered market participant* of its intention not to comply with a *dispatch instruction* pursuant to section 7.1.2C shall not constitute non-compliance with the *dispatch instruction* by the *registered market participant* for all purposes under these *market rules*, including but not limited to section 7.5.

7.1.3 The *IESO* shall issue *dispatch instructions*, in the form of *interchange schedules*, for each *registered facility* that is a *boundary entity*, for which a *dispatch instruction* is required prior to each *dispatch hour*. The *IESO* shall:

7.1.3.1 [Intentionally left blank]

7.1.3.2 issue such *dispatch instructions* using the systems and protocols defined in the applicable *market manual*; and

7.1.3.3 record and time-stamp all such *dispatch instructions,* store such records for at least seven years and make such records available for purposes of audit and dispute resolution in accordance with these *market rules*.

7.1.3A Each *registered market participant* shall acknowledge receipt of each *dispatch instruction* issued to it in accordance with section 7.1.3 in respect of each of its *registered facilities* that is a *boundary entity* using the systems and protocols defined in the applicable *market manual* and within the time required by such *market manual*.

7.1.3B [Intentionally left blank – section deleted]

7.1.3B.1 [Intentionally left blank – section deleted]

7.1.3B.2 [Intentionally left blank – section deleted]

7.1.3C [Intentionally left blank – section deleted]

7.1.4 The *IESO* may issue *dispatch instructions* within the *dispatch interval*, instructing any *registered facility* with a valid *energy offer* or *bid*, to increase or decrease *energy* production or consumption as specified in its *offers* or *bids* for *energy*.

When a *dispatch instruction* is issued within a *dispatch interval* pursuant to this section 7.1.4, the last *dispatch instruction* for *energy* or each class of *operating reserve,* as the case may be, shall be the sole *dispatch instruction* used for *settlement* purposes for that *dispatch interval.*

7.1.5 Where a *contingency event* is occurring or has occurred, the *IESO* may temporarily cease issuing *dispatch instructions* in the manner otherwise required by section 7.1.2. In such cases, *registered market participants* shall comply with section 7.3.3 or 7.4.3, as the case may be.

7.1.6 The *IESO* shall, on a best efforts basis, determine and issue *dispatch* advisories for each *registered dispatchable facility*, for information purposes only. *Dispatch* advisories are determined and issued every 5 minutes to each *registered dispatchable facility* to provide an indication of potential future *dispatch instructions* and *operating reserve* schedules.

7.2 Information Used to Determine Dispatch Instructions

7.2.1 The *IESO* shall use its best endeavours to ensure that the *dispatch instructions* issued with respect to each *registered facility*, that is not a *boundary entity*, for each *dispatch interval* closely approximate the most recent *real-time schedule* for that *registered facility* and *dispatch interval*. The *IESO* may, however, issue *dispatch instructions* that depart from the *real-time schedule* if:

7.2.1.1 the *security* and *adequacy* of the system would be endangered by implementing the most recent *real-time schedule*;

7.2.1.2 the *dispatch algorithm* has failed, or has produced a *real-time schedule* that is clearly and materially in error;

7.2.1.3 material changes subsequent to determination of the most recent *real-time schedule*, such as failure of an element of a *transmission system* or failure of a *registered facility* to follow *dispatch instructions*, have occurred; or

7.2.1.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13.

7.2.2 If the *IESO* anticipates that an over-generation or an under-generation condition may occur, it shall issue advisory notices in accordance with section 12.1 but shall continue using the procedures described in sections 5 and 6 to determine *pre-dispatch schedules*, *real-time schedules* and the associated projected and *market prices* and *market schedules.*

7.2.3 If the *IESO* determines prior to issuing *dispatch instructions* that the market responses to the projected or *market prices* will be sufficient to eliminate the over-generation or under-generation condition, the *IESO* shall take no *emergency* action and shall issue advisory notices so indicating.

7.2.4 If the *IESO* determines prior to issuing *dispatch instructions* that market responses will not eliminate the over-generation or under-generation condition, it shall declare an *emergency operating state* to resolve the conditions in accordance with section 7.7.

7.2.5 The *IESO* shall use its best endeavours to ensure that the *dispatch instructions* issued with respect to each *registered facility*, that is a *boundary entity*, for each *dispatch hour* reflect the *pre-dispatch schedule* for that *dispatch hour* as determined in accordance with section 6.1.3 of Chapter 7. The *IESO* may, however, issue *dispatch instructions* that depart from the *pre-dispatch schedule* if:

7.2.5.1 the *security* and *adequacy* of the system would be endangered by implementing the *pre-dispatch schedule*;

7.2.5.2 the *dispatch algorithm* has failed, or has produced a *pre-dispatch schedule* that is clearly and materially in error;

7.2.5.3 material changes subsequent to determination of the *pre-dispatch schedule*, such as failure of an element of a *transmission system* or failure of a *registered facility* to follow *dispatch instructions*, have occurred; or

7.2.5.4 the operation of all or part of the *IESO-administered markets* has been suspended pursuant to section 13; or

7.2.5.5 an external *control area operator* calls a *called capacity export* in accordance with section 20.

7.3 The Content of Dispatch Instructions

7.3.1 The *IESO* shall, subject to section 7.1.1A, issue *dispatch instructions* for each *dispatch interval* to each *registered facility* that is a not a *boundary entity* indicating for that *dispatch interval*:

7.3.1.1 the rate at which *energy* is to be injected into or withdrawn from the *IESO-controlled grid* (in MW) at the end of the *dispatch interval*;

7.3.1.2 the amount of each class of *operating reserve* that is to be in a condition to respond to a *dispatch instruction* issued pursuant to section 7.4.3 calling for additional *energy* production; and

7.3.1.3 the amount of *reactive support* and *regulation* that is to be provided under *contracted ancillary service* contracts or *reliability must-run contracts* or as a consequence of any requirement to provide same which derives from the application of these *market rules*.

7.3.2 The dispatch instructions for any registered facility that is not a boundary entity shall:

7.3.2.1 be consistent with the current operating status of that *registered facility* and with any operational constraints described in the most recent *dispatch data* submitted by the *registered market participant* for that *registered facility*;

7.3.2.2 be used by the *IESO* for the purpose of declaring the *registered facility* as non-conforming in accordance with section 7.5.4; and

7.3.2.3 subject to Appendix 7.6, be used in the *IESO settlement process* for determining any *settlement amounts* for congestion management pursuant to section 3.5 of Chapter 9.

7.3.3 [Intentionally left blank – section deleted]

7.3.4 The IESO shall issue dispatch instructions for each dispatch hour to each registered facility that is a boundary entity, indicating for that dispatch hour:

7.3.4.1 the rate at which *energy* is to be injected into or withdrawn from the *IESO-controlled grid* (in minutes) from the specified *intertie zone*, which rate shall be consistent with all relevant *reliability standards*;

7.3.4.2 the amount of each class of *operating reserve* that is scheduled and the ramp rates associated with the *energy* if called on; and

7.3.4.3 the amount of *reactive support* and *regulation* that is to be provided under *reliability must-run contracts* or as a consequence of any requirement to provide same which derives from the application of these *market rules.*

7.3.5 The dispatch instructions for any registered facility that is a boundary entity shall:

7.3.5.1 be consistent with the current *dispatch data* for that *registered facility* and with any *interconnection* limitations associated with the *registered facility*; and

7.3.5.2 be used in the *IESO settlement process* for determining any *settlement amounts* for congestion management pursuant to section 3.5 of Chapter 9.

7.3.6 [Intentionally left blank – section deleted]

7.4 IESO Dispatch of Operating Reserve

7.4.1 The *IESO* shall:

7.4.1.1 subject to section 7.1.1A, issue to each *registered facility*, other than a *boundary entity*, which has made an *offer* for the delivery of *operating reserve* for a particular *dispatch hour*, *dispatch instructions* for each *dispatch interval* consistent with the results of the *dispatch algorithm* and the procedures detailed in sections 6.2 to 6.4, instructing the *registered market participant* responsible for that *registered facility* as to the quantity of *operating reserve* that is to be provided by that *registered facility* in that *dispatch interval*; and

7.4.1.2 issue to each *registered facility,* that is a *boundary entity,* which has made an *offer* for the delivery of *operating reserve* for a particular *dispatch hour*, *dispatch instructions* for that *dispatch hour* consistent with the results of the *dispatch algorithm* and the procedures detailed in sections 6.1 to 6.4, instructing the *registered market participant* responsible for that *registered facility* as to the quantity of *operating reserve* to be provided by that *registered facility* in that *dispatch hour.*

7.4.2 Each *registered facility* to which section 7.4.1 applies shall maintain unused *generation capacity, electricity storage capacity,* or load reduction capacity during that *dispatch interval*, consistent with the *dispatch instructions* issued to it under these *market rules*, so as to be able to increase *energy* production or reduce *energy* withdrawal as soon as possible upon being instructed to do so by the *IESO* pursuant to section 7.4.3.

7.4.2.1 A *market participant* shall be subject to non-accessibility charges if it fails to maintain unused *generation capacity, electricity storage capacity,* or load reduction capacity equal to or greater than its total amount of scheduled *operating reserve* during any *interval* in which it is scheduled to provide *operating reserve* but is not *dispatched* to increase *energy generation* or reduce energy withdrawal pursuant to section 7.4.3. The *market participant* may also be subject to compliance actions in accordance with section 6 of Chapter 3.

7.4.3 Where a *contingency event* has occurred or is occurring, the *IESO* may issue *dispatch instructions* within the *dispatch interval*, instructing a *registered facility*, other than a *boundary entity*, providing *operating reserve* to begin increasing *energy* production or reducing *energy* withdrawal as specified in its *offers* of *operating reserve*. *Dispatch instructions* issued in respect of a *registered facility* that is a *boundary entity* providing *operating reserve* shall be such as to ensure that the *energ*y associated with each *offer* of *operating reserve* is scheduled by the *IESO* in a manner consistent with all relevant *reliability standards* for activation of *operating reserve* and as agreed upon by the entity scheduling the resulting *energy* transfer.

7.4.4 The *IESO* shall, when *dispatching registered facilities* providing *operating reserve* to produce *energy* pursuant to section 7.4.3, call first on the *registered facility* in each area that has offered the lowest price (in $/MWh) for *energy* produced from scheduled *operating reserve* in that area. If such *registered facility* is instructed to produce *energy* but does not do so as rapidly as instructed, or if the *IESO* needs additional *energy* from *operating reserve* in that area, the *IESO* shall call upon the *registered facility* offering the next-lowest price for *energy* from *operating reserve*. If the *IESO* determines that calling upon *registered facilities* in strict order of increasing price of *energy* would mean that it would be unable to respond in a timely fashion to a contingency for which the *IESO* would issue a *dispatch instruction* pursuant to section 7.4.3, the *IESO* may call upon *registered facilities* out of such strict order but shall as far as is practical call *registered facilities* to reflect the intent of this section 7.4.4.

7.4.5 When *operating reserves* are activated as a result of a *contingency event*, the otherwise applicable *ten-minute operating reserve* requirements shall be reduced by a corresponding amount and shall subsequently be recovered to pre-contingency levels in a manner consistent with sections 4.5.10 and 4.5.21 of Chapter 5.

7.4.6 A *registered facility* that failed to maintain unused *generation* (or load reduction) *capacity* equal to or greater than their total amount of scheduled *operating reserve* is not entitled to any inappropriate congestion management *settlement* credits determined in accordance with section 3.5.2 of Chapter 9. The *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

7.5 Compliance with Dispatch Instructions

7.5.1 Each *registered market participant* shall ensure that each of its *registered facilities* complies with *dispatch instructions* issued to it under these *market rules*. Without limiting the generality of section 6.2 of Chapter 3, non-compliance with *dispatch instructions* other than for the reasons referred to in section 7.5.3 shall be a breach of the *market rules* and may be sanctioned in accordance with section 6.2 of Chapter 3 and with this section 7.5.

7.5.2 A *registered market participant* that expects its *registered facility*, other than a *boundary entity*, to operate in a manner that, for any reason, differs materially from the *dispatch instructions* issued to it in accordance with these *market rules* shall so notify the *IESO* as soon as possible. The *IESO* shall issue guidelines defining when a difference is material and how notice shall be provided for the purposes of this section 7.5.2 and of section 7.5.3.

7.5.3 Compliance with a *dispatch instruction* for a *registered facility* other than a *boundary entity* is not required if such compliance would endanger the safety of any person, damage equipment, or violate any *applicable law*. A *market participant* that departs from *dispatch instructions* for any such reason shall so notify the *IESO* in accordance with section 7.5.2.

7.5.4 If failure by a *registered facility,* other than a *boundary entity*, to comply with a *dispatch instruction* endangers *electricity system reliability*, the *IESO* shall declare the *registered facility* to be non-conforming and shall take any actions allowed by sections 7.5.5 to 7.5.7 or any other provisions of these *market rules* which the *IESO* determines appropriate.

7.5.4A [Intentionally left blank – section deleted]

7.5.5 Subject to section 7.5.5A, if a *registered facility* other than a *boundary entity* produces or withdraws more or less *energy* in a *dispatch interval* than implied by a valid *dispatch instruction* issued by the *IESO*, the *IESO* shall, for pricing and *settlement* purposes:

7.5.5.1 treat the difference in *energy* production or withdrawal as a change in *non-dispatchable load* at its location , in accordance with sections 4.4.3.2, and 6.4.2.6; and

7.5.5.2 use any trade-off curves between *energy* and *operating reserves* in the *dispatch data* for that *registered facility* to determine an appropriate adjustment in the quantity of *operating reserve* of each class supplied by the *registered facility*.

7.5.5A Section 7.5.5 shall not apply until such time that locational pricing is implemented in the *IESO-administered markets*.

7.5.6 If the *IESO* declares a *registered facility* other than a *boundary entity* to be non-conforming under section 7.5.4:

7.5.6.1 the *IESO* shall require the *registered market participant* for that *registered facility* to explain the reason for the non-compliance and shall record the response;

7.5.6.2 if the *IESO* determines that the *registered facility* is physically incapable of implementing the *dispatch instructions*, the *IESO* may require revision in the registration information for the non-conforming *registered facility*; and

7.5.6.3 if the *IESO* is not satisfied that the *registered facility* will respond to future *dispatch instructions*, the *IESO* may direct the *registered facility* to follow, as closely as practicable, an output or withdrawal profile specified by the *IESO*, and shall thereafter represent the *registered facility* as a *self-scheduling generation facility, self-scheduling electricity storage facility* or *non-dispatchable load* having the specified profile until the non-conforming *registered facility* satisfies the *IESO* that it has remedied the conditions causing the non-conformance.

7.5.7 Until the *registered market participant* for a non-conforming *registered facility* responds to the requirements of this section 7.5 to the satisfaction of the *IESO*, such *registered facility* shall continue to be designated as non-conforming, and such failure to respond on the part of that *registered market participant* may be referred by the *IESO* to the *market surveillance panel* at any time.

7.5.8 The *IESO* shall assume that a *registered facility* that is a *boundary entity* will comply fully with all *dispatch instructions* for *energy* or *operating reserves* upon confirmation of the relevant *interchange schedule* with the appropriate scheduling entity.

7.5.8A A *registered market participant* associated with a *registered facility* that is a *boundary entity* shall, other than for the bona fide and legitimate reasons referred to in section 7.5.8B, schedule *energy* and *operating reserve*, in accordance with section 6.1.3, with the appropriate scheduling entity, or scheduling entities as the case may be.

7.5.8B The *IESO* may take actions pursuant to section 6.6.10A of Chapter 3 and shall assess a real-time import or export failure charge as determined in section 3.8C of Chapter 9 where a *registered market participant* associated with a *registered facility* that is a *boundary entity* fails to schedule *energy* or *operating reserve*, in accordance with section 6.1.3 of Chapter 7, with the appropriate scheduling entity, or scheduling entities as the case may be, according to the applicable *interchange schedule*, other than for bona fide and legitimate reasons as determined by the *IESO*. Bona fide and legitimate reasons shall include failures caused by actions and circumstances beyond the control of the *market participant* or due to *IESO* or external scheduling entity error or action, including those reasons specified in the applicable *market manual*.

7.5.9 In addition to any other sanction or consequence provided for in these *market rules*, the *IESO* may disqualify from future participation in the *operating reserve market* any *registered facility* that consistently fails to increase *energy* generation or reduce *energy* withdrawal when called upon in accordance with Chapter 7.

7.6 Dispatch Scheduling Errors

7.6.1 A *dispatch scheduling error* shall be deemed to have occurred if either:

7.6.1.1 an *arbitrator* determines that the *IESO* has made a *dispatch scheduling error*; or

7.6.1.2 the *IESO* declares that it has made a *dispatch scheduling error*, on its own initiative, including pursuant to section 6.9 of Chapter 9 or further to a *notice of disagreement* filed or other *settlement* dispute initiated by a *market participant* pursuant to section 6.8 or 6.10 of Chapter 9.

7.6.2 When a *dispatch scheduling error* has occurred, the *IESO* shall not adjust *market prices* but shall, subject to section 7.6.3 and notwithstanding section 13.1.2 of Chapter 1, be strictly liable to compensate a *market participant* for damages suffered by the *market participant* as a result of the *dispatch scheduling error,* assessed in accordance with section 13.1.4 of Chapter 1.

7.6.3 A *market participant* that wishes to claim compensation pursuant to section 7.6.2 shall:

7.6.3.1 where the *dispatch scheduling error* was determined to have been made pursuant to section 7.6.1.1, request the *arbitrator* to determine the *market participant's* entitlement to and amount of, if any, such compensation; and

7.6.3.2 where the *dispatch scheduling error* was determined to have been made pursuant to section 7.6.1.2, request that the *IESO* determine the *market participant's* entitlement to and amount of, if any, such compensation,

with the amount, if any, in either case being determined in accordance with section 7.6.4.

7.6.4 Any amount determined by an *arbitrator* or by the *IESO,* as the case may be, pursuant to section 7.6.3 or 7.6.5 shall be assessed in accordance with section 13.1.4 of Chapter 1 and shall exclude such amount as may be required to account for any congestion management *settlement* credit triggered by the relevant *dispatch scheduling error* and already credited to the *market participant.*

7.6.5 If a *market participant* wishes to dispute a determination made by the *IESO* pursuant to section 7.6.3.2, it shall submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall, if the good faith negotiations referred to in section 2.4 of that Chapter fail to resolve the matter, request in the *notice of dispute* that the *arbitrator* determine the *market participant's* entitlement to the compensation referred to in section 7.6.2, the amount, if any, of such compensation or both, as the case may be.

7.7 Additional IESO Powers in Emergency and High-Risk Conditions

7.7.1 During real-time operations, the *IESO* is responsible for declaring an *emergency operating state* or a *high-risk operating state* under circumstances described in sections 2.3 and 2.4 of Chapter 5.

7.7.2 The *IESO*'s primary responsibility in an *emergency operating state* or a *high-risk operating state* is to preserve system *reliability*, with a secondary responsibility to restore normal system conditions and operation of the *IESO-administered markets* as soon as practicable.

7.7.3 Where an *emergency operating state* or a *high-risk operating state* has been declared, the *IESO* may implement any of the actions detailed in sections 2.3, 2.4, 5.8 and 5.9 of Chapter 5.

7.7.4 The *IESO* may determine any additional compensation payable in respect of *physical services* acquired during an *emergency operating state* or a *high-risk operating state*.

7.8 Publication of Real-Time Dispatch Information

7.8.1 The *IESO* shall, within one hour after each *dispatch hour*, *publish* information concerning system results and events during that *dispatch hour*. This information shall include, but is not limited to:

7.8.1.1 total load met;

7.8.1.2 transmission capacity between the *IESO-controlled grid* and each *intertie zone*;

7.8.1.3 subject to section 7.8.2, any *outages* of transmission *facilities*;

7.8.1.4 total *operating reserve* scheduled, and total *energy* called from such *operating reserve*, by area;

7.8.1.5 the market prices for each *dispatch interval*; and

7.8.1.6 the uniform *hourly Ontario energy price* (HOEP) determined in accordance with section 8.3.1.

7.8.2 Until the date that is the first day of the fourth 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, the *IESO* shall not *publish* information concerning *outages* of transmission *facilities* referred to in section 7.8.1.3.

8. Determining Market Prices

8.1 Purpose and Timing of Determining Market Prices

8.1.1 The *IESO* shall use the procedures in this section 8 to determine the uniform *market prices* in the *IESO control area* and the *intertie zone* prices for *energy* and *operating reserve* that are used for the market *settlement process* pursuant to the provisions of Chapter 9.

8.1.1A The *IESO* shall determine the *intertie congestion price* associated with each *intertie zone* for each *dispatch hour* based on the *pre-dispatch schedule* referred to in section 6.1.3.

8.1.2 Subject to section 8.4A, the *IESO* shall determine and *publish market prices* for *energy* and *operating reserve* in accordance with sections 8.2 and 8.3 within five minutes after the end of each *dispatch interval*, as provided in section 6.4.

8.1.2.1 [Intentionally left blank]

8.1.2.2 [Intentionally left blank]

8.1.2.3 [Intentionally left blank]

8.1.3 [Intentionally left blank]

8.2 Ex-post Prices for Each Dispatch Interval

8.2.1 The *IESO* shall determine *market prices* for *energy* and *operating reserve* for each *dispatch interval*, using the *dispatch algorithm* as follows:

8.2.1.1 the data and information described in section 4.4 shall be used as inputs, using the most recent valid *dispatch data* submitted by *registered market participants* and the most accurate system data and *metering data* for that *dispatch interval* that is available at the time the *market prices* are being determined;

8.2.1.2 the unconstrained *IESO-controlled grid* model shall be used;

8.2.1.3 the operating status of each *registered facility*, in the *dispatch algorithm* at the start of each *dispatch interval* shall be set equal to the operating status in the *market schedule* determined for the end of the preceding *dispatch interval* for that *registered facility* and, subject to section 8.2.3, recognizing by the adjustment to the input data any *registered facility* in respect of which a *forced outage* has occurred or of which the *interchange schedule* has been curtailed due to constraints external to the *IESO control area* during that *dispatch interval*;

8.2.1.4 the *dispatch algorithm* shall be run to determine *the market schedules* that maximise the economic gains from trade under the assumptions made pursuant to this section 8.2.1; and

8.2.1.5 subject to section 8.2.2, the marginal costs from the *dispatch algorithm* for *energy* and each class of *operating reserve*, in the *IESO control area* and in each *intertie zone*, shall be the *market prices* for that *dispatch interval*.

8.2.2 The prices produced as part of the output of the market scheduling and pricing process described in Appendix 7.5 for a pricing run shall not necessarily be the prices that are used for *settlement* purposes. Without limiting the generality of the foregoing, the following prices shall be used for *settlement* purposes:

8.2.2.1 the *energy* price for an *intertie zone* adjoining the *IESO control area* shall for *settlement* purposes, and subject to sections 8.2.2.4 to 8.2.2.7, equal the uniform Ontario *energy* price modified by the difference between the *intertie zone energy* price and the uniform Ontario *energy* price determined in the projected *market schedule*;

8.2.2.2 the *operating reserve* price for each class of *operating reserve* supplied from within the *IESO control area* shall for *settlement* purposes, and subject to sections 8.2.2.4 to 8.2.2.7, be formed:

a. from the shadow prices associated with the *operating reserve* requirements within the *IESO control area* during *dispatch intervals* when such requirements can be met; or

b. from the greater of the highest priced *offer* associated with the scheduled *operating reserve* or the *energy* prices for the *dispatch interval* during which the *operating reserve* requirements within the *IESO control area* cannot be met;

8.2.2.3 the *operating reserve* price for each class of *operating reserve* in an *intertie zone* adjoining the *IESO control area* shall for *settlement* purposes, and subject to section 8.2.2.4 to 8.2.2.7, equal the corresponding uniform *operating reserve* price for the *IESO control area* for that class of *operating reserve* modified by the difference between the corresponding *operating reserve* price for the *intertie zone* and the uniform *operating reserve* price for the *IESO control area* determined in the projected *market schedule*;

8.2.2.4 any *energy* price produced which exceeds *MMCP* shall be set equal to *MMCP* for *settlement* purposes;

8.2.2.5 any *energy* price produced which is less than negative *MMCP* shall be set equal to negative *MMCP* for *settlement* purposes;

8.2.2.6 any price for *operating reserve* produced which exceeds *MORP* shall be set equal to *MORP* for *settlement* purposes; and

8.2.2.7 any price for *operating reserve* produced which is negative will be set equal to zero for *settlement* purposes.

8.2.3 In the calculation of *market prices*, the *IESO* shall:

8.2.3.1 in the manner specified in section 8.2.1.3, adjust the input data at the start of a *dispatch interval* of a *registered facility* in respect of which a *forced outage* or *interchange schedule* curtailment due to constraints external to the *IESO control area* has occurred during the preceding or an earlier *dispatch interval*; and

8.2.3.2 make the adjustment referred to in section 8.2.1.3 in respect of such *registered facility* only to the extent that the input data can be adjusted having regard to the timing of the *forced outage* or *interchange schedule* curtailment due to constraints external to the *IESO control area* and the *IESO's* procedures for updating input data.

8.3 Uniform Ex-post Prices for Each Hour

8.3.1 The *IESO* shall determine, for each *dispatch hour*, a uniform *hourly Ontario energy price* (HOEP) in accordance with the formulation described as $HOEP_h$ in section 3.1.3 of Chapter 9.

8.4 [Intentionally left blank]

8.4A Administrative Pricing and Corresponding Schedules – Revised

8.4A.1 This section 8.4A applies only in respect of the establishment of *administrative prices* for the *real-time energy market* and the *operating reserve market.*

8.4A.2 The *IESO* shall establish *administrative prices* and, where applicable, corresponding *market schedules* when:

8.4A.2.1 the *energy market* or the *operating reserve market* has been suspended in accordance with section 13;

8.4A.2.2 the *IESO* is unable to *publish* an *energy market price* or *operating reserve market price* in accordance with section 8.1.2 due to a failure in or *planned outage* of the software, hardware or communications systems that supports the operation of the *dispatch algorithm*;

8.4A.2.3 the *IESO* determines, pursuant to guidelines approved by the *IESO Board* relating to price error materiality and acceptable causal events, that a *published energy market price* or *operating reserve market price* is incorrect due to incorrect inputs which affected the outcome of the *dispatch algorithm*;

and all such *administrative prices* shall be the *energy market price* and the *operating reserve market price* for the applicable *dispatch interval* for all purposes under these *market rules*.

8.4A.3 Where the *IESO* establishes *administrative prices* pursuant to section 8.4A.2 it shall do so within two *business days* of the event causing *market prices* to be administered. The *IESO* shall inform *market participants* as soon as practicable whenever a *published market price* is an *administrative price*.

Administration of Prices Due to Failures or Planned Outages of Market Systems, Publication of Incorrect Prices or Implementation of an Emergency Control Action

8.4A.4 In circumstances where *administrative prices* are required under sections 8.4A.2.2, or 8.4A.2.3 the *IESO* shall establish *administrative prices* and corresponding *market schedules* that would, to the extent practical, reflect the *market prices* and corresponding *market schedules* that would have otherwise been produced by the *real-time markets*, but for the event causing *market prices* to be administered.

8.4A.5 Where the *IESO* establishes *administrative prices* pursuant to sections 8.4A.2.2, or 8.4A.2.3 in respect of one or more *dispatch intervals*, it shall use the best available *dispatch data* for *energy* or *operating reserve*, as the case may be, pertaining to the *dispatch interval* to which the *administrative price* is to be applied and the *market prices* and corresponding *market schedule* for that *dispatch interval* shall be as the *IESO* determines appropriate consistent with the principle stated in section 8.4A.4, and shall be the *market price* and corresponding *market schedule* from:

8.4A.5.1 the closest preceding *dispatch interval* that has not been administered, up to a maximum of 24 *dispatch intervals*;

8.4A.5.2 the closest subsequent *dispatch interval* that has not been administered, up to a maximum of 24 *dispatch intervals*; or

8.4A.5.3 a combination of the closest preceding and closest subsequent *dispatch intervals* that have not been administered, provided that neither the preceding nor subsequent *dispatch intervals* are selected for more than 24 *dispatch intervals* and are applied in a continuous manner such that the *administrative price* chosen from the preceding *dispatch interval* shall apply until changed to the *administrative price* selected from the subsequent *dispatch interval*.

8.4A.6 Where the *IESO* establishes an *administrative price* pursuant to sections 8.4A.2.2, or 8.4A.2.3 the *IESO* shall, if the need for *administrative prices* extends beyond 48 *dispatch intervals*, establish *administrative prices* for the remaining *dispatch intervals* of the event causing *market prices* to be administered within the *IESO control area* and the *intertie zones,* using an average *HOEP* for the *energy market* and the hourly average of the *operating reserve* prices for the applicable *dispatch intervals* for the *operating reserve markets*, determined from the corresponding hour or hours from each of the 4 most recent *business days* or non-*business days*, as the case may be, excluding those hours from any day in which *administrative pricing* has been established under this section. Prices for the excluded hours shall be replaced by prices that have not been administered under this section from the corresponding hours of the most recent earlier *business days* or non-*business days*, as the case may be.

8.4A.7 Where the *IESO* establishes an *administrative price* for a *dispatch interval* pursuant to section 8.4A.6, there shall be no congestion management *settlement* credit payments made under section 3.5.2 of Chapter 9 for that *dispatch interval*.

Administration of Prices Due to Market Suspension

8.4A.8 Where the *IESO* establishes *administrative prices* during a market suspension pursuant to section 8.4A.2.1, it shall establish the *administrative price* as one of the following, as the *IESO* determines appropriate:

8.4A.8.1 where *market operations* have been suspended for reasons other than a failure in the software that generates *market prices* and operations of the *IESO-controlled grid* are based to some extent on market-based information and signals, a *market price* calculated using that software; or

8.4A.8.2 where operations of the *IESO-controlled grid* are being conducted without regard to the market, for the *IESO control area* and the *intertie zones,* an average *HOEP* for the *energy market* and the hourly average of the *operating reserve* prices for the applicable *dispatch intervals* for the *operating reserve markets*, determined from the corresponding hour or hours from each of the 4 most recent *business days* or non-*business days*, as the case may be, excluding those hours from any day in which *administrative pricing* has been established under this section, and there shall be no congestion management *settlement* credit payments made under section 3.5.2 of Chapter 9 for the period of *market suspension*. Prices for the excluded hours shall be replaced by prices that have not been administered under this section from the corresponding hours of the most recent earlier *business days* or non-*business days*, as the case may be.

Additional Compensation for Complying with Dispatch Instructions

8.4A.9 Where the *IESO* has established an *administrative price* pursuant to sections 8.4A.6 and 8.4A.8.2 and subject to any materiality limits published in the applicable *market manual*,

8.4A.9.1 a *market participant* with a *generation facility* that has complied with *dispatch instructions* issued by the *IESO* shall be entitled to additional compensation determined under section 8.4A.10;

8.4A.9.2 a *market participant* with a *dispatchable load facility* shall be entitled to additional compensation on those consumption amounts where their *bid* price is less than the *administrative price,* equal to the difference between its applicable *bid* price and the *administrative price* multiplied by those consumption amounts if:

- the *market participant's bid* price, for the level of consumption to which it was dispatched, is less than the *administrative price;*
- the *market participant* has complied with *dispatch instructions* issued by the *IESO*; and
- the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9;

8.4A.9.3 a *market participant* with an *electricity storage facility* that injected *energy* into the *electricity system* shall be entitled to additional compensation on those injection amounts where its *offer* price is greater than the *administrative price*, equal to the difference between its applicable *offer* price and the *administrative price* multiplied by those injection amounts if;

- the *market participant's offer* price, for the level of injection to which it was dispatched, is greater than the *administrative price;*
- for the *dispatch hour,* where both *energy offers* and *bids* are submitted for the same *electricity storage facility*, these *energy*

offers and *bids* were submitted in accordance with section 21.4.2 of this Chapter;

- the market participant has complied with the dispatch instruction for the dispatch interval to which the administrative price applies; and

- the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9; and

8.4A.9.4 a *market participant* with an *electricity storage facility* that withdrew *energy* from the *electricity system* shall be entitled to additional compensation on those withdrawal amounts where its *bid* price is less than the *administrative price*, equal to the difference between its applicable *bid* price and the *administrative price* multiplied by those consumption amounts if:

- the *market participant's bid* price, for the level of withdraws to which it was dispatched, is less than the *administrative price;*

- for the *dispatch hour,* where both *energy offers* and *bids* are submitted for the same *electricity storage facility*, these *energy offers* and *bids* were submitted in accordance with section 21.4.2 of this Chapter;

- the market participant has complied with the dispatch instruction for the dispatch interval to which the administrative price applies; and

- the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9;

and the *IESO* shall recover any such compensation amounts in accordance with section 4.8 of Chapter 9.

8.4A.9A If the *energy market* is suspended and no *bid* prices are available to make the determination in section 8.4A.9.2 that a *bid* price is less than the *administrative price*, a *market participant* with a *dispatchable load facility* shall provide to the *IESO* evidence that its average historical *bid* price is less than the *administrative price*. Average historical *bid* prices shall be determined for each interval from the corresponding interval from each of the four most recent *business days* or non-*business days*, as the case may be, prior to the event that gave rise to the *administrative price*.

8.4A.9B If the *energy market* is suspended and no *offer* prices are available to make the determination in section 8.4A.9.3 that an *offer* price is greater than the *administrative price*, a *market participant* with an *electricity storage facility* shall provide to the *IESO* evidence that its average historical *offer* price is greater than the *administrative price*. Average historical *offer* prices shall be determined for each interval from the corresponding interval from each of the four most recent *business days* or non-*business days*, as the case may be, prior to the event that gave rise to the *administrative price*.

8.4A.9C If the *energy market* is suspended and no *bid* prices are available to make the determination in section 8.4A.9.4 that a *bid* price is less than the *administrative price*, a *market participant* with an *electricity storage facility* shall provide to the *IESO* evidence that its average historical *bid* price is less than the *administrative price*. Average historical *bid* prices shall be determined for each interval from the corresponding interval from each of the four most recent *business days* or non-*business days*, as the case may be, prior to the event that gave rise to the *administrative price*.

Dispatchable Generator, Electricity Storage Facility while Injecting, and Import:

$$\text{Compensation} = (-1) * OP(EMP_h^{\,m,t^*}, AQEI_{k,\,h}^{\,m,t^*}, BE)$$

Where:

t^* = *metering interval* of administrative price period

$EMP_h^{\,m,t^*}$ is the administrative price in the metering interval t^* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

Dispatchable Load, Electricity Storage Facility while Withdrawing and Export:

$$\text{Compensation} = OP(EMP_h^{\,m,t^*}, AQEW_{k,h}^{\,m,t^*}, BL)$$

Where:

t^* = *metering interval* of administrative price period

$EMP_h^{\,m,t^*}$ is the administrative price in the metering interval t^* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

8.4A.10 The compensation referred to in section 8.4A.9.1 shall be calculated as the aggregate of:

8.4A.10.1 the fuel costs or, where applicable, the other costs referred to in section 8.4A.11, and the variable operating and maintenance costs incurred by the *market participant* in complying with the *dispatch instructions* issued by the *IESO,* which fuel costs or other costs and variable operating and maintenance costs shall be subject to verification and audit by the *IESO*; and

8.4A.10.2 subject to section 8.4A.11, an amount equal to 10% of the amount determined pursuant to section 8.4A.10.1,

less the amount of the *administrative price* already paid or payable to the *market participant* under sections 8.4A.6 and 8.4A.8.2.

8.4A.11 Where the compensation referred to in sections 8.4A.9.1 relates to a *generation facility* that is energy limited by design or by bona fide contractual commitments, the *IESO* may accept, in lieu of the costs referred to in section 8.4A.10.1, such assessment of the expected future value or the opportunity costs of the fuel or water consumed:

8.4A.11.1 during the period while *administrative prices* were in effect; and

8.4A.11.2 in order to comply with the *dispatch instruction* issued by the *IESO*;

as the *IESO* considers reasonable. Where such value or costs are submitted in lieu of the costs referred to in section 8.4A.10.1, no amount shall be payable pursuant to section 8.4A.10.2 if, in the *IESO's* opinion, such value or costs include or adequately cover such amount.

Settlement Amount Adjustments Resulting from Administration of Prices Due to Failures or Planned Outages of Market Systems or Due to Publication of Incorrect Prices

8.4A.13 Where the *IESO* has established an *administrative price* pursuant to section 8.4A.5, a *market participant* may, subject to any materiality limits published in the applicable *market manual*, be eligible for an adjustment to its *settlement amounts* if:

8.4A.13.1 that *market participant* has been assessed a negative hourly congestion management *settlement* credit pursuant to section 3.5 of Chapter 9 for any of the applicable *dispatch intervals*;

8.4A.13.2 no *intertie* offer guarantee that would offset that negative hourly congestion management *settlement* credit has been assessed for that *market participant* pursuant to section 3.8A of Chapter 9;

8.4A.13.3 the *market schedule* determined pursuant to section 8.4A.5 is carried forward or backward to another *dispatch hour* that is the *dispatch hour* to which the negative congestion management *settlement* credit referred to in section 8.4A.13.1 applies;

8.4A.13.4 the price and/or quantity values in the *dispatch data* submitted by the *market participant* are different in the *dispatch hour* from which the *market schedule* referred to in section 8.4A.13.3 was established compared to the *dispatch data* submitted by the *market participant* for the *dispatch hour* to which the negative congestion management *settlement* credit referred to in section 8.4A.13.1 applies;

8.4A.13.5 the *market participant* complied with the *dispatch instructions* issued by the *IESO* for the applicable *dispatch intervals*;

8.4A.13.6 the negative hourly congestion management *settlement* credit referred to in section 8.4A.13.1 arose strictly due to the circumstances outlined in section 8.4A.13.3 through 8.4A.13.5; and

8.4A.13.7 the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9 providing evidence that the circumstances outlined in section 8.4A.13.1 through 8.4A.13.6 have occurred.

8.4A.14 If the *market participant*, pursuant to section 8.4A.13, has demonstrated to the satisfaction of the *IESO* that circumstances outlined in section 8.4A.13.1 through 8.4A.13.6 have occurred, the *IESO* shall, in accordance with section 6.6 of Chapter 9, adjust the *market participant's settlement amounts* by an amount to offset the negative hourly congestion management *settlement* credit referred to in section 8.4A.13.1.

8.4A.15 Where the *IESO* has established an *administrative price* pursuant to section 8.4A.5, a *market participant* may, subject to any materiality limits published in the applicable *market manual*, be eligible for additional compensation if:

8.4A.15.1 the *market participant* has been assessed an hourly net *energy market settlement* credit for a *dispatchable facility* or *boundary entity* that represents either an underpayment or overcharge, as the case may be, when comparing the *administrative price* used for determining the hourly net *energy market settlement* credit to the *market participant's* applicable *offer* or *bid* price;

8.4A.15.2 no *intertie* offer guarantee that would offset that underpayment has been assessed for that *market participant* pursuant to section 3.8A of Chapter 9;

8.4A.15.3 no hourly congestion management *settlement* credit that would offset that overcharge or underpayment has been assessed for that *market participant* pursuant to section 3.5 of chapter 9;

8.4A.15.4 the *market schedule* determined pursuant to section 8.4A.5 is carried forward or backward to another *dispatch hour* that is the *dispatch hour* to which the hourly net *energy market settlement* credit referred to in section 8.4A.15.1 applies;

8.4A.15.5 the price and/or quantity values in the *dispatch data* submitted by the *market participant* are different in the *dispatch hour* from which the *market schedule* referred to in section 8.4A.15.4 was established compared to the *dispatch data* submitted by the *market participant* for the *dispatch hour* to which the above hourly net *energy market settlement* credit applies referred to in section 8.4A.15.1;

8.4A.15.6 the *market participant* complied with the *dispatch instructions* issued by the *IESO* for the applicable *dispatch intervals*;

8.4A.15.7 the hourly net *energy market settlement* credit referred to in section 8.4A.15.1 and the resulting overcharge or underpayment arose strictly due to the circumstances outlined in section 8.4A.15.4 through 8.4A.15.6; and

8.4A.15.8 the *market participant* issues to the *IESO* a *notice of disagreement* in accordance with section 6.8 of Chapter 9 providing evidence that the circumstances outlined in section 8.4A.15.1 through 8.4A.15.7 have occurred.

8.4A.16 If the *market participant*, pursuant to section 8.4A.15 has demonstrated to the satisfaction of the *IESO* that circumstances outlined in section 8.4A.15.1 through 8.4A.15.7 have occurred, the *IESO* shall, in accordance with section 6.8 of

Chapter 9, adjust the *market participant's settlement amounts* by the following amount to offset the overcharge or underpayment, referred to in section 8.4A.15.1, as the case may be.

Dispatchable Generator and Import:

Compensation = (-1) * $OP(EMP_h^{m,t^*}, AQEI_{k,h}^{m,t^*}, BE)$

Where:

t^* = *metering interval* of administrative price period

EMP_h^{m,t^*} is the administrative price in the metering interval t* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

Dispatchable Load and Export:

Compensation = $OP(EMP_h^{m,t^*}, AQEW_{k,h}^{m,t^*}, BL)$

Where:

t^* = *metering interval* of administrative price period

EMP_h^{m,t^*} is the administrative price in the metering interval t* of settlement hour h

OP is the profit function as described in Chapter 9, Section 3.5.2

Conditions to Cease the Administration of Prices

8.4A.17 The *IESO* shall cease to apply *administrative prices*:

8.4A.17.1 where section 8.4A.2.1 applies, from the commencement of the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2;

8.4A.17.2 where section 8.4A.2.2 applies due to a failure in software, hardware or communications systems, from the commencement of the first *dispatch interval* after the failure referred to in that section has been rectified;

8.4A.17.3 where section 8.4A.2.2 applies due to a *planned outage* of software, hardware or communications systems, from the commencement of the first *dispatch interval* after the *planned outage* referred to in that section has been completed; and

8.4A.17.4 where section 8.4A.2.3 applies, from the commencement of the first *dispatch interval* after the incorrect inputs referred to in that section have been corrected.

9. IESO Procurement Markets

9.1 Introduction

9.1.1 The *IESO* shall procure, primarily through contracts, certain *physical services* that are needed to maintain *reliable* system operations but that are not offered in the *real-time markets*. The *IESO* may also enter into contracts allowing it to direct the operations of specific *generation facilities, electricity storage facilities* or *load facilities* that are critical to system *reliability* under certain conditions. This section 9 describes such *physical services* and the manner in which the *IESO* shall procure them.

9.2 Definition of Contracted Ancillary Services

9.2.1 Subject to sections 9.4 and 9.5.2, the *IESO* shall procure *contracted ancillary services* through contracts between the *IESO* and *ancillary service providers* that are *registered market participants* who have demonstrated the ability to provide such *contracted ancillary services* from *registered facilities* in accordance with the performance standards and other applicable requirements of section 4 of Chapter 5. *Contracted ancillary services* shall meet all applicable standards set forth in section 4 of Chapter 5 and shall be procured such as to enable the *IESO* to meet its obligations thereunder.

9.2.2 The principal *contracted ancillary services* that the *IESO* will procure pursuant to section 9.2.1 are:

9.2.2.1 *regulation*: this *ancillary service* allows total system generation to match total system load (plus losses) minute-by-minute or even second-by-second as required on an electricity grid;

9.2.2.2 *voltage control* and *reactive support*: this *ancillary service* involves the control and maintenance of prescribed voltages at specific locations, using defined reactive capacity, *energy* and manoeuvrability to support system operations. *Reactive support* is provided by *generation units, electricity storage units* as well as by synchronous condensers, capacitors and other electrostatic equipment that is often owned and operated by *transmitters*; and

9.2.2.3 *black start capability*: this *ancillary service* involves *generation facilities* that are tested and/or assessed for their ability to be a *certified black start facility*, and from which the *IESO* may direct the delivery of power without assistance from the electrical system.

9.2.2.4 [Intentionally left blank – section deleted]

9.2.3 The IESO shall procure each contracted ancillary service:

9.2.3.1 in sufficient quantities and at the appropriate locations to enable the *IESO* to meet its obligations under Chapter 5 to ensure *reliable* operation of the *electricity system*, in accordance with all applicable *reliability standards*; and

9.2.3.2 using, to the extent practicable, competitive processes appropriate to the specific technical and market characteristics of each *contracted ancillary service*, to acquire each *contracted ancillary service* at competitively determined prices.

9.3 Contracted Ancillary Service Contracts

9.3.1 The *IESO* shall enter into *contracted ancillary service* contracts with *ancillary service providers*. Such agreements shall, subject to sections 9.3.4 and 9.3.6:

9.3.1.1 [Intentionally left blank – section deleted]

9.3.1.2 compensate any *ancillary service provider* for levels of service above those required to be provided by the *connection* requirements of Chapter 4.

9.3.2 Subject to section 9.3.6, the *IESO* shall use one or a combination of the following processes to conclude *contracted ancillary service* contracts with *ancillary service providers*:

9.3.2.1 where practical, the *IESO* shall employ a competitive tendering or negotiation process to identify multiple potential *ancillary service providers* and to determine competitive prices and other terms for the *contracted ancillary service* contracts; or

9.3.2.2 the *IESO* may negotiate *contracted ancillary service* contracts with a single potential *ancillary service provider* where the *IESO* determines that this will result in reasonable prices and other terms.

9.3.3 [Intentionally left blank]

9.3.3.1 [Intentionally left blank]

9.3.3.2 [Intentionally left blank]

9.3.3.3 [Intentionally left blank]

9.3.4 The provisions of sections 9.3.1 and 9.5.1 shall be subject to any contrary provisions contained in:

9.3.4.1 any *licence*; or

9.3.4.2 the terms of any *contracted ancillary service* contract the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*.

9.3.5 Each person that:

9.3.5.1 has entered into a *contracted ancillary service* contract with the *IESO*; and

9.3.5.2 is not, at any time during the term of such *contracted ancillary service* contract, the r*egistered market participant* for that *facility*,

shall ensure that the *registered market participant* for that *facility* complies with the provisions of the *contracted ancillary service* contract.

9.3.6 Where the *IESO* and the *ancillary service provider* are unable to reach agreement upon the terms and condition of a proposed *ancillary service* contract, or an amendment to an *ancillary service* contract, the matter shall be determined by the *Ontario Energy Board*.

9.4 The Effect of Grid Connection Requirements

9.4.1 The *IESO* may at any time direct a *registered facility* to provide the level of any *ancillary service* that the *registered facility* is required to provide as a condition of any *licence* or as a result of any *connection* requirements provided for in Chapter 4.

9.4.2 Subject to section 9.4.4, a *registered facility* shall not be entitled to compensation from the *IESO* for any *ancillary service* that must be provided pursuant to the *connection* requirements provided for in Chapter 4 unless and until the *IESO* develops a market for such *ancillary service* that pays all providers of the *ancillary service* and/or that requires any *registered facility* to pay for the failure to supply up to some standard that may be less than that attributable to the *connection* requirement.

9.4.3 If the *IESO* directs a *registered facility* to provide a level of any *ancillary service* above the levels required by the *licence* applicable to that *registered facility* or any connection requirements provided for in Chapter 4 and the *registered facility* is not otherwise subject to a *contracted ancillary service* contract with the *IESO*, the *IESO* shall compensate the *registered facility* for any costs, including lost opportunity costs, incurred by the *registered facility* in complying with the *IESO*'s direction.

9.4.4 If the *IESO* directs a *registered facility* to provide *reactive support* within the range required by the *connection* requirements provided for in Chapter 4, the *IESO* shall only be required to compensate the *registered facility* to the extent that the *registered facility* incurs additional costs, provided that such additional costs are demonstrated to the satisfaction of the *IESO* to have been incurred in order to comply with the *IESO's* direction.

9.4.5 If the *IESO* directs a *registered facility* to provide *reactive support* within the range required by the *connection* requirements provided for in Chapter 4 or as stipulated in the applicable *contracted ancillary service* contract, and that *registered facility* has to reduce its active power output in order to comply with the *IESO*'s direction, that *registered facility* shall not be entitled to a congestion management *settlement* credit for that reduction in active power output.

9.5 Payment for Ancillary Services and Recovery of Costs

9.5.1 Subject to sections 9.3.4 and 9.3.6, the price payable by the *IESO* under a *contracted ancillary service* contract may cover any of the following:

9.5.1.1 the cost of being available to provide a *contracted ancillary service* if instructed by the *IESO* to do so;

9.5.1.2 the out-of-pocket costs and the opportunity costs of actually providing the *contracted ancillary service* when instructed by the *IESO* to do so; and

9.5.1.3 such other compensation as the *IESO* determines to be fair and reasonable under the circumstances.

9.5.2 The *IESO* is authorised, when necessary to maintain system *reliability* or when the *IESO-controlled grid* is in an *emergency operating state* to direct a *registered facility* to provide any class of *contracted ancillary services* even though the *IESO* does not have a *contracted ancillary service* contract with that *registered facility*. When this occurs:

9.5.2.1 the *IESO* shall compensate the *registered facility* for any costs, including opportunity costs, it incurs in complying with the *IESO's* direction; and

9.5.2.2 any dispute about the compensation payable pursuant to section 9.5.2.1 shall be resolved using the dispute resolution process set forth in section 2 of Chapter 3.

9.5.3 The *IESO* shall, in accordance with section 4.2 of Chapter 9, recover from *market participants* any costs it incurs in procuring *ancillary services*.

9.6 Definition and Principles of Must-Run Contracts

9.6.1 The *IESO* may, under the conditions and in accordance with the processes specified in this section 9.6, enter into a *reliability must-run contract* with the *registered market participant* or the prospective *registered market participant* for a *reliability must-run resource.* Where the *IESO* and a *registered market participant* or prospective *registered market participant* enter into a *reliability must-run contract* with respect to a given *reliability must-run resource*, the *IESO* may direct that *reliability must-run resource* to operate in specific ways when instructed by the *IESO* to do so for reasons of *reliability*, other than for reasons of a lack of overall *adequacy* of the *IESO-controlled grid*, regardless of whether *dispatch data* has been submitted with respect to that *reliability must-run resource*. Nothing in this section shall be construed as preventing the *IESO* from taking such other action in respect of such *reliability must-run resource* as may be permitted by these *market rules* to address a concern for overall *adequacy.*

9.6.2 Subject to section 9.6.4, the *IESO* may enter into a *reliability must-run contract* based on studies performed by the *IESO* that indicate:

9.6.2.1 in accordance with section 9.6.3, that a *reliability must-run resource* is required to be available for the purposes of *reliability*, other than in situations of overall *adequacy* of the *IESO-controlled grid*; or

9.6.2.2 a *reliability must-run resource* is likely to be *dispatched* as a *constrained on facility* or a *constrained off facility* and that such a contract would avail to the mutual benefit of the parties.

9.6.3 The studies referred to in section 9.6.2.1 shall include a consideration of whether concerns regarding *reliability*, other than regarding a lack of overall *adequacy* of the *IESO-controlled grid*, can be addressed by means of the process for directing the submission of *dispatch data* or for imposing a restriction on the revision of *dispatch data* referred to in sections 3.3.10 to 3.3.17 or of the process by which the *IESO* approves *outages* pursuant to section 6 of Chapter 5.

9.6.4 The IESO shall enter into a reliability must-run contract pursuant to section 9.6.2.2 in respect of a reliability must-run resource only where the registered market participant or the prospective registered market participant for the reliability must-run resource so agrees.

9.6.5 Where:

9.6.5.1 the *IESO* would be required to reject, revoke *advance approval* of, or recall the *planned outage* of a *registered facility* pursuant to section 6 of Chapter 5 but for the availability of a *reliability must-run resource*; and

9.6.5.2 the *reliability must-run resource* referred to in section 9.6.5.1 has planned a temporary reduction in staff that would restrict or prevent operation of that other *registered facility,*

the *IESO* may enter into a *reliability must-run contract* in respect of the *reliability must-run resource* referred to in section 9.6.5.1 provided that:

9.6.5.3 staffing adequate to permit that *reliability must-run resource* to operate under the *reliability must-run contract* can be arranged by that *reliability must-run resource* within the time required; and

9.6.5.4 the conclusion of the *reliability must-run contract* referred to in section 9.6.5.3 would avoid the need for the *IESO* to reject, revoke *advance approval* of, or recall the *planned outage* referred to in section 9.6.5.1.

9.6.6 The *IESO* may call upon a *reliability must-run resource* that is subject to a *reliability must-run contract* if and only if the *IESO* determines that *market participants* will not offer sufficient *physical services* into the *real-time markets* to enable the *IESO* to maintain *reliability*, other than in respect of a lack of overall *adequacy* of the *IESO-controlled grid*.

9.6.7 Subject to section 9.6.13, the *IESO* shall use one or a combination of the following processes to conclude *reliability must-run contracts* pursuant to section 9.6.2:

9.6.7.1 where practical, the *IESO* shall employ a competitive tendering or negotiation process to identify multiple potential suppliers and to determine competitive prices and other terms for the *reliability must-run contract*; or

9.6.7.2 the *IESO* may negotiate *reliability must-run contracts* with a single potential supplier where the *IESO* determines that this will result in reasonable prices and other terms.

9.6.8 Subject to sections 9.6.11 and 9.6.13:

9.6.8.1 the *IESO* may develop standard forms of *reliability must-run contracts* for use in conjunction with sections 9.6 and 9.7,

provided that

9.6.8.2 a standard form *reliability must-run contract* developed for use in conjunction with a *reliability must-run resource* that has planned a temporary reduction in staff that would restrict or prevent its operation, including but not limited to the circumstances described in section 9.6.5, shall provide compensation only for the out-of-pocket costs including, but not limited to, the costs of providing adequate staffing, incurred solely to permit the *reliability must-run resource* to be prepared to provide *physical services* if *dispatched* to do so, but no such compensation shall be payable in respect of *dispatch intervals* when the *reliability must-run resource* is *dispatched* to provide such *physical services* and is entitled to payment therefore as a result of such dispatch.

9.6.9 Subject to sections 9.6.11 and 9.6.13, the *IESO* may include in any *reliability must-run contract,* other than a standard form *reliability must-run contract* referred to in section 9.6.8.2, the compensation provisions referred to in section 9.6.8.2 or such other compensation provisions as the *IESO* determines appropriate.

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9.6.11 The provisions of sections 9.6.8, 9.6.9 and 9.7.1 shall be subject to any contrary provisions contained in:

9.6.11.1 any *licence*; or

9.6.11.2 the terms of any *reliability must-run contract* the terms of which are required by a *licence* to be, and have been, approved by the *Ontario Energy Board*.

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9.6.13 Where the *IESO* and the *registered market participant* or prospective *registered market participant* are unable to reach agreement upon the terms and condition of a *proposed reliability must-run contract*, or an amendment to a *reliability must-run contract*, the matter shall be determined by the *Ontario Energy Board*.

9.7 Terms and Conditions of Must-Run Contracts

9.7.1 Subject to sections 9.6.11 and 9.6.13, the *IESO* shall include in each *reliability must-run contract* terms and conditions that address, at a minimum, the following:

9.7.1.1 the duration of the *reliability must-run contract*, which shall not exceed 1 year;

9.7.1.2 the situations in which the *reliability must-run resources* may be called;

9.7.1.3 the situations under which some or all of the terms of the *reliability must-run contract* may be suspended;

9.7.1.4 the nature and timing of any advance notice required for the *IESO* to call upon the *reliability must-run resources*;

9.7.1.5 payment terms, including the amount and timing of any availability payment;

9.7.1.6 agreed *dispatch data* that the *IESO* shall use to *dispatch* the *reliability must-run resource* when it is called by the *IESO* to operate in various modes under the *reliability must-run contract*, and provisions for the revision of such *dispatch data*, when necessary;

9.7.1.7 the process for amending the terms of the *reliability must-run contract*; and

9.7.1.8 any penalties payable by either party for failure to satisfy its obligations under the *reliability must-run contract*.

9.7.2 The *IESO* shall, in accordance with section 4.2 of Chapter 9, recover through charges on *market participants* the incremental costs of its *reliability must-run contracts* above any normal payments for *energy* and *operating reserves* recovered in the *real-time markets.*

9.8 Publication of Procurement Contract Information

9.8.1 The *IESO* shall treat information relating to the procurement of *contracted ancillary services* and *reliability must-run contracts* as follows:

9.8.1.1 the *IESO* shall *publish* annually the total costs of all contracted *ancillary services* subject to contracted *ancillary service* contracts and of all *reliability must-run contracts*;

9.8.1.2 the *IESO* shall *publish* annually the quantities of each *contracted ancillary service* covered under *contracted ancillary service* contracts and the quantities of each *physical service* provided under *reliability must-run contracts*, together with estimates of any additional quantities the *IESO* expects to acquire during the next 12 months;

9.8.1.3 where the *IESO* obtains *contracted ancillary services* or *reliability must-run contracts* in the absence of market power, the commercial terms of the *contracted ancillary service* contracts and of the *reliability must-run contracts* shall be treated as *confidential information*; and

9.8.1.4 where the *IESO* obtains *contracted ancillary services* or *reliability must-run contracts* in the presence of market power, as confirmed by the *market surveillance panel*, the *IESO* shall *publish* the relevant terms and conditions of the contracts, except for price which shall not be disclosed, in order to encourage competition.

9.9 Dispute Resolution

9.9.1 Subject to the *licence* of the *IESO* and of the relevant *market participant*, all disputes arising pursuant to a *contracted ancillary services* contract or a *reliability must-run contract* shall be resolved using the dispute resolution process set forth in section 2 of Chapter 3.

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11. Generator and Electricity Storage Participant Synchronization Procedures

11.1 Introduction

11.1.1 No generator or electricity storage participant:

11.1.1.1 may physically *connect* and synchronize to the *IESO-controlled grid* or de-synchronize and *disconnect* from the *IESO-controlled grid*; or

11.1.1.2 if an *embedded generator* or *embedded electricity storage participant* may physically *connect* and synchronize to the embedding *facility* or de-synchronize and *disconnect* from the embedding *facility*,

except as provided in Chapter 4 and in this section 11.

11.1.2 All *generation facilities* located within the *IESO control area* are subject to the provisions of this section 11 except for *self-scheduling generation facilities* with name-plate ratings of less than 10 MW, *intermittent generators*, any *generators* classified as *minor generation facilities* or as *small generation facilities, generation facilities* that, for the purposes of the application of the provisions of this section 11, have been designated by the *IESO* as not impairing the ability of the *IESO* to maintain the *security* or adequacy of the electricity system, and any *generators* exempt from the provisions of the Electricity Act, 1998 by regulation made thereunder.

11.1.3 [Intentionally left blank]

11.1.4 All *electricity storage facilities* located within the *IESO control area* are subject to the provisions of this section 11 except for *self-scheduling electricity storage facilities* with an *electricity storage facility* size of less than 10 MW, any *electricity storage facilities* classified as *minor electricity storage facilities* or as *small electricity storage facilities*, *electricity storage facilities* that, for the purposes of the application of the provisions of this section 11, have been designated by the *IESO* as not impairing the ability of the *IESO* to maintain the *security* or adequacy of the electricity system.

11.2 Process for Synchronization

11.2.1 A *generator* or *electricity storage participant* that intends to synchronize a *generation unit* or *electricity storage unit* to the *IESO-controlled grid* or embedding *facility*, as the case may be, must notify the *IESO* at least two hours in advance of the intended synchronization time unless an under-generation advisory notice is in force, in which case the *IESO* may reduce the required notification time to that specified in the advisory notice.

11.2.2 If a *generator* or *electricity storage participant* does not advise the *IESO* at least two hours in advance of synchronization, or any shorter interval allowed by an under-generation advisory notice, the *IESO* may approve synchronization only if, in the *IESO*'s judgement, synchronization will not impair the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

11.2.3 The *IESO* shall notify the *generator* or *electricity storage participant* of the *IESO*'s acceptance or rejection of the *generation unit's* or *electricity storage unit's* synchronization plans within 5 minutes of receiving such plans. In the event that the *IESO* does not approve synchronization, the *registered market participant* responsible for the *registered facility,* of which the *generation unit* or *electricity storage unit* is a part, must revise its *dispatch data* in accordance with section 3.

11.2.4 Receipt by the *generator* or *electricity storage participant* of notification of acceptance by the *IESO* under section 11.2.3 gives the *generator* or *electricity storage participant* the right to synchronize the *generation unit* or *electricity storage unit* to the *IESO-controlled grid* or the embedding *facility*, as the case may be. This right does not preclude the *IESO* from requiring de-synchronization of a *generation unit* or *electricity storage unit* in the event of over-generation in accordance with any applicable provisions of these *market rules* relating to over-generation.

11.2.5 The exact time of synchronization shall be subject to directions from the *IESO* and to the terms and conditions specified in the *generator's* or *electricity storage participant's connection agreement* or, in the case of an *embedded generation unit* or *embedded electricity storage unit* its connection agreement, in such form as may be prescribed by the *OEB*, with the *distributor* with whom it is *connected.*

11.2.6 Each *generator* or *electricity storage participant* shall notify the *IESO* of any revisions to its synchronization plans without delay. Upon receipt of such notice, the *IESO* shall re-assess any prior acceptance of a synchronization plan and shall notify the *generator* or *electricity storage participant* accordingly.

11.3 Process for De-synchronization

11.3.1 A *generator* or *electricity storage participant* intending to de-synchronize a *generation unit* or *electricity storage unit* from the *IESO-controlled grid* or embedding *facility*, as the case may be shall notify the *IESO* one hour in advance of the intended de-synchronization time, unless an advisory notice for over-generation is in effect, in which event the *generation unit* or *electricity storage unit* may de-synchronize at will subject to the conditions of the advisory notice.

11.3.2 If a *generator* or *electricity storage participant* does not advise the *IESO* at least one hour prior to its planned de-synchronization, or any shorter interval allowed by an over-generation advisory notice, the *IESO* may approve de-synchronization only if, in the *IESO*'s judgement, the unit's de-synchronization will not impair the ability of the *IESO* to maintain the *security* or *adequacy* of the *electricity system*.

11.3.3 The *IESO* shall approve any request to de-synchronize unless:

11.3.3.1 the *generation unit* or *electricity storage unit* is operating under the provisions of a *reliability must-run contract* and the *IESO* has directed it to operate;

11.3.3.2 the *IESO* requires the *generation unit* or *electricity storage unit* to remain synchronized to maintain the *security* or *adequacy* of the *electricity system*; or

11.3.3.3 an under-generation advisory notice is in force.

11.3.4 The *IESO* shall notify the *generator* or *electricity storage participant* of the *IESO*'s acceptance or rejection of the *generation unit's or electricity storage unit's* de-synchronization plans within 5 minutes of receiving such plans.

11.3.5 The exact time of de-synchronization shall be subject to directions from the *IESO* and to the terms and conditions specified in the *generator's* or *electricity storage participant's connection agreement* or, in the case of an *embedded generation unit*, or *embedded electricity storage unit* its connection agreement, in such form as may be prescribed by the *OEB*, with the *distributor* with whom it is *connected.*

11.3.6 Receipt by the *generator* or *electricity storage participant* of notification of acceptance by the *IESO* under section 11.3.4 gives the *generator* or *electricity storage participant* the right to commence shut-down of the *generation unit* or *electricity storage unit*.

11.3.7 Each *generator* or *electricity storage participant* shall notify the *IESO* of any revisions to its de-synchronization plans without delay. Upon receipt of such notice, the *IESO* shall re-assess any prior acceptance of a de-synchronization plan and shall notify the *generator* or *electricity storage participant* accordingly.

12. Status Reports, Advisories, and Protocols

12.1 IESO System Status Reports and Advisory Notices

12.1.1 The *IESO* shall *publish*, in addition to the daily assessments specified in section 7.3.1.4 of Chapter 5, system status reports to:

12.1.1.1 to 12.1.1.5 [Intentionally left blank – sections deleted]

12.1.1.6 provide forecasts, with respect to each *dispatch day*, as projected for future *dispatch hours* and as estimated for the current *dispatch hour*, where appropriate, of expected hourly *demand*, *generation capacity*, *electricity storage capacity*, *energy* capability of *generation facilities*, exports and imports of *energy*, and *operating reserve* requirements, *published* at the following times:

12.1.1.6.1 05:30 EST of the *pre-dispatch day*;

12.1.1.6.2 09:00 EST of the *pre-dispatch day*;

12.1.1.6.3 after each successful run of the day-ahead commitment process, of the *pre-dispatch day*;

12.1.1.6.4 after 15:00 EST, and hourly thereafter, of the *pre-dispatch day*; and

12.1.1.6.5 hourly on the *dispatch day;*

12.1.1.7 provide forecasts of expected transmission capacity with all elements in-service, *published* daily, as soon as practicable; and

12.1.1.8 provide forecasts of expected transmission limits with *outages*, for the *dispatch day* and the two days following the *dispatch day*, *published* hourly on the *dispatch day.*

12.1.2 Where the *IESO publishes* an advisory notice, it shall do so in one of the following forms, in accordance with the applicable *market manual*:

12.1.2.1 an alert notice, which shall provide situational awareness and provide time for advanced preparations;

12.1.2.2 a warning notice, which shall indicate the actions the *IESO* intends to take if the *IESO-administered markets* do not or cannot respond sufficiently to eliminate an identified or potential problem; or

12.1.2.3 an action notice, which shall indicate the actions the *IESO* and *market participants* must take in order to eliminate an identified or potential problem.

12.1.3 The *IESO* shall *publish*, in accordance with the applicable *market manual*, advisory notices for the following reasons:

12.1.3.1 if a major change in expected *generation capacity, electricity storage capacity* or *transmission capacity* has occurred since the last system status report was issued;

12.1.3.2 if the *IESO* expects over-generation, under-generation or shortfalls in *operating reserve* or *contracted ancillary services*, or an advisory of the total MW of *energy* being directed to submit *bids* or *offers* from the aggregate of *reliability must run resources* under *reliability must run contracts*;

12.1.3.3 if the IESO expects an emergency operating state, a high-risk operating state, or a conservative operating state; and

12.1.3.4 if the *IESO* is suspending or resuming operation of all or part of the *IESO-administered markets;*

12.1.3A The *IESO* may *publish* advisory notices in addition to those in 12.1.3, in accordance with the applicable *market manual*, for any additional reason identified by the *IESO* in which the *IESO* believes that the *publication* of an advisory notice would be in the interest of the *IESO-administered markets, market participants,* or the *IESO-controlled grid.*

12.1.4 Where applicable, the corresponding information related to the advisory notices in section 12.1.3 shall be included by the *IESO* in a subsequent *publication* of a scheduled report under section 12.1.1.

12.1.5 The reports referred to in section 12.1.1 and 12.1.3 shall be prepared by the *IESO* in such form and shall contain such information as may be specified in the applicable *market manual*.

12.2 Over-Generation and Under-Generation Advisories

12.2.1 If the *IESO* issues an over-generation advisory notice pursuant to section 12.1.3, the *IESO* shall, unless the *IESO* determines that it is not able to do so for operational or system *security* reasons, and notwithstanding any notification requirements or other conditions specified elsewhere in these *market rules*:

12.2.1.1 solicit and accept additional or revised *bids* from *dispatchable loads* or *electricity storage facilities* willing to increase demand in response to low prices;

12.2.1.2 allow *generators* or *electricity storage facilities* to de-synchronize from the *IESO-controlled grid* or the embedding *facility*, as the case may be, without penalty, some or all of the *generation units* or *electricity storage units* within any *registered facility* in locations designated by the *IESO;* and/or

12.2.1.3 solicit and accept revised *offers* from *generators, electricity storage participants* or *wholesale sellers* that will decrease generation resources in response to low prices, in locations designated by the *IESO*.

12.2.2 If the *IESO* issues an under-generation advisory notice pursuant to section 12.1.3, the *IESO* shall, unless the *IESO* determines that it is not able to do so for operational or system security reasons, and notwithstanding any notification requirements or other conditions specified elsewhere in these *market rules*:

12.2.2.1 solicit and accept additional or revised *bids* from *dispatchable loads* and *electricity storage facilities* that will reduce load in response to higher prices;

12.2.2.2 allow *generators* or *electricity storage facilities* to synchronize to the *IESO-controlled grid* or the embedding *facility*, as the case may be, without penalty, some or all of the *generation units* or *electricity storage units* within any *registered facility* in locations designated by the *IESO*; and/or

12.2.2.3 solicit and accept additional or revised *offers* from *generators, electricity storage participants* or *wholesale sellers* that will increase generation resources or injections of *energy* in response to higher prices, in locations designated by the *IESO*.

12.2.3 If the *IESO* issues an *operating reserve* shortfall advisory notice pursuant to section 12.1.3, the *IESO* shall, within the period specified in the advisory notice, accept additional or revised *offers* for *operating reserve*.

13. Suspension of Market Operations

13.1 Introduction

13.1.1 The *IESO* may, or may be required to, suspend the operation of all or part of the *IESO-administered markets* in accordance with this section 13. For purposes of this section 13, unless otherwise noted the term "*market operations*" shall mean the operation of all or part of the *IESO-administered markets*.

13.1.2 This section 13 sets forth the procedures the *IESO* must follow in:

13.1.2.1 determining whether to declare a suspension of *market operations;*

13.1.2.2 directing the operation of the *IESO-controlled grid* during suspension of *market operations*; and

13.1.2.3 restoring *market operations* once the conditions triggering suspension are eliminated.

13.1.3 This section 13 also sets forth the requirements that *market participants* must meet immediately prior to, during, and immediately after a suspension of *market operations*.

13.2 Market Suspension Events

13.2.1 Subject to section 13.3, the *IESO* may suspend *market operations* if it determines that any of the conditions described in section 13.2.4 exists or is imminent.

13.2.2 As soon as practical the *IESO* shall notify the *IESO Board,* the *OEB* and relevant government authorities of any suspension of *market operations* pursuant to this section 13.

13.2.3 Upon being notified under section 13.2.2, the *IESO Board* may determine whether to continue the suspension or to resume normal *market operations* under such conditions as the *IESO Board* may specify.

13.2.4 The *IESO* may suspend *market operations* in the event of:

13.2.4.1 *market operations* cannot be continued in a normal manner due to a failure in the software, hardware or communication systems that support *market operations*;

13.2.4.2 a major blackout;

13.2.4.2A the *IESO-controlled grid* breaks up into two or more electrical islands;

13.2.4.3 an *emergency* situation requiring the *IESO* to evacuate its principal control centre and move to a backup control centre, under conditions and subject to the requirements of Chapter 5; or

13.2.4.4 a declaration of an emergency by the Premier of Ontario or a direction from the *Minister* to the *IESO* or to a *market participant* to implement an *emergency* preparedness *plan*.

13.3 Insufficient Reasons for Market Suspension

13.3.1 Notwithstanding section 13.2.4, the *IESO* may suspend *market operations* in response to an event described in that section only if the *IESO* determines that its ability to operate the *IESO-administered markets* in accordance with these *market rules* has become substantially impaired.

13.3.2 The *IESO* shall not suspend *market operations* solely because:

13.3.2.1 the *market price* has reached positive or negative *MMCP*; or

13.3.2.2 some load has been *curtailed*.

13.4 IESO Declaration of Market Suspension

13.4.1 Only a declaration by the *IESO* may suspend *market operations*. If the *IESO* declares a suspension of *market operations*, the *IESO* shall:

13.4.1.1 immediately notify *market participants*; and

13.4.1.2 issue to *market participants* a market suspension notice via such means as the *IESO* determines will ensure timely notification, informing *market participants* of the nature and scope of the suspension and its expected duration, if known.

13.4.2 Any suspension of *market operations* shall commence at the start of the next *dispatch* after the *IESO* makes the declaration, unless the *IESO* suspends *market operations* to protect or restore *reliability*, in which case the suspension shall commence at the time the *IESO* makes the declaration.

13.4.3 The *IESO* may not declare a retroactive suspension of *market operations*.

13.5 IESO Responsibilities During Market Suspension

13.5.1 While a suspension of *market operations* is in effect, the *IESO* shall:

13.5.1.1 prescribe and apply procedures for restoring and maintaining *reliable* operation of the *electricity system* and restoring *market operations* as rapidly as practical, consistent with the safety of persons and *facilities*;

13.5.1.2 endeavour to continue use of normal market information, scheduling and pricing procedures to the extent practical;

13.5.1.3 prescribe and apply *administrative prices* in accordance with section 8.4A.8;

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13.5.1.5 provide timely information to *market participants* concerning the reasons for the suspension and efforts by the *IESO* to resume normal *market operations*; and

13.5.1.6 issue directions, through market suspension advisory notices to *market participants*, that will enable the *IESO* to continue *reliable* operations, continue non-suspended *market operations* and resume normal *market operations* as soon as practical.

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13.6 Participant Responsibilities and Compensation

13.6.1 If the *IESO* suspends market operations, each *market participant* shall:

13.6.1.1 comply with the *IESO's* market suspension advisory notices and any other directions issued by the *IESO*;

13.6.1.2 conduct their operations and interactions with the *IESO* in a manner consistent with such advisory notices and directions; and

13.6.1.3 upon resumption of normal *market operations*, resume normal operations and interactions with the *IESO* pursuant to these *market rules*.

13.6.2 The *IESO* may issue *dispatch instructions* while a suspension of *market operations* is in effect and shall compensate *market participants* for following these *dispatch instructions* based on *administrative prices* established in accordance with section 8.4A.8 rather than on market-determined prices.

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13.7 Ending and Reporting on Market Suspension

13.7.1 The *IESO* shall monitor the conditions which triggered the suspension of *market operations* and, subject to any decision or direction that the *IESO Board* may have given pursuant to section 13.2.3, shall issue a market advisory notice declaring the end of the suspension:

13.7.1.1 as soon as the *IESO* determines that normal *market operations* are possible and will maintain *reliable* system operations; and

13.7.1.2 indicating the *dispatch hour* for which normal *market operations* are to resume, providing at least one hour advance notice.

The *IESO* may, if circumstances warrant and in order to resume normal *market operations* as soon as possible, issue a market advisory declaring the end of the suspension prior to issuing the notice specified in section 13.2.2.

13.7.2 The *IESO* shall, immediately following the end of the suspension of *market operations*, begin a review of events leading to and occurring during the suspension. The *IESO* may require *market participants* to submit information regarding their operations immediately prior to and during the suspension and to assist the *IESO* in analysing the suspension.

13.7.3 Within 10 *business days* following the resumption of normal *market operations*, the *IESO Board* shall provide to all *market participants,* the *OEB* and relevant government authorities a preliminary report describing:

13.7.3.1 the circumstances that triggered suspension of *market operations*;

13.7.3.2 the steps taken by the *IESO* during the period of suspension to ensure *reliable* operations and remedy the causes of the suspension;

13.7.3.3 the actions of *market participants* during the suspension; and

13.7.3.4 any conclusions or recommendations for avoiding similar suspensions in the future.

13.7.4 The *IESO Board* shall provide a final report containing information in the nature of that described in section 13.7.3 to *market participants* and the public as soon as it is practicable to do so.

13.7.5 If the *IESO Board* determines that one or more corrective measures by *market participants* are warranted to avoid the recurrence of a suspension of *market operations*, the *IESO* may direct the affected *market participants* to implement the corrective measures and the affected *market participants* shall implement the corrective measures as soon as practicable.

13.7.6 A *market participant* directed by the *IESO* to implement corrective measures under section 13.7.5 may apply for compensation from the *IESO* where compliance with the *IESO's* direction results in costs or damages to the *market participant*.

13.7.7 Any disputes regarding the compensation referred to in section 13.7.6 shall be resolved using the dispute resolution process set forth in section 2 of Chapter 3.

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18. Capacity Auctions

18.1 Purpose of Capacity Auctions

18.1.1 The *capacity auctions* will acquire *auction capacity* through a competitive auction.

18.1.2 The *IESO* shall specify and *publish* a target capacity amount to be acquired in each *capacity auction*, as specified in the applicable *market manual.*

18.1A Capacity Auction – Transitional Market Rules

18.1A.1 For the purposes of participation in a *capacity auction, market rules* and *market manuals* that specifically concern *capacity auction* participation, the satisfaction of *capacity obligations,* or the performance of requirements directly related to that participation, shall remain in effect from the date of the *capacity auction* until the end of its associated *commitment period,* except as otherwise provided in sections 18.1A.1.1 and 18.1A.3.

18.1A.1.1 Nothing in this section 18.1A shall limit the effectiveness of a *market rule* amendment or *market manual* amendment that expressively excludes the application of sections 18.1A.1 and 18.1A.2.

18.1A.2 Except as otherwise provide in sections 18.1A.1.1 and 18.1A.3, changes to the *market rules* and applicable *market manuals* that specifically concern *capacity auction* participation, the satisfaction of *capacity obligations*, or the performance of requirements directly related to that participation, and which are brought into effect between the date of a given *capacity auction* and the end of its associated *commitment period*, shall be applicable to subsequent *capacity auctions* and their associated *commitment periods.*

18.1A.3 Nothing in this section 18.1A shall limit the effectiveness of an *urgent rule amendment.*

18.1A.4 The *IESO* shall maintain a *published* archive of *market rules* and applicable *market manuals* in effect on the date of a *capacity auction* for a period of 2 years following the end of its associated *commitment period.*

18.2 Participation in Capacity Auctions

18.2.1 No person may participate in a *capacity auction* nor receive a *capacity obligation* unless that person has:

18.2.1.1 been authorized by the *IESO* as a *capacity auction participant* in accordance with section 3 of Chapter 2 and in accordance with the applicable *market manual*;

18.2.1.2 submitted to the *IESO* a *capacity qualification request*, using forms and procedures as may be established by the *IESO* in the applicable *market manual*; and

18.2.1.3 no less than five *business days* prior to the date on which a *capacity auction* is to be conducted, provided to the *IESO* a *capacity auction deposit,* in one or both of the forms set forth in section 18.4.

18.2.2 The following provisions of the *market rules* shall not apply to a *capacity auction participant* that is authorized by the *IESO* to participate only in a *capacity auction* with an *hourly demand response resource*:

18.2.2.1 Chapters 4, 5, and 6;

18.2.2.2 Chapter 7 other than this section 18; and

18.2.2.3 Chapters 8 and 10.

18.2.3 A *capacity auction participant* who obtains a *capacity obligation* shall apply to become authorized by the *IESO* as a *capacity market participant* in accordance with section 3 of Chapter 2.

18.2A Capacity Auction - Capacity Qualification

18.2A.1 For each *obligation period* in a *capacity auction*, the *IESO* shall determine the *unforced capacity* of each *capacity auction resource* where:

18.2A.1.1 the *unforced capacity* of a *capacity auction eligible generation resource*, a *capacity auction eligible storage resource*, or a *capacity dispatchable load resource* is calculated as:

UCAP = ICAP × availability de-rating factor x *performance adjustment factor*

18.2A.1.2 the *unforced capacity* of a *system-backed capacity auction eligible import resource* is calculated as:

UCAP = ICAP x *performance adjustment factor*

18.2A.1.3 the *unforced capacity* of a *generator-backed import resource* is calculated as:

UCAP = (exU*CAP* + esfICAP × *availability de-rating factor)* x *performance adjustment factor*

Where:

(a) 'exU*CAP'* is the total equivalent capacity (in MW) for all *generator-backed import contributors* that are *generation facilities*, as determined by the applicable *control area operator* and provided to the *IESO* in accordance with the applicable *market manual;*

(b) 'esfICAP' is the total *ICAP* (in MW) of all *generator-backed import contributors* that are *electricity storage facilities,* as provided to the *IESO* in accordance with the applicable *market manual.*

18.2A.1.4 the *unforced capacity* of an *hourly demand response resource* is calculated as:

UCAP = ICAP x *performance adjustment factor*

18.2A.2 No *capacity auction resource* may participate in a *capacity auction*, nor receive a *capacity obligation*, in respect of any *obligation period* in relation to which the *capacity auction resource* has an *unforced capacity* of less than one MW.

18.2A.3 The *IESO s*hall notify each *capacity auction participant* of the *unforced capacity* for each of the *capacity auction participant's capacity auction resources* on the date specified in accordance with section 18.5.4.1A.

18.3 Calculation of Capacity Auction Deposits

18.3.1 Following the determination of *unforced capacity* in accordance with section 18.2A, the *IESO* shall determine for each *capacity auction participant*, a *capacity auction deposit* for a *capacity auction* as specified in the applicable *market manual*.

18.3.2 The *IESO* shall review the *capacity auction deposit* and *capacity auction prudential support* of a *capacity transferee* upon receipt of a request for a *capacity obligation* transfer in accordance with section 18.9.1. As a result of a transfer request, the *IESO* may increase the *capacity auction deposit* or *capacity auction prudential support* of a *capacity transferee* and the *IESO* shall notify the *capacity transferee* of any such increase.

18.3.3 Where the amount of a *capacity auction deposit* provided by a *capacity auction participant* exceeds the amount required by the *IESO*, the *IESO* shall return the excess amount to the *capacity auction participant* within five *business days* of such a request from the *capacity auction participant*. Otherwise, that amount shall be held by the *IESO* and shall form part of that *capacity auction participant's capacity auction deposit* for its participation in a subsequent *capacity auction*.

18.4 Capacity Auction Deposits

18.4.1 A *capacity auction deposit* shall be in one or both of the following forms:

18.4.1.1 an irrevocable commercial letter of credit provided by a bank named in a Schedule to the *Bank Act*, (Canada), S.C. 1991, c. 46; or

18.4.1.2 a cash deposit made with the *IESO* by or on behalf of the *capacity auction participant.*

18.4.2 Where all or part of a *capacity auction deposit* is in the form of a standby letter of credit, the following provisions shall apply:

18.4.2.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 1993 Revision, ICE Publication No. 500 or The International Standby Practices 1998;

18.4.2.2 the *IESO* shall be named as beneficiary in the letter of credit, the letter of credit shall be irrevocable and partial draws on the letter of credit shall not be prohibited;

18.4.2.3 the only condition on the ability of the *IESO* to draw on the letter of credit shall be the delivery of a certificate by an officer of the *IESO* that a specified amount is owing by the *capacity auction participant* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate;

18.4.2.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *capacity auction participant* shall arrange for and deliver additional *capacity auction deposits* if the *capacity auction participant* intends to continue to participate in a *capacity auction*. If such additional *capacity auction deposits* are not received by the *IESO* ten (10) *business days* before the expiry of a letter of credit, the *IESO* shall be entitled as of that time to payment of the full face amount of the letter of credit which amount, once drawn by the *IESO*, shall be treated as a *capacity auction deposit* in the form of cash; and

18.4.2.5 by including a letter of credit as part of a *capacity auction deposit*, the *capacity auction participant* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *capacity auction participant*.

18.4.3 Notwithstanding any other provision of these *market rules*, a person that applies for authorization to participate in the *capacity auction* and that has not applied for authorization to participate, or is not participating, in any other *IESO-administered market* shall not be required to comply with any requirements for authorization other than those set forth in sections 18.2.1.1 to 18.2.1.3.

18.4.4 In the event a *capacity auction participant* has not satisfied the applicable eligibility requirements specified in sections 19.2, 19.3, 19.6, 19.8, 19.9A, or 19.10 of Chapter 7 prior to the start of the applicable *obligation period* and has not elected to buy-out the *capacity obligation* in accordance with section 4.7J.3 of Chapter 9, the *IESO* shall revoke the *capacity obligation* and the *capacity auction participant* shall, at the *IESO's* sole discretion, forfeit its *capacity auction deposit.*

18.5 Capacity Auction Parameters

18.5.1 The *IESO* shall conduct *capacity auctions* at least on an annual basis to acquire *capacity* for a future one-year *commitment period*. In each *capacity auction* the *IESO* shall acquire *auction capacity* for each *obligation period* as specified in the applicable *market manual*.

Demand Curve, Zonal Constraints and Pre-Auction Reports

18.5.2 The *IESO* shall, in accordance with the applicable *market manual*, *publish* a pre-auction report in advance of each *capacity auction*, including the following *capacity auction* demand curve reference points:

18.5.2.1 a *target capacity* in accordance with section 18.1.2;

18.5.2.2 a *capacity auction reference price*;

18.5.2.3 a maximum and minimum *capacity auction clearing price*;

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18.5.2.5 a maximum *auction capacity* limit at the maximum *capacity auction clearing price* that a *capacity auction* shall clear; and

18.5.2.6 a maximum *auction capacity* limit that a *capacity auction* shall clear.

18.5.3 The *IESO* shall define *capacity auction zonal constraints* for each *capacity auction* and the *IESO* shall *publish*, in the pre-auction report, those requirements as specified in the applicable *market manual*.

18.5.4 The *IESO* shall specify and *publish* in the pre-auction report the following timelines associated with a *capacity auction*:

18.5.4.1 the deadline to submit a *capacity qualification request* pursuant to section 18.2.1.2;

18.5.4.1A the date on which the *IESO* shall notify *capacity auction participants* of the *unforced capacity* for each *capacity auction resource*;

18.5.4.2 the deadline for a *capacity auction participant* to submit a *capacity auction deposit* in accordance with section 18.2.1.3;

18.5.4.3 the dates on which a *capacity auction participant* may submit *capacity auction offers* for a *capacity auction*;

18.5.4.4 the period over which the *IESO* shall conduct the *capacity auction*; and

18.5.4.5 the date of *capacity auction* post-auction reporting in accordance with sections 18.8.1 and 18.8.2.

18.5.5 The *IESO* shall define the total *auction capacity* that may be provided by all *system-backed capacity import resources* and *generator-backed capacity import resources* in a *capacity auction* for each *obligation period.* The *IESO* shall *publish*, in the pre-auction report, these requirements as specified in the applicable *market manual*.

18.5.6 The *IESO* shall define the total *auction capacity* that may be provided by all *system-backed capacity import resources* and *generator-backed capacity import resources* on each applicable *intertie* in a *capacity auction* for each *obligation period.* The *IESO* shall *publish*, in the pre-auction report, these requirements as specified in the applicable *market manual.*

18.6 Capacity Auction Offers

18.6.1 A capacity auction offer:

18.6.1.1 may be submitted or revised by the *capacity auction participant* on the dates specified in accordance with section 18.5.4 and the applicable *market manual*;

18.6.1.2 shall only be applicable to the *obligation periods* for which a *capacity auction participant* has submitted a *capacity auction offer*, in accordance with the applicable *market manual*; and

18.6.1.3 shall be time stamped by the *IESO* when received.

18.6.2 A *capacity auction offer* shall only be submitted in respect of a given *capacity auction* if:

18.6.2.1 the *capacity auction participant* complies with the *capacity auction participant* requirements in section 18.2.1; and

18.6.2.2 the *capacity auction participant* has not been disqualified from full or partial participation in the *capacity auction* pursuant to sections 19.4.8, 19.5.4, 19.7.4, 19.9.4 or 19.11.4.

18.6.3 A *capacity auction offer* may include up to twenty *price-quantity* pairs for each *obligation period* and shall comply with the following:

18.6.3.1 the *capacity auction offer* shall be for and applicable over an entire *obligation period* associated with a *capacity auction*;

18.6.3.2 the capacity auction offer price in any price-quantity pair shall:

- be expressed in dollars and whole cents per MW-day of *auction capacity* to be provided in each hour of the *availability window* throughout the *obligation period* associated with that *capacity auction*;

- be greater than or equal to $0.00/MW-day;

- not exceed the applicable maximum *capacity auction clearing price;* and

- increase as the associated *capacity auction offer* quantity increases.

18.6.3.3 the *capacity auction offer* quantity in any *price-quantity pair* shall be expressed in MW to not more than one decimal place and the total offered quantity shall not exceed the *unforced capacity* of the *capacity auction resource*; and

18.6.3.4 the *capacity auction offer* shall indicate whether the *capacity auction participant* is willing to clear a *capacity auction* with the full amount of *auction capacity* offered in a lamination or a partial amount of the *auction capacity* offered in a lamination, in accordance with the applicable *market manual*.

18.7 Capacity Auction Clearing Prices and Quantities

18.7.1 The *IESO* shall determine a *capacity auction* demand curve to be utilized for each *obligation period* based upon the *capacity auction* parameters detailed in the pre-auction report pursuant to section 18.5 and in accordance with the applicable *market manual*.

18.7.2 The *IESO* shall, in each *capacity auction*, determine for each *obligation period* the *capacity auction clearing price* in accordance with the applicable *market manual*.

18.7.3 The *IESO* shall, in each *capacity auction*, determine for each *obligation period* the *capacity obligation* for each *capacity auction participant's capacity auction resource(s)* in accordance with section 18.7.5 and the applicable *market manual*.

18.7.4 The IESO shall, for each *capacity auction*, determine for each *obligation period* associated with the *capacity auction*:

18.7.4.1 the *capacity auction clearing prices* for each electrical zone identified in the pre-auction report; and

18.7.4.2 the zonal capacity obligation for each capacity auction participant's capacity auction resource(s),

18.7.5 If two or more *capacity auction participants* submit a *capacity auction offer* at the same price*,* for the last available quantity, the *capacity auction offer* with the earlier time stamp shall be selected as the successful *capacity auction offer*, in accordance with the applicable *market manual.*

18.8 Post-Auction Notification and Publication

18.8.1 The *IESO* shall, as soon as practicable following the conclusion of a *capacity auction*, *publish* the following in accordance with the applicable *market manual*:

18.8.1.1 the capacity auction clearing price;

18.8.1.2 the amount of *auction capacity* that has been acquired in each electrical zone; and,

18.8.1.3 those capacity auction participants who received a capacity obligation and all respective capacity obligations.

18.8.1.4 [Intentionally left blank – section deleted]

18.8.2 The *IESO* shall, following the conclusion of a *capacity auction*, issue post-auction reports to each *capacity auction participant* by the date specified in accordance with section 18.5.4.5, to detail the *capacity auction offers* that have cleared in the *capacity auction* and the associated *capacity obligations* and *cleared ICAPs* for each *obligation period* in accordance with the applicable *market manual*:

18.8.2.1 the *cleared ICAP* is calculated as:

$$cleared\ ICAP = cleared\ UCAP \times \left(\frac{1}{availability\ de\text{-}rating\ factor}\right) \times \left(\frac{1}{performance\ adjustment\ factor}\right)$$

18.8.2.1.1 For the purposes of calculating a *cleared ICAP* where a *capacity auction resource* is not subject to an *availability de-rating factor* as per section 18.2A.1, an *availability de-rating factor* of 1 shall be applied.

18.9 Capacity Obligation Transfers

18.9.1 A *capacity transferor* may, subject to *IESO* approval and in accordance with the applicable *market manual*, request a transfer of all or a portion of its *capacity obligation* to a *capacity transferee* provided that the following criteria are met:

18.9.1.1 the quantity to be transferred does not exceed the difference between the *capacity transferee's unforced capacity* of a *capacity auction resource* for the applicable *obligation period,* and its existing *capacity obligation* of such *capacity auction resource* for the applicable *obligation period*;

18.9.1.1.1 [Intentionally left blank – section deleted]

18.9.1.2 the *capacity transferor* provides written confirmation to the *IESO* from the *capacity transferee* of its willingness to accept the transfer of a *capacity obligation* from the *capacity transferor*;

18.9.1.3 the *capacity obligation* transfer shall consist of the same attributes (e.g. physical or virtual), as detailed in the applicable *market manual,* as the *capacity transferor's capacity obligation*;

18.9.1.4 the quantity to be transferred is in increments of 0.1MW, and the resulting *capacity obligations* for both the *capacity transferor* and *capacity transferee* following the transfer shall be 0 MW, or greater than or equal to one MW; and

18.9.1.5 [Intentionally left blank – section deleted]

18.9.1.6 [Intentionally left blank – section deleted]

18.9.1.7 [Intentionally left blank – section deleted]

18.9.1.8 *capacity obligation* transfers must not result in the violation of any constraint as defined in the pre-auction report

18.9.1A Where the *capacity obligation* is transferred between electrical zones, the *capacity transferee* shall be settled based upon the *capacity auction clearing price* received by the *capacity transferor* when the *capacity obligation* first cleared the *capacity auction* in accordance with the applicable *market manual*.

18.9.2 For each transfer request that satisfies the criteria in section 18.9.1, the *IESO* shall determine the *capacity transferee's* revised *capacity auction deposit* and/or *capacity prudential support obligation*, as applicable, in accordance with section 18.3.2 and section 5B.3.3 of Chapter 2.

18.9.3 The *capacity transferee* shall provide the *IESO*, within five *business days* of receiving notification from the *IESO* or within such a longer period of time as may be agreed between the *IESO* and the *capacity transferee*, any additional *capacity auction deposit* and/or *capacity prudential support obligation* that may be required as a result of a transfer request.

18.9.4 After the revised *capacity auction deposits* and/or *capacity prudential support obligations* have been satisfied by the *capacity transferee*, the *IESO* shall notify the *capacity transferor* and *capacity transferee* of its approval or rejection, and the *IESO* shall *publish* updated post-auction reports pursuant to section 18.8. If the *IESO* approves the transfer, the *capacity transferor* may request a reassessment of its *capacity auction deposits* and/or *capacity prudential support obligation* to reflect its revised *capacity obligation* and the *IESO* shall remit any excess *capacity auction deposits* and/or *capacity prudential support obligation*.

19. Capacity Market Participants with Capacity Obligations

19.1 Purpose

19.1.1 This section details how a *capacity market participant* must satisfy a *capacity* obligation with a *capacity auction resource*.

19.1.2 Capacity auction resources eligible to satisfy a capacity obligation are:

19.1.2.1 an hourly demand response resource;

19.1.2.2 a capacity dispatchable load resource;

19.1.2.3 a capacity generation resource;

19.1.2.4 a system-backed capacity import resource;

19.1.2.5 a capacity storage resource; or

19.1.2.6 a generator-backed capacity import resource.

19.1.3 [Intentionally left blank – section deleted]

19.2 Eligibility Requirements for Hourly Demand Response Resources

19.2.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with an *hourly demand response resource* provided that the *capacity market participant*:

19.2.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.2.1.2 registers its *facilities* and *demand response contributors* as applicable, to the satisfaction of the *IESO*, in accordance with the applicable *market manual*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.2.1.3 [Intentionally left blank – section deleted]

19.2.1.4 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.2.2 The *IESO* may refuse the participation of an *hourly demand response resource* in a future *capacity auction* if the resource's participation would negatively impact the *reliable* operation of the *IESO-controlled grid*.

19.2.3 The *IESO* may remove or temporarily remove a *capacity market participant's hourly demand response resource* from its participation as a *capacity market participant* if the resource's continued participation would negatively impact the *reliable* operation of the *IESO-controlled grid.* A *capacity market participant* that is removed pursuant to this section 19.2.3 shall not receive an availability payment in accordance with section 19.4.1 for the duration of the removal.

19.2.4 The following provisions of the *market rules* shall not apply to a *capacity market participant* that is authorized by the *IESO* to participate only with an *hourly demand response resource* and is not a *wholesale consumer* that is a *non-dispatchable load*:

19.2.4.1 Chapter 2, sections 5A and 8;

19.2.4.2 Chapter 5, other than section 1.2.1 to 1.2.3, 2.3, 2.4, 5.8 and 5.9;

19.2.4.3 Chapter 7 section 7; and

19.2.4.4 Chapters 6, 8, 10.

19.2.5 A *wholesale consumer* that is a *non-dispatchable load* may participate as a *demand response contributor* to an *hourly demand response resource* to satisfy a *capacity obligation*, provided that the *non-dispatchable load* meets all the applicable eligibility requirements of this section 19.2, and the requirements in the *market rules* that are applicable to a *wholesale consumer* that is a *non-dispatchable load*.

19.3 Eligibility Requirements for Capacity Dispatchable Load Resources

19.3.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *capacity dispatchable load resource*, provided that the *capacity market participant*:

19.3.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.3.1.2 is authorized as a *wholesale consumer;*

19.3.1.3 registers its *facilities* in accordance with the registration requirements for *wholesale consumers* that are *dispatchable loads*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any resource without first requesting *IESO* authorization and approval in accordance with the applicable *market manual*;

19.3.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the *applicable market manual*;

19.3.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.3.2 [Intentionally left blank – section deleted]

19.3.3 [Intentionally left blank – section deleted]

19.4 Energy Market Participation for Hourly Demand Response Resources

19.4.1 A *capacity market participant* with a *capacity obligation* participating with an *hourly demand response resource* shall receive an availability payment during the *obligation period* in accordance with this section and the applicable *market* *manual.* Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Standby and Activation Notices

19.4.2 If an *hourly demand response resource* has a day-ahead *schedule of record* or a *pre-dispatch schedule* less than the resource's total *bid* quantity, or if the applicable pre-dispatch shadow price for an *hourly demand response resource* is equal to or greater than the standby notice price threshold, determined by the *IESO,* for at least one hour during the *dispatch day availability window*, the *IESO* shall issue a standby notice to the applicable *capacity market participant* by 07:00 EST in accordance with the applicable *market manual*.

19.4.3 If the *IESO* does not issue a standby notice to a *capacity market participant* by 07:00 EST, the *capacity market participant* shall remove their *bids* for the *hourly demand response resource* as soon as practicable and before 9:00 EST. A capacity *market participant* that does not remove their *bids* for the *hourly demand response resource* before 9:00 EST shall comply with any corresponding activation notices issued by the *IESO* in accordance with section 19.4.5.

19.4.4 The *IESO* shall issue an activation notice to a *capacity market participant* ahead of the activation period, in accordance with the applicable *market manual* if a standby notice has been issued in accordance with section 19.4.2 or a *capacity market participant* has not removed their *bids* in accordance with section 19.4.3, and the applicable *hourly demand response resource* has a *pre-dispatch schedule* less than the resource's total *bid* quantity for at least one hour during the *dispatch day availability window*.

19.4.5 If a *capacity market participant* receives an activation notice pursuant to section 19.4.4, the *capacity market participant* shall comply with the activation notice, unless such a reduction would endanger the safety of any person, damage equipment, or violate any *applicable law*. In such circumstances, the *capacity market participant* shall notify the *IESO* as soon as practicable.

19.4.6 A *capacity market participant* may be subject to non-performance charges, and the *IESO* may take action pursuant to sections 19.2.2 and 19.2.3 if a *capacity market participant* does not comply with an activation notice pursuant to this section 19, in accordance with the applicable *market manual*. The *capacity market participant* may also be subject to compliance actions in accordance with section 6 of Chapter 3.

19.4.7 A *capacity market participant* that expects its *hourly demand response resource* to operate in a manner that differs from the activation notice issued to it in accordance with this section 19 shall notify the *IESO* as soon as possible and in accordance with the applicable *market manual*.

19.4.8 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to reduce its consumption in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Non-performance Events for Hourly Demand Response Resources

19.4.9 In the event of a reduction in the *demand response capacity* of an *hourly demand response resource*, associated with a *capacity obligation* acquired through a *capacity auction*, the *capacity market participant* shall notify the *IESO* as per the procedures and criteria specified in the applicable *market manual*.

19.4.9A [Intentionally left blank – section deleted]

19.4.10 A *capacity market participant* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can provide in accordance with section 3.5.6 and due to any non-performance event related to an *hourly demand response resource* in an *obligation period*.

19.4.10A Where a *contributor outage* has occurred and such *contributor outage*:

(a) began not more than 14 days prior to the day on which there is an activation; and

(b) ends within one hour prior to such activation or within the *activation window* of such activation;

then the *capacity market participant* may *notify* the *IESO* within five *business days* of the activation notice, in accordance with the process and requirements described in the applicable *market manual*.

19.4.10B Where the *IESO* receives a valid *contributor outage* notice pursuant to section 19.4.10A, the *IESO* shall adjust the assessment of the *capacity market participant's* performance as set out in the applicable *market manual.*

Capacity Auction Testing for Hourly Demand Response Resources

19.4.11 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* with a *capacity obligation* to perform a *capacity auction dispatch test* for each *hourly demand response resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period.*

19.4.11A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *hourly demand response resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.4.12 If a *capacity market participant* fails during a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.4.11 or 19.4.11A, respectively, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual* and Chapter 9. Failure during a *capacity auction dispatch test* or a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.4.13 The *IESO* shall provide a *capacity market participant* day-ahead notification of a *capacity auction dispatch test* pursuant to section 19.4.11 and the test activation shall occur within the *availability window* of an *obligation period*.

19.4.14 The *capacity auction dispatch test* shall occur in accordance with the *hourly demand response resource* activation process specified in this section 19.4.

19.4.15 The *hourly demand response resource* shall be entitled to compensation for valid *capacity auction dispatch tests* conducted during a *commitment period* pursuant to this section 19.4 and in accordance with the applicable *market manuals*. The *hourly demand response resource* shall not be entitled to compensation for any costs related to any *capacity auction capacity test*.

19.4.16 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines, the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test* or *capacity auction dispatch test*, as the case may be.

19.4.17 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.4.18 Where the notice referred to in section 19.4.17 indicates that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP* and such *capacity market participant* has not filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with section 6.8 of chapter 9, such *capacity market participant's capacity obligation* for such *hourly demand response resource* shall, effective as of one *business day* following the time period referred to in section 6.3.14 of chapter 9, be reduced to the amount of capacity that was determined by the *IESO,* in accordance with the applicable *market manual,* to have been provided by the *capacity market participant* during the *capacity auction capacity test*. If such reduction in the *capacity market participant's capacity obligation* for such *hourly demand response resource* results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such *hourly demand response resource* is forfeited effective as of one *business day* following the time period referred to in section 6.3.14 of chapter 9.

19.4.19 Where the notice referred to in section 19.4.17 indicates that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*, such *capacity market participant* shall be subject to an in-period *cleared UCAP* adjustment charge pursuant to section 4.7J.2.9 of Chapter 9.

19.4.20 After the relevant *capacity market participant* has made payment in full of any *settlement amount* owing pursuant to section 4.7J.2.9 of Chapter 9, in respect of the same *capacity auction capacity test* for which its *capacity obligation* is being reduced pursuant to this section 19.4.16, the *capacity market participant* may request a reassessment of its *capacity prudential support obligation* to reflect its revised *capacity obligation* and the *IESO* shall remit any excess prudential support.

Activation of Hourly Demand Response Resources leading up to or during an Emergency Operating State

19.4.21 A *capacity market participant* satisfying a *capacity obligation* using an *hourly demand response resource* shall be entitled to compensation for an activation leading up to or during an *emergency operating state* pursuant to section 2.3 of Chapter 5, and in accordance with the applicable *market manuals*.

19.5 Energy Market Participation for Capacity Dispatchable Load Resources

19.5.1 A *capacity market participant* with a *capacity obligation* participating with a *capacity dispatchable load resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market* *manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Capacity Dispatchable Load Resources

19.5.2 The *IESO* shall schedule a *capacity dispatchable load resource* in the *real-time market* and issue a *dispatch instruction* in accordance with Chapter 7.

19.5.3 A *capacity dispatchable load resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.5.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to reduce its consumption in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Dispatchable Load Resources

19.5.5 Each *capacity dispatchable load resource* shall comply with the *outage* notification requirements of Chapter 5.

19.5.6 A *capacity dispatchable load resource* shall reduce its *bid* to take into account and reflect the maximum *demand response capacity* that it reasonably expects it can consume in accordance with section 3.5.6.

Capacity Auction Testing for Capacity Dispatchable Load Resources

19.5.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each resource up to a maximum of two *capacity auction dispatch test* per *obligation period.*

19.5.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity dispatchable load resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.5.8 If a *capacity market participant* fails a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.5.7 or 19.5.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.5.9 The *IESO* shall provide a *capacity dispatchable load resource* day-ahead notification of a *capacity auction dispatch test* and the test activation shall occur within the *availability window* of an *obligation period*.

19.5.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* for a *dispatchable load facility* specified in this section 19.5.

19.5.11 The *capacity dispatchable load resource* shall not be entitled to compensation for any costs related to any valid *capacity auction dispatch test* or *capacity auction capacity test* conducted during an *obligation period* pursuant to this section 19.5.

19.5.12 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines, the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.5.13 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.6 Eligibility Requirements for Capacity Generation Resources

19.6.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* as a *capacity generation resource*, provided that the *capacity market participant*:

19.6.1.1 demonstrates to the satisfaction of the IESO that it can provide the *capacity obligation*, as specified in the applicable *market manual;*

19.6.1.2 is authorized as a *generator;*

19.6.1.3 registers its *facilities* in accordance with the registration requirements applicable to *generation facilities*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.6.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the applicable *market manual;*

19.6.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.7 Energy Market Participation for Capacity Generation Resources

19.7.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity generation resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Resources

19.7.2 The *IESO* shall schedule a *capacity generation resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.7.3 A *capacity generation resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.7.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to inject *energy* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Generation Resources

19.7.5 Each *capacity generation resource* shall comply with the *outage* notification requirements of Chapter 5.

19.7.6 A *capacity generation resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject in accordance with section 3.5.6.

Capacity Auction Testing for Capacity Generation Resources

19.7.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *capacity generation resource* up to a maximum of two *capacity auction dispatch tests* per *obligation period.*

19.7.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity generation resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than ten *business days* prior to the first day of the testing window.

19.7.8 If a *capacity market participant* fails a *capacity auction dispatch test* or a *capacity auction capacity test* performed pursuant to section 19.7.7 or 19.7.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual*. Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.7.9 The *IESO* shall provide a *capacity generation resource* that is not a *quick start facility* notification up to one *business day* in advance of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.7.9A The *IESO* shall provide a *capacity generation resource* that is a *quick start facility* notification at least one hour in advance of the dispatch hour of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.7.10 The *capacity auction dispatch test* shall occur in accordance with the *dispatch instructions* specified in this section 19.7

19.7.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.7.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.8 Eligibility Requirements for System-Backed Capacity Import Resources

19.8.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *system-backed capacity import resource* provided that the *capacity market participant*:

19.8.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.8.1.2 is authorized as a *market participant* eligible to import *energy;*

19.8.1.3 is registered as a *boundary entity* pursuant to section 2.2.7; and

19.8.1.4 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.9 Energy Market Participation for System-Backed Capacity Import Resources

19.9.1 A *capacity market participant* satisfying its *capacity obligation* with a *system-backed capacity import resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of System-Backed Capacity Import Resources

19.9.2 The *IESO* shall schedule a *system-backed capacity import resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.9.3 A *system-backed capacity import resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.9.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to schedule *energy* with the appropriate *scheduling entity* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for System-Backed Capacity Import Resources

19.9.5 A *system-backed capacity import resource* shall reduce or remove its *offer* to reflect the maximum capacity that it reasonably expects it can provide in accordance with section 3.5.6.

Capacity Auction Testing for System-Backed Capacity Import Resources

19.9.6 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction capacity test* for each *system-backed capacity import resource,* up to a maximum of two *capacity auction capacity tests* per *obligation period,* to verify that the *cleared ICAP* can be satisfied for a duration specified in the applicable *market manual* by the *system-back capacity import resource.*

19.9.7 If a *capacity market participant* fails a *capacity auction capacity test* performed pursuant to section 19.9.6, the *capacity market participant* shall be subject to non-performance charges in accordance with Chapter 9 and the applicable *market manual.* Failure during a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.9.8 The *IESO* shall provide a *system-backed capacity import resource* notification at least two hours in advance of the dispatch hour of the *capacity auction capacity test* and the *capacity auction capacity test* shall occur within the *availability window* of an *obligation period*.

19.9.9 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.9.

19.9.10 The *IESO* shall assess, in accordance with the applicable *market manual,* the relevant testing and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.9A Eligibility Requirements for Generator-Backed Capacity Import Resources

19.9A.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *generator-backed capacity import resource* provided that the *capacity market participant*:

19.9A.1.1 demonstrates to the satisfaction of the *IESO* that it can provide the *capacity obligation*, as specified in the applicable *market manual*;

19.9A.1.2 is authorized as a *market participant* eligible to import *energy* in association with a *boundary entity; and*

19.9A.1.3 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.9B Energy Market Participation for Generator-Backed Capacity Import Resources

19.9B.1 A *capacity market participant* satisfying its *capacity obligation* with a *generator-backed capacity import resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Generator-Backed Capacity Import Resources

19.9B.2 The *IESO* shall schedule a *generator-backed capacity import resource* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.9B.3 A *generator-backed capacity import resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.9B.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to schedule *energy* with the appropriate scheduling entity in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Generator-Backed Capacity Import Resources

19.9B.5 A *generator-backed capacity import resource* shall reduce or remove its *offer* to reflect the maximum capacity that it reasonably expects it can provide in accordance with section 3.5.6.

19.9B.6 A *generator-backed capacity import resource* shall comply with the *outage* notification requirements specified in the applicable *market manual.*

Capacity Auction Testing for Generator-Backed Capacity Import Resources

19.9B.7 A *capacity market participant* satisfying its *capacity obligation* with a *generator-backed capacity import resource* must perform a *capacity auction capacity test*, per *obligation period*,, in accordance with the applicable *market manual*, by scheduling an *energy* import into the *IESO-administered market* for at least one hour that coincides with the timing of its scheduled four hour activation in the neighbouring *control area*, on a date that falls within the first two months of the applicable *obligation period* and by submitting data to the *IESO* to confirm the capability of the *generator-backed capacity import resource* to inject at least its *cleared ICAP* into the *control area* in which it is located for four consecutive hours within the *availability window.*

19.9B.8 A *capacity market participant* that fails to submit data pursuant to section 19.9B.7 in the form specified by the *IESO,* in a timely manner shall be subject to a capacity obligation administration charge pursuant to section 4.7J.2.3 of Chapter 9.

19.9B.9 If a *capacity market participant* fails a *capacity auction capacity test* performed pursuant to section 19.9B.7, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during a *capacity auction dispatch test* or a *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.9B.10 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.9B.

19.9B.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.9B.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

19.10 Eligibility Requirements for Capacity Storage Resources

19.10.1 A *capacity market participant* is eligible to satisfy its *capacity obligation* with a *capacity storage resource* provided that the *capacity market participant*:

19.10.1.1 demonstrates to the satisfaction of the *IESO* that it can satisfy the *capacity obligation*, as specified in the applicable *market manual.*

Capacity storage resources must satisfy *capacity obligations* with injections of *energy* into the *IESO-controlled grid*;

19.10.1.2 is a registered *market participant* authorized as an *electricity storage participant* in accordance with the applicable *market manual;*

19.10.1.3 registers its *facilities* in accordance with the registration requirements applicable to *electricity storage facilities*. The *capacity market participant* shall not modify, vary or amend in any material respect any of the features or specifications of any *facility* without first requesting *IESO* authorization and approval in accordance with the applicable *market manual;*

19.10.1.4 satisfies the *connection assessment* requirements in accordance with section 6 of Chapter 4, if required by the *IESO* in accordance with the applicable *market manual;*

19.10.1.5 has provided *prudential support* and *capacity prudential support* in accordance with section 5 of Chapter 2.

19.11 Energy Market Participation for Capacity Storage Resources

19.11.1 A *capacity market participant* satisfying its *capacity obligation* with a *capacity storage resource* shall receive an availability payment during the *obligation period*, in accordance with this section and the applicable *market manual*. Availability payments may be offset by non-performance charges in accordance with section 4.7J of Chapter 9.

Dispatch of Capacity Storage Resources

19.11.2 The *IESO* shall schedule a *capacity storage resource* as it would an *electricity storage facility* in the *energy market,* and issue *dispatch instructions* in accordance with Chapter 7.

19.11.3 A *capacity storage resource* shall comply with *IESO dispatch instructions* in accordance with Chapter 7.

19.11.4 The *IESO* may disqualify from future participation in the *capacity auction* any *capacity market participant* that fails to inject *energy* in order to satisfy its *capacity obligation* when called upon in accordance with this section 19.

Outage Notification Requirements for Capacity Storage Resources

19.11.5 Each *capacity storage resource* shall comply with its *outage* notification requirements as outlined in Chapter 5.

19.11.6 A *capacity storage resource* shall reduce its *offer* to reflect the maximum capacity that it reasonably expects it can inject in accordance with section 3.5.6.

Capacity Auction Testing for Capacity Storage Resources

19.11.7 The *IESO* may, in accordance with the applicable *market manual*, direct a *capacity market participant* to perform a *capacity auction dispatch test* for each *capacity storage resource* up to a maximum of two *capacity auction dispatch tests*per *obligation period.*

19.11.7A The *capacity market participant* shall perform a *capacity auction capacity test* once per *obligation period* for each *capacity storage resource*, in accordance with the applicable *market manual*. The *capacity auction capacity test* shall occur within a five *business day* testing window determined by the *IESO*. The *IESO* shall provide notification to a *capacity market participant* of the *capacity auction capacity test* no less than *ten business* days prior to the first day of the testing window.

19.11.8 If a *capacity market participant* fails a test performed pursuant to section 19.11.7 or 19.11.7A, the *capacity market participant* shall be subject to non-performance charges in accordance with the applicable *market manual.* Failure during a *capacity auction dispatch test* or *capacity auction capacity test* shall be considered a breach of the *market rules* and may result in sanctions in accordance with section 6.2 of Chapter 3.

19.11.9 The *IESO* shall provide a *capacity storage resource* notification at least one hour in advance of the dispatch hour of the *capacity auction dispatch test* and the *capacity auction dispatch test* shall occur within the *availability window* of an *obligation period*.

19.11.10 The *capacity auction capacity test* shall occur in accordance with the *dispatch instructions* specified in this section 19.11.

19.11.11 The *capacity market participant* shall submit to the *IESO* all of the testing data and other information in accordance with the requirements and deadlines set out in the applicable *market manual*. If the *capacity market participant* fails to submit the entirety of such testing data and other information within such deadlines the *capacity market participant* is deemed to have delivered zero MWh during the *capacity auction capacity test*.

19.11.12 The *IESO* shall assess, in accordance with the applicable *market manual,* the testing data and other information submitted by the *capacity market participant* and shall provide notice to the *capacity market participant* of the results of the *capacity auction capacity test.*

20. Capacity Exports in the IESO-Administered Market

20.1 Capacity Export Request and IESO Review

20.1.1 A *market participant* that wishes to export eligible capacity shall submit a *capacity export request* to the *IESO,* in the form, within the timelines and as further prescribed in the applicable *market manual*.

20.1.2 The *IESO* shall approve or deny *capacity export requests* based on the *IESO's* review, as prescribed in the applicable *market manual.*

20.1.3 The *IESO* may, after approving or partially approving a *capacity export request* and prior to the *market participant* committing capacity to an external *control area*, revoke an approval of a *capacity export request* in order to maintain the *reliability* of the *IESO-controlled grid*, or if the *IESO* becomes aware of any event or change in circumstances that may alter the *IESO's* approval of a *capacity export request*.

20.2 Capacity Export Commitment Process

20.2.1 A *market participant* may only commit capacity to an external *control area* in accordance with the time periods, quantities and other terms and conditions of the *IESO's* approval of the *capacity export request*.

20.2.2 A *market participant* that commits its capacity to an external *control area* shall notify the *IESO* of the commitment and any subsequent changes to the commitment in the time and manner prescribed in the applicable *market manual*.

20.3 Called Capacity Exports

20.3.1 The *IESO* shall only accept and schedule a *called capacity export* in accordance with section 20.4 when advised by the external *control area operator* that the applicable external *control area* is anticipating or experiencing an *adequacy* shortfall, as may be specified in the applicable *capacity export agreement*.

20.3.2 A *market participant* shall notify the *IESO* concerning the details of a *called capacity export* in the time and manner prescribed in the applicable *market manual*.

20.4 Called Capacity Export Scheduling and Dispatch

20.4.1 All export *bids* for *called capacity exports* shall be submitted in the form and within the timelines prescribed in the applicable *market manual*.

20.4.2 Notwithstanding any provision of the *market rules* that may require the *IESO* to restrict exports in order to maintain the *adequacy* of the *IESO-controlled grid*, the *IESO* may schedule and *dispatch called capacity exports* in accordance with applicable *capacity export agreements* (the relevant details of which are specified in the applicable *market manual*).

21. Electricity Storage in the IESO-Administered Market

21.1 Purpose

21.1.1 This section 21 sets out *market rules* intended to facilitate the near-term inclusion of *electricity storage participants* in the *IESO-administered markets* and the connection of *electricity storage facilities* to the *electricity system*. A number of the provisions of this section would, based on their subject matter, ordinarily be included under different chapters or sections of the *market rules*. However, these provisions have been gathered together here under a single section for convenience of reference and until such time that *electricity storage participants* and *electricity storage facilities* are more fully integrated under these *market rules*.

21.2 Market Registration

21.2.1 This section 21.2 applies for the purposes of the market registration process set out in Section 2.2 of this Chapter 7.

21.2.2 An *electricity storage participant* wishing to register an *electricity storage facility* as a *self-scheduling electricity storage facility*, shall:

21.2.2a register all *electricity storage units* associated with that *electricity storage facility* as *self-scheduling generation units* to inject electricity;

21.2.2b register all electricity storage units associated with that same *electricity storage facility* as *non-dispatchable loads* to withdraw electricity; and

21.2.2c fulfill all other applicable requirements for market registration relating to *self-scheduling generation facilities* and *non-dispatchable loads*, including those requirements set out in Appendix 4.24 of Chapter 4 (IESO Monitoring Requirements: Electricity Storage Facilities) and Appendix 4.25 of Chapter 4 (Monitoring Requirements: Electricity Storage Performance Standards)".

21.2.3 Subject to the *market rules* governing participation in the *energy* markets and the provision of *ancillary services* to the *IESO,* a *self-scheduling electricity storage facility* may only be registered to participate in the *energy market* and to provide *reactive support service*, *voltage control service*, or *regulation* service or combinations of the foregoing, except that it shall not be registered to both participate in the *energy market* and provide *regulation* service.

21.2.4 An *electricity storage participant* wishing to register an *electricity storage facility* as a dispatchable *electricity storage facility*, in addition to the requirements for market registration outlined elsewhere in the *market rules* pertaining to the facility types referenced below, shall:

21.2.4a register all *electricity storage units* associated with that *electricity storage facility* as dispatchable *generation units* to inject electricity;

21.2.4b register all *electricity storage units* associated with the same *electricity storage facility* as *dispatchable loads* to withdraw electricity; and

21.2.4c fulfill all other applicable requirements for market registration relating to dispatchable *generation units* and *dispatchable loads*, including those requirements set out in Appendix 4.24 of Chapter 4 (IESO Monitoring Requirements: Electricity Storage Facilities) and Appendix 4.25 of Chapter 4 (Monitoring Requirements: Electricity Storage Performance Standards).

21.2.5 Subject to the *market rules* governing participation in the *energy* markets and the provision of *ancillary services* to the *IESO,* a dispatchable *electricity storage facility* may only be registered to provide *energy*, *operating reserve, reactive support service* or *voltage control service*, or combinations of the foregoing and may participate in the *capacity auction.*

21.3 Provision of Regulation Service

21.3.1 An e*lectricity storage participant* wishing to provide *regulation* services must register its *electricity storage facility* as a *self-scheduling electricity storage facility* as set forth in section 21.2.2, but excluding section 21.2.2b.

21.3.2 Notwithstanding section 2.2.9A.1, an *electricity storage participant* may apply to register as a *self-scheduling electricity storage facility* any *electricity storage facility* that has an e*lectricity storage capacity* greater than 10 MW up to 50 MW in capacity for the purposes of providing *regulation services* only, provided that the *IESO* determines that there are no adverse impacts on the reliable operation of the *IESO-controlled grid*;

21.3.3 An *electricity storage facility* that is registered to provide *regulation services* may not participate in the *energy* market or the *operating reserve* market.

21.4 Day-Ahead - Energy Offers and Energy Bids

21.4.1 In addition to submitting either an *offer* to inject *energy* or a *bid* to withdraw *energy* as part of the day-ahead commitment process, an *electricity storage participant* may also submit both an *offer* to inject *energy* and a *bid* to withdraw *energy* for a single dispatchable *electricity storage unit* for the same *dispatch hour*.

21.4.2 For each *dispatch hour* in which both *energy offers* and *bids* are submitted in accordance with section 21.4.1, the *electricity storage participant* shall ensure that the lowest price of the *offers* submitted for that *electricity storage unit* to inject *energy* is greater than the highest price of any *bid* for that same *electricity storage unit* to withdraw *energy*.

21.5 Real Time Energy Offers and Energy Bids

21.5.1 Notwithstanding section 3.5.1, an *electricity storage participant* that is registered and wishes to submit *energy offers* or *energy bids* relating to a dispatchable *electricity storage unit* may submit both an *offer* to inject *energy* and a *bid* to withdraw *energy* for that *electricity storage unit* during the same *dispatch hour*.

21.5.2 For each *dispatch hour* in which both *energy offers* and *bids* are submitted in accordance with section 21.4.1, the *electricity storage participant* shall ensure that the lowest price of the *offers* submitted for that *electricity storage unit* to inject *energy* is greater than the highest price of any *bid* for that same *electricity storage unit* to withdraw *energy*.

21.5.3 An *electricity storage provider* whose lowest *offer* price for an *electricity storage unit* to inject *energy* in any *dispatch hour* is less than or equal to its highest *bid* price for the same *electricity storage unit* to withdraw *energy* in that same *dispatch hour* is not entitled to congestion management *settlement* credit determined in accordance with section 3.5.2 of Chapter 9 in respect of that *dispatch hour*, and if paid the *IESO* may recover such inappropriate congestion management *settlement* credit in accordance with section 3.5.6E of Chapter 9

21.6 Revisions to Dispatch Data

21.6.1 Notwithstanding section 3.3.5, the *IESO* shall approve reduced injections or withdrawal amounts included in revised *dispatch data* from *electricity storage participants* submitted within 2 hours of a given *dispatch hour,* up to a closing time stipulated in the applicable *market manual*, where the *electricity storage participant* determines, acting reasonably that its *electricity storage unit* may reach its:

21.6.1a. *lower energy limit* in that *dispatch hour*, and will likely prevent the *electricity storage unit* from injecting *energy* in accordance with its *offer*; or

21.6.1.b *upper energy limit* in that *dispatch hour*, and will likely prevent the *electricity storage unit* from withdrawing *energy* in accordance with its *bid*.

21.7 Operating Reserve

21.7.1 An *electricity storage participant* shall not offer *operating reserve* from a dispatchable *electricity storage facility* in any *dispatch hour* when there is a simultaneous *energy* bid and *energy* offer in the real-time market for that facility in the same dispatch hour.

21.7.2 An electricity storage participant shall only *offer operating reserve* from the *electricity storage unit* registered as a dispatchable *generation unit* to represent its injection capabilities pursuant to Section 21.2.2a if:

21.7.2.1 the dispatchable *electricity storage unit* is exclusively *offered* as a dispatchable *generation unit* for the entire *dispatch hour*;

21.7.2.2 the dispatchable *electricity storage unit* registered as a *dispatchable load* shall not *bid* to withdraw *energy* from the *real-time market* nor *offer operating reserve* in the subsequent *dispatch hour*; and

21.7.2.3 the *remaining duration of service* at the time stipulated in the applicable *market manual* is greater than or equal to the period of time stipulated in the applicable *market manual.*

21.7.3 An *electricity storage participant* shall only offer *operating reserve* from the *electricity storage* unit registered as a *dispatchable load* to represent its withdrawal capabilities pursuant to Section 21.2.2b if:

21.7.3.1 The dispatchable *electricity storage unit* is exclusively bid as a *dispatchable load* for the entire *dispatch hour*;

21.7.3.2 The dispatchable *electricity storage unit* registered as a dispatchable *generator* shall not offer to inject *energy* in the *real-time market* nor offer *operating reserve* in the subsequent *dispatch hour*; and

21.7.3.3 The *remaining duration of service* at the time stipulated in the applicable *market manual* is greater than or equal to a period of time stipulated in the applicable *market manual.*

21.8 Interpretation

21.8.1 To the extent of any conflict or inconsistency between the provisions of this section 21 and any other provisions of the *market rules*, the provisions of this section 21 shall govern.

21.8.2 With respect to Chapter 7, System Operations and Physical Markets-Appendices, the *IESO* will, acting reasonably and consistently at all times with the scope and intent of the amendments referenced in section 21.1:

21.8.2a treat electricity storage injecting, or proposing to inject *energy*, as either a dispatchable or self-scheduling generation resource; and

21.8.2b treat electricity storage withdrawing, or proposing to withdraw *energy*, as either a *dispatchable load* or *non-dispatchable load*, in each case, deeming such changes to be made to the applicable provisions of such Appendices or applicable *market manuals* as may be necessary to give full meaning to the foregoing.

21.8.3 For further certainty, the reference in section 21.7.2a to the use of dispatchable or self-scheduling generation resources in the interpretation of Chapter 7, System Operations and Physical Markets-Appendices and the applicable *market manuals*, shall not include any features or attributes that pertain primarily to and are distinctive of *intermittent generators, flexible nuclear generators, variable generators,* or *transitional scheduling generators*.

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Market Rules

Chapter 7
System Operations and Physical Markets - Appendices

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Appendix 7.1 – Energy Offer, Schedule or Forecast Information

1.1 Within the IESO Control Area

1.1.1 Unique plant identifier (by *generation unit* or *generation units* that have been aggregated with the approval of the *IESO*).

1.1.2 Contact information.

1.1.3 Hour(s) for which *offer*, schedule or forecast applies.

1.1.4 [Intentionally left blank – section deleted]

1.1.5 For a *dispatchable generation facility*, two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*. If the *generator* has specified *forbidden regions*, the submitted *offer price-quantity pairs* must include a quantity equal to each of the lower and upper limits of each *forbidden region*.

1.1.6 For a *dispatchable generation facility*, one to five sets of ramp quantity and ramp up/ramp down values for each *dispatch hour* applicable to the entire range of generator output contained in the *offer*.

1.1.7 Daily *energy* limit (if applicable).

1.1.8 [Intentionally left blank – section deleted]

1.1.9 [Intentionally left blank – section deleted]

1.1.10 Is this a standing *offer*, schedule or forecast? Yes/No. If Yes, Date To: ________ For which day(s) of the week? ____________________

1.2 Offers Outside the IESO Control Area

1.2.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.2.2 Contact information.

1.2.3 Hour(s) for which *offer* applies.

1.2.4 [Intentionally left blank]

1.2.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *offer*.

1.2.6 Daily *energy* limit (if applicable).

1.2.7 [Intentionally left blank]

1.2.8 Is this a standing *offer*? – Yes/No. If Yes, Date To: _____ For which day(s) of the week? __________

1.2.9 Source *control area* (determined by selecting appropriate *boundary entity* resource).

1.2.10 [Intentionally left blank]

1.2.10A *NERC* transaction tag identification.

1.2.11 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.11.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates;

1.2.11.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*; and

1.2.11.3 interchange scheduling defaults specified by the relevant *standards authority* shall be used unless otherwise approved by the *IESO*. Transactions shall be one hour in duration, in accordance with agreements between *control areas* along the path. Transactions shall ramp in/out over the hour and shall respect a ten-minute ramp period.

1.3 [Intentionally left blank – section deleted]

1.3.1 [Intentionally left blank – section deleted]

1.3.2 [Intentionally left blank – section deleted]

1.3.3 [Intentionally left blank – section deleted]

1.3.4 [Intentionally left blank – section deleted]

Appendix 7.2 – Energy Bid Information

1.1 Within the IESO Control Area

1.1.1 Unique load identifier.

1.1.2 Contact information.

1.1.3 Hours for which *bid* applies.

1.1.4 [Intentionally left blank]

1.1.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

1.1.6 One to five ramp sets of ramp quantity and ramp up/ramp down values for each *dispatch hour* applicable to the entire range of load contained in the *bid*.

1.1.7 [Intentionally left blank]

1.1.8 [Intentionally left blank]

1.1.9 Is this a standing *bid*? Yes/No. If Yes, Date To:_________ For which day(s) of the week? __________________

1.2 Bids Outside the IESO Control Area

1.2.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.2.2 Contact information.

1.2.3 Hour(s) for which *bid* applies.

1.2.4 [Intentionally left blank]

1.2.5 Two to twenty *price-quantity pairs* for each *dispatch hour*, the final of which represents the maximum quantity of the *bid*.

1.2.6 [Intentionally left blank]

1.2.7 [Intentionally left blank]

1.2.8 Is this a standing *bid*? – Yes/No. If Yes, Date To: ________ For which day(s) of the week? ______

1.2.9 Sink *control area* (determined by selecting appropriate *boundary entity* resource).

1.2.10 [Intentionally left blank]

1.2.10A *NERC* transaction tag identification.

1.2.11 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.11.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates;

1.2.11.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*; and

1.2.11.3 interchange scheduling defaults specified by the relevant *standards authority* shall be used unless otherwise approved by the *IESO*. Transactions shall be one hour in duration, in accordance with agreements between *control areas* along the path. Transactions shall ramp in/out over the hour and shall respect a ten-minute ramp period.

Appendix 7.3 – Operating Reserve Offer Information

1.1 Generators Within the IESO Control Area

1.1.1 Unique plant identifier (by *generation unit* or *IESO*-approved aggregated *generation units*).

1.1.2 Contact information.

1.1.3 Hour(s) for which *offer* applies.

1.1.4 Minimum MW level of *generator* output at which the *generation unit* can offer its maximum level of *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*.

1.1.5 Minimum MW level of generator output at which the *generation unit* can offer its maximum level of *thirty-minute operating reserve*.

1.1.6 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.1.7 One ramping rate applicable for all categories of *operating reserve* being offered.

1.1.8 [Intentionally left blank]

1.1.9 [Intentionally left blank]

1.1.10 [Intentionally left blank]

1.1.11 Is this a standing *offer*? Yes/No. If Yes, Date To: _________ For which day(s) of the week? _________

1.2 Offers Outside the IESO Control Area

1.2.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.2.2 Contact information.

1.2.3 Hour(s) for which *offer* applies.

1.2.4 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.2.5 [Intentionally left blank]

1.2.6 Is this a standing *offer*? – Yes/No. If Yes, Date To: _____ For which day(s) of the week?______

1.2.7 Source *control area* (determined by selecting appropriate *boundary entity* resource).

1.2.7A *NERC* transaction tag identification.

1.2.8 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.2.8.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates; and

1.2.8.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*.

1.3 Load Within the IESO Control Area

1.3.1 Unique load identifier.

1.3.2 Contact information.

1.3.3 Hour(s) for which *offer* applies.

1.3.4 [Intentionally left blank]

1.3.5 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.3.6 One ramping rate applicable for all categories of *operating reserve* being offered.

1.3.7 [Intentionally left blank]

1.3.8 [Intentionally left blank]

1.3.9 Is this a standing *offer*? Yes/No. If Yes, Date To: _______ For which day(s) of the week? __________

1.4 Loads Outside the IESO Control Area

1.4.1 Unique *boundary entity* identifier (by *boundary entity* resource as created by the *IESO*).

1.4.2 Contact information.

1.4.3 Hour(s) for which *offer* applies.

1.4.4 Two to five *price-quantity pairs* for each *dispatch hour* for each category of *operating reserve* being offered, the final of which represents the maximum quantity of the *offer*.

1.4.5 [Intentionally left blank]

1.4.6 Is this a standing *offer* – Yes/No. If Yes, Date To: _________ For which day(s) of the week? _____

1.4.7 Sink *control area* (determined by selecting appropriate *boundary entity* resource).

1.4.7A *NERC* transaction tag identification.

1.4.8 *NERC* transaction tags shall be submitted within the times outlined in the *IESO* interchange tagging procedures and in accordance with the following:

1.4.8.1 all resources shall be designated as firm for the Ontario flowgates and the Ontario portion of the *intertie* flowgates; and

1.4.8.2 each *registered market participant* shall submit its transaction tag to the *IESO* through the electronic information system sanctioned by the relevant *standards authority* or, when not available, by such alternative means as may be specified by the *IESO* consistent with the policies of the relevant *standards authority*.

Appendix 7.4 – Transmission Information Required for Scheduling and Dispatching

1.1 Transmission Information Required for Scheduling and Dispatching

1.1.1 Full *connection-related reliability information* and transmission system data is required to be provided and updated to the *IESO* in accordance with Section 2.2.5 of Chapter 7 and Appendix 4.16 of Chapter 4.

1.1.2 Advance outage information is required to be provided to the *IESO* in terms of Chapter 5.

1.1.3 The following information is required to be advised to the *IESO* for scheduling and *dispatch* purposes:

1.1.3.1 any change to the maximum thermal rating of any transmission branch as advised by the *IESO* to be included in the scheduling *dispatch* and pricing algorithm; and

1.1.3.2 any change to the proposed *outage* plan as advised to and approved by the *IESO*.

Appendix 7.5 – The Market Clearing and Pricing Process

1.1 Process Overview and Interpretation

1.1.1 This Appendix sets forth a description of the process to be used to determine *pre-dispatch schedules*, *real-time schedules*, *market schedules* and *market prices*. A detailed mathematical description is also provided in the sections that follow.

1.1.2 [Intentionally left blank]

1.1.3 References to "outputs" in this Appendix refer to data produced by software and the *IESO* shall not be required to *publish* such data except where expressly required by these *market rules*.

2. The Dispatch Scheduling and Pricing Process

2.1 Modes of Operation

2.1.1 The *dispatch* scheduling and pricing software may be operated to determine either a *pre-dispatch schedule* or a *real-time schedule* and any associated prices as required by these *market rules*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

2.1.1.1 The *pre-dispatch schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The *pre-dispatch schedule* so produced represents the *energy* forecast to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant* in each *dispatch hour*, and each class of *operating reserve* to be maintained by each *market participant* in each *dispatch hour*;

2.1.1.2 The *real-time schedule* shall represent individual *dispatch intervals*. The *real-time schedule* so produced represents the *energy* to be injected into or withdrawn from the *IESO-controlled grid* by each *market participant*, and the *operating reserve* to be maintained by each *market participant*, in each *dispatch interval*; and

2.1.1.3 Only the *pre-dispatch schedule* shall include daily *energy* limits specified pursuant to section 3.5.7 of this Chapter.

2.1.1.4 The schedules corresponding to *offers* and *bids* located in *intertie zones* adjoining the *IESO control area* shall be fixed for all *dispatch intervals* within a *dispatch hour* in the *real-time schedule* to equal the *interchange schedules* determined for that same *dispatch hour* based on the last *pre-dispatch schedule* determined prior to solving the *real-time schedule*.

2.2 Inputs

2.2.1 The required inputs to the *dispatch* scheduling and pricing process are:

2.2.1.1 *offers* for *energy* submitted by *generators*;

2.2.1.2 *offers* for each class of *operating reserve* submitted by *generators*;

2.2.1.3 self-schedules submitted by self-scheduling generation facilities for energy and the energy price below which each self-scheduling generation facility reasonably expects to reduce the energy output of such self-scheduling generation facility to zero determined in accordance with section 3.4.4A of this Chapter;

2.2.1.4 forecasts of *energy* submitted by *transitional scheduling generators* and intermittent *generators*;

2.2.1.5 *bids* for *energy* submitted by *dispatchable loads*;

2.2.1.6 *offers* for each class of *operating reserve* submitted by *dispatchable loads*;

2.2.1.7 forecasts of *energy* expected to be withdrawn by *non-dispatchable loads*;

2.2.1.8 coefficients of the penalty functions associated with violation of system constraints (generation, *operating reserves* and transmission) that allow relaxation of these constraints in a specified hierarchical order when the solution to the scheduling problem is otherwise infeasible;

2.2.1.9 *generation facility output* and *dispatchable load* levels prevailing at the start of the *dispatch period* calculation;

2.2.1.10 in respect of the *pre-dispatch schedule* only, daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter;

2.2.1.10A in respect of the *real time* constrained *dispatch schedule* only, the start-up and shut-down times for each *generation facility*;

2.2.1.11 the operating characteristics of all *generation facilities* and *dispatchable loads* including, but not limited to ramp-rate limits and *operating reserve* response parameters and for the *real time* constrained *dispatch schedule* only, the *minimum loading point, forbidden regions* and *period of steady operation*;

2.2.1.12 the operating characteristics of the *IESO-controlled grid* including, but not limited to, the physical flow and loss characteristics and flow limits of *transmission facilities*;

2.2.1.13 the requirements for each of *ten-minute operating reserve* that is synchronized to the *IESO-controlled grid*, *ten-minute operating reserve* that is non-synchronized to the *IESO-controlled grid* and *thirty-minute operating reserve*, and the area requirements for *ten-minute operating reserve*;

2.2.1.14 security constraints determined by the *IESO* to be applicable;

2.2.1.14A the outage schedules for transmission facilities;

2.2.1.15 the limits to be applied, where applicable, on *energy bids*, *energy offers, offers* for *operating reserve*, and *dispatch data* as the case may be, to reflect:

a. transmission loading relief constraints;

b. *generation facility outages*;

c. applicable *contracted ancillary services* arranged for use outside of the market clearing mechanism; and for the *real time* constrained *dispatch schedule* only;

d. start-up and shut-down times;

e. *minimum loading point*;

f. *forbidden regions*;

g. *period of steady operation*; and

h. forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*.

2.2.1.16 imports or exports between the *IESO-control area* and other control areas required by the *IESO* to meet its obligations under requirements established by all relevant standards authorities and which are outside the normal market *bids* and *offers* including but not limited to inadvertent *intertie* flows and simultaneous activation of reserve. These shall be represented as an increase or decrease in *non-dispatchable load*.

2.3 Optimisation Objective

2.3.1 The *dispatch* scheduling and pricing process shall be a mathematical optimisation algorithm that will determine optimal schedules for each time period referred to in section 2.1.1, given the *bids* and *offers* submitted and applicable constraints on the use of the *IESO-controlled grid*. Marginal cost-based prices shall also be produced and, for such purpose, *offer* prices shall be assumed to represent the actual costs of suppliers and *bid* prices shall be assumed to represent the actual benefits of consumption by *dispatchable load facilities*.

2.3.2 The *dispatch* scheduling and pricing process shall have as its mathematical objective function maximising the economic gain from trade among *market participants* as described in sections 4.3.2 and 4.3.3 of Chapter 7.

2.3.3 In respect of the *real time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall have as its objective function maximizing the weighted sum of the economic gain from trade among *market participants*, as described in section 4.3.2 and 4.3.3 of Chapter 7, for the *dispatch interval* and for advisory intervals within the study period. Critical intervals are those selected from the study period to be used as input to the objective function. The first critical interval is always the *dispatch interval*. The remaining critical intervals are advisory intervals.

2.4 The IESO-Controlled Grid

2.4.1 The *dispatch* scheduling and pricing process shall represent power flow relationships between locations on the *IESO-controlled grid* and between the *IESO control area* and adjoining *control areas*.

2.4.2 The *dispatch* scheduling and pricing process shall utilise a security-constrained optimal power flow with explicit representation of electrical flows on each transmission element.

2.4.3 Limits on transmission flows in either direction of flow shall be explicitly represented.

2.4.4 Security constraints may limit *generation facility* output and *dispatchable load* or any other variable so as to represent the *security limits* applicable to the *IESO-controlled grid*.

2.4.5 Subject to section 2.4.6, the *IESO* shall estimate static transmission losses and model transmission losses using penalty factors. The *IESO* shall adjust *bid* and *offer* prices using the applicable penalty factor. The *IESO* shall notify *market participants* in a timely manner of any changes to the applicable penalty factors.

2.4.6 The *IESO* shall apply a uniform penalty factor to *variable generators* that are *registered market participants*.

2.5 Operating Reserve

2.5.1 The *dispatch* scheduling and pricing process shall simultaneously optimise *energy* and *operating reserve* schedules, respecting the trade-off functions for *energy* and *operating reserve* of each *registered facility*.

2.5.2 *Operating reserve* shall be scheduled to meet all applicable *reliability standards.*

2.5.3 For the real-time *dispatch* schedule and immediately following a *contingency event*, the *operating reserve* requirements shall be reduced while *operating reserves* are restored in accordance with all applicable *reliability standards*.

2.5.4 The *dispatch* scheduling and pricing process shall respect the trade-off function between *energy* and each class of *operating reserve* separately.

2.5.5 The *operating reserve* scheduled for a *generation facility* shall reflect the ability of that *generation facility* to provide *operating reserve* over the *dispatch interval* given its ramping capability.

2.5.6 *Offers* for each class of *operating reserve* in an area shall be used to meet the requirements for that class of *operating reserve* in that area.

2.5.6A *Offers* for *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid* that are not scheduled to meet that proportion of *ten-minute operating reserve* which is required to be synchronized with the *IESO-controlled* *grid* may be scheduled to satisfy the remaining portion of *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*.

2.5.7 Offers for *ten-minute operating reserve* –that is synchronized with the *IESO-controlled grid* or for *ten-minute operating reserve* –that is not synchronized with the *IESO-controlled grid* and that are not scheduled to meet the *ten-minute operating reserve* requirement may be scheduled to satisfy the requirements for a *thirty-minute operating reserve*.

2.5.8 The penalty function applicable as the result of a deficiency in any class of *operating reserve* shall be allowed to have an impact on the *energy* and *operating reserve* prices in the same *dispatch period*.

2.6 Contracted Ancillary Service

2.6.1 The *dispatch* scheduling and pricing process shall include constraints specified by the *IESO* to ensure the adequate provision of *contracted ancillary services*.

2.6.2 The *IESO* may apply constraints to the scheduling of *offers* submitted by *generators* and *bids* submitted by *dispatchable loads* which have contracted to provide *contracted ancillary services* so as to ensure that they are scheduled in a manner to meet their obligations under their respective contracted *ancillary service contracts*.

2.7 Constraint Penalty Functions and Violation Variables

2.7.1 The *dispatch* scheduling and pricing process shall include penalty functions and violation variables which will allow it to automatically violate transmission constraints and operational constraints imposed by the *IESO* (but not *bids* or *offers* or the physical limits of the *facilities* of *market participants*) in situations where no solution would otherwise exist.

2.7.2 Penalty functions for the violation of constraints shall be as specified from time to time by the *IESO Board* in accordance with section 4.4.6.2 of Chapter 7.

2.7.3 Different penalty functions may apply for each of the various *transmission* and operating constraints, reflecting the relative flexibility of *transmission* and operating limits.

2.7.4 The use of violation variables shall indicate that a feasible schedule is possible as long as some constraints are relaxed. If relaxation of such constraints is acceptable for purposes of real-time operations, such feasible schedule shall be accepted. If relaxation of such constraints is not acceptable for purposes of real-time operations*,* the *dispatch instructions* issued may differ so that an acceptable schedule can be determined.

2.7.5 The penalty functions used by the *IESO* in an acceptable schedule determined under section 2.7.4 shall be allowed to influence *energy* and *operating reserve* prices.

2.8 Tie-Breaking

2.8.1 Except as otherwise noted in section 2.8.5, if two or more *energy offers* have the same *offer* price and interactions with the *operating reserve market* do not create differences in the cost to the market of utilising each *offer*, the schedules from these *offers* shall be prorated based on an adjusted amount of *energy offered* at that *offer price*. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.2 If two or more *energy bids* have the same *bid* price and interactions with the *operating reserve market* do not create differences in the cost to the market as a whole of utilising each *bid*, the schedules from these *bids* shall be prorated based on an adjusted amount of *energy bid* at that *bid* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.3 If two or more *offers* for a given class of *operating reserve* have the same *offer* price and provided that interactions with the *energy* market and markets for other classes of *operating reserve* do not create differences in the cost to the market as a whole of utilising each *offer*, then the schedules from these *offers* shall be prorated based on an adjusted amount of *operating reserve offered* at that *offer* price. The adjustment shall reflect the current capability of the *facility* by including any current limitations on the *facility* e.g. ramping, deratings.

2.8.4 The *IESO* shall randomly determine a daily *dispatch* order for *variable generators* that are *registered market participants*, and shall regularly update and publish such daily *dispatch* order in accordance with the applicable *market manual.*

2.8.5 For *variable generators* that are *registered market participants*, if two or more *energy offers* have the same *offer* price resulting in no differences in the cost to the *IESO-administered market* of utilising any of the *offers,* the schedules for these *offers* shall be determined utilising the daily dispatch order determined in accordance with section 2.8.4.

2.9 Load Curtailment

2.9.1 If *non-dispatchable load* cannot be satisfied, the *dispatch* scheduling and pricing process shall violate the power balance for the system as a whole, with *energy* prices being calculated in accordance with section 4.4.6 of this Chapter.

2.10 Self-Scheduling Generation

2.10.1 A *self-scheduling generation facility* shall be treated as a resource that will be scheduled when *energy* prices exceed the greater of negative *MMCP* and the price, if any, specified by that *self-scheduling generation facility* in its *dispatch data* pursuant to section 3.4.4A of Chapter 7. Within the software that implements the formulation described in this Appendix, each *self-schedule* shall be represented in the form of an *energy offer* each with a single *price-quantity* pair.

2.11 Inter-temporal Linkages

2.11.1 Except for the *real-time* constrained *dispatch schedule*, 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 *IESO*.

2.11.3 The *real-time* constrained *dispatch schedule* utilizes a two step optimization technique to maximize the weighted sum of the economic gain from trade among *market participants* for a number of critical intervals over a forward looking study period. For each *real time* constrained *dispatch schedule* critical intervals are selected by the *IESO* from the study period based on defined selection criteria. The first critical interval is always the *dispatch interval*, and the remaining critical intervals are advisory intervals. Both the length of the study period and the number of advisory intervals are configurable and may be changed by the *IESO* in the event of significant improvement or degradation of either computer software and hardware performance, the accuracy of the predicted *demand* values or malfunction of the algorithm. Changing the number of critical intervals will affect the number of intervals provided to *market participants* on the *dispatch* advisory reports. The number of critical intervals and the length of the study period will be documented in the applicable *market manuals*.

2.11.4 The *IESO* may switch to a single interval optimization in the event of a malfunction of the multi-interval optimization algorithm.

2.11.5 In respect of the *real-time* constrained *dispatch schedule* only, the *dispatch* scheduling and optimization process shall consist of two steps. The first step considers all of the selected critical intervals together to provide an optimal solution. This uses linearized resource characteristics. The second step solves a set of single interval *dispatch* problems to respect the non-linearities that reflect physical characteristics of resources in accordance with section 6.5.

2.12 Outputs

2.12.1 The *dispatch* scheduling and pricing process shall produce the following outputs:

2.12.1.1 the cost to the marketplace as a whole of the solution;

2.12.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;

2.12.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;

2.12.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;

2.12.1.5 the energy output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;

2.12.1.6 the level and location of all load curtailment;

2.12.1.7 flows along all transmission lines;

2.12.1.8 losses on the *IESO-controlled grid*, in the aggregate and by transmission line;

2.12.1.9 the locational *energy* prices at each set of nodes identified by the *IESO* for this purpose for each *dispatch* period;

2.12.1.10 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*;

2.12.1.10A the area price of *ten-minute operating reserve*; and

2.12.1.11 penalty function values that are greater than zero.

3. The Market Scheduling and Pricing Process

3.1 Modes of Operation

3.1.1 The market scheduling and pricing software may be operated to determine either a projected *market schedule* or a *market schedule*. While different numerical values may be used in each mode, the mathematical formulation shall be the same in both modes except that:

3.1.1.1 the projected *market schedule* shall represent between 1 and 24 individual periods each of a duration of 1 hour. The projected *market schedule* so produced represents the state of the *IESO-controlled grid* at the end of the *dispatch hour*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *pre-dispatch schedule* for the corresponding *dispatch hour*;

3.1.1.2 the *market schedules* shall represent individual *dispatch intervals*. Each schedule so produced represents the state of the *IESO-controlled grid* at the end of a *dispatch interval*. Unless otherwise provided in these *market rules*, this process shall use the same information and data used for determining the *real-time schedule* for the corresponding *dispatch interval*;

3.1.1.3 the projected *market schedule* shall include daily *energy* limits where specified pursuant to section 3.5.7 of this Chapter; and

3.1.1.4 subject to section 3.1.2, the *market schedule* process shall take, as inputs, the output levels of *generation facilities* and *dispatchable load facilities* from the preceding period of the corresponding *market schedule* and pricing solution.

3.1.2 Section 3.1.1.4 shall not apply if market operations have been suspended or *administrative prices* have been applied pursuant to section 8.4A.2.2 of this Chapter. In such cases, the *generation facility* and *dispatchable load facility* initial condition inputs used to calculate the first *market schedule* determined from the first *dispatch interval* in the *dispatch hour* referred to in section 13.7.1.2 or from the *dispatch interval* referred to in section 8.4A.17.2 of this Chapter 7, as the case may be, shall be the output levels of *generation facilities* and *dispatchable load facilities* from the last *dispatch interval* of the last corresponding *market schedule* and pricing solution solved, with corresponding modifications to the initial ramp rates to reflect the maximum amount of ramping possible during the *dispatch intervals* for which no *market schedules* were produced.

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 *IESO control area* shall be removed. The market scheduling and pricing process shall assume that all *physical services* are provided and consumed in the *IESO 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 *IESO 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 *IESO 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 *IESO control area*. No *intertie zone* prices are required to be produced by the *market schedule* as these values are subsequently derived from the uniform Ontario prices produced by the *market schedule* 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 *market schedule* 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 *market schedule*;

3.2.1.4 with the exception of *emergency energy* purchases, any imports or exports between the *IESO control area* and other control areas required by the *IESO* 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*. *Emergency energy* purchases shall not be represented as a decrease in *non-dispatchable load* in the *market schedule*;

3.2.1.5 [Intentionally left blank]

3.2.1.6 [Intentionally left blank]

3.2.1.7 [Intentionally left blank]

3.2.1.8 [Intentionally left blank]

3.2.1.9 [Intentionally left blank]

3.2.1.10 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*;

3.2.1.11 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*; and

3.2.1.12 during any period when the *IESO* undertakes an *emergency* control action as described in the applicable *market manual* that affects market *demand*, the *IESO* shall, as software capabilities permit, adjust market *demand* in the *market schedule* to offset the impact of the *emergency* control action on the market *demand* where such impact can be determined with reasonable certainty.

3.3 Outputs

3.3.1 The market scheduling and pricing process shall produce the following outputs:

3.3.1.1 the cost to the marketplace as a whole of the solution;

3.3.1.2 the schedule for each *energy offer* submitted by a *generation facility* for each *dispatch period*;

3.3.1.3 the schedule for each *offer* for each class of *operating reserve* for each *dispatch period*;

3.3.1.4 the schedule for each *energy bid* submitted by a *dispatchable load* for each *dispatch period*;

3.3.1.5 the output of each transitional scheduling generator and self-scheduling generation facility for each dispatch period;

3.3.1.6 the uniform Ontario *energy* price. The projected *market schedule* shall also produce *energy* prices for each intertie zone;

3.3.1.7 the uniform Ontario price for each class of *operating reserve* for each *dispatch period*. The *pre-dispatch schedule* shall also produce corresponding prices for all *intertie zones*. The *real-time schedule* need not produce corresponding prices for all *intertie zones* as the *real-time schedule intertie zone* prices are subsequently derived from the *real-time schedule* uniform Ontario prices and the *pre-dispatch schedule intertie congestion prices*; and

3.3.1.8 [Intentionally left blank]

3.3.1.9 penalty function values that are greater than zero.

3.3.2 As described in section 8.2.2 of this Chapter, the prices produced as part of the output of the market scheduling and pricing process shall not necessarily be the prices that are used for *settlement* purposes.

4. Glossary of Sets, Indices, Variables, and Parameters

4.1 Interpretation

4.1.1 Unless otherwise noted, all variables and parameters shall be non-negative.

4.1.2 [Intentionally left blank]

4.2 Time

4.2.1 Except where explicitly stated otherwise in Appendix 7.5 or elsewhere, the formulation presented in this Appendix represents a single *dispatch period*.

4.3 Fundamental Sets and Indices

4.3.1 Areas and Nodes

4.3.1.1 An area, interpreted in accordance with section 1.2.3 of this Chapter, is represented by an element of the set AREAS and is indexed by a.

4.3.1.2 [Intentionally left blank]

4.3.1.3 [Intentionally left blank]

4.3.1.4 Any *energy offer*, *energy bid* or *offer* for *operating reserve* can be associated with a node belonging to the set NODES. NODES has a subset INTERNALACNODES to represent those nodes in the *IESO control area* and a subset EXTERNALACNODES to represent those nodes in the *intertie zones* adjoining the *IESO control area*. NODES also has subsets INTERTIEZONE, indexed by z, describing all of those nodes within *intertie zone* z.

4.3.2 *Offers*

4.3.2.1 An *offer* is represented by an element of the set OFFERS and is indexed by g.

4.3.2.2 An *offer* has associated with it an area and a node.

4.3.2.3 [Intentionally left blank]

4.3.2.4 [Intentionally left blank]

4.3.2.5 A subset of OFFERS called $\text{OFFERS}_{\text{ENERGYLIMITED}}$ represents the *offers* which have a daily *energy* limit in force in accordance with section 3.5.7 of this Chapter.

4.3.2.6 Each element of g of OFFERS has a set of offer blocks, $\text{GENERATIONOFFERBLOCKS}_g$.

4.3.2.7 $\text{SECURITYGENERATIONGROUP}_v$ is the group of *offers* constrained with security constraint v.

4.3.2.8 Each *energy offer* has associated with it a set of $\text{GENERATIONRAMPUPBLOCKS}_g$ and a set of $\text{GENERATIONRAMPDOWNBLOCKS}_g$. Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy offer.*

4.3.2.9 The set ENERGYOFFERBOUNDS, which is indexed by g, describes the set of *energy offers* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits, *generation facility outages* as well as limits imposed by *contracted ancillary services* contracts, and forecasts of *energy* for the *facilities* of *variable generators* that are *registered market participants* produced by the *forecasting entity*. These limits restrict both the *energy* and *operating reserve* output of a *generation facility*.

4.3.3 *Bids*

4.3.3.1 A *bid* is represented by an element of the set BIDS and is indexed by p

4.3.3.2 A *bid* has associated with it an area and a node.

4.3.3.3 [Intentionally left blank]

4.3.3.4 Each element of p of BIDS has a set of load blocks, $\text{PURCHASEBIDBLOCKS}_p$.

4.3.3.5 $\text{SECURITYPURCHASEGROUP}_v$ is the group of *bids* constrained with security constraint v. 4.3.3.6 Each *energy bid* p has associated with it a set of $\text{PURCHASERAMPUPBLOCKS}_p$ and a set of $\text{PURCHASERAMPDOWNBLOCKS}_p$. Each set may be used to specify not less than 1 and not more than 5 ramp rates associated with the *energy bid.*

4.3.3.7 The set PURCHASEBOUNDS, which is indexed by p, describes the set of *energy bids* to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.

4.3.4 Operating Reserve Offers

4.3.4.1 An *offer* to provide *operating reserve* by either a *generator* or a *dispatchable load* is represented by an element of the set RESERVEOFFERS and is indexed by r. The index elements r(g) and r(p) mean the value of r denoting the *operating reserve offer* associated with *generator* g and *dispatchable load* p, respectively.

4.3.4.2 An *offer* to provide *operating reserve* has associated with it an area and a node.

4.3.4.3 Each element r of RESERVEOFFERS and c of RESERVECLASSES has a set of offer blocks, $\text{RESERVEOFFERBLOCKS}_{r,c,j}$ where j is the index for the blocks.

4.3.4.4 The set RESERVEBOUNDS_c, which is indexed by r, describes the set of *operating reserve offers*, for each *operating reserve* class c, to which minimum and maximum output levels may be applied so as to represent transmission loading relief limits.

4.3.5 [Intentionally left blank]

4.3.5.1 [Intentionally left blank]

4.3.5.2 [Intentionally left blank]

a. [Intentionally left blank]
b. [Intentionally left blank]
c. [Intentionally left blank]

4.3.6 Classes of *Operating Reserve*

4.3.6.1 A class of *operating reserve* is represented by an element of the set RESERVECLASSES and is indexed by c.

4.3.6.2 RESERVECLASSES = {RS10,RNS10,R30} where:

a. RS10 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

b. RNS10 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

c. R30 denotes *thirty-minute operating reserve*.

4.3.7 Security Measures

4.3.7.1 A security measure is represented by an element of the set SECURITY and is indexed by v.

4.3.7.2 The *IESO* may establish parameters for these security measures so as to maintain the security and adequacy of the electricity system.

4.3.7.3 [Intentionally left blank]

4.3.7.4 [Intentionally left blank]

4.3.8 Security Classes

4.3.8.1 Security classes represent the different types of security constraints that may be imposed by the *IESO* and are represented by SECURITYCLASSES.

4.3.8.2 SECURITYCLASSES ={GenericMaximum, GenericMinimum}where GenericMaximum and GenericMinimum are generic constraints that can place limits on combinations of *generation facilities* that are *dispatched* by the *IESO*, *dispatchable load* and AC branch flow simultaneously.

4.3.9 Penalty Functions

4.3.9.1 The formulation contains a number of penalty functions that allow certain constraints to be violated to some extent, with a high penalty cost.

4.3.9.2 Penalty functions have five blocks, indexed by j, so that the per unit penalty can be increased for larger violations. The blocks used are:

a. DEFICITGENERATIONBLOCKS;

b. SURPLUSGENERATIONBLOCKS;

c. [Intentionally left blank]

(i) [Intentionally left blank]

(ii) [Intentionally left blank]

(iii) [Intentionally left blank]

c1. DEFICIT10MINRESERVEBLOCKS;

c2. DEFICITSYNCH10MINRESERVEBLOCKS;

c3. DEFICITTOTALRESERVEBLOCKS;

c4. DEFICITAREARESERVEBLOCKS;

c5. SURPLUSAREARESERVEBLOCKS;

c6. DEFICITINTERTIEBLOCKS;

c7. SURPLUSINTERTIEBLOCKS;

c8. DEFICITEXPORT^{MMCP}BLOCKS;

d. For each v in DEFICITSECURITYBLOCKS$_{v;}$ and

e. For each v in SURPLUSSECURITYBLOCKS$_{v.}$

4.4 Derived Sets

4.4.1 There are numerous subsets that can be derived from the fundamental sets described above. A subscripted fundamental set represents all elements of the fundamental set having the attribute represented by the subscript where the subscript is either the unique index identifier or a set of specified elements of another fundamental set.

4.4.2 Examples of derived sets are:

4.4.2.1 RESERVEOFFERS$_{a,}$ which is the set of all *offers* for *operating reserve* located within *operating reserve* area a; and

4.4.2.2 [Intentionally left blank]

4.4.2.3 OFFERS$_{INTERNALACNODES,}$ which is the set of all *energy offers* at nodes in the set INTERNALACNODES (*energy offers* made from within the *IESO control area*).

4.4.2.4 [Intentionally left blank]

4.4.2.5 [Intentionally left blank]

4.5 Functions Defined on Sets

4.5.1 For ease of description, the following functions are defined that operate on elements of sets and return either another set or a single element:

4.5.1.1 *g*(.), where the argument could be an *operating reserve offer* r , or a security measure v, gives the *offer* associated with the argument.

4.5.1.2 *p*(.), where the argument could be an *operating reserve offer* r or security measure v, gives the *bid* associated with the argument.

4.5.1.3 [Intentionally left blank]

4.6 Offers and Bids

4.6.1 Parameters

$GenerationBlockMax_{g,j}$	The MW element of the j[th] block of the *offer*.
$GenerationOfferPrice_{g,j}$	The price element of the j[th] block of the *offer*. The parameter is unbounded.
$PurchaseBlockMax_{p,j}$	The MW element of the j[th] block of the *bid*.
$PurchaseBidPrice_{p,j}$	The price element of the j[th] block of the *bid*. The parameter is unbounded.
$EnergyOfferMax_g$	The maximum MW level for *energy* and *operating reserve* associated with *energy offer* g∈ **ENERGYOFFERBOUNDS**
$EnergyOfferMin_g$	The minimum MW *energy* level associated with *energy* offer g∈ **ENERGYOFFERBOUNDS**
$EnergyBidMax_p$	The maximum MW *energy* level associated with *energy bid* p ∈ **PURCHASEBOUND**
$EnergyBidMin_p$	The minimum MW *energy* level associated with *energy bid* p ∈ **PURCHASEBOUND**

4.6.2 Derived Parameters

$GenerationMaximum_g$	The maximum MW *energy* level associated with *energy offer* g∈ **OFFERS**.
$PurchaseMaximum_p$	The maximum MW *energy* level associated with *energy bid* p∈ **BIDS**.
FixedPurchases	A representation of the net amount of non-price responsive withdrawal to be supplied from *energy offers* and *energy bids*.
$GenPF_g$	The loss penalty factor for *energy offer* g∈ **OFFERS**.
$PurPF_p$	The loss penalty factor for *energy bid* p∈ **BIDS**.

4.6.3 Variables

Generation_g	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy offer* g∈ **OFFERS**.
$\text{GenerationBlock}_{gj}$	The MW *energy* scheduled from the j^{th} block of *energy offer* g∈ **OFFERS**.
Purchase_p	The total MW *energy* scheduled as at the end of the *dispatch period* corresponding to *energy bid* p∈ **BIDS**.
$\text{PurchaseBlock}_{pj}$	The MW *energy* scheduled from the j^{th} block of *energy bid* p∈ **BIDS**.

4.7 Power Balance

4.7.1 Parameters [Intentionally left blank]

4.7.2 Derived Parameters [Intentionally left blank]

4.7.3 Variables

LOSS	The MW losses for the entire *IESO-controlled grid*.

4.8 Operating Reserve

4.8.1 [Intentionally left blank]

4.8.2 Parameters

$\text{ReserveOfferPrice}_{r,c,j}$	The price element of block j of *operating reserve* of class c associated with *operating reserve offer* r. The parameter is unbounded.
$\text{ReserveBlockMaximum}_{r,c,j}$	The maximum MW *operating reserve* of class c available from block j of *operating reserve offer* r.
$\text{ReserveLoadingPoint10}_{r}$	The *operating reserve* loading point for *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid* associated with *operating reserve offer* r. This defines the minimum *energy* value required for a generator to reach its maximum *ten-minute operating reserve offer*.
$\text{ReserveLoadingPoint30}_{r}$	The *operating reserve* loading point for *thirty-minute operating reserve* associated with *operating reserve offer* r. This defines the minimum *energy* value required for a generator to reach its maximum *thirty-minute operating reserve offer*.
ReserveRequirement10	The amount of *operating reserve* required to meet the *ten-minute operating reserve* requirement of the *IESO control area*.
ReserveRequirement30	The amount of *operating reserve* required to meet the *thirty-minute operating reserve* requirement of the *IESO control area*.
SynchReserveProportion	The fraction of *ten-minute operating reserve* that must be supplied by *operating reserve* that is synchronized to the *IESO-controlled grid*.
$\text{ReserveOfferMax}_{r}$	The maximum MW level associated with *operating reserve offer* $r \in$ **RESERVEBOUNDS**.
$\text{ReserveOfferMin}_{r}$	The minimum MW level associated with *operating reserve offers* $r \in$ **RESERVEBOUNDS**.

4.8.3 Derived Parameters

$ReserveMaximum10_r$	The maximum total *ten-minute operating reserve* from *operating reserve offer* r that can be delivered within ten minutes given the ramping rate for *operating reserve*.
$ReserveMaximum30_r$	The maximum total *operating reserve* from *operating reserve offer* r that can be delivered within thirty minutes given the ramping rate for *operating reserve*.

4.8.4 Variables

$Reserve_{r,c}$	The scheduled *operating reserve* of class c corresponding to *operating reserve offer r*.
$ReserveBlock_{r,c,j}$	The scheduled *operating reserve* of class c corresponding to block j of *operating reserve offer* r.

4.9 Security

4.9.1 Limits may be imposed on the output of *generation facilities*, *dispatchable load facilities* and flow on transmission equipment for *security* reasons.

4.9.2 Parameters

$GenericSecurityMinLimit_v$	The lower limit imposed on the combination of *energy offers* and *energy bids* in security constraint $v \in$**SECURITY.** The parameter is unbounded.
$GenericSecurityMaxLimit_v$	The upper limit imposed on the combination of *energy offers* and *energy bids* in security constraint v∈**SECURITY**. The parameter is unbounded.
$SecurityGroupGenerationWeight_{v,g}$	The weight associated with *energy offer* g∈$\mathbf{SECURITYGENERATIONGROUP}_v$ in security constraint v. The parameter is unbounded.

$\text{SecurityGroupPurchaseWeight}_{v,p}$	The weight associated with *energy bid* $p \in$ **SECURITYPURCHASEGROUP**$_v$ in security constraint v. The parameter is unbounded.
$\text{MaxIntertieZoneFlow}_z$	The upper limit imposed on the combination of *energy* and *operating reserve* by constraint $z \in$ **INTERTIEZONES**. The parameter is unbounded.
$\text{MinIntertieZoneFlow}_z$	The lower limit imposed on the combination of *energy* and *operating reserve* by constraint $z \in$ **INTERTIEZONES**. The parameter is unbounded.

4.10 Ramping

4.10.1 *Dispatchable load facilities* and *dispatchable generation facilities* have limits on their ability to move from one level of consumption or production to another. Ramping constraints are enforced by constraining the level of consumption or production to be between an upper and a lower limit. These limits are pre-determined, based on starting load and generation levels and *bid* and *offer* ramp rates. These limits are applicable to all *pre-dispatch schedules*, *market schedule* intervals, and to the first *dispatch interval* of each *real-time* constrained *dispatch*.

4.10.1A In the first step, of the *real time* constrained *dispatch schedule,* as described in section 2.11.5, the ramp limits are linearized and respected in the optimization.

4.10.1B In the second step, the ramp limits are determined by pre-processing based on *dispatch* load and generation in the critical intervals that precede and follow the interval under consideration. The solution is bounded by:

a) the prior critical interval solution as calculated by the second step and applicable non-linearized ramp rates; and

b) back calculating from the following critical interval solution as calculated from the first step using the applicable non-linearized ramp rates.

In the event that these two sets of bounds do not intersect then a) governs.

4.10.2 Parameters for the optimisation determined by pre-processing

$\text{GenerationEndMax}_g$	The maximum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.
$\text{GenerationEndMin}_g$	The minimum *generation facility* output level associated with *energy offer* g∈**OFFERS**, given the corresponding starting *generation facility* output level.
PurchaseEndMax_p	The maximum load level associated with *energy bid* p∈ **BIDS**, given the corresponding starting load level.
PurchaseEndMin_p	The minimum load level associated with *energy bid* p∈ **BIDS**, given the corresponding starting load level.

4.10.3 Parameters for Pre-processing

$\text{RampRate}_{g,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j[th] block of $\text{GENERATIONRAMPUPBLOCK}_g$ for g∈**OFFERS.**
$\text{RampRate}_{g,j}^{Down}$	The *energy* ramping down rate in MW per minute associated with the j[th] block of $\text{GENERATIONRAMPDOWNBLOCK}_g$ for g∈**OFFERS**.
$\text{Generation}_g^{Start}$	The MW *energy* level associated with the *energy offer* at the start of a *dispatch period*. This will be the corresponding $\textit{Generation}_g$ variable from the previous *dispatch period* for the *market schedule* and the constrained *pre-dispatch schedule*, but will be based on operational *metering data* and/or the schedule from the previous *dispatch period* for the *real-time schedule*. If the schedule from the previous *dispatch period* is not available (non-critical intervals in *the real time* constrained *dispatch schedule*) it will be produced by interpolating the *dispatches* from the critical intervals before and after it.

$\text{OperatingReserveRampRate}_g$	The single *operating reserve* ramp rate in MW per minute associated with g∈**OFFERS**.
$\text{RampRate}_{p,j}^{Up}$	The *energy* ramping up rate in MW per minute associated with the j[th] block of $\text{PURCHASERAMPUPBLOCK}_p$ p∈**BIDS**
$\text{RampRate}_{p,j}^{Down}$	The *energy* ramping down rate in MW per minute associated with the j[th] block of $\text{PURCHASERAMPDOWNBLOCK}_p$ for p∈**BIDS**
$\text{Purchase}_p^{Start}$	The MW *energy* level associated with the *energy bid* at the start of a *dispatch period*. This will be the corresponding $Purchase_p$ variable from the previous *dispatch period* for the *market schedule* and the constrained *pre-dispatch schedule*, but will be based on operational *metering data* and/or the schedule from the previous *dispatch period* for the *real-time schedule*.
$\text{OperatingReserveRampRate}_p$	The single *operating reserve* ramp rate in MW per minute associated with p∈**BIDS**.
$\text{GenerationRampBlockMax}_{g,j}$	The MW component of the jth block of the generator ramp up/down block minus the MW component of the (j-1)th block of the generator ramp up/down block.
$\text{PurchaseRampBlockMax}_{p,j}$	The MW component of the jth block of the *dispatchable load* ramp up/down block minus the MW component of the (j-1)th block of the *dispatchable load* ramp up/down block.

4.10.4 Variables Used in Pre-processing

$\text{TimeTrajStart}_g^{Up}$	The time, on the ramp up trajectory for the *energy offer*, associated with the $Generation_g$ variable from the previous *dispatch period*.
RampTraj_g^{Up}	The ramp up trajectory for the *energy offer*
$\text{TimeTrajStart}_g^{Down}$	The time, on the ramp down trajectory for the *energy offer*, associated with the $Generation_g$ variable from the previous *dispatch period*.
RampTraj_g^{Down}	The ramp down trajectory for the *energy offer*
$\text{TimeTrajStart}_p^{Up}$	The time, on the ramp up trajectory for the *energy bid*, associated with the $Purchase_p$ variable from the previous *dispatch period*.
RampTraj_p^{Up}	The ramp up trajectory for the *energy bid*
$\text{TimeTrajStart}_p^{Down}$	The time, on the ramp down trajectory for the *energy bid*, associated with the $Purchase_p$ variable from the previous *dispatch period*.
RampTraj_p^{Down}	The ramp down trajectory for the *energy bid*

4.10.5 Parameters Determined by Pre-processing and Multi-Interval Optimization

$\text{GenerationRampBlock}_{g,j}$	The MW *dispatched* from the jth block of the *generation facility* ramp up/down block.
$\text{PurchaseRampBlock}_{p,j}$	The MW *dispatched* from the jth block of the *dispatchable load* ramp up/down block.

4.11 Energy Constrained Generation Units

4.11.1 Parameters for the Optimisation Determined by Pre-processing

EnergyRemaining_g	The amount of *energy* remaining at the beginning of the current *dispatch period* for *energy* constrained *generation facility*, as described in sections 6.6 and 8.3, associated with *energy offer* g.
$\text{Generation}_g^{Previous}$	The amount of *energy* scheduled from *energy offer* g in the preceding dispatch period.

4.11.2 Parameters for Pre-processing

EnergyOffered_g	The total *energy* limit for the *trading day* associated with *energy offer* $g \in \textbf{OFFERS}$.

4.12 Violation Variables

4.12.1 Violation variables have been added to all constraints which might potentially be violated. Most will have a very high cost indicating that the problem has no solution, but some may have lower costs indicating that the constraint can be relaxed to some degree.

4.12.1.1 Parameters

$DeficitGenerationPenalty_{j}$	The penalty per unit of the $DeficitGenerationBlock_{j}$ variable.
$SurplusGenerationPenalty_{j}$	The penalty per unit of the $SurplusGenerationBlock_{j}$ variable.
$Deficit10MinReservePenalty_{j}$	The penalty per unit of the $Deficit10MinReserveBlock_{j}$ variable.
$DeficitSynch10MinReservePenalty_{j}$	The penalty per unit of the $DeficitSynch10MinReserveBlock_{j}$ variable.
$DeficitTotalReservePenalty_{j}$	The penalty per unit of the $DeficitTotalReserveBlock_{j}$ variable.
$DeficitSecurityPenalty_{j,v}$	The penalty per unit of the $DeficitSecurityBlock_{j,v}$ variable.
$SurplusSecurityPenalty_{v,j}$	The penalty per unit of the $SurplusSecurityBlock_{v,j}$ variable.
$SurplusInterTiePenalty_{z,j}$	The penalty per unit of the $SurplusIntertieBlock_{z,j}$ variable.
$DeficitIntertiePenalty_{z,j}$	The penalty per unit of the $DeficitIntertieBlock_{z,j}$ variable.
$Deficit\ Export^{MMCP}Penalty_{z,j}$	The penalty per unit of the $Deficit\ Export^{MMCP}\ Block_{z,j}$ variable.

These penalties, which are set by the *IESO Board* as specified in section 4.4.6 of this Chapter, equal a fixed number multiplied by a quadratic function equal to constant1(x^2) + constant2(x) + constant3. The three constants are user-defined for each penalty function while x equals the sum of total fixed demand and transmission losses divided by the total capacity represented by the *energy offers*.

4.12.1.2 Variables

$DeficitGenerationBlock_j$	The amount by which the aggregate of load plus losses exceeds the *energy* generated. The blocks are cleared in order of increasing cost, so the further the power balance equation is violated, the more extreme the penalty per unit.
$SurplusGenerationBlock_j$	The amount by which *energy* generated exceeds the aggregate of load plus losses.
$Deficit10MinReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement exceeds the *ten-minute operating reserve* scheduled.
$Deficit\ Export^{MMCP}\ Block_j$	The amount contributed by block j in accounting for the amount by which the exports (bid at MMCP) have been unsatisfied.
$DeficitSynch10MinReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement that is synchronized to the *IESO-controlled grid* exceeds the *ten-minute operating reserve* scheduled.
$DeficitTotalReserveBlock_j$	The amount contributed by block j in accounting for the amount by which the total *operating reserve* requirement exceeds the total *operating reserve* scheduled.
$DeficitSecurityBlock_{v,j}$	The amount of deficit in meeting security constraint v, in violation block j.
$SurplusSecurityBlock_{v,j}$	The amount of surplus in security constraint v, in violation block j.
$SurplusIntertieBlock_{z,j}$	The amount of surplus in *intertie zone* constraint z, in violation block j.
$DeficitIntertieBlock_{z,j}$	The amount of deficit in *intertie zone* constraint z, in violation block j.

$DeficitAreaReserveBlock_{a,j}$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a exceeds the *ten-minute operating reserve* scheduled in area a.
$SurplusAreaReserveBlock_{a,j}$	The amount contributed by block j in accounting for the amount by which the *ten-minute operating reserve* requirement in area a is less than the *ten-minute operating reserve* scheduled in area a.

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 15 minutes in respect of a *market schedule,* as the case may be.

5. Objective Function

5.1.1 As well as the market terms that are used in the objective function, violation variables associated with the various constraints also appear in the objective function.

5.1.1.1 The NetBenefit is maximised, where:

$$\begin{aligned} NetBenefit = & \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times PurPF_p \times PurchaseBlock_{p,j} \\ & - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times GenerationBlock_{g,j} \\ & - \sum_{\{j,r,c \mid j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times ReserveBlock_{r,c,j} \\ & - ViolationVariables - TieBreaking \end{aligned}$$

In respect of the *real time* constrained *dispatch schedule* only, the first step of the optimization process will maximize the weighted sum of the net benefits from trades in the *dispatch interval* and the advisory intervals. The *IESO* will set the weights for the intervals in the *real time* constrained *dispatch* study period to account for reduced accuracy of inputs for future intervals. The *IESO* shall establish the process by which weights assigned to non-critical intervals are allocated to the critical intervals.

$$\begin{aligned}
NetBenefit = & \sum_{\{j,p \mid j \in \text{PURCHASEBIDBLOCKS}_p, \text{where } p \in \text{BIDS}\}} \text{PurchaseBidPrice}_{p,j} \times PurPF_p \times PurchaseBlock_{p,j} \\
& - \sum_{\{j,g \mid j \in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g \in \text{OFFERS}\}} \text{GenerationOfferPrice}_{g,j} \times \text{GenPF}_g \times GenerationBlock_{g,j} \\
& - \sum_{\{j,r,c \mid j \in \text{RESERVEOFFERBLOCKS}_{r,c}, \text{where } r \in \text{RESERVEOFFERS and } c \in \text{RESERVECLASSES}\}} \text{ReserveOfferPrice}_{r,c,j} \times ReserveBlock_{r,c,j} \\
& - ViolationVariables - TieBreaking
\end{aligned}$$

Where W_c is the weight assigned to the critical interval c.

5.1.1.2 Wherever the following notation is found:

$$\{\text{j}, x \mid \text{j} \in \textbf{XBLOCKS}_x, \text{where } x \in \textbf{GROUP}\}$$

it shall be interpreted as, for each x in the set **GROUP**, take each of the corresponding blocks from **XBLOCKS**.

5.1.1.3 Violation Variable Terms

$$
\begin{aligned}
ViolationVariables = & \sum_{\{j | j \in \text{DEFICITGENERATIONBLOCKS}\}} \text{DeficitGenerationPenalty}_j \times DeficitGenerationBlock_j \\
+ & \sum_{\{j | j \in \text{SURPLUSGENERATIONBLOCKS}\}} \text{SurplusGenerationPenalty}_j \times SurplusGenerationBlock_j \\
+ & \sum_{\{j | j \in \text{DEFICIT10MINRESERVEBLOCKS}\}} \text{Deficit10MinReservePenalty}_j \times Deficit10MinReserveBlock_j \\
+ & \sum_{\{j | j \in \text{DEFICITSYNCH10MINRESERVEBLOCKS}\}} \text{Deficit10MinSynchReservePenalty}_j \times DeficitSynch10MinReserveBlock_j \\
+ & \sum_{\{j | j \in \text{DEFICITTOTALRESERVEBLOCKS}\}} \text{DeficitTotalReservePenalty}_j \times DeficitTotalReserveBlock_j \\
+ & \sum_{\{j,a | j \in \text{DEFICITAREARESERVEBLOCKS}_A \text{, where } a \in AREAS\}} \text{Deficit10MinReservePenalty}_j \times DeficitAreaReserveBlock_{a,j} \\
+ & \sum_{\{j,a | j \in \text{SURPLUSAREARESERVEBLOCKS}_A \text{, where } a \in AREAS\}} \text{Surplus10MinReservePenalty}_j \times SurplusAreaReserveBlock_{a,j} \\
+ & \sum_{\{j,v | j \in \text{DEFICITSECURITYBLOCKS}_v \text{, where } v \in \text{SECURITYMIN}\}} \text{DeficitSecurityPenalty}_{v,j} \times DeficitSecurityBlock_{v,j} \\
+ & \sum_{\{j,v | j \in \text{SURPLUSSECURITYBLOCKS}_v \text{, where } v \in \text{SECURITYMAX}\}} \text{SurplusSecurityPenalty}_{v,j} \times SurplusSecurityBlock_{v,j} \\
+ & \sum_{\{j,z | j \in \text{SURPLUSINTERTIEBLOCKS}_z \text{, where } z \in \text{INTERTIEZONES}\}} \text{SurplusIntertiePenalty}_{z,j} \times SurplusIntertieBlock_{z,j} \\
+ & \sum_{\{j,z | j \in \text{DEFICITINTERTIEBLOCKS}_z \text{, where } z \in \text{INTERTIEZONES}\}} \text{DeficitIntertiePenalty}_{z,j} \times DeficitIntertieBlock_{z,j} \\
+ & \sum_{\{j,z | j \in \text{DEFICITEXPORT}^{\text{MMCP}}\text{BLOCKS}_z \text{, where } z \in \text{INTERTIEZONES}\}} \text{DeficitExport}^{\text{MMCP}}\text{Penalty}_{z,j} \times DeficitExport^{MMCP}Block_{z,j}
\end{aligned}
$$

5.1.1.4 The Tie Breaking Term

$$TieBreaking = \sum_{\{j,p|j\in \text{PURCHASEBIDBLOCKS}_p, \text{where } p\in \text{BIDS}\}} \left\{ \frac{0.0005\times\left(PurchaseBlock_{p,j}\right)^2}{\text{PurchaseBlockMax}_{p,j}} \right\}$$
$$+ \sum_{\{j,g|j\in \text{GENERATIONOFFERBLOCKS}_g, \text{where } g\in \text{OFFERS}\}} \left\{ \frac{0.0005\times\left(GenerationBlock_{g,j}\right)^2}{\text{GenerationBlockMax}_{g,j}} \right\}$$
$$+ \sum_{\substack{\{j,r,c|j\in \text{RESERVEOFFERBLOCKS}_{r,c}, \\ \text{where } r\in \text{RESERVEOFFERS and } c\in \text{RESERVECLASSES}\}}} \left\{ \frac{0.0005\times\left(ReserveBlock_{r,c,j}\right)^2}{\text{ReserveBlockMax}_{r,c,j}} \right\}$$

The tie breaking term involves a penalty cost of 0.0005 prorated by the amount scheduled over the maximum amount that could be scheduled from each block. When this cost is multiplied by the amount scheduled from that block, we get a quadratic function that increases as the amount scheduled increases. The penalty cost adders effectively increases the *bid* or *offer* price by zero if nothing is scheduled from the block but by 0.0005 if the entire amount represented by the *bid* or *offer* block is scheduled. This slight price gradient, which is smaller than the minimum step size of *bid* or *offer* prices, will ensure that, for example, two otherwise tied *energy offer* blocks will be scheduled to the point where their modified costs are identical, effectively achieving a prorated result.

6. Dispatch Constraints

6.1 Offers and Bids

6.1.1

$$GenerationBlock_{g,j} \leq \text{GenerationBlockMax}_{g,j}$$

$$\{\text{j,g} \mid \text{j} \in \textbf{GENERATIONOFFERBLOCKS}_{g}, \text{where g} \in \textbf{OFFERS}\}$$

6.1.2

$$Generation_{\mathrm{g}} = \sum_{\mathrm{j} \in \mathbf{GENERATIONOFFERBLOCKS}_{\mathrm{g}}} GenerationBlock_{\mathrm{g,j}}$$

$$\{\mathrm{g} \in \mathbf{OFFERS}\}$$

6.1.3

$$Generation_{\mathrm{g}} \geq \mathrm{EnergyOfferMin}_{g}$$

$$\{\mathrm{g} \in \mathbf{ENERGYOFFERBOUNDS}\}$$

6.1.4

$$Generation_{\mathrm{g}} + \sum_{c \in \mathrm{RESERVECLASSES}} Reserve_{r(g),c} \leq \mathrm{EnergyOfferMax}_{g}$$

$$\{\mathrm{g} \in \mathbf{ENERGYOFFERBOUNDS}\}$$

6.1.5

$$PurchaseBlock_{\mathrm{p,j}} \leq \mathrm{PurchaseBlockMax}_{\mathrm{p,j}}$$

$$\{\mathrm{j,p} \mid \mathrm{j} \in \mathbf{PURCHASEBIDBLOCKS}_{\mathrm{p}}, \text{where } \mathrm{p} \in \mathbf{PURCHASES}\}$$

6.1.6

$$Purchase_{\mathrm{p}} = \sum_{\mathrm{j} \in \mathbf{PURCHASEBIDBLOCKS}_{\mathrm{p}}} PurchaseBlock_{\mathrm{p,j}}$$

$$\{\mathrm{p} \in \mathbf{PURCHASES}\}$$

6.1.7

$$Purchase_{\mathrm{p}} \geq \mathrm{EnergyBidMin}_{\mathrm{p}}$$

$$\{\mathrm{p} \in \mathbf{PURCHASEBOUNDS}\}$$

6.1.8

$$Purchase_p \leq \text{EnergyBidMax}_p$$

$$\{p \in \textbf{PURCHASEBOUNDS}\}$$

All *energy offers* are entered as *offers* to supply a block of *energy* at a minimum price. Similarly, *energy bids* for *dispatchable load* are entered as *bids* to buy a block of *energy* at a maximum price. *Energy offers* must have the price increasing with increasing quantity while *energy bids* must have the price decreasing with increasing quantity.

6.2 Power Balance

6.2.1 The power balance equation states that the total generation must equal the sum of scheduled *energy bids* , withdrawals by *non-dispatchable load* and losses. The sum of withdrawals by *non-dispatchable load* and associated losses are input based on forecasted demand.

6.2.1.1

$$\sum_{g \in \text{OFFERS}} Generation_g = \sum_{p \in \text{BIDS}} Purchase_p + \text{FixedPurchases} + LOSS$$
$$- \sum_{j \in \text{DEFICITGENERATIONBLOCKS}} DeficitGenerationBlock_j$$
$$+ \sum_{j \in \text{SURPLUSGENERATIONBLOCKS}} SurplusGenerationBlock_j$$

6.2.1.2 [Intentionally left blank]

6.2.1.3 [Intentionally left blank]

6.3 Operating Reserve

6.3.1 [Intentionally left blank]

6.3.2 Operating reserve requirements for the IESO control area are specified for each of ten-minute operating reserve and thirty-minute operating reserve. The ten-minute operating reserve that is required to be synchronized with the IESO-controlled grid is given as a fraction of the ten-minute operating reserve requirement. Since ten-minute operating reserve that is not required for purposes of the ten-minute operating reserve requirement can be used to satisfy the thirty-minute operating reserve requirement, a total operating reserve requirement is defined and is the sum of the ten-minute operating reserve requirement and the thirty-minute operating reserve requirement.

6.3.2A Following a *contingency event*, and subject to section 4.5.10 and 4.5.21 of Chapter 5, the *IESO* shall, over one or more *dispatch intervals*, restore at a constant rate the *operating reserve* requirements to be input into the *dispatch algorithm*. To the extent practicable, the *IESO* shall restore *operating reserve* requirements so as to avoid exceeding the ability to meet those requirements through the *IESO-administered markets*.

6.3.2B *Operating reserve* requirements for areas within the *IESO control area* are specified as lower and upper limits on the amount of *ten-minute operating reserve* to be scheduled in each such area.

6.3.3 [Intentionally left blank]

6.3.3.1

$$ReserveBlock_{r,c,j} \leq \mathrm{ReserveBlockMax}_{r,c,j}$$

$$\{j,r,c \mid j \in \mathbf{RESERVEOFFERBLOCKS}_r, \text{ where } r \in \mathbf{RESERVEOFFERS} \text{ and } c \in \mathbf{RESERVECLASSES}\}$$

6.3.3.2

$$Reserve_{r,c} = \sum_{j \in RESERVEOFFERBLOCKS_{r,c}} ReserveBlock_{r,c,j}$$

$$\{r \in \mathbf{RESERVEOFFERS},\ c \in \mathbf{RESERVECLASSES}\}$$

6.3.3.3 [Intentionally left blank]

6.3.3A

$$Reserve_{r,c} \geq \mathrm{ReserveOfferMin}_{r,c}$$

$$\{r \in \mathbf{RESERVEBOUNDS}_c, c \in \mathbf{RESERVECLASSES}\}$$

6.3.3B

$$Reserve_{r,c} \leq \text{ReserveOfferMax}_{r,c}$$

$$\{ r \in \mathbf{RESERVEBOUNDS}_c , c \in \mathbf{RESERVECLASSES} \}$$

6.3.3C The *operating reserve* scheduled from *dispatchable loads* cannot exceed the amount of *dispatchable load* scheduled.

$$\sum_{c \in RESERVECLASSES} Reserve_{r(p),c} \leq Purchase_p$$

$$\{ p \in \mathbf{BIDS} \}$$

6.3.4 The *energy* and *operating reserves* scheduled from a *generation facility* must be within the capacity of the *generation facility*.

6.3.4.1

$$Generation_g + \sum_{c \in \text{RESERVECLASSES}} Reserve_{r(g),c} \leq \text{GenerationMaximum}_g$$

$$\{ g \in \mathbf{OFFERS} \}$$

6.3.5 If a *generation facility* is operating at a low level of output, then the amount of *operating reserve* it is capable of providing may be restricted. The Reserve Loading Point corresponds to the minimum level of output at which generators can supply the maximum *operating reserve* within the time required. This maximum *operating reserve* quantity declines to zero as output reduces to zero. The maximum *operating reserve* that can be provided differs for *ten-minute operating reserve* and *thirty-minute operating reserve*, and reflects the differing amount of time available for the *generation facility* to increase its output if the *operating reserve* is activated.

6.3.5.1

$$Reserve_{r(g),RS10} \le Generation_g \times \frac{\text{ReserveMaximum10}_g}{\text{ReserveLoadingPoint10}_{r(g)}}$$

$\{g \in \mathbf{OFFERS}\}$

$$Reserve_{r(g),R30} \le Generation_g \times \frac{\text{ReserveMaximum30}_g}{\text{ReserveLoadingPoint30}_{r(g)}}$$

$\{g \in \mathbf{OFFERS}\}$

Where:

ReserveMaximum10$_g$ = OperatingReserveRampRate$_{r(g)}$×10
ReserveMaximum30$_g$ = OperatingReserveRampRate$_{r(g)}$×30

If either one of ReserveLoadingPoint10$_{r(g)}$ or ReserveLoadingPoint30$_{r(g)}$ equals zero then the corresponding equation shall not be included in formulation.

6.3.5.2 [Intentionally left blank]

6.3.5.3 [Intentionally left blank]

6.3.5A The amount of *ten-minute operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within ten minutes. The total *operating reserve* scheduled from a *generation facility* cannot exceed the maximum amount by which *operating reserve* can be ramped up by that *generation facility* within thirty minutes.

6.3.5A.1

$$\sum_{c \in \{\text{RS10, RNS10}\}} Reserve_{r(g),c} \le \text{Reserve Maximum10}_g$$

$\{g \in \mathbf{OFFERS}\}$

6.3.5A.2

$$\sum_{c \in \text{RESERVECLASSES}} Reserve_{r(g),c} \leq \text{ReserveMaximum30}_g$$

$$\{g \in \textbf{OFFERS}\}$$

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.

6.3.5B.1

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \{RS10, RNS10\}}} Reserve_{r(g),c} \leq \text{Generation}_g^{start} + \text{ReserveMaximum10}_g$$

$$\{g \in \textbf{OFFERS}\}$$

6.3.5B.2

$$Generation_g + \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \text{RESERVECLASSES}}} Reserve_{r(g),c} \leq \text{Generation}_g^{start} + \text{ReserveMaximum30}_g$$

$$\{g \in \textbf{OFFERS}\}$$

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

6.3.6 *Operating reserve* is scheduled to meet the *operating reserve* requirements of the *IESO control area*.

6.3.6.1 Ten-minute operating reserve

$$\text{ReserveRequirement10} \leq \sum_{\substack{r \in \text{RESERVEOFFERS}, \\ c \in \{RS10, RNS10\}}} Reserve_{r,c} + \sum_{j \in \text{DEFICT10MINRESERVEBLOCKS}} Deficit10MinReserveBlock_j$$

6.3.6.2 Ten-minute operating reserve synchronized with the IESO-controlled grid

$$\text{SynchReserveProportion} \times \text{ReserveRequirement10} \leq \sum_{r \in \text{RESERVEOFFERS}, c \in \{\text{RS10}\}} Reserve_{r,c} + \sum_{j \in \text{DEFICITSYNCH10MINRESERVEBLOCKS}} DeficitSynch10MinReserveBlock_j$$

6.3.6.3 Total operating reserve

$$\text{ReserveRequirement10} + \text{ReserveRequirement30} \leq \sum_{r \in \text{RESERVEOFFERS}, c \in \text{RESERVECLASSES}} Reserve_{r,c} + \sum_{j \in DEFICITTOTALRESERVEBLOCKS} DeficitTotalReserveBlock_j$$

6.3.6.3A Area *operating reserve* requirements

$$\text{MinimumAreaOperatingReserve}_a \leq \sum_{r \in RESERVEOFFERS_a, c \in \{RS10, RNS10\}} Reserve_{r,c} + \sum_{j \in DEFICITAREARESERVEBLOCKS} DeficitAreaReserve_{j,a}$$

$$\text{MaximumAreaOperating Reserve}_a \geq \sum_{r \in RESERVEOFFERS_a, c \in \{RS10, RNS10\}} Reserve_{r,c} - \sum_{j \in SURPLUSAREARESERVEBLOCKS} SurplusAreaReserve_{j,a}$$

$$\{a \in \textbf{AREAS}\}$$

6.3.6.4 The SynchReserveProportion shall be set in accordance with requirements established by *NERC*.

6.4 Security Constraints

6.4.1 In order to enable the *IESO* to direct the operations of the *IESO-controlled grid* so as to fulfil its obligations under Chapter 5, the *IESO* must define network security constraints. These network security constraints are specified in the form of maximum and minimum constraints on linear combinations of line flows, *energy offers*, and *energy bids*. During the process of solving for schedules and prices, these network security constraints, as well as other transmission constraints represented automatically within the tools, are reduced to generic *security* constraints which impose limits on the weighted sum of the $Generation_g$ and $Purchase_p$ variables, with flows being converted to constants.

6.4.2 [Intentionally left blank]

6.4.3 Generic *security* constraints only appear in the *dispatch* scheduling and pricing process and are expressed as:

6.4.3.1

$$\sum_{n \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchase Weight}_{v,p} \times Purchase_p$$
$$+ \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times Generation_g$$
$$- \sum_{j \in \text{SURPLUSSECURITYBLOCKS}_v} SurplusSecurityBlock_{j,v} \leq \text{Generic Max SecurityLimit}_v$$

$$\{v \in \textbf{SECURITY}_{GenericMaximum}\}$$

6.4.3.2

$$\sum_{p \in \text{SECURITYPURCHASEGROUP}_v} \text{SecurityGroupPurchaseWeight}_{v,p} \times Purchase_p + \sum_{g \in \text{SECURITYGENERATIONGROUP}_v} \text{SecurityGroupGenerationWeight}_{v,g} \times Generation_g + \sum_{j \in \text{DEFICITSECURITYBLOCKS}_v} DeficitSecurityBlock_{v,j} \geq \text{GenericMinSecurityLimit}_v$$

$$\{v \in \textbf{SECURITY}_{GenericMinimum}\}$$

6.4.4 Constraints separate from the generic security constraints impose limits on the total *energy* flows and *operating reserve* scheduled from *intertie zones* outside the *IESO control area*. These constraints apply to both the *pre-dispatch schedule* and the *market schedule*.

$$\sum_{g \in \text{OFFERS}_z} Generation_g - \sum_{p \in \text{BIDS}_z} Purchase_p + \sum_{r \in \text{RESERVEOFFERS}_z, c \in \text{RESERVECLASSES}} Reserve_{r,c} - \sum_{j \in \text{SURPLUSINTERTIEBLOCKS}_z} SurplusInterieBlock_{z,j} \leq \text{MaxIntertieZoneFlow}_z$$

$$\sum_{g \in \text{OFFERS}_z} Generation_g - \sum_{p \in \text{BIDS}_z} Purchase_p + \sum_{j \in \text{DEFICITINTERTIEBLOCKS}_z} DeficitInterieBlock_{z,j} \geq \text{MinIntertieZoneFlow}_z$$

$$\{z \in \textbf{INTERTIEZONES}\}$$

6.5 Ramping

6.5.1 Any change in the output of a *generation facility* or the consumption by a *dispatchable load facility* is subject to up and down ramp rate limits. These constrain the schedule for these *facilities* at the end of the *dispatch period* to be within a band which is set by pre-processing based on knowledge of the schedule at the start of the *dispatch period* and the ramp rates.

6.5.2 Except for the advisory intervals in the *real time* constrained *dispatch*, ramping constraints are expressed as:

6.5.2.1

$$Generation_g \leq \text{GenerationEndMax}_g \qquad \{g \in \mathbf{OFFERS}\}$$

6.5.2.2

$$Generation_g \geq \text{GenerationEndMin}_g \qquad \{g \in \mathbf{OFFERS}\}$$

6.5.2.3

$$Purchase_p \leq \text{PurchaseEndMax}_p \qquad \{p \in \mathbf{BIDS}\}$$

6.5.2.4

$$Purchase_p \geq \text{PurchaseEndMin}_p \qquad \{p \in \mathbf{BIDS}\}$$

6.5.3 For purposes of sections 6.5.2.1 to 6.5.2.4, $\text{GenerationEndMax}_g$, $\text{GenerationEndMin}_g$, PurchaseEndMax_p and PurchaseEndMin_p are determined by pre-processing as described in section 8.2.

6.5.4 The ramping constraints for the advisory intervals in the first step of the multi-interval optimization of the *real time* constrained *dispatch* are linearized and included in the optimization as follows:

6.5.4.1

$$Generation_g = \sum GenerationRampBlock_{g,j} \qquad \{g \in \mathbf{OFFERS}\}$$

6.5.4.2

$$Purchase_p = \sum PurchaseRampBlock_{p,j} \qquad \{p \in BIDS\}$$

6.5.4.3

$$0 \leq GenerationRampBlock_{g,\,j} \leq GenerationRampBlockMax_{g,\,j}$$
$$\{g \in OFFERS\}$$

6.5.4.4

$$0 \leq PurchaseRampBlock_{p,j} \leq PurchaseRampBlockMax_{p,j}$$
$$\{p \in BIDS\}$$

6.5.4.5

$$-RampRate_{g,j}^{Down} \times T_{g,j} \leq GeneratorRampBlock(i+1th\ \mathrm{int}\ erval)$$
$$-GeneratorRampBlock_{g,\,j}(ith\ \mathrm{int}\ erval) \leq RampRate_{g,j}^{Up} \times T_{g,j}$$

Where $T_{g,j} \geq 0$ and $\sum T_{g,j} \leq$ Time Interval; and

$T_{g,j}$ is the time that the generator ramps in the *GeneratorRampBlock*$_{g,j}$*;* where Time Interval is equal to the length of the *dispatch interval.*

6.5.4.6

$$RampRate_{p,j}^{Down} \times T_{p,j} \leq PurchaseRampBlock(i+1th\, interval) - PurchaseRampBlock_{p,j}(ith\, interval) \leq RampRate_{p,j}^{Up} \times T_{p,j}$$

Where $T_{p,j} \geq 0$ and $\sum T_{p,j} \leq$ Time Interval; and

$T_{p,j}$ is the time that the purchase ramps in the *PurchaseRampBlock*$_{p,j}$*;* where Time Interval is equal to the length of the *dispatch interval.*

6.6 Energy Constrained Generation Units

6.6.1 Some *generation units*, referred to as "*energy* constrained *generation units*", have a defined amount of *energy* which they are able to generate within the course of a *trading day*. Each *energy* constrained *generation unit* may specify an *energy* limit which will apply over the *trading day*. Where an *energy* limit is specified pursuant to section 3.5.7 of this Chapter, starting with this value a running total, EnergyRemaining, is kept by subtracting the *energy* scheduled in each *dispatch hour* from the quantity of *energy* available at the start of the *dispatch hour*.

6.6.2 Because the model is not inter-temporal, it will not use *energy* at the times at which it is of most value. Instead, it will use *energy* over the first opportunities in which it is economical to do so. Thus, it may use all of the *energy* during the low load early morning period, leaving none left during the higher price periods. It is left to the *generator* to submit *energy offers* for a *generation unit* at appropriate times to maximise the value of the *energy* available.

6.6.3 The following constraint is included only in the *pre-dispatch schedules:*

$$\text{TradingPeriodLength} \times Generation_g \leq \text{EnergyRemaining}_g$$

$$\{g \in \mathbf{OFFERS}_{ENERGYLIMITED}\}$$

6.7 Nodal Price Calculation

6.7.1

$$\lambda_n = \lambda_s + (DF_n - 1) * \lambda_s + \sum_k DF_n * a_{nk} * \mu_k$$

where:

λ_n	nodal price at an injection or withdrawal node n (i.e., a node connected to a *generation facility* or *load facility*)
λ_s	system marginal cost
DF_n	delivery factor for node n (reciprocal of penalty factor)
a_{nk}	sensitivity factor for injection at node n on *transmission* line k
μ_k	shadow price for *transmission* line k constraint

6.7.2 Nodal prices may be decomposed into an *energy* component, a loss component, and a component for all other *transmission* and system constraints (the three terms on the right hand side, respectively.)

7. Market Constraints

7.1 Introduction

7.1.1 The market model removes all of the AC *transmission* lines inside the *IESO control area*, and consolidates the nodes into a single representative node, the ONTARIONODE. The losses associated with the *transmission* lines in the *IESO control area* are consolidated to this node.

7.1.2 The only AC *transmission* lines in the market model are the *interties* with neighbouring *control areas*. Although these *interties* have flow variables in the market model, under current procedures each interface will have its flows constrained to the scheduled quantities for the relevant *dispatch period*, using *security* constraints.

7.2 Offers and Bids

7.2.1 The market constraints for *energy offers* and *energy bids* are identical to the *dispatch* constraints described in section 6.1 with the exception that constraints associated with the sets ENERGYOFFERBOUNDS and PURCHASEBOUNDS shall not be present if those constraints pertain to transmission loading relief.

7.3 Power Balance

7.3.1 The market power balance equations are identical to the *dispatch* power balance equations described in section 6.2, with the following exceptions:

7.3.1.1 subject to section 7.3.2, losses within the *IESO control area* will be added to FixedPurchases;

7.3.1.2 all loss sensitivity parameters (and corresponding penalty functions) for *generators* and *loads* within each *control area* outside the *IESO control grid* will be identical and will reflect the losses on the external area and the relevant *intertie;* and

7.3.1.3 subject to section 7.3.2, the following adjustments, as further defined in section 8.4, shall be made in the *real-time schedule* to reflect deviations between scheduled and actual MW output and load:

ActualPurchaseAdjustment – ActualGenerationAdjustment

7.3.2 Until such time that locational pricing is implemented in the *IESO-administered markets*:

7.3.2.1 the losses referred to in section 7.3.1.1 shall be incorporated in FixedPurchases in the manner described in section 8.4.3 ; and

7.3.2.2 no adjustments shall be made pursuant to section 7.3.1.3.

7.4 Operating Reserve

7.4.1 The market treatment of risk and *operating reserve* is identical to the *dispatch* treatment of these elements as described in section 6.3, with the exception that:

7.4.1.1 constraints on *offers* for *operating reserve* associated with the set RESERVEBOUNDS_c for *operating reserve* class c shall not be present if those constraints pertain to transmission loading relief; and

7.4.1.2 the area *operating reserve* requirements are ignored.

7.5 Security Constraints

7.5.1 The only security constraints to be represented are the limits imposed on the flows of *energy* and on *operating reserve* scheduled to or from *intertie zones* outside the *IESO control area* as described in section 6.4.4.

7.6 Ramping

7.6.1 The mathematical description of the market constraints for ramping is identical to the mathematical description of the ramping *dispatch* constraints used in the *pre-dispatch* and the *dispatch interval* of the *real time* multi-interval *dispatch*, as described in section 6.5, except for the information and data differences specified in section 6.4 of Chapter 7.

7.7 Energy Constrained Generation Units

7.7.1 This constraint is only included in the *pre-dispatch schedules*. The market *energy* constraints are identical to the *dispatch energy* constraints as described in section 6.6.

8. Parameters and Pre-processing

8.1 Introduction

8.1.1 This section 8 contains calculations that take place before the optimization algorithm. The purpose of these calculations is to convert raw input data into the specific inputs required by the optimisation algorithm.

8.2 Ramping

8.2.1 The pre-processing calculations described in sections 8.2.2 and 8.2.3 are performed for all *energy offers* $\{g \in \mathbf{OFFERS}\}$. The pre-processing calculations described in sections 7.2.4 and 7.2.5 are performed for all *bids* by *dispatchable loads* $\{p \in \mathbf{BIDS}\}$.

8.2.2 The *energy offer* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\text{GenerationEndMax}_g = RampTraj_g^{Up}(TimeTrajStart_g^{Up} + \text{TradingPeriodlength})$$

where

$$Generation_g^{Start} = RampTraj_g^{Up}(TimeTrajStart_p^{Up})$$

8.2.3 The *energy offer* ramp down model is defined by the set of ramp down rates and ramp down blocks. Combined these rates and blocks define the ramp trajectory which gives the maximum decrease of output as a function of time. The output at the end of a *dispatch period* is then calculated by:

$$\text{GenerationEndM in}_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down} + \text{TradingPeriodlength}).$$

where

$$Generation_g = RampTraj_g^{Down}(TimeTrajStart_g^{Down})$$

8.2.4 The *energy bid* ramp up model is defined by the set of ramp up rates and ramp up blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum increase of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$\text{Purchase EndMax}_p = RampTraj_p^{Up}(TimeTrajStart_p^{Up} + \text{TradingPeriodlength})$$

where

$$Purchase_p^{Start} = RampTraj_p^{Up}(TimeTrajStart_p^{Up})$$

8.2.5 The *energy bid* ramp down model is defined by the set of ramp down rates and ramp down blocks. When combined, these rates and blocks define the ramp trajectory which gives the maximum decrease of *dispatchable load* as a function of time. The *dispatchable load* at the end of a *dispatch period* is then calculated by:

$$\text{Purchase EndM in}_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down} + \text{TradingPeriodlength}).$$

where

$$Purchase_p = RampTraj_p^{Down}(TimeTrajStart_p^{Down})$$

8.3 Energy Constrained Generation Units

8.3.1 $$\mathrm{EnergyRemaining}_g = \mathrm{EnergyRemaining}_g^{Previous} - \mathrm{Generation}_g^{Previous} \times \mathrm{SchedPeriod}$$

where SchedPeriod is the scheduling period measured in hours, currently 1 hour. If $\mathrm{EnergyRemaining}_g$ ever takes a value of less than zero then it shall be set to zero. If $\mathrm{EnergyRemaining}_g$ is ever lower than a lower bound constraint imposed on *energy offer* g, then as part of the pre-processing process the relevant lower bounds will be reduced accordingly.

8.3.2 $\mathrm{EnergyRemaining}_g = \mathrm{EnergyOffered}_g$ in the first *dispatch period*.

8.4 Actual Dispatch Adjustment

8.4.1 Subject to section 8.4.3, Actual Generation Adjustment shall be:

8.4.1.1 for the ONTARIONODE:

$$\mathrm{ActualGenerationAdjustment}_{\mathbf{ONTARIONODE}} = \sum_{n \in \mathbf{INTERNALNODES}} \sum_{g \in \mathbf{OFFERS}_n} (Generation_g^{Actual} - Generation_g^{Scheduled})$$

where $\mathrm{Generation}_g^{\mathrm{Actual}}$ is the actual generation for generator g, and $\mathrm{Generation}_g^{\mathrm{Scheduled}}$ is the *dispatch instruction* issued for generator g; and

8.4.1.2 for $n \in$ EXTERNALACNODES:

$$\mathrm{ActualGenerationAdjustment}_n = \sum_{g \in \mathbf{OFFERS}_n} (Generation_g^{Actual} - Generation_g^{Scheduled})$$

where $\mathrm{Generation}_g^{\mathrm{Actual}}$ is the actual generation for generator g, and $\mathrm{Generation}_g^{\mathrm{Scheduled}}$ is the *dispatch instruction* issued for generator g.

8.4.2 Subject to section 8.4.3, Actual Purchase Adjustment shall be:

8.4.2.1 for the ONTARIONODE:

$$\text{ActualPurchaseAdjustment}_{\textbf{ONTARIONODE}} = \sum_{n \in \textbf{INTERNALNODES}} \sum_{p \in \textbf{BIDS}_n} (Purchase_p^{Actual} - Purchase_p^{Scheduled})$$

where $\text{Purchase}_p^{\text{Actual}}$ is the actual load for *dispatchable load* p, and $\text{Purchase}_p^{\text{Scheduled}}$ is the *dispatch instruction* issued for *dispatchable load* p; and

8.4.2.2 for $n \in$ EXTERNALACNODES:

$$\text{ActualPurchaseAdjustment}_n = \sum_{p \in \textbf{BIDS}_n} (Purchase_p^{Actual} - Purchase_p^{Scheduled})$$

where $\text{Purchase}_p^{\text{Actual}}$ is the actual load for *dispatchable load* p, and $\text{Purchase}_p^{\text{Scheduled}}$ is the *dispatch instruction* issued for *dispatchable load* p.

8.4.3 Until such time that locational pricing is implemented in the *IESO-administered markets*, there shall be no actual dispatch adjustment effected pursuant to section 8.4.1 or 8.4.2 and rather than adding the losses within the *IESO control area* to FixedPurchases, FixedPurchases shall be defined to include losses and shall be:

8.4.3.1 the sum of:

a. actual metered generation within the *IESO control area;* and

b. net scheduled flows over all *interties,*

minus

8.4.3.2 the amount of scheduled *dispatchable load* within the *IESO control area.*

Appendix 7.5A – The DACP Calculation Engine Process

1.1 Interpretation

1.1.1 This appendix describes the DACP calculation engine process used to determine commitments, constrained schedules, and shadow prices.

1.1.1.1 Commitment refers to the availability of *generation facilities* and imports to provide *energy* and/or *operating reserve* and *dispatchable loads* and exports to provide *operating reserve*.

1.1.1.2 The constrained schedules of the *schedule of record* are assessed in the calculation of production cost guarantees.

1.1.1.3 The shadow price of a location indicates the price of meeting an infinitesmal amount of change in load at that location.

1.1.2 The mathematical description of the optimization algorithm of the DACP calculation engine process is also described in this appendix.

1.1.3 The DACP calculation engine "outputs" described in this appendix refer to data produced by DACP calculation engine and the *IESO* shall not be required to *publish* such data except where expressly required by these *market rules*.

2. DACP Calculation Engine

2.1 Overview

2.1.1 The DACP calculation engine is a core component of the DACP process that performs the functions of commitment and constrained scheduling over a 24-hour period for *energy* and *operating reserves,* and the calculation of shadow prices. The DACP calculation engine executes three passes to produce the final *schedule of record*.

2.1.1.1 Pass 1, the Commitment Pass determines the initial set of commitments and constrained schedules required to satisfy the average forecast *demand* of the next day. Details of Pass 1 are described in section 4.

2.1.1.2 Pass 2, the Reliability Pass ensures that if the resources committed by Pass 1 are insufficient to satisfy peak forecast *demand*, additional resources are committed and scheduled. Details of Pass 2 are described in section 5.

2.1.1.3 Pass 3, the Scheduling Pass uses the commitments made in Passes 1 and 2 to determine the *schedule of record* and the associated constrained schedules to meet average forecast *demand*. Details of Pass 3 are described in section 6.

2.1.2 Since each pass provides constrained schedules, the DACP calculation engine will iterate the calculations for constrained schedules with *security* assessments until there are no *security* violations. The *security* assessment functionality is described in section 4.4.

3. Inputs into the DACP Calculation Engine

3.1 Demand Forecast

3.1.1 The *IESO* shall prepare forecasts of the total *demand* in Ontario for each hour of the next day. This hourly forecast will be modified by the DACP calculation engine so that the expected consumption associated with *dispatchable loads* will be removed. Average hourly *demand* forecasts will be used as inputs to Passes 1 and 3. Peak hourly *demand* forecasts will be used as inputs to Pass 2.

3.2 Energy Offers and Bids

3.2.1 A registered market participant may submit an energy offer or energy bid and associated dispatch data with respect to a given registered facility for each dispatch hour of the next day for DACP. Energy offers, bids and dispatch data shall be submitted in accordance to Chapter 7 and may be limited in accordance with section 2.2.1.15 of Appendix 7.5.

3.3 Operating Reserve Offers

3.3.1 A *registered market participant* may submit an *offer* and associated *dispatch data* to provide each class of *operating reserve* for each *dispatch hour* of the next day for DACP. *Operating reserve offers* and *dispatch data* shall be submitted in accordance to Chapter 7.

3.4 Forecasts from Self-Scheduling Generation Facilities, Transitional Scheduling Generators and Intermittent Generators

3.4.1 The DACP calculation engine will take into account the expected output of *self-scheduling generation facilities, transitional scheduling generators and intermittent generators* when committing resources to meet forecast *demand* for the next day. The *registered market participant* representing such generation at each location will inform the *IESO* of the amount of *energy* it expects to produce in each hour of the next day as a function of price in accordance to Chapter 7.

3.5 Ramp up to Minimum Loading Point

3.5.1 In order for the DACP calculation engine to determine constrained schedules in Pass 3 that account for the *energy* produced by *generation facilities* during ramping to their *minimum loading points*, an approximate value of this *energy* will be used. This *energy* will be represented by a fraction of the unit's *minimum loading point* in the hour prior to the first hour it is scheduled.

3.6 Energy Limited Resources

3.6.1 *Energy* limited resources constitute a subset of *generation facilities* that at times can be limited in the amount of *energy* they can provide during each day.

3.6.2 An *energy* limited resource shall designate the daily limit on the amount of *energy* it could be scheduled to generate over the course of the day.

3.7 Transmission Inputs

3.7.1. Transmission inputs are based on information prepared by the *IESO* for the *security* assessment function of the DACP calculation engine described in section 4.4. These inputs include:

3.7.1.1 Internal transmission constraints;

3.7.1.2 Limits on imports and exports;

3.7.1.3 Loop flows; and

3.7.1.4 Transmission losses.

3.8 Other Inputs

3.8.1 The *IESO* shall also provide other inputs into the DACP calculation engine that are necessary in order to ensure a solution that is consistent with system *reliability*. These include:

3.8.1.1 Distribution of internal *demand*;

3.8.1.2 Distribution of imports, exports and loop flows;

3.8.1.3 *Operating reserve* requirements;

3.8.1.4 Must-run resources for other reliability purposes;

3.8.1.5 Regulation *(AGC);*

3.8.1.6 Voltage constraints;

3.8.1.7 Initializing assumptions regarding resources in operation; and

3.8.1.8 Costs of violations.

4. Pass 1: Constrained Commitment to Meet Average Demand

4.1 Overview

4.1.1 Pass 1 performs a least cost, *security* constrained, unit commitment and constrained scheduling to meet the forecast average *demand* and *IESO*-specified *operating reserve* requirements for each hour of the next day.

4.1.2 This pass will use *bids* and *offers* and associated *dispatch data* submitted by *registered market participants* to maximize the gains from trade (i.e., the difference between the total price of *bids* submitted by *market participants* whose *bids* were scheduled, and the total price of *offers* submitted by *market participants* whose *offers* were scheduled). The optimization is subject to the constraints accompanying those *bids* and *offers*, and constraints imposed by the *IESO* to ensure reliable service.

4.2 Inputs for Pass 1

4.2.1 Inputs for Pass 1 include those described in section 3.

4.3 Optimization Objective for Pass 1

4.3.1 The objective function of Pass 1 is to maximize the gains from trade. This is accomplished by maximizing the sum of the following quantities for each hour of the trade day:

The value of:

- Scheduled exports;

Less the *offered* costs of:

- Scheduled *operating reserve* from exports;
- The foregone opportunity due to scheduled load reductions;
- Scheduled operating reserve from dispatchable load;
- Scheduled hourly imports;
- Scheduled *operating reserve* from imports;
- Scheduled operating reserve from generation facilities;
- Scheduled generation;
- Hourly costs for speed no-load for committed *generation facilities*; and
- Startup cost for committed generation facilities;

Less the cost of:

- Scheduled violation variables.

4.3.2 The cost for each violation variable for each hour is the hourly magnitude of the violation variable multiplied by the price (in $ per MW per hour) for relaxing the particular constraint. The hourly cost associated with all violation variables is the sum of the individual hourly costs for:

- Projected load curtailment due to a supply deficit;

- Scheduling additional load to offset surplus must-run *generation facility* requirements (the minus sign is required since the violation price is negative);
  - *Operating reserve* requirement deficits;
  - All reserve area minimum *operating reserve* requirement deficits;
  - All reserve area *operating reserve* excesses above maximum requirements;
  - Pre-contingency and post-contingency limit violations for internal transmission facilities;
  - Pre-contingency limit violations for import or export *interties*; and
  - Exceeding the up or down ramp limits for the total net schedule change for imports and exports.

4.4 Security Assessment

4.4.1 For constrained scheduling, the DACP calculation engine iterates a *security* assessment function with the scheduling function. The scheduling function produces schedules which are passed to the *security* assessment function. The *security* assessment function determines losses and additional constraints which feed back to the subsequent iteration of the scheduling function.

4.4.2 The *security* assessment function used by Pass 1 is common to all passes of the DACP calculation engine process.

4.4.3 The *security* assessment function performs the following calculations and analyses:

4.4.3.1 Base case solution: A base case solution function prepares a power flow solution for each hour. This function automatically selects the power system model state (i.e., breaker/switch status, tap positions, desired voltages, etc) applicable to the forecast of conditions for the hour and input schedules. An AC load flow program is used; however, a DC load flow may be used should the AC load flow fail to converge.

4.4.3.2 Loss calculation: The solved power flow is used to calculate Ontario *transmission system* losses, incremental loss factors and loss adjustments to be used in the power balance constraint of the scheduling function.

4.4.3.3 Pre-contingency *security* assessment: Continuous thermal limits for all monitored equipment and operating *security limits* are monitored to check for pre-contingency limit violations. Violated limits are linearized and incorporated as constraints for use by the scheduling function.

4.4.3.4 Linear contingency analysis: A variation of the DC load flow is used to simulate all valid contingencies, calculate post contingency flows and check for limited time (i.e. emergency) thermal limit violations. Violated limits are linearized and incorporated as constraints for use by the scheduling function.

4.4.4 In the first iteration, before any processing by the *security* assessment functions, an initial default set of incremental loss factors and loss adjustments is used in the scheduling function. In this iteration, there are no transmission constraints from the *security* assessment. In subsequent iterations, the outputs from the *security* assessment function are used.

4.4.5 The *IESO* maintains sets of data as outlined in Appendix 7.5, section 2.4 for use in the *security* assessment processes for the *real-time market* and operation. The *security* assessment function will use this same set of data to obtain:

4.4.5.1 the power system model;

4.4.5.2 status of power system equipment;

4.4.5.3 list of contingencies to be simulated;

4.4.5.4 list of monitored equipment;

4.4.5.5 equipment thermal limits; and

4.4.5.6 operating *security limits* (angular stability, voltage stability and voltage decline).

4.4.6 Constraint violation variables, when violated indicate the type of problem that is not allowing the optimization of the objective function to have a solution. The equivalent constraint violation variables and their values as used in the *real-time market* and described Appendix 7.5, section 4.12 are utilized by the DACP calculation engine. Further details of these inputs for the DACP calculation engine are described in section 4.6.2.4.

4.5 Outputs from Pass 1

4.5.1 The primary outputs of Pass 1 which are used in Pass 2 and other DACP processes include the following:

4.5.1.1 Commitments;

4.5.1.2 Constrained schedules for *energy*; and

4.5.1.3 Shadow prices for *energy*.

4.6 Glossary of Sets, Indices, Variables and Parameters for Pass 1

4.6.1 Fundamental Sets and Indices

A	The set of all *intertie zones a*.
B	The set of buses *b* within Ontario, corresponding to *bids* and offers at locations on the *IESO-controlled grid.*
C	The set of contingencies conditions *c* to be considered in the *security* assessment.
D	The set of buses *d* outside Ontario, corresponding to *bids* and offers at *intertie zones*.
F	The set of transmission *facilities* (or groups of transmission *facilities*) *f* in Ontario for which constraints have been identified.
J	The set of all *bids j*. Each *price-quantity pair* of a *bid* submitted by a *market participant* would be represented by a unique element *j* in the set.
J_b	The subset of those *bids j* consisting of *bids* for a *dispatchable load* resource at a bus *b*.
J_d	The subset of those *bids j* consisting of *bids* for an export to *intertie zone* sink bus *d*.
K	The set of all *offers*. Each *price-quantity pair* of an *offer* submitted by a *market participant* would be represented by a unique element *k* in the set.
K_b	The subset of those *offers* consisting of *offers* for a *generation facility* at a bus *b.*
K_d	The subset of those *offers* consisting of *offers* for an import to *intertie zone* source bus *d.*
ORREG	The set of reserve areas, or regions, for which minimum and maximum *operating reserve* requirements have been defined. Each region *r* of the set *ORREG* consists of a set of buses at which *operating reserve* satisfying the minimum and maximum *operating reserve* requirement for that region may be located.
Z_{sch}	The set of all *interties* (or groups of *interties) z* for which constraints have been identified.

a	An *intertie zone*.
b	A bus corresponding to *bids* and *offers*. A single *facility* for which multiple *energy bids* are allowed may be represented as multiple buses, corresponding to the individual *bids*.
c	A contingency condition considered in the *security* assessment.
d	A bus outside Ontario corresponding to *bids* and *offers* in *intertie zones*.
f	A transmission *facility* for which a constraint has been identified. This includes groups of transmission *facilities*.
h	One of the day-ahead hours, from 1 to 24.
j	A *bid* or portion of a *bid* representing a single *price-quantity pair*.
k	An *offer* or portion of an *offer* representing a single *price-quantity pair*.
r	An *operating reserve* region within Ontario.
z	An *intertie* for which a constraint has been identified. This includes groups of *interties*.

4.6.2 Variables and Parameters

4.6.2.1 Bid and Offer Inputs

Dispatchable Loads:

$QPRL_{j,h,b}$	An incremental quantity of reduction in *energy* consumption that may be scheduled for a *dispatchable load* in hour h at bus b in association with *bid* j.
$PPRL_{j,h,b}$	The lowest *energy* price at which the incremental quantity of reduction in *energy* consumption specified in *bid* j should be scheduled in hour h at bus b.

$10SQPRL_{j,h,b}$	The synchronized *ten-minute operating reserve* quantity associated with *bid j* in hour *h* at bus *b* for *dispatchable loads* qualified to do so.
$10SPPRL_{j,h,b}$	The price of being scheduled to provide synchronized *ten-minute operating reserve* associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$10NQPRL_{j,h,b}$	The non-synchronized *ten-minute operating reserve* quantity associated with *bid j* in hour *h* at bus *b* for *dispatchable loads* qualified to do so.
$10NPPRL_{j,h,b}$	The price of being scheduled to provide non-synchronized *ten-minute operating reserve* associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$30RQPRL_{j,h,b}$	The *thirty-minute operating reserve* quantity associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$30RPPRL_{j,h,b}$	The price of being scheduled to provide *thirty-minute operating reserve* associated with *bid j* in hour *h* at bus *b*, for *dispatchable loads* qualified to do so.
$ORRPRL_b$	The *operating reserve* ramp rate per minute for reductions in load consumption at bus *b*.
$URRPRL_b$	The maximum rate per minute at which a *dispatchable load* that wishes to consume *energy* at bus *b* can decrease its amount of energy consumption.
$DRRPRL_b$	The maximum rate per minute at which a *dispatchable load* that wishes to consume *energy* at bus *b* can increase its amount of load consumption.

Exports:

$QHXL_{j,h,d}$	The maximum quantity of *energy* for which an export to *intertie zone* sink bus *d* in hour *h* may be scheduled in association with *bid j*.

$PHXL_{j,h,d}$	The highest price at which *energy* should be scheduled for an export to *intertie zone* sink bus *d* in hour *h* in association with *bid j*.
$QX10N_{j,h,d}$	The non-synchronized *ten-minute operating reserve* quantity associated with *bid j* in hour *h* at *intertie zone* sink bus *d* for an export qualified to do so.
$PX10N_{j,h,d}$	The price of being scheduled to provide non-synchronized *ten-minute operating reserve* associated with *bid j* in hour *h* at *intertie zone* sink bus *d*, for an export qualified to do so.
$QX30R_{j,h,d}$	The *thirty-minute operating reserve* quantity associated with *bid j* in hour *h* at *intertie zone* sink bus *d*, for an export qualified to do so.
$PX30R_{j,h,d}$	The price of being scheduled to provide *thirty-minute operating reserve* associated with *bid j* in hour *h* at *intertie zone* sink bus *d*, for an export qualified to do so.
$ORRHXL_d$	The *operating reserve* ramp rate per minute for exports at *intertie zone* sink bus *d*, as specified by the *IESO*.

Dispatchable Generators:

$MinQPRG_{h,b}$	The *minimum loading point* which is the minimum amount of *energy* that a *generation facility* at bus *b* is willing to produce in hour *h*, if scheduled to operate.
$SUPRG_{h,b}$	The *offered start-up cost* that a *generation facility* at bus *b* incurs in order to start and synchronize in hour *h*.
$SNL_{h,b}$	The *offered speed no-load cost* to maintain a *generation facility* synchronized with zero net *energy* injected into the system in hour *h*.
$MGOPRG_{h,b}$	The *offered* minimum generation cost for a *generation facility* at bus *b* in order to operate at its *minimum loading point* in hour *h.* This is calculated as the sum of $SNL_{h,b}$ and the incremental price, $PPRG_{k,h,b}$ for *energy* up to the *minimum loading point*, $MinQPRG_{h,b}$.

$QPRG_{k,h,b}$	An incremental quantity of *energy* generation (above and beyond the *minimum loading point*) that may be scheduled at bus *b* in hour *h* in association with *offer k.*
$PPRG_{k,h,b}$	The lowest *energy* price at which incremental generation should be scheduled at bus *b* in hour *h* in association with *offer k*.
$10SPPRG_{k,h,b}$	The *offered* price of being scheduled to provide synchronized *ten-minute operating reserve* in hour *h* at bus *b* in association with *offer k.*
$10SQPRG_{k,h,b}$	The *offered* quantity of synchronized *ten-minute operating reserve* in hour *h* at bus *b* in association with *offer k*.
$10NPPRG_{k,h,b}$	The *offered* price of being scheduled to provide non-synchronized *ten-minute operating reserve* in hour *h* at bus *b* in association with *offer k*.
$10NQPRG_{k,h,b}$	The *offered* quantity of non-synchronized *ten-minute operating reserve* in association with *offer k*.
$30RPPRG_{k,h,b}$	The *offered* price of being scheduled to provide *thirty-minute operating reserve* in association with *offer k*.
$30RQPRG_{k,h,b}$	The *offered* quantity of *thirty-minute operating reserve* in hour *h* at bus *b* in association with *offer k*.
$ORRPRG_b$	The maximum *operating reserve* ramp rate per minute at bus *b*.
$MRTPRG_b$	The *minimum generation block run time* period for which a *generation facility* at bus *b* must be scheduled to operate if its *offer* to generate is accepted.
$MDTPRG_b$	The *minimum generation block down time* period between the end of one period when a *generation facility* at bus *b* is scheduled to operate and the beginning of the next period when it is scheduled to operate.

$MaxStartsPRG_b$	The maximum number of times per day a *generation facility* at bus *b* can be scheduled tostart.
$URRPRG_b$	The maximum rate per minute at which a *generation facility offering* to produce at bus *b* can increase the amount of *energy* it supplies.
$DRRPRG_b$	The maximum rate per minute at which a *generation facility offering* to produce at bus *b* can decrease the amount of *energy* it supplies.
EL_b	The daily limit on the amount of *energy* that an *energy* limited resource at bus *b* may be scheduled to generate over the course of the day (*maximum daily energy limit*).

Imports:

$QHIG_{k,h,d}$	The maximum quantity of *energy* for which an import from *intertie zone* source bus *d* in hour *h* may be scheduled in association with *offer k*.
$PHIG_{k,h,d}$	The lowest price at which an import from *intertie zone* source bus *d* in hour *h* in association with *offer k* should be scheduled.
$QI10N_{k,h,d}$	The non-synchronized *ten-minute operating reserve* quantity associated with *offer k* in hour *h* at *intertie zone* source bus *d*.
$PI10N_{k,h,d}$	The price of being scheduled to provide non-synchronized *ten-minute operating reserve* associated with *offer k* in hour *h* at *intertie zone* source bus *d*.
$QI30R_{k,h,d}$	The non-synchronized *thirty-minute operating reserve* quantity associated with *offer k* in hour *h* at *intertie zone* source bus *d*.
$PI30R_{k,h,d}$	The price of being scheduled to provide non-synchronized *thirty-minute operating reserve* associated with *offer k* in hour *h* at *intertie zone* source bus *d*.

$ORRHIG_d$	The *operating reserve* ramp rate per minute for imports at *intertie zone* source bus *d*, as specified by the *IESO*.

4.6.2.2 Transmission and Security Inputs and Intermediate Variables

$EnCoeff_{a,z}$	The coefficient for calculating the contribution of scheduled *energy* flows (and *operating reserve*, in the case of inflows) over *intertie zone a* which is part of the *intertie* group *z*. $EnCoeff_{a,z}$ takes the value +1 to account for limits on scheduled flows into Ontario and the value -1 to account for limits on scheduled flows out of Ontario.
$MaxExtSch_{z,h}$	The maximum flow limit over an *intertie z* in hour *h*.
$ExtDSC_h$	The maximum decrease in total net flows over all *interties* from hour to hour, which limits the hour-to-hour decreases in net imports (calculated as imports less exports) from all the *intertie zones*.
$ExtUSC_h$	The maximum increase in total net flows over all *interties* from hour to hour, which limits the hour-to-hour increases in net imports (calculated as imports less exports) from all the *intertie zones*.
$PF_{h,a}$	The anticipated inflow into Ontario from *intertie zone a* in hour *h* that result from loop flows.
$MglLoss_{h,b}$	The marginal impact on transmission losses resulting from transmitting *energy* from the *reference bus* to serve an increment of additional load at the bus *b* in hour *h*.
$LossAdj_h$	The adjustment needed for hour *h* to correct for any discrepancy between actual Ontario total system losses using a base case power flow from the *security* assessment function and system losses that would be calculated using the marginal transmission loss factors.
$With^1_{h,b}$	The total amount of withdrawals scheduled in Pass 1 at each bus *b* in each hour *h*, for scheduled *dispatchable loads*.

$With^{1}_{h,d}$	The total amount of withdrawals scheduled in Pass 1 at each bus *d* in each hour *h*, for exports and outflows associated with loop flows for buses in *intertie zones*.
$Inj^{1}_{h,b}$	The total amount of injections scheduled in Pass 1 at each bus *b* in each hour *h*, for scheduled generation.
$Inj^{1}_{h,d}$	The total amount of injections scheduled in Pass 1 at each bus *d* in each hour *h*, for imports and inflows associated with loop flows for buses in *intertie zones*.
$PreConSF_{b,f,h}$	The fraction of *energy* injected at bus *b* which flows on transmission *facility f* during hour *h* under pre-contingency conditions.
$AdjNormMaxFlow_{f,h}$	The maximum flow allowed on transmission *facility f* in hour *h* as determined by the *security* assessment for pre-contingency conditions.
$SF_{b,f,c,h}$	The fraction of *energy* injected at bus *b* which flows on a transmission *facility f* during hour *h* under post-contingency conditions.
$AdjEmMaxFlow_{f,c,h}$	The maximum flow allowed on transmission *facility f* in hour *h* as determined by the *security* assessment for post-contingency condition *c*.

4.6.2.3 Other Inputs

Distribution of Load, Imports and Exports and Loop Flows

$LDF_{h,b}$	Load distribution factors, for loads which are distributed across Ontario, representing the proportion of the load at bus *b* in hour *h*. This is based on historical telemetry data.
AFL_{h}	Average Ontario *demand* forecast in hour *h* with the expected consumption associated with *dispatchable loads* removed.
PFL_{h}	Peak Ontario *demand* forecast in hour *h* with the expected consumption associated with *dispatchable loads* removed.

$ProxyUPIWt_{d,a}$	The proportion of inflows associated with loop flows from *intertie zone a* that shall be assigned to each bus *d* in the *control area* in which that *intertie zone* is located.
$ProxyUPOWt_{d,a}$	The proportion of outflows associated with loop flows from *intertie zone a* that shall be assigned to each bus *d* in the *control area* in which that *intertie zone* is located.
10ORConv	The factor applied to scheduled *ten-minute operating reserve* for *energy* limited resources to convert MW into MWh. This factor shall be 1.0.
30ORConv	The factor applied to scheduled *thirty-minute operating reserve* for *energy* limited resources to convert MW into MWh. This factor shall be 1.0.

Operating Reserve Requirements:

$TOT10R_h$	Minimum requirement for the total amount of *ten-minute operating reserve*.
$TOT10S_h$	The total amount of synchronized *ten-minute operating reserve* required in hour *h,* which is a percentage of the total *ten-minute operating reserve* requirement.
$TOT30R_h$	Minimum requirement for the total amount of *thirty-minute operating reserve*.
$REGMin10R_{r,h}$	The minimum requirement for *ten-minute operating reserve* in region *r* in hour *h*.
$REGMax10R_{r,h}$	The maximum amount of *ten-minute operating reserve* that may be provided in region *r* in hour *h.*
$REGMin30R_{r,h}$	The minimum requirement for *thirty-minute operating reserve* in region *r* in hour *h*.
$REGMax30R_{r,h}$	The maximum amount of *thirty-minute operating reserve* that may be provided in region *r* in hour *h.*

Other Ancillary Service and Resource Initializing Assumptions:

$MaxPRL_{h,b}$	The maximum amount of load reduction that a *dispatchable load* can achieve at bus *b* in hour *h*.

$MinPRG_{h,b}$	The minimum output for a *generation facility* at bus *b* in hour *h,* that is the most restrictive of the limits for *regulation* or voltage support, providing *AGC* or due to outages.
$MaxPRG_{h,b}$	The maximum output for a *generation facility* at bus *b* in hour *h,* that is the most restrictive of the limits for *regulation* or voltage support, providing *AGC* or due to outages.
$InitOperHrs_b$	The number of consecutive hours at the end of the previous day for which the *generation facility* or load at bus *b* was scheduled to operate.

4.6.2.4 Constraint Violation Price Inputs

PLdViol	The value that the DACP calculation engine will assign to scheduling the forecast load. As measured by the effect on the value of the objective function, if the cost of serving that load (in dollars per MWh) exceeds *PLdViol*, then that load would not be scheduled. This is not applicable to Pass 1 since *PLdViol* will exceed maximum *bid* price allowed and no *bid* load could be scheduled at this price. This equals the shortage cost for *energy* applied in the *real-time market*.
PGenViol	The price at which additional load will be included above the scheduled amount when the amount of *energy generation facilities* produce at their *minimum loading points* exceeds the amount of load scheduled on the system. This equals the negative of the shortage cost for *energy* applied in the *real-time market*.
P10SViol	The price at which the overall minimum synchronized *ten-minute operating reserve* requirement may be violated. This equals the shortage cost for synchronized *ten-minute operating reserve* applied in the *real-time market*.

P10RViol	The price at which the overall minimum *ten-minute operating reserve* requirement may be violated. This equals the shortage cost for total *ten-minute operating reserve* applied in the *real-time market*.
P30RViol	The price at which the overall minimum *thirty-minute operating reserve* requirement may be violated. This equals the shortage cost for total *thirty-minute operating reserve* applied in the *real-time market*.
PREG10RViol	The price at which the regional minimum *ten-minute operating reserve* requirements may be violated. This equals the shortage cost for the corresponding value applied in the *real-time market*.
PXREG10RViol	The price at which the regional maximum *ten-minute operating reserve* requirements may be violated. This equals the shortage cost for the corresponding value applied in the *real-time market*.
PREG30RViol	The price at which the regional minimum *thirty-minute operating reserve* requirements may be violated This equals the shortage cost for the corresponding value applied in the *real-time market*.
PXREG30RViol	The price at which the regional maximum *thirty-minute operating reserve* requirements may be violated. This equals the shortage cost for the corresponding value applied in the *real-time market*.
PPreConITLViol	The price at which pre-contingency flows over internal transmission may exceed that *facility*'s limit. This equals the shortage cost for base case *security limits* applied in the *real-time market*.
PITLViol	The price at which flows over an internal transmission *facility* following a contingency may exceed that *facility*'s limit. This equals the shortage cost for contingency constrained *security limits* applied in the *real-time market*.

PPreConXTLViol	The price at which the pre-contingency import and export *intertie* limits may be violated. This equals the shortage cost for inter *control area* scheduling limits applied in the *real-time market*.
PRmpXTLViol	The price at which the limit for hour to hour changes (up and down) of total net scheduled imports from *intertie zones* may be violated. This equals the shortage cost for inter *control area* scheduling limits applied in the *real-time market*.

4.6.2.5 Output Schedule and Commitment Variables

$SHXL^{1}_{j,h,d}$	The amount of exports scheduled in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SX10N^{1}_{j,h,d}$	The amount of non-synchronized *ten-minute operating reserve* scheduled from the export in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SX30R^{1}_{j,h,d}$	The amount of *thirty-minute operating reserve* scheduled from the export in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SPRL^{1}_{j,h,b}$	The amount of *dispatchable load* reduction scheduled at bus *b* in hour *h* in Pass 1 in association with *bid j*.
$10SSPRL^{1}_{j,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 1 in association with *bid j*.
$10NSPRL^{1}_{j,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 1 in association with *bid j*.
$30RSPRL^{1}_{j,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 1 in association with *bid j*.

$SHIG^{1}_{k,h,d}$	The amount of hourly imports scheduled in hour *h* from *intertie zone* source bus *d* in Pass 1 in association with *offer k.*
$SI10N^{1}_{k,h,d}$	The amount of imported *ten-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 1 in association with *offer k.*
$SI30R^{1}_{k,h,d}$	The amount of imported *thirty-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 1 in association with *offer k.*
$SPRG^{1}_{k,h,b}$	The amount of *energy* scheduled for the *generation facility* at bus *b* in hour *h* in Pass 1 in association with *offer k*. This is in addition to any $MinQPRG_{h,b}$, the *minimum loading point*, which must also be committed.
$OPRG^{1}_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled in hour *h* in Pass 1.
$IPRG^{1}_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled to start in hour *h* in Pass 1.
$10SSPRG^{1}_{k,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 1 in association with *offer k*.
$10NSPRG^{1}_{k,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 1 in association with *offer k*.
$30RSPRG^{1}_{k,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 1 in association with *offer k*.

4.6.2.6 Output Violation Variables

$ViolCost^{1}_{h}$	The cost incurred in order to avoid having the Pass 1 schedules for hour *h* violate specified constraints.
$SLdViol^{1}_{h}$	Projected load curtailment, that is, the amount of load that cannot be met using *offers* scheduled or committed in hour *h* in Pass 1.

$SGenViol^{1}_{h}$	The amount of additional load that must be scheduled in hour *h* in Pass 1 to ensure that there is enough load on the system to offset the must-run requirements of *generation facilities*.
$S10SViol^{1}_{h}$	The amount by which the overall synchronized *ten-minute operating reserve* requirement is not met in hour *h* of Pass 1 because the cost of meeting that portion of the requirement was greater than or equal to *P10SViol.*
$S10RViol^{1}_{h}$	The amount by which the overall *ten-minute operating reserve* requirement is not met in hour *h* of Pass 1 (above and beyond any failure to meet the synchronized *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P10RViol.*
$S30RViol^{1}_{h}$	The amount by which the overall *thirty-minute operating reserve* requirement is not met in hour *h* of Pass 1 (above and beyond any failure to meet the *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P30RViol.*
$SREG10RViol^{1}_{r,h}$	The amount by which the minimum *ten-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 1 because the cost of meeting that portion of the requirement was greater than or equal to *PREG10RViol.*
$SREG30RViol^{1}_{r,h}$	The amount by which the minimum *thirty-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 1 because the cost of meeting that portion of the requirement was greater than or equal to *PREG30RViol.*
$SXREG10RViol^{1}_{r,h}$	The amount by which the *ten-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 1 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG10RViol.*

$SXREG30RViol^{1}_{r,h}$	The amount by which the *thirty-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 1 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG30RViol.*
$SPreConITLViol^{1}_{f,h}$	The amount by which pre-contingency flows over *facility f* in hour *h* of Pass 1 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConITLViol.*
$SITLViol^{1}_{f,c,h}$	The amount by which flows over *facility f* that would follow the occurrence of contingency *c* in hour *h* of Pass 1 exceed the emergency limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PITLViol.*
$SPreConXTLViol^{1}_{z,h}$	The amount by which *intertie* flows over *facility z* in hour *h* of Pass 1 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConXTLViol.*
$SURmpXTLViol^{1}_{h}$	The amount by which the total net scheduled import increase for hour *h* in Pass 1 exceeds the up ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*
$SDRmpXTLViol^{1}_{h}$	The amount by which the total net scheduled import decrease in hour *h* of Pass 1 exceed the down ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

4.6.2.7 Output Shadow Prices

Shadow Prices of Constraints:

SPL^{1}_{h} The Pass 1 shadow price measuring the rate of change of the objective function for a change in load at the *reference bus* in hour *h*.

$SPNormT^{1}_{f,h}$ The Pass 1 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjNormMaxFlow_{f,h}$, on flows over transmission *facilities* in normal conditions for *facility f* in hour *h*.

$SPEmT^{1}_{f,c,h}$ The Pass 1 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjEmMaxFlow_{f,c,h}$, on flows over transmission *facilities* in emergency conditions for *facility f* in monitored contingency *c* in hour *h*.

Shadow Price for Energy:

$LMP^{1}_{h,b}$ The Pass 1 locational marginal price for *energy* at each bus *b* in each hour *h.* It measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of supply at that bus in that hour in Pass 1.

4.6.2.8 Energy Ramp Rates

$RmpRngMaxPRL_{j,b}$ The maximum load reduction to which the ramp rates $URRPRL_{j,b}$ and $DRRPRL_{j,b}$ apply for a *dispatchable load* at bus *b*. The largest $RmpRngMaxPRL_{j,b}$ must be greater than or equal to maximum load reduction bid.

$URRPRL_{j,b}$ The maximum rate per minute at which a *dispatchable load* at bus *b* can decrease its consumption of energy while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b}$.

$DRRPRL_{j,b}$ The maximum rate per minute at which a *dispatchable load* at bus *b* can increase its consumption of energy while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b}$.

$RmpRngMaxPRG_{k,b}$ The maximum output level to which the ramp rates $URRPRG_{k,b}$ and $DRRPRG_{k,b}$ apply for a *generation facility* at bus *b*. The largest $RmpRngMaxPRG_{k,h,b}$ must be greater than or equal to maximum *energy offered*.

$URRPRG_{k,b}$ The maximum rate per minute at which a *generation facility* at bus *b* can increase its output while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$.

DRRPRG$_{k,b}$ The maximum rate per minute at which a *generation facility* at bus b can decrease its output in hour h while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$.

4.7 Objective Function

4.7.1 The optimization of the objective function in Pass 1 is to maximize the expression:

$$\sum_{h=1,\dots,24}\left\{\begin{array}{l}
\sum_{d\in DX, j\in J_d}(SHXL^1_{j,h,d}\cdot PHXL_{j,h,d} - SX10N^1_{j,h,d}\cdot PX10N_{j,h,d} - SX30R^1_{j,h,d}\cdot PX30R_{j,h,d}) \\
-\sum_{b\in B}\left[\begin{array}{l}\sum_{j\in J_b} SPRL^1_{j,h,b}\cdot PPRL_{j,h,b} \\
+\sum_{j\in J_b}\begin{array}{l}10SSPRL^1_{j,h,b}\cdot 10SPPRL_{j,h,b}+10NSPRL^1_{j,h,b}\cdot 10NPPRL_{j,h,b}+ \\ 30RSPRL^1_{j,h,b}\cdot 30RPPRL_{j,h,b}\end{array}\end{array}\right] \\
-\sum_{d\in DI, k\in K_d}\left(SHIG^1_{k,h,d}\cdot PHIG_{k,h,d} + SI10N^1_{k,h,d}\cdot PI10N_{k,h,d} + SI30R^1_{k,h,d}\cdot PI30R_{k,h,d}\right) \\
-\sum_{b\in B}\left[\begin{array}{l}\sum_{k\in K_b}\left(SPRG^1_{k,h,b}\cdot PPRG_{k,h,b}\right) \\
+OPRG^1_{h,b}\cdot MGOPRG_{h,b} + IPRG^1_{h,b}\cdot SUPRG_{h,b} \\
+\sum_{k\in K_b}\begin{array}{l}10SSPRG^1_{k,h,b}\cdot 10SPPRG_{k,h,b}+10NSPRG^1_{k,h,b}\cdot 10NPPRG_{k,h,b} \\ +30RSPRG^1_{k,h,b}\cdot 30RPPRG_{k,h,b}\end{array}\end{array}\right] \\
-ViolCost^1_h
\end{array}\right\};$$

where $ViolCost^1{}_h$ is calculated as follows:

$$
\begin{aligned}
ViolCost_h^1 &= SLdViol_h^1 \cdot PLdViol - SGenViol_h^1 \cdot PGenViol \\
&+ S10SViol_h^1 \cdot P10SViol + S10RViol_h^1 \cdot P10RViol \\
&+ S30RViol_h^1 \cdot P30RViol \\
&+ \sum_{r \in ORREG} \begin{pmatrix} SREG10RViol_{r,h}^1 \cdot PREG10RViol \\ + SREG30RViol_{r,h}^1 \cdot PREG30RViol \\ + SXREG10RViol_{r,h}^1 \cdot PXREG10RViol \\ + SXREG30RViol_{r,h}^1 \cdot PXREG30RViol \end{pmatrix} \\
&+ \sum_{f \in F} SPreConITLViol_{f,h}^1 \cdot PPreConITLViol \\
&+ \sum_{f \in F, c \in C} SITLViol_{f,c,h}^1 \cdot PITLViol \\
&+ \sum_{z \in Z} SPreConXTLViol_{z,h}^1 \cdot PPreConXTLViol \\
&+ SURmpXTLViol_h^1 \cdot PRmpXTLViol \\
&+ SDRmpXTLViol_h^1 \cdot PRmpXTLViol.
\end{aligned}
$$

4.7.2 The Pass 1 maximization is subject to the constraints described in the next section.

4.8 Constraints Overview

4.8.1 The constraints that apply to the optimization above can be broken into the categories:

a) Single hour constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *bids* and *offers* submitted by *registered market participants*;

b) Inter-hour and multi-hour constraints to ensure that the schedules determined in the optimization do not violate the parameters specified in the *bids* and *offers* submitted by *registered market participants*; and

c) Constraints to ensure that those schedules do not violate *reliability* criteria established by the *IESO*.

4.9 Bid/Offer Constraints Applying to Single Hours

4.9.1 Status Variables and Capacity Constraints

4.9.1.1 A Boolean variable, $OPRG^1_{h,b}$ indicates whether a *dispatchable generation facility* at bus *b* is committed in hour *h*. A value of zero indicates that a resource is not committed, while a value of one indicates that it is committed. Therefore:

$$OPRG^1_{h,b} = 0 \text{ or } 1,$$

for all hours *h* and buses *b*.

4.9.1.2 Must-run resources will be considered committed for all must-run hours. Regulating units will be considered committed for all the hours that they are regulating. *Generation facilities* with zero commitment cost (i.e., their *minimum loading point*s, *start-up costs minimum generation block run-times* and *minimum generation block down times* are zero) and hourly loads*,* imports and exports will be considered committed for all the hours.

4.9.1.3 No schedule can be negative, nor can any schedule exceed the amount of capacity *offered* for that service (*energy* and *operating reserve*). Therefore:

$$0 \le SPRL^1_{j,h,b} \le QPRL_{j,h,b};$$

$$0 \le 10SSPRL^1_{j,h,b} \le 10SQPRL_{j,h,b};$$

$$0 \le 10NSPRL^1_{j,h,b} \le 10NQPRL_{j,h,b};$$

$$0 \le 30RSPRL^1_{j,h,b} \le 30RQPRL_{j,h,b};$$

$$0 \le SHXL^1_{j,h,d} \le QHXL_{j,h,d};$$

$$0 \le SX10N^1_{j,h,d} \le QX10N_{j,h,d};$$

$$0 \le SX30R^1_{j,h,d} \le QX30R_{j,h,d};$$

$$0 \le SHIG^1_{k,h,d} \le QHIG_{k,h,d};$$

$$0 \le SI10N^1_{k,h,d} \le QI10N_{k,h,d}; \text{ and}$$

$$0 \le SI30R^1_{k,h,d} \le QI30R_{k,h,d}$$

for all *bids* j, *offers* k, hours h, buses b and *intertie zones* sink/source bus d.

4.9.1.4 In the case of *generation facilities*, in addition to restrictions on their schedules similar to those above, their schedules must be consistent with their operating status as described above. *Generation facilities* can be scheduled to produce *energy* and/or *operating reserve* only if they are committed. Therefore:

$$0 \le SPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot QPRG_{k,h,b};$$

$$0 \le 10SSPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot 10SQPRG_{k,h,b};$$

$$0 \le 10NSPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot 10NQPRG_{k,h,b}; \text{ and}$$

$$0 \le 30RSPRG^1_{k,h,b} \le OPRG^1_{h,b} \cdot 30RQPRG_{k,h,b}$$

for all *offers* k, hours h, and buses b.

4.9.1.5 In the case of linked wheeling transactions (the export *bid* and the import *offer* have the same *NERC* tag identifier), the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore:

$$\sum_{j \in J_d} SHXL^1_{j,h,dx} = \sum_{k \in k_d} SHIG^1_{k,h,di}$$

where *dx* and *di* are the respective buses of the export and import schedules associated with the wheeling transactions.

4.9.1.6 The minimum and/or maximum output of internal resources may be limited because of *outages* and/or de-ratings or in order for the units to provide *regulation* or voltage support. These constraints will take the form:

$$MinPRG_{h,b} \le MinQPRG_{h,b} \cdot OPRG^1_{h,b} + \sum_{k \in K_b} SPRG^1_{k,h,b} \le MaxPRG_{h,b}.$$

4.9.1.7 Similarly, the maximum level of load reduction is the mechanism by which a *dispatchable load* indicates any de-rating to its registered maximum load reduction level due to mechanical or operational adjustments to their equipment. The constraint will take the form:

$$\sum_{j \in J_b} SPRL^1_{j,h,b} \le MaxPRL_{h,b}.$$

4.9.2 Operating Reserve Constraints

4.9.2.1 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load (maximum load *bid* minus the load reductions). These conditions can be enforced by the following two constraints:

$$\sum_{j\in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq 30 \cdot ORRPRL_b\text{; and}$$

$$\sum_{j\in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq \sum_{j\in J_b}(QPRL_{j,h,b} - SPRL^1_{j,h,b}).$$

4.9.2.2 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to increase load reduction (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8):

$$\sum_{j\in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq -\sum_{j\in J_b}\left[\left(QPRL_{j,h-1,b} - SPRL^1_{j,h-1,b}\right) - \left(QPRL_{j,h,b} - SPRL^1_{j,h,b}\right)\right]$$
$$+ 60 \cdot URRPRL_b.$$

4.9.2.3 Finally, the total 10-minute synchronized, 10-minute non-synchronized and 30-minute *operating reserve* from committed *dispatchable load* cannot exceed the *dispatchable load's* Pass 1 scheduled consumption:

$$\sum_{j\in J_b}(10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})$$
$$\leq MaxPRL_{h,b} - \sum_{j\in J_b} SPRL^1_{j,h,b}.$$

4.9.2.4 The amount of 10-minute synchronized reserve plus the 10-minute non-synchronized reserve that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_b} 10SSPRL^1_{j,h,b} + 10NSPRL^1_{j,h,b} \leq 10 \cdot ORRPRL_b.$$

4.9.2.5 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *generation facility* cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b})$$
$$\leq 30 \cdot ORRPRG_b \text{; and}$$

$$\sum_{k \in K_b} (10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b})$$
$$\leq \sum_{k \in K_b} (QPRG_{k,h,b} - SPRG^1_{k,h,b}).$$

4.9.2.6 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable generation facility* cannot exceed the *generation facility's* ramp capability (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8). Ramping considerations from start ups or shut downs are not carried forward from one day to the next:

$$\sum_{k\in K_b}(10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}) \le \sum_{k\in K_b}\left(SPRG^1_{k,h-1,b} - SPRG^1_{k,h,b}\right) + 60 \times URRPRG_b$$

and

$$\sum_{k\in K_b}\left(10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}\right) + \sum_{k\in K_b}\left(SPRG^1_{kh,b}\right) \le [(h-n) * 60 + 30] \times URRPRG_b \times OPRG^1_{h,b}$$

where n is the hour of the last start before or in hour h
and

$$\sum_{k\in K_b}\left(10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b}\right) + \sum_{k\in K_b}\left(SPRG^1_{k,h,b}\right) \le [(m-h) * 60 + 30] \times DRRPRG_b \times OPRG^1_{h,b}$$

where m is the hour of the last shut down in or after hour h.

4.9.2.7 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *generation facility* cannot exceed its Pass 1 unscheduled capacity:

$$\sum_{k\in K_b}(10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b})$$
$$\leq MaxPRG_{h,b} - \sum_{k\in K_b} SPRG^1_{k,h,b} - MinQPRG_{h,b}.$$

4.9.2.8 The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *generation facility* is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k\in K_b}(10SSPRG^1_{k,h,b} + 10NSPRG^1_{k,h,b}) \leq 10 \cdot ORRPRG_b.$$

4.9.2.9 The total reserve (10-minute non-synchronized and 30-minute) from hourly exports cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled export. These conditions can be enforced by the following two constraints:

$$\sum_{j\in J_d}(SX10N^1_{j,h,d} + SX30R^1_{j,h,d}) \leq 30 \cdot ORRHXL_d; \text{ and}$$

$$\sum_{j\in J_d}(SX10N^1_{j,h,d} + SX30R^1_{j,h,d}) \leq \sum_{j\in J_d} SHXL^1_{j,h,d}.$$

4.9.2.10 The amount of 10-minute non-synchronized reserve that hourly export is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j\in J_d}(SX10N^1_{j,h,d}) \leq 10 \cdot ORRHXL_d.$$

4.9.2.11 The total reserve (10-minute non-synchronized and 30-minute) from hourly imports cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_d} (SI10N^1_{k,h,d} + SI30R^1_{k,h,d}) \leq 30 \cdot ORRHIG_d \text{; and}$$

$$\sum_{k \in K_d} (SI10N^1_{k,h,d} + SI30R^1_{k,h,d}) \leq \sum_{k \in K_d} (QHIG_{k,h,d} - SHIG^1_{k,h,d}).$$

4.9.2.12 The amount of 10-minute non-synchronized reserve that hourly import is scheduled to provide cannot exceed the amount by which it can increase the output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_d} SI10N^1_{k,h,d} \leq 10 \cdot ORRHIG_d.$$

4.10 Bid/Offer Inter-Hour/Multi-Hour Constraints

4.10.1 Status Variables

4.10.1.1 A Boolean variable, $IPRG^1_{h,b}$, indicates that a *generation facility* at bus *b* is scheduled to start up on hour *h*. A value of zero indicates that a resource is not scheduled to start up, while a value of one indicates that it is scheduled to start up. Therefore, for $h > 1$:

$$IPRG^1_{h,b} = \begin{cases} 1, & \text{if } OPRG^1_{h-1,b} = 0 \text{ and } OPRG^1_{h,b} = 1 \\ 0, & \text{otherwise.} \end{cases}$$

4.10.1.2 For $h = 1$, the determination of whether a resource was previously operating must make reference to the initial conditions:

$$IPRG_{h,b}^{1} = \begin{cases} 1, \text{ if } InitOperHrs_b = 0 \text{ and } OPRG_{h,b}^{1} = 1 \\ 0, \text{ otherwise.} \end{cases}$$

4.10.2 Ramping

4.10.2.1 *Energy* schedules for each resource cannot vary by more than an hour's ramping capacity for that resource. The *energy* schedule change in the hour in which the unit is scheduled to start or shut down depends on the unit ramp rate below its *minimum loading point*. Almost all non-quick start units will need one or more hours to reach their *minimum loading point* and to go down from *minimum loading point* to zero. Since non-committed units must be assigned zero output and committed units must operate at or above their *minimum loading point*, it is assumed that these units will be at their *minimum loading point* at the beginning of the first commitment hour and at the end of the hour before shut down.

4.10.2.2 The following three part constraint ensures that *energy* schedules do not exceed the *generation facility's* ramp capability in the hours where the *generation facility* starts, stays on and shuts down.

Start Up Scenario ($OPRG^1_{h,b} = 1$, and $OPRG^1_{h-1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^1_{k,h,b} \leq \sum_{k \in K_b} 30 \times URRPRG_b$$

Continued On Scenario ($OPRG^1_{h-1,b} = OPRG^1_{h,b} = 1$)

$$\sum_{k \in K_b} \left(SPRG^1_{k,h-1,b}\right) - 60 \times DRRPRG_b \leq \sum_{k \in K_b} SPRG^1_{k,h,b}$$

$$\leq \sum_{k \in K_b} \left(SPRG^1_{k,h-1,b}\right) + 60 \times URRPRG_b$$

Shut Down Scenario ($OPRG^1_{h,b} = 1$, and $OPRG^1_{h+1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^1_{k,h,b} \leq \sum_{k \in K_b} 30 \times DRRPRG_b$$

4.10.2.3 It should be noted that this ramp up/down is in addition to the *minimum loading point*. The unit commitment process handles the *minimum loading point* change. This ramp only affects the incremental change above the *minimum loading point*.

4.10.2.4 The *dispatchable loads* are considered committed in all hours. Similar logic is applied to *dispatchable loads* to arrive at the following constraint:

$$\sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^1_{j,h-1,b}\right) - 60 \cdot URRPRL_{h,b}$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^1_{j,h,b}\right)$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^1_{j,h-1,b}\right) + 60 \cdot DRRPRL_{h,b}.$$

4.10.2.5 The above two constraints apply for all hours from 1 to 24. In the above two constraints the variables related to hour zero belong to the last hour of the previous day and are obtained from the initializing assumptions.

4.10.2.6 The ramping rates in the ramping constraints must be adjusted to allow the resource to:

a) Ramp down from its lower limit in hour (*h-1*) to its upper limit in hour *h*.

b) Ramp up from its upper limit in hour (*h-1*) to its lower limit in hour *h*.

4.10.2.7 This will allow a solution to be obtained when changes to the upper and lower limits between hours are beyond the ramping capability of the resources.

4.10.2.8 In the above ramping constraints, a single ramp up and a single ramp down, $URRPRG_b$ and $DRRPRG_b$ for *generation facilities* and $URRPRL_b$ and $DRRPRL_b$ for *dispatchable loads* are used. The ramp rate is assumed constant over the full operating range of the *dispatchable load* and *generation facility*. However, this is not the case. *Dispatchable load bids* and *generator offers* will include multi-*energy* ramp rates.

4.10.2.9 In the *dispatchable load bids*, multi-*energy* ramp rates would be specified as:

a) $RmpRngMaxPRL_{j,\, b}$ shall designate the level of maximum load reduction to which the ramp rates $URRPRL_{j,b}$ and $DRRPRL_{j,b}$ shall apply. $RmpRngMaxPRL_{5,b}$ must be greater than or equal to maximum load reduction *bid*.

b) $URRPRL_{j,b}$ shall designate the maximum rate per minute at which a *dispatchable load* at bus *b* can increase load reduction while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b}$. $RmpRngMaxPRL_{0,b}$ is equal to the minimum load reduction.

c) $DRRPRL_{j,b}$ shall designate the maximum rate per minute at which a *dispatchable load* at bus *b* can decrease load reduction while operating in the range between $RmpRngMaxPRL_{j-1,b}$ and $RmpRngMaxPRL_{j,b}$. $RmpRngMaxPRL_{0,b}$ is equal to the minimum load reduction.

4.10.2.10 The multi-*energy* ramp rates would be specified for *generation facilities* as:

a) $RmpRngMaxPRG_{k,b}$ shall designate the maximum generation output level to which the ramp rates $URRPRG_{k,b}$ and $DRRPRG_{k,b}$ shall apply. $RmpRngMaxPRG_{5,b}$ must be greater than or equal to maximum generation output *offered*.

b) $URRPRG_{k,b}$ shall designate the maximum rate per minute at which a *generation facility* at bus *b* can increase its output while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$. $RmpRngMaxPRG_{0,b}$ is equal to its *minimum loading point*.

c) $DRRPRG_{k,b}$ shall designate the maximum rate per minute at which a *generation facility* at bus *b* can decrease its output while operating in the range between $RmpRngMaxPRG_{k-1,b}$ and $RmpRngMaxPRG_{k,b}$. $RmpRngMaxPRG_{0,b}$ is equal to its *minimum loading point*.

4.10.3 Minimum Generation Block Run Time and Minimum Generation Block Down Time

4.10.3.1 Schedules for *generators* must observe *minimum generation block run times* and *minimum generation block down times*. At the beginning of the day, a *generation facility*'s previous day schedule is considered,

if $0 < InitOperHrs_b < MRTPRG_b$, then that *generation facility* has yet to complete its *minimum generation block run time*, and:

$$OPRG^1_{1,b}, OPRG^1_{2,b}, \ldots, OPRG^1_{\min(24, MRTPRG_b - InitOperHrs_b), b} = 1.$$

4.10.3.2 During the day,

if $OPRG^1_{h,b} = 1$, $OPRG^1_{h+1,b} = 0$, and $MDTPRG_b > 1$, then the *generation facility* at bus *b* has been scheduled to shut down during hour $h + 1$. It must be scheduled to remain off until it has completed its *minimum generation block down time* or we reach the end of the day. Therefore:

$$OPRG^1_{h+2,b}, OPRG^1_{h+3,b}, \ldots, OPRG^1_{\min(24, h+MDTPRG_b), b} = 0.$$

And if $OPRG^{1}_{h,b} = 0$, $OPRG^{1}_{h+1,b} = 1$, and $MRTPRG_b > 1$, then the *generation facility* at bus b has been scheduled to start up during hour $h + 1$. It must be scheduled to remain in operation until it has completed its *minimum generation block run time* or we reach the end of the day, so:

$$OPRG^{1}_{h+2,b}, OPRG^{1}_{h+3,b}, \ldots, OPRG^{1}_{\min(24, h+MRTPRG_b), b} = 1, \text{and}$$

$$OPRG^{1}_{0,b} = \begin{cases} 0, \text{ if } InitOperHrs_b = 0 \\ 1, \text{ otherwise.} \end{cases}$$

4.10.4 Energy Limited Resources

4.10.4.1 A constraint must be added in order to ensure that *energy* limited units are not scheduled to provide more *energy* than they have indicated they are capable of providing. In addition to limiting *energy* schedules over the course of the day to the *energy* limit specified for a unit, this constraint must also ensure that units are not scheduled to provide *energy* in amounts that would preclude them from providing reserve when activated. Given these factors, therefore:

$$\sum_{h=1}^{1}\left(OPRG^{1}_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}SPRG^{1}_{k,h,b}\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^{1}_{k,1,b}+\sum_{k\in K_b}10NSPRG^{1}_{k,1,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^{1}_{k,1,b}\le EL_b;$$

$$\sum_{h=1}^{2}\left(OPRG^{1}_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}SPRG^{1}_{k,h,b}\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^{1}_{k,2,b}+\sum_{k\in K_b}10NSPRG^{1}_{k,2,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^{1}_{k,2,b}\le EL_b;$$

M

$$\sum_{h=1}^{24}\left(OPRG^{1}_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}SPRG^{1}_{k,h,b}\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^{1}_{k,24,b}+\sum_{k\in K_b}10NSPRG^{1}_{k,24,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^{1}_{k,24,b}\le EL_b$$

for all buses *b* at which *energy*-limited resources are located. The factors *10ORConv* and *30ORConv* are applied to scheduled *ten-minute* and *thirty-minute operating reserves* for *energy*-limited resources to convert MW into MWh. This factor is initially set to unity.

4.10.5 Maximum Number of Starts

4.10.5.1 To ensure that *generation facilities* are not scheduled to be cycled on and off more than their specified maximum number in a day, the following constraint is defined:

$$\sum_{h=1}^{24}IPRG^{1}_{h,b}\le MaxStartsPRG_b.$$

4.11 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

4.11.1 Load

4.11.1.1 For each hour of the DACP, the total amount of *energy* generated in the DACP schedule, plus scheduled imports must be sufficient to meet forecast *demand*, scheduled exports, and transmission losses consistent with these schedules. It will be easiest to break the derivation of the constraint that will ensure this occurs into several steps.

4.11.1.2 The total amount of withdrawals scheduled in Pass 1 at each bus b in each hour h, $With^1_{h,b}$, is the sum of:

- the portion of the load forecast for that hour that has been allocated to that bus; and
- all *dispatchable load bid*, net of the amount of load reduction scheduled (since the *dispatchable load* is excluded from the *demand* forecast by the DACP calculation engine), yielding:

$$With^1_{h,b} = LDF_{h,b} \cdot AFL_h + \left[\sum_{j \in J_h} \left(QPRL_{j,h,b} - SPRL^1_{j,h,b} \right) \right]; \text{ and}$$

the total amount of withdrawals scheduled in Pass 1 at each *intertie zone* sink bus d in each hour h, $With^1_{h,d}$, is the sum of:

- exports from Ontario to each *intertie zone* sink bus; and
- outflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$With^1_{h,d} = \sum_{j \in J_d} (SHXL^1_{j,h,d}) - \sum_{a \in A} ProxyUPOWt_{d,a} \cdot \min(0, PF_{h,a}).$$

4.11.1.3 The total amount of injections scheduled in Pass 1 at each bus b in each hour h, $Inj^1_{h,b}$, is the sum of

- *generation facilities* scheduled at that bus, yielding:

$$Inj^{1}_{h,b} = OPRG^{1}_{h,b} \cdot MinQPRG_{h,b} + \sum_{k \in K_b} SPRG^{1}_{k,h,b}\text{; and}$$

the total amount of injections scheduled in Pass 1 at each *intertie zone* source bus d in each hour h, $Inj^{1}_{h,b}$, is the sum of:

- imports into Ontario from each *intertie zone* source bus; and
- inflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose:

$$Inj^{1}_{h,d} = \sum_{k \in K_d} SHIG^{1}_{k,h,d} + \sum_{a \in A} ProxyUPIWt_{d,a} \cdot \max(0, PF_{h,a}).$$

4.11.1.4 Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses (or reduction in losses) that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between actual and marginal losses. Load reduction associated with the *demand* constraint violation will be subtracted from the total load and generation reduction will be subtracted from total generation associated with the *demand* constraint violation to ensure that the DACP calculation engine will always produce a solution. These violation variables are assigned a very high cost to limit their use to infeasible cases.

$$\begin{aligned}&\sum_{b \in B}(1 + MglLoss_{h,b})With^{1}_{h,b} + \sum_{d \in D}(1 + MglLoss_{h,d})With^{1}_{h,d} - SLdViol^{1}_{h} \\ &= \sum_{b \in B}(1 + MglLoss_{h,b})Inj^{1}_{h,b} \\ &\quad + \sum_{d \in D}(1 + MglLoss_{h,d})Inj^{1}_{h,d} - SGenViol^{1}_{h} + LossAdj_{h}.\end{aligned}$$

4.11.2 Operating Reserve

4.11.2.1 Sufficient *operating reserve* must be provided on the system to meet system wide requirements for 10-minute synchronized reserve, *ten-minute operating reserve* and *thirty-minute operating reserve*, as well as all applicable regional minimum and maximum requirements for *operating reserve*.

4.11.2.2 Therefore, taking into consideration the potential not to meet these minimum and maximum requirements if the cost of meeting those requirements becomes too high:

$$\sum_{b \in B}\left(\sum_{k \in K_b} 10SSPRG^1_{k,h,b}\right) + \sum_{b \in B}\left(\sum_{j \in J_b} 10SSPRL^1_{j,h,b}\right) + S10SViol^1_h \geq TOT10S_h;$$

$$\sum_{b \in B}\left(\sum_{j \in J_b} 10SSPRL^1_{j,h,b}\right) + \sum_{b \in B}\left(\sum_{k \in K_b} 10SSPRG^1_{k,h,b}\right) + S10RViol^1_h + \sum_{b \in B}\left(\sum_{k \in K_b} 10NSPRG^1_{k,h,b}\right) + \sum_{b \in B}\left(\sum_{j \in J_b} 10NSPRL^1_{j,h,b}\right) + \sum_{d \in D}\left(\sum_{k \in K_d} SI10N^1_{k,h,d}\right) + \sum_{d \in D}\left(\sum_{j \in J_d} SX10N^1_{j,h,d}\right) \geq TOT10R_h; \text{ and}$$

$$\sum_{b \in B}\left(\sum_{j \in J_b} 10SSPRL^1_{j,h,b}\right) + \sum_{b \in B}\left(\sum_{k \in K_b} 10SSPRG^1_{k,h,b}\right) + S30RViol^1_h + \sum_{b \in B}\left(\sum_{k \in K_b}(10NSPRG^1_{k,h,b} + 30RSPRG^1_{k,h,b})\right) + \sum_{b \in B}\left(\sum_{j \in J_b}(10NSPRL^1_{j,h,b} + 30RSPRL^1_{j,h,b})\right) + \sum_{d \in D}\left(\sum_{k \in K_d}(SI10N^1_{k,h,d} + SI30R^1_{k,h,d})\right) + \sum_{d \in D}\left(\sum_{j \in J_d}(SX10N^1_{j,h,d} + SX30R^1_{j,h,d})\right) \geq TOT30R_h$$

for all hours h, and

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^1_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^1_{k,h,b}\right)+SREG10RViol^1_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^1_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^1_{j,h,b}\right)$$
$$\geq REGMin10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^1_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^1_{k,h,b}\right)-SXREG10RViol^1_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^1_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^1_{j,h,b}\right)$$
$$\leq REGMax10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^1_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^1_{k,h,b}\right)+SREG30RViol^1_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} (10NSPRG^1_{k,h,b}+30RSPRG^1_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b} (10NSPRL^1_{j,h,b}+30RSPRL^1_{j,h,b})\right)$$
$$\geq REGMin30R_{r,h};\text{ and}$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^1_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^1_{k,h,b}\right)-SXREG30RViol^1_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} (10NSPRG^1_{k,h,b}+30RSPRG^1_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b} (10NSPRL^1_{j,h,b}+30RSPRL^1_{j,h,b})\right)$$
$$\leq REGMax30R_{r,h}$$

for all hours h, and for all regions r in the set *ORREG*.

4.11.3 Internal Transmission Limits

4.11.3.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 1 of the DACP calculation engine would not violate any *security limits* in either the pre-contingency state or after any contingency.

4.11.3.2 To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus will be used.

4.11.3.3 The *security* assessment function of the DACP calculation engine will linearize binding (violated) pre-contingency limits on transmission *facilities* within Ontario. The linearized constraints will take the form:

$$\sum_{b\in B} PreConSF_{b,f,h}(Inj^1_{h,b} - With^1_{h,b}) + \sum_{d\in D} PreConSF_{d,f,h}(Inj^1_{h,d} - With^1_{h,d}) - SPreConITL\ Viol^1_{f,h} \le AdjNormMax\ Flow_{f,h}$$

where B is the set of buses within Ontario and D is the set of sink and source buses outside Ontario, for all *facilities* f and hours h.

4.11.3.4 Similarly, the linearized binding post-contingency limits will take the form:

$$\sum_{b\in B} SF_{b,f,c,h}(Inj^1_{h,b} - With^1_{h,b}) + \sum_{d\in D} SF_{d,f,c,h}(Inj^1_{h,d} - With^1_{h,d}) - SITLViol^1_{f,c,h} \le AdjEmMaxFl\ ow_{f,c,h}$$

for all *facilities* f, hours h, and monitored contingencies c.

4.11.4 Intertie Limits and Constraints on Net Imports

4.11.4.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 1 of the DACP calculation engine would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. To ensure this, we must calculate the net amount of *energy* scheduled to flow over each *intertie* in each hour and the amount of *operating reserve* scheduled to be provided by resources in that *control area*. This will be summed over all affected *interties*. The result will be compared to the limit associated with that constraint. Consequently:

$$\sum_{a\in A}\left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d\in DI_a,k\in K_d}(SHIG^1_{k,h,d})+PF_{h,a}-\sum_{d\in DX_a,j\in J_d}(SHXL^1_{j,h,d})\right)+ \\ 0.5(EnCoeff_{a,z}+1)\left[\begin{array}{l}\sum_{d\in DI_a,k\in K_d}\left(SI10N^1_{k,h,d}+SI30R^1_{k,h,d}\right) \\ +\sum_{d\in DX_a,j\in J_d}\left(SX10N^1_{j,h,d}+SX30R^1_{j,h,d}\right)\end{array}\right]\end{array}\right]$$
$$\leq MaxExtSch_{z,h}$$

for all hours h, for all *intertie zones* a relevant to the constraint z

$(EnCoeff_{a,z} \neq 0)$,

and for all constraints z in the set Z_{sch}.

4.11.4.2 In addition, changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour. It cannot exceed the sum of net import schedule for all *interties* for the previous hour plus the maximum permitted hourly increase. It cannot be less than the sum of the net import schedule for all *interties* for the previous hour minus the maximum permitted hourly decrease. Violation variables are provided for both the up and down ramp limits to ensure that the DACP calculation engine will always find a solution. Therefore:

$$\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^1_{k,h-1,d})-\sum_{j\in J_d}(SHXL^1_{j,h-1,d})\right)-ExtDSC_h-SDRmpXTLViol^1_h$$
$$\leq\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^1_{k,h,a})-\sum_{j\in J_d}(SHXL^1_{j,h,d})\right)$$
$$\leq\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^1_{k,h-1,d})-\sum_{j\in J_d}(SHXL^1_{j,h-1,d})\right)+ExtUSC_h+SURmpXTLViol^1_h$$

for all hours h (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8).

4.12 Shadow Prices for Energy

4.12.1 The Pass 1 shadow price at each bus *b* in each hour *h* measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of generation at that bus in that hour in Pass 1. The Pass 1 shadow price at each bus *b* in each hour *h,* given the inputs and constraints into Pass 1, shall be calculated at internal locations as:

$$LMP^{1}_{h,b} = \left(1 + MglLoss_{h,b}\right) \cdot SPL^{1}_{h} + \sum_{f} \begin{pmatrix} PreConSF_{b,f,h} \cdot SPNormT^{1}_{f,h} \\ + \sum_{c} SF_{b,f,c,h} \cdot SPEmT^{1}_{f,c,h} \end{pmatrix}$$

4.12.2 The first portion of the right-hand side of this equation measures the cost of meeting load at bus *b*, incorporating the effect of marginal losses. It reflects the quantity of *energy* that must be injected at the *reference bus* to meet additional load at each bus *b*. The term in the summation reflects the cost of transmission congestion resulting from an infinitesimal increase in withdrawals at each bus *b* on each pre- and post-contingency internal transmission constraint. It is calculated as the product of each:

a) Shadow price, which measures the impact on the cost on that constraint if there were a one-to-one correspondence between increases in load and flows on the constraint (i.e., if each MW of increased load caused an increase in 1 MW inflows over the constraint); and

b) The shift factor for that bus and that constraint, which measures the actual impact of additional withdrawals at each bus on flows over that constraint.

4.12.3 [Intentionally left blank – section deleted]

5. Pass 2: Constrained Commitment to

Meet Peak Demand

5.1 Overview

5.1.1 Pass 2 performs a least cost, *security* constrained unit commitment and constrained scheduling to meet the forecast peak *demand* and *IESO*-specified *operating reserve* requirements.

5.1.2 In each hour, peak *demand* occurs for a fraction of that hour. If additional commitment of *generation facilitie*s above those made in Pass 1 are required to meet peak *demand*, these *generation facilities* would only need to be operating for a fraction of the hour. Therefore, in Pass 2, the DACP calculation engine performs least cost optimization with respect to minimizing commitment costs to satisfy peak *demand*.

5.1.3 Imports and exports can only be scheduled on an hourly basis and *generation facilities* and *dispatchable load*s can follow 5-minute dispatches to meet peak *demand*. To account for this difference in scheduling, the incremental prices of *generator offer*s and *dispatchable load bids* will be evaluated on this basis against import *offer*s and export *bids*. This evaluation of *generator offer*s and *dispatchable load bids* is explained in detail in section 5.7.

5.1.4 *Generation facilities* already committed in Pass 1 is taken as committed in Pass 2. These resources will be scheduled to no less than their *minimum loading points*. Additional commitments of *offers* from *generators* are allowed.

5.1.5 Imports scheduled in Pass 1 must be scheduled to at least that value in Pass 2. Additional hourly imports may be scheduled. Hourly exports may be scheduled to a lower but not higher value than that determined in Pass 1. The import and export components of linked wheel transactions can be scheduled higher or lower than the schedules produced in Pass 1. The commitments and schedules calculated in Pass 2 will be used in Pass 3.

5.2 Inputs into Pass 2

5.2.1 All inputs identified in section 3 will be used in Pass 2. In addition, Pass 1 *generation facility* commitments, import schedules, exports schedules and shadow prices will also be used as input into Pass 2.

5.3 Optimization Objective for Pass 2

5.3.1 As for Pass 1, the gains from trade shall be maximized for Pass 2. This is accomplished by maximizing the same objective function described in section 4.3 used for Pass 1.

5.4 Security Assessment

5.4.1 The same *security* assessment is performed as described in section 4.4.

5.5 Outputs from Pass 2

5.5.1 The primary outputs of Pass 2 which are used in Pass 3 and other DACP processes include the following:

5.5.1.1 Commitments; and

5.5.1.2 Constrained schedules for *energy*.

5.6 Glossary of Sets, Indices, Variables and Parameters for Pass 2

5.6.1 Fundamental Sets and Indices

5.6.1.1 Same as those described in section 4.6.1.

5.6.2 Variables and Parameters

5.6.2.1 Bid and Offer Inputs

Same as those described in 4.6.2.1. In addition, the variables below are used to account for the fact that *generation facilities* and *dispatchable loads* are able to follow 5-minute dispatches to meet peak *demand* but imports and exports are only scheduled on an hourly basis:

$PmtPRG_{k,h,b}$ The lowest incremental *energy price* at which an incremental amount of *energy* should be scheduled at bus b in hour h in association with offer k to meet peak *demand*.

$PmtPRL_{j,h,b}$ The lowest incremental *energy price* at which an incremental quantity of reduction in *energy* consumption should be scheduled at bus b in hour h in association with bid j to meet peak *demand*.

PriceMultiplier	A *bid* and *offer* adjustment factor to account for the value of energy from *dispatchable loads* and *generation facilities* dispatched on a 5-minute basis to meet peak *demand* of any hour. This factor shall be 12.

5.6.2.2 Transmission and Security Inputs and Intermediate Variables

Same as those described in 4.6.2.2.

5.6.2.3 Other Inputs

Same as those described in 4.6.2.3.

5.6.2.4 Constraint Violation Price Inputs

Same as those described in 4.6.2.4.

5.6.2.5 Variables determined in Pass 1 and Used in Pass 2

$SHXL^1_{j,h,d}$	The amount of exports scheduled in hour *h* in Pass 1 from *intertie zone* sink bus *d* in association with *bid j*.
$SHIG^1_{k,h,d}$	The amount of imports scheduled in hour *h* in Pass 1 from *intertie zone* source bus *d* in associate with *offer k*.
$OPRG^1_{h,b}$	Indication of whether a *generation facility* at bus *b* was scheduled to operate in hour *h* in Pass 1.
$LMP^1_{h,b}$	The Pass 1 locational marginal price for *energy* at each bus *b* in each hour *h*.

5.6.2.6 Output Schedule and Commitment Variables

$SHXL^2_{j,h,d}$	The amount of exports scheduled in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j.*
$SX10N^2_{j,h,d}$	The amount of non-synchronized *ten-minute operating reserve* scheduled from the export in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j.*
$SX30R^2_{j,h,d}$	The amount of *thirty-minute operating reserve* scheduled from the export in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j.*

$SPRL^2_{j,h,b}$	The amount of *dispatchable load* reduction scheduled at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$10SSPRL^2_{j,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$10NSPRL^2_{j,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$30RSPRL^2_{j,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 2 in association with *bid j*.
$SHIG^2_{k,h,d}$	The amount of hourly imports scheduled in hour *h* from *intertie zone* source bus *d* in Pass 2 in association with *offer k.*
$SI10N^2_{k,h,d}$	The amount of imported *ten-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 2 in association with *offer k.*
$SI30R^2_{k,h,d}$	The amount of imported *thirty-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 2 in association with *offer k.*
$SPRG^2_{k,h,b}$	The amount of *energy* scheduled for the *generation facility* at bus *b* in hour *h* in Pass 2 in association with *offer k*. This is in addition to any $MinQPRG_{h,b}$, the *minimum loading point*, which must also be committed.
$OPRG^2_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled in hour *h* in Pass 2.
$IPRG^2_{h,b}$	Represents whether *generation facility* at bus *b* has been scheduled to start in hour *h* in Pass 2.
$10SSPRG^2_{k,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 2 in association with *offer k*.
$10NSPRG^2_{k,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 2 in association with *offer k*.

$30RSPRG^2_{k,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 2 in association with *offer k*.

5.6.2.7 Output Violation Variables

$ViolCost^2_h$	The cost incurred in order to avoid having the Pass 2 schedules for hour *h* violate specified constraints.
$SLdViol^2_h$	Projected load curtailment, that is, the amount of load that cannot be met using *offers* scheduled or committed in hour *h* in Pass 2.
$SGenViol^2_h$	The amount of additional load that must be scheduled in hour *h* in Pass 2 to ensure that there is enough load on the system to offset the must-run requirements of *generation facilities*.
$S10SViol^2_h$	The amount by which the overall synchronized *ten-minute operating reserve* requirement is not met in hour *h* of Pass 2 because the cost of meeting that portion of the requirement was greater than or equal to *P10SViol.*
$S10RViol^2_h$	The amount by which the overall *ten-minute operating reserve* requirement is not met in hour *h* of Pass 2 (above and beyond any failure to meet the synchronized *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P10RViol.*
$S30RViol^2_h$	The amount by which the overall *thirty-minute operating reserve* requirement is not met in hour *h* of Pass 2 (above and beyond any failure to meet the *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P30RViol.*
$SREG10RViol^2_{r,h}$	The amount by which the minimum *ten-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 2 because the cost of meeting that portion of the requirement was greater than or equal to *PREG10RViol.*
$SREG30RViol^2_{r,h}$	The amount by which the minimum *thirty-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 2 because the cost of meeting that portion of the requirement was greater than or equal to *PREG30RViol.*

$SXREG10RViol^2_{r,h}$ The amount by which the *ten-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 2 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG10RViol*.

$SXREG30RViol^2_{r,h}$ The amount by which the *thirty-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 2 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG30RViol*.

$SPreConITLViol^2_{f,h}$ The amount by which pre-contingency flows over *facility f* in hour *h* of Pass 2 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConITLViol*.

$SITLViol^2_{f,c,h}$ The amount by which flows over *facility f* that would follow the occurrence of contingency *c* in hour *h* of Pass 2 exceed the emergency limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PITLViol*.

$SPreConXTLViol^2_{z,h}$ The amount by which *intertie* flows over *facility z* in hour *h* of Pass 2 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConXTLViol*.

$SURmpXTLViol^2_{h}$ The amount by which the total net scheduled import increase for hour *h* in Pass 2 exceeds the up ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol*.

$SDRmpXTLViol^2_{h}$ The amount by which the total net scheduled import decrease in hour *h* of Pass 2 exceed the down ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol*.

5.6.2.8 Energy Ramp Rates

Same as those in section 4.6.2.8.

5.7 Evaluation of Generator Offers and Dispatchable Load Bids

5.7.1 All *offers* for *generation facilities* that were committed in Pass 1 will be evaluated in Pass 2 as such:

5.7.1.1 $PmtPRG_{k,h,b}$, designates the lowest incremental *energy* price at which an incremental amount of *energy* should be scheduled at bus *b* in hour *h* in association with *offer k.* It shall be set to:

$$PmtPRG_{k,h,b} = LMP^{1}_{h,b} + \frac{PPRG_{k,h,b} - LMP^{1}_{h,b}}{PriceMultiplier}$$

for $PPRG_{k,h,b} > LMP^{1}_{h,b}$ and

$$PmtPRG_{k,h,b} = PPRG_{h,b}$$

for $PPRG_{k,h,b} \leq LMP^{1}_{h,b}$.

5.7.1.2 All other elements of the *offers* will be used in Pass 2 as submitted.

5.7.2 All *dispatchable load bids* will be evaluated in Pass 2 as such:

5.7.2.1 $PmtPRL_{j,h,b}$, designates the lowest incremental *energy price* at which an incremental quantity of reduction in *energy* consumption specified in *bid j* should be scheduled in hour *h* at bus *b.* It shall be set to:

$$PmtPRL_{j,h,b} = LMP^{1}_{h,b} + \frac{PPRL_{j,h,b} - LMP^{1}_{h,b}}{PriceMultiplier}$$

for $PPRL_{j,h,b} > LMP^{1}_{h,b}$ and

$$PmtPRL_{j,h,b} = PPRL_{h,b}$$

for $PPRL_{j,h,b} \leq LMP^{1}_{h,b}$.

5.7.2.2 Other elements of the *dispatchable load bids* will be used in Pass 2 as submitted.

5.8 Objective Function

5.8.1 The optimization of the objective function in Pass 2 is to maximize the expression:

$$\sum_{h=1,\ldots,24}\left\{\begin{array}{l}
\sum_{d\in DX,j\in J_d}(SHXL^2_{j,h,d}\cdot PHXL_{j,h,d}-SX10N^2_{j,h,d}\cdot PX10N_{j,h,d}-SX30R^2_{j,h,d}\cdot PX30R_{j,h,d})\\
-\sum_{b\in B}\left[\begin{array}{l}\sum_{j\in J_b}SPRL^2_{j,h,b}\cdot PmtPRL_{j,h,b}\\
+\sum_{j\in J_b}\begin{array}{l}10SSPRL^2_{j,h,b}\cdot 10SPPRL_{j,h,b}+10NSPRL^2_{j,h,b}\cdot 10NPPRL_{j,h,b}+\\ 30RSPRL^2_{j,h,b}\cdot 30RPPRL_{j,h,b}\end{array}\end{array}\right]\\
-\sum_{d\in DI,k\in K_d}\left(SHIG^2_{k,h,d}\cdot PHIG_{k,h,d}+SI10N^2_{k,h,d}\cdot PI10N_{k,h,d}+SI30R^2_{k,h,d}\cdot PI30R_{k,h,d}\right)\\
-\sum_{b\in B}\left[\begin{array}{l}\sum_{k\in K_b}\left(SPRG^2_{k,h,b}\cdot PmtPRG_{k,h,b}\right)\\
+OPRG^2_{h,b}\cdot MGOPRG_{h,b}+IPRG^2_{h,b}\cdot SUPRG_{h,b}\\
+\sum_{k\in K_b}\begin{array}{l}10SSPRG^2_{k,h,b}\cdot 10SPPRG_{k,h,b}+10NSPRG^2_{k,h,b}\cdot 10NPPRG_{k,h,b}\\ +30RSPRG^2_{k,h,b}\cdot 30RPPRG_{k,h,b}\end{array}\end{array}\right]\\
-ViolCost^2_h
\end{array}\right\};$$

where $ViolCost^2{}_h$ is calculated as follows:

$$
\begin{aligned}
ViolCost_h^2 = {} & SLdViol_h^2 \cdot PLdViol - SGenViol_h^2 \cdot PGenViol \\
& + S10SViol_h^2 \cdot P10SViol + S10RViol_h^2 \cdot P10RViol \\
& + S30RViol_h^2 \cdot P30RViol \\
& + \sum_{r \in ORREG} \begin{pmatrix} SREG10RViol_{r,h}^2 \cdot PREG10RViol \\ + SREG30RViol_{r,h}^2 \cdot PREG30RViol \\ + SXREG10RViol_{r,h}^2 \cdot PXREG10RViol \\ + SXREG30RViol_{r,h}^2 \cdot PXREG30RViol \end{pmatrix} \\
& + \sum_{z \in Z} \left(SPreConXTLViol_{z,h}^2 \cdot PPreConXTLViol \right) \\
& + SURmpXTLViol^2 \cdot PRmpXTLViol + SDRmpXTLViol^2 \cdot PRmpXTLViol \\
& + \sum_{f \in F} SPreConITLViol_{f,h}^2 \cdot PPreConITLViol \\
& + \sum_{f \in F, c \in C} SITLViol_{f,c,h}^2 \cdot PITLViol.
\end{aligned}
$$

5.8.2 The Pass 2 maximization is subject to the constraints described in the next section.

5.9 Constraints Overview

5.9.1 The constraints applied to the Pass 2 optimization mirror those used in Pass 1 and described in sections 4.8 through 4.11. They must be modified to:

a) Apply to schedules determined in Pass 2;

b) Reflect peak *demand* forecast compared to average *demand* forecast used in Pass 1; and

c) Reflect additional constraints limiting changes in internal resource (*generation facilities* and *dispatchable loads*) commitments, import and export schedules determined in Pass 1.

5.10 Bid/Offer Constraints Applying to Single Hours

5.10.1 Status Variables and Capacity Constraints

5.10.1.1 For the same reasons as discussed in section 4.9 for Pass 1:

$OPRG_{h,b}^2 = 0$ or 1, for all hours h and buses b;

$$0 \le SPRL_{j,h,b}^2 \le QPRL_{j,h,b};$$

$$0 \le 10SSPRL_{j,h,b}^2 \le 10SQPRL_{j,h,b};$$

$$0 \le 10NSPRL_{j,h,b}^2 \le 10NQPRL_{j,h,b};$$

$$0 \le 30RSPRL_{j,h,b}^2 \le 30RQPRL_{j,h,b};$$

$$0 \le SI10N_{k,h,d}^2 \le QI10N_{k,h,d};$$

$$0 \le SI30R_{k,h,d}^2 \le QI30R_{k,h,d};$$

$$0 \le SHIG_{k,h,d}^2 \le QHIG_{k,h,d};$$

$$0 \le SHXL_{j,h,d}^2 \le QHXL_{j,h,d};$$

$$0 \le SX10N_{j,h,d}^2 \le QX10N_{j,h,d};$$

$$0 \le SX30R_{j,h,d}^2 \le QX30R_{j,h,d};$$

$$0 \le SPRG_{k,h,b}^2 \le OPRG_{h,b}^2 \cdot QPRG_{k,h,b};$$

$$0 \le 10SSPRG_{k,h,b}^2 \le OPRG_{h,b}^2 \cdot 10SQPRG_{k,h,b};$$

$$0 \le 10NSPRG_{k,h,b}^2 \le OPRG_{h,b}^2 \cdot 10NQPRG_{k,h,b}; \text{ and}$$

$$0 \le 30RSPRG_{k,h,b}^2 \le OPRG_{h,b}^2 \cdot 30RQPRG_{k,h,b}$$

for all modified *bids* j, modified *offers* k, hours h, and buses b, and *intertie zones* source/sink bus d.

5.10.1.2 In the case of linked wheeling transactions (the export *bid* and the import *offer* have the same *NERC* tag identifier), the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore:

$$\sum_{j \in J_d} SHXL^2_{j,h,dx} = \sum_{k \in k_d} SHIG^2_{k,h,di}$$

where *dx* and *di* are the respective buses of the export and import schedules associated with the wheeling transactions.

5.10.1.3 The minimum and/or maximum output of the *generation facilities* may be limited because of *outages* and/or de-ratings or in order for the units to provide *regulation* or voltage support. These constraints will take the form:

$$MinPRG_{h,b} \le MinQPRG_{h,b} \cdot OPRG^2_{h,b} + \sum_{k \in K_b}(SPRG^2_{k,h,b}) \le MaxPRG_{h,b}.$$

5.10.1.4 Similarly, the maximum level of load reduction is the mechanism by which a *dispatchable load* indicates any de-rating to its registered maximum load reduction level due to mechanical or operational adjustments to their *facility*. The constraint will take the form:

$$\sum_{j \in J_b} SPRL^2_{j,h,b} \le MaxPRL_{h,b}.$$

5.10.2 Operating Reserve Constraints

5.10.2.1 The total reserve (10-minute synchronized and non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load (maximum load *bid* minus the load reductions). These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_b}(10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\le 30 \cdot ORRPRL_b\text{; and}$$

$$\sum_{j \in J_b}(10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\le \sum_{j \in J_b}(QPRL_{j,h,b} - SPRL^2_{j,h,b}).$$

5.10.2.2 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to increase load reduction (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8):

$$\sum_{j\in J_b}(10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\leq -\sum_{j\in J_b}\left[\left(QPRL_{j,h-1,b} - SPRL^2_{j,h-1,b}\right) - \left(QPRL_{j,h,b} - SPRL^2_{j,h,b}\right)\right]$$
$$+ 60 \cdot URRPRL_b.$$

5.10.2.3 Finally, the total (10-minute synchronized, 10-minute non synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* Pass 2 scheduled consumption:

$$\sum_{j\in J_b}(10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} + 30RSPRL^2_{j,h,b})$$
$$\leq MaxPRL_{h,b} - \sum_{j\in J_b} SPRL^2_{j,h,b}.$$

5.10.2.4 The amount of 10-minute synchronized and non-synchronized reserve that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j\in J_b} 10SSPRL^2_{j,h,b} + 10NSPRL^2_{j,h,b} \leq 10 \cdot ORRPRL_b.$$

5.10.2.5 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *generation facility* cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\leq 30 \cdot ORRPRG_b \text{; and}$$

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\leq \sum_{k \in K_b} (QPRG_{k,h,b} - SPRG^2_{k,h,b}).$$

5.10.2.6 In addition, this next constraint ensures that the total(10-minute synchronized, 10-minute non-synchronized and 30-minute) from the committed *generation facility* cannot exceed its ramp capability (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8). Ramping considerations from start ups or shut downs are not carried forward from one day to the next:

$$\sum_{k \in K_b} (10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\leq \sum_{k \in K_b} \left(SPRG^2_{k,h-1,b} - SPRG^2_{k,h,b}\right) + 60 \times URRPRG_b$$

and

$$\sum_{k \in K_b} \left(10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b}\right) + \sum_{k \in K_b} \left(SPRG^2_{k,h,b}\right)$$
$$\leq [(h-n) * 60 + 30] \times URRPRG_b \times OPRG^2_{h,b}$$

where n is the hour of the last start before or in hour h

and

$$\sum_{k \in K_b} \left(10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b}\right) + \sum_{k \in K_b} \left(SPRG^2_{k,h,b}\right)$$
$$\leq [(m-h) * 60 + 30] \times DRRPRG_b \times OPRG^2_{h,b}$$

5.10.2.7 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from the committed *generation facility* cannot exceed its Pass 2 unscheduled capacity:

$$\sum_{k \in K_b}(10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b} + 30RSPRG^2_{k,h,b})$$
$$\le MaxPRG_{h,b} - \sum_{k \in K_b} SPRG^2_{k,h,b} - MinQPRG_{h,b}.$$

5.10.2.8 The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *generation facility* is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_b}(10SSPRG^2_{k,h,b} + 10NSPRG^2_{k,h,b}) \le 10 \cdot ORRPRG_b.$$

5.10.2.9 The total reserve (10-minute non-synchronized and 30-minute) from hourly exports cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled export. These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_d}(SX10N^2_{j,h,d} + SX30R^2_{j,h,d}) \le 30 \cdot ORRHXL_d; \text{ and}$$

$$\sum_{j \in J_d}(SX10N^2_{j,h,d} + SX30R^2_{j,h,d}) \le \sum_{j \in J_d} SHXL^2_{j,h,d}.$$

5.10.2.10 The amount of 10-minute non-synchronized reserve that an hourly export is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_d} SX10N^2_{j,h,d} \le 10 \cdot ORRHXL_d.$$

5.10.2.11 The total reserve (10-minute non-synchronized and 30-minute) from hourly imports cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_d} (SI10N^2_{k,h,d} + SI30R^2_{k,h,d}) \leq 30 \cdot ORRHIG_d \text{; and}$$

$$\sum_{k \in K_d} (SI10N^2_{k,h,d} + SI30R^2_{k,h,d}) \leq \sum_{k \in K_d} (QHIG_{k,h,d} - SHIG^2_{k,h,d}).$$

5.10.2.12 The amount of 10-minute non-synchronized reserve that hourly import is scheduled to provide cannot exceed the amount by which it can increase the output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_d} SI10N^2_{k,h,d} \leq 10 \cdot ORRHIG_d.$$

5.11 Bid/Offer Inter-Hour/Multi-Hour Constraints

5.11.1 Status Variables

5.11.1.1 For the same reasons as discussed for Pass 1, for *generation facilities* that are scheduled to start up, and for hour, $h > 1$:

$$IPRG^2_{h,b} = \begin{cases} 1, \text{ if } OPRG^2_{h-1,b} = 0 \text{ and } OPRG^2_{h,b} = 1 \\ 0, \text{ otherwise.} \end{cases}$$

For $h = 1$:

$$IPRG^2_{h,b} = \begin{cases} 1, \text{ if } InitOperHrs_b = 0 \text{ and } OPRG^2_{h,b} = 1 \\ 0, \text{ otherwise.} \end{cases}$$

5.11.2 Ramping

5.11.2.1 Constraints limiting hour-to-hour changes in *energy* schedules are congruous to those used in Pass 1.

Start Up Scenario ($OPRG^2_{h,b} = 1$, and $OPRG^2_{h-1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^2_{k,h,b} \leq \sum_{k \in K_b} 30 \times URRPRG_b$$

Continued On Scenario ($OPRG^2_{h-1,b} = OPRG^2_{h,b} = 1$)

$$\sum_{k \in K_b} \left(SPRG^2_{k,h-1,b}\right) - 60 \times DRRPRG_b \leq \sum_{k \in K_b} SPRG^2_{k,h,b}$$
$$\leq \sum_{k \in K_b} \left(SPRG^2_{k,h-1,b}\right) + 60 \times URRPRG_b$$

Shut Down Scenario ($OPRG^2_{h,b} = 1$, and $OPRG^2_{h+1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^2_{k,h,b} \leq \sum_{k \in K_b} 30 \times DRRPRG_b$$

5.11.2.2 Similarly, the ramping constraint for the *dispatchable load* will be as follows:

$$\sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^2_{j,h-1,b}\right) - 60 \cdot URRPRL_b$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^2_{j,h,b}\right)$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^2_{j,h-1,b}\right) + 60 \cdot DRRPRL_b.$$

5.11.2.3 The above two constraints apply for all hours from 1 to 24. In the above two constraints the variables related to hour zero belong to the last hour of the previous day and are obtained from the initializing assumptions.

5.11.2.4 The ramping rates in the ramping constraints must be adjusted to allow the resource to:

a) Ramp down from its lower limit in hour (*h-1*) to its upper limit in hour *h*.

b) Ramp up from its upper limit in hour (*h-1*) to its lower limit in hour *h*.

5.11.2.5 This will allow a solution to be obtained when changes to the upper and lower limits between hours are beyond the ramping capability of the resources.

5.11.2.6 In the above ramping constraints, a single ramp up and a single ramp down, $URRPRG_b$ and $DRRPRG_b$ for *generation facilities* and $URRPRL_b$ and $DRRPRL_b$ for *dispatchable loads* are used. The ramp rate is assumed constant over the full operating range of the *dispatchable load* and *generation facility*. However, this is not the case. *Dispatchable load bids and generator offers* will include multi-*energy* ramp rates. The multiple ramp rates are described in sections 4.10.2.8 and 4.10.2.9.

5.11.3 Minimum Generation Block Run-Time and Minimum Generation Block Down Time

5.11.3.1 Constraints pertaining to *minimum generation block run-times* and *minimum generation block down times* precisely mirror those used in Pass 1. Therefore,

if $0 < InitOperHrs_b < MRTPRG_b$, then

$$OPRG^2_{1,b}, OPRG^2_{2,b}, \ldots, OPRG^2_{\min(24, MRTPRG_b - InitOperHrs_b), b} = 1;$$

if $OPRG^2{}_{h,b} = 1$, $OPRG^2{}_{h+1,b} = 0$, and $MDTPRG_b > 1$, then

$$OPRG^2_{h+2,b}, OPRG^2_{h+3,b}, \ldots, OPRG^2_{\min(24, h+MDTPRG_b), b} = 0; \text{ and}$$

and if $OPRG^2{}_{h,b} = 0$, $OPRG^2{}_{h+1,b} = 1$, and $MRTPRG_b > 1$, then

$$OPRG^2_{h+2,b}, OPRG^2_{h+3,b}, \ldots, OPRG^2_{\min(24, h+MRTPRG_b), b} = 1$$

for all hours h and buses b and

$$OPRG^2_{0,b} = \begin{cases} 0, \text{ if } InitOperHrs_b = 0 \\ 1, \text{ otherwise.} \end{cases}$$

5.11.4 Energy Limited Resources

5.11.4.1 A constraint must be added in order to ensure that *energy* limited units are not scheduled to provide more *energy* than they have indicated they are capable of providing. In addition to limiting *energy* schedules over the course of the day to the *energy* limit specified for a unit, this constraint must also ensure that units are not scheduled to provide *energy* in amounts that would preclude them from providing reserve when activated. Given those factors:

Therefore:

$$\sum_{h=1}^{1}\left(OPRG^{2}_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}(SPRG^{2}_{k,h,b})\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^{2}_{k,1,b}+\sum_{k\in K_b}10NSPRG^{2}_{k,1,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^{2}_{k,1,b}\le EL_b;$$

$$\sum_{h=1}^{2}\left(OPRG^{2}_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}(SPRG^{2}_{k,h,b})\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^{2}_{k,2,b}+\sum_{k\in K_b}10NSPRG^{2}_{k,2,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^{2}_{k,2,b}\le EL_b;$$

M

$$\sum_{h=1}^{24}\left(OPRG^{2}_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}(SPRG^{2}_{k,h,b})\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^{2}_{k,24,b}+\sum_{k\in K_b}10NSPRG^{2}_{k,24,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^{2}_{k,24,b}\le EL_b$$

for all buses *b* at which *energy* limited resources are located. The factors *10ORConv* and *30ORConv* are applied to scheduled *ten-minute* and *thirty-minute operating reserves* for *energy* limited resources to convert MW into MWh. This factor is set to unity.

5.11.5 Maximum Number of Starts

5.11.5.1 To ensure that *generation facilities* are not scheduled to cycle on and off more than their specified maximum number in a day, the following constraints are defined:

$$\sum_{h=1}^{24} IPRG_{h,b}^{2} \leq MaxStartsPRG_{b}.$$

5.12 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

5.12.1 Load

5.12.1.1 Load constraints are structured in the same manner as described in section 4.11.1 for Pass 1.

5.12.1.2 The total amount of withdrawals scheduled in Pass 2 at each bus *b* in each hour *h*, $With^{2}_{h,b}$, is the sum of:

- the portion of the load forecast for that hour that has been allocated to that bus; and
- all *dispatchable load bid*, net of the amount of load reduction scheduled (since the *dispatchable load* is excluded from the *demand* forecast by the DACP calculation engine), yielding:

$$With_{h,b}^{2} = LDF_{h,b} \cdot PFL_{h} + \left[\sum_{j \in J_{b}} \left(QPRL_{j,h,b} - SPRL_{j,h,b}^{2} \right) \right]; \text{and}$$

the total amount of withdrawals scheduled in Pass 2 at each *intertie zone* sink bus *d* in each hour *h*, $With^{2}_{h,d}$, is the sum of:

- exports from Ontario to each *intertie zone* sink bus; and
- outflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$With^2_{h,d} = \sum_{j \in J_d} (SHXL^2_{j,h,d}) - \sum_{a \in A} ProxyUPOWt_{d,a} \cdot \min(0, PF_{h,a}).$$

5.12.1.3 The total amount of injections scheduled in Pass 2 at each bus b in each hour h, $Inj^2_{h,b}$, is the sum of:

- *generation facilities* scheduled at that bus, yielding:

$$Inj^2_{h,b} = OPRG^2_{h,b} \cdot MinQPRG_{h,b} + \sum_{k \in K_b} \left(SPRG^2_{k,h,b}\right); \text{ and}$$

the total amount of injections scheduled in Pass 2 at each *intertie zone* source bus d in each hour h, $Inj^2_{h,d}$, is the sum of:

- imports into Ontario from each *intertie zone* source bus; and
- inflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$Inj^2_{h,d} = \sum_{k \in K_d} (SHIG^2_{k,h,d}) + \sum_{a \in A} ProxyUPIWt_{d,a} \cdot \max(0, PF_{h,a}).$$

5.12.1.4 Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses (or reduction in losses) that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between actual and marginal losses. Load reduction associated with the *demand* constraint violation will be subtracted from the total load and generation reduction associated with the *demand* constraint violation will be subtracted from total generation to ensure that the calculation engine will always produce a solution. These violation variables are assigned a very high cost to limit their use to infeasible cases.

$$\sum_{b\in B}(1+MglLoss_{h,b})With_{h,b}^{2}+\sum_{d\in D}(1+MglLoss_{h,b})With_{h,d}^{2}-SLdViol_{h}^{2}$$
$$=\sum_{b\in B}(1+MglLoss_{h,b})Inj_{h,b}^{2}$$
$$+\sum_{d\in D}(1+MglLoss_{h,d})Inj_{h,d}^{2}-SGenViol_{h}^{2}+LossAdj_{h}.$$

5.12.2 Operating Reserve

5.12.2.1 Sufficient *operating reserve* must be provided on the system to meet system wide requirements for 10-minute synchronized reserve, *ten-minute operating reserve* and *thirty-minute operating reserve*, as well as all applicable regional minimum and maximum requirements for *operating reserve*.

5.12.2.2 Therefore, taking into consideration the potential not to meet these minimum and maximum requirements if the cost of meeting those requirements becomes too high:

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+S10SViol^2_h$$
$$\geq TOT10S_h;$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+S10RViol^2_h$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b} 10NSPRG^2_{k,h,b}\right)+\sum_{b\in B}\left(\sum_{j\in J_b} 10NSPRL^2_{j,h,b}\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d} SI10N^2_{k,h,d}\right)+\sum_{d\in D}\left(\sum_{j\in J_d} SX10N^2_{j,h,d}\right)\geq TOT10R_h; \text{ and}$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+S30RViol^2_h$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b}(10NSPRG^2_{k,h,b}+30RSPRG^2_{k,h,b})\right)$$
$$+\sum_{b\in B}\left(\sum_{j\in J_b}(10NSPRL^2_{j,h,b}+30RSPRL^2_{j,h,b})\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d}(SI10N^2_{k,h,d}+SI30R^2_{k,h,d})\right)$$
$$+\sum_{d\in D}\left(\sum_{j\in J_d}(SX10N^2_{j,h,d}+SX30R^2_{j,h,d})\right)\geq TOT30R_h$$

for all hours h, and

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+SREG10RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^2_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^2_{j,h,b}\right)$$
$$\geq REGMin10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)-SXREG10RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^2_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^2_{j,h,b}\right)$$
$$\leq REGMax10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)+SREG30RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^2_{k,h,b}+30RSPRG^2_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^2_{j,h,b}+30RSPRL^2_{j,h,b})\right)$$
$$\geq REGMin30_{r,h}; \text{ and}$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^2_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^2_{k,h,b}\right)-SXREG30RViol^2_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^2_{k,h,b}+30RSPRG^2_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^2_{j,h,b}+30RSPRL^2_{j,h,b})\right)$$
$$\leq REGMax30R_{r,h}$$

for all hours h, and for all regions r in the set *ORREG*.

5.12.3 Internal Transmission Limits

5.12.3.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 2 of the calculation engine would not violate any *security limits* in either the pre-contingency state or in any contingency. To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus will be used.

5.12.3.2 Then the pre-contingency limits on transmission within Ontario will not be violated if:

$$\sum_{b\in B} PreConSF_{b,f,h}(Inj^2_{h,b} - With^2_{h,b}) + \sum_{d\in D} PreConSF_{d,f,h}(Inj^2_{h,d} - With^2_{h,d}) - SPreConITLViol^2_{f,h} \le AdjNormMaxFlow_{f,h}$$

for all *facilities* f and hours h.

5.12.3.3 Post-contingency limits on transmission *facilities* within Ontario will not be violated if:

$$\sum_{b\in B} SF_{b,f,c,h}(Inj^2_{h,b} - With^2_{h,b}) + \sum_{d\in D} SF_{d,f,c,h}(Inj^2_{h,d} - With^2_{h,d}) - SITLViol^2_{f,c,h} \le AdjEmMaxFlow_{f,c,h}$$

for all *facilities* f, hours h, and monitored contingencies c.

5.12.4 Intertie Limits and Constraints on Net Imports

5.12.4.1 The calculation engine would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. To ensure this, we must calculate the net amount of *energy* scheduled to flow over each *intertie* in each hour and the amount of *operating reserve* scheduled to be provided by resources in that *control area*. This will be summed over all affected *interties*. The result will be compared to the limit associated with that constraint. Consequently:

$$\sum_{a\in A}\left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d\in DI_a,k\in K_d}(SHIG^2_{k,h,d}) + PF_{h,a} - \sum_{d\in DX_a,j\in J_d}\left(SHXL^2_{j,h,d}\right)\right) + \\ 0.5(EnCoeff_{a,z}+1)\left[\begin{array}{l}\sum_{d\in DI_a,k\in K_d}\left(SI10N^2_{k,h,d} + SI30R^2_{k,h,d}\right) \\ + \sum_{d\in DX_a,j\in J_d}\left(SX10N^2_{j,h,d} + SX30R^2_{j,h,d}\right)\end{array}\right]\end{array}\right] \le MaxExtSch_{z,h}$$

for all hours *h*, for all *intertie zones* *a* relevant to the constraint *z*

($EnCoeff_{a,z} \neq 0$), and for all constraints *z* in the set Z_{sch}.

5.12.4.2 In addition, changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour. It cannot exceed the sum of net import schedule for all *interties* for the previous hour plus the maximum permitted hourly increase. It cannot be less than the sum of the net import schedule for all *interties* for the previous hour minus the maximum permitted hourly decrease. Violation variables are provided for both the up and down ramp limits to ensure that the calculation engine will always find a solution.

Therefore:

$$\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^2_{k,h-1,d})-\sum_{j\in J_d}(SHXL^2_{j,h-1,d})\right)-ExtDSC_h-SDRmpXTLViol^2_h$$
$$\leq \sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^2_{k,h,d})-\sum_{j\in J_d}(SHXL^2_{j,h,d})\right)$$
$$\leq \sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^2_{k,h-1,d})-\sum_{j\in J_d}(SHXL^2_{j,h-1,d})\right)+ExtUSC_h+SURmpXTLViol^2_h$$

for all hours *h* (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8).

5.12.5 Intertie Schedule Limits Based on Pass 1 Output

5.12.5.1 Pass 2 will not reduce the amount of imported *energy* scheduled from each *intertie zone* in any hour. Additional imports of *energy* may be scheduled in Pass 2. Therefore, for imports that are not part of a linked wheeling transaction:

$$SHIG^2_{k,h,d} \geq SHIG^1_{k,h,d}$$

for all *offers* *k*, hours *h* and *intertie zones* source bus *d*.

5.12.5.2 Pass 2 will not increase the amount of exported *energy* scheduled from each *intertie zone* sink bus in any hour over the amount scheduled in Pass 1.

5.12.5.3 Therefore, for exports that are not part of a linked wheeling transaction:

$$SHXL^2_{j,h,d} \leq SHXL^1_{j,h,d}$$

for all *bids j*, hours *h* and *intertie zones* sink bus *d*.

5.12.5.4 Finally, the purpose of Pass 2 is to determine whether additional *generation facilities* need to be committed to ensure that the *IESO* can meet peak forecast load, given the resources committed in Pass 1 (and if so, which resources are committed). Consequently, it will be necessary to ensure that resources committed in Pass 1 are not de-committed in this pass. Therefore:

$$OPRG^2_{h,b} \geq OPRG^1_{h,b}$$

for all hours *h* and buses.

6. Pass 3: Constrained Scheduling to Meet Average Demand

6.1 Overview

6.1.1 Pass 3 performs a least cost, *security* constrained scheduling to meet the forecast average *demand* and *IESO*-specified *operating reserve* requirements.

6.1.2 The *commitment* for generation and schedules for imports *and* exports, resulting from Pass 2 are used to schedule the least cost set of resources (*dispatchable loads, generation facilities,* imports and exports) to meet average forecast *demand* and *IESO*-specified *operating reserve* requirements, taking account of all transmission limitations including *intertie* transfer limits.

6.1.3 *Generation facilities* committed in Passes 1 and 2 will be scheduled. There will be no additional exports scheduled beyond what was scheduled in Pass 2. Imports will not be scheduled below what was scheduled in Pass 2. The import and export components of linked wheel transactions are allowed to go higher or lower than schedules produced in Pass 2.

6.2 Inputs into Pass 3

6.2.1 Inputs for Pass 3 include those described in section 3.

6.2.2 In addition, commitments from Passes 1 and 2 and schedules from Pass 2 are used as inputs.

6.3 Optimization Objective for Pass 3

6.3.1 As for Passes 1 and 2, the gains from trade shall be maximized for Pass 3. This is accomplished by maximizing an objective function similar to that described in 4.3. The Pass 3 objective function is different in that it does not include the variables for commitment. This is so because no more commitment is required for Pass 3.

6.4 Security Assessment

6.4.1 The same *security* assessment is performed as described in section 4.4.

6.5 Outputs from Pass 3

6.5.1 The primary outputs of Pass 3 include the following:

4.5.1.1 Constrained schedules for *energy* for the *schedule of record*; and

4.5.1.2 Shadow prices.

6.6 Glossary of Sets, Indices, Variables and Parameters for Pass 3

6.6.1 Fundamental Sets and Indices

6.6.1.1 Same as those described in section 4.6.1.

6.6.2 Variables and Parameters

6.6.2.1 Bid and Offer Inputs

Same as those described in 4.6.2.1.

6.6.2.2 Transmission and Security Inputs and Intermediate Variables

Same as those described in 4.6.2.2.

6.6.2.3 Other Inputs

Same as those described in 4.6.2.3.

6.6.2.4 Constraint Violation Price Inputs

Same as those described in 4.6.2.4.

6.6.2.5 Variables determined in Pass 2 and Used in Pass 3

$SHXL^2_{j,h,d}$ The amount of exports scheduled in hour *h* in Pass 2 from *intertie zone* sink bus *d* in association with *bid j*.

$SHIG^2_{k,h,d}$ The amount of imports scheduled in hour *h* in Pass 2 from *intertie zone* source bus *d* in association with *offer k*.

$OPRG^2_{h,b}$ Indication of whether a *generation facility* at bus *b* was scheduled to operate in hour *h* in Pass 2.

$IPRG^2_{h,b}$ Indication of whether a *generation facility* at bus *b* was scheduled to start in hour *h* in Pass 2.

6.6.2.6 Output Schedule and Commitment Variables

$SHXL^3_{j,h,d}$ The amount of exports scheduled in hour *h* in Pass 3 from *intertie zone* sink bus *d* in association with *bid j.*

$SX10N^3_{j,h,d}$ The amount of non-synchronized *ten-minute operating reserve* scheduled from the export in hour *h* in Pass 3 from *intertie zone* sink bus *d* in association with *bid j.*

$SX30R^3_{j,h,d}$ The amount of *thirty-minute operating reserve* scheduled from the export in hour *h* in Pass 3 from *intertie zone* sink bus *d* in association with *bid j.*

$SPRL^3_{j,h,b}$ The amount of *dispatchable load* reduction scheduled at bus *b* in hour *h* in Pass 3 in association with *bid j*.

$10SSPRL^3_{j,h,b}$ The amount of synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 3 in association with *bid j*.

$10NSPRL^3_{j,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 3 in association with *bid j*.
$30RSPRL^3_{j,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *dispatchable load* is scheduled to provide at bus *b* in hour *h* in Pass 3 in association with *bid j*.
$SHIG^3_{k,h,d}$	The amount of hourly imports scheduled in hour *h* from *intertie zone* source bus *d* in Pass 3 in association with *offer k.*
$SI10N^3_{k,h,d}$	The amount of imported *ten-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 3 in association with *offer k.*
$SI30R^3_{k,h,d}$	The amount of imported *thirty-minute operating reserve* scheduled in hour *h* from *intertie zone* source bus *d* in Pass 3 in association with *offer k.*
$SPRG^3_{k,h,b}$	The amount of *energy* scheduled for the *generation facility* at bus *b* in hour *h* in Pass 3 in association with *offer k*. This is in addition to any $MinQPRG_{h,b}$, the *minimum loading point*, which must also be committed.
$OPRG^3_{h,b}$	Represents whether the *generation facility* at bus *b* has been scheduled in hour *h* in Pass 3.
$IPRG^3_{h,b}$	Represents whether *generation facility* at bus *b* has been scheduled to start in hour *h* in Pass 3.
RAMPUP_ENRG	The coefficient used to calculate the estimated fraction of a *generation facility*'s *minimum loading point* in the hour prior to the first hour it is scheduled. This value is used by the DACP calculation engine to determine constrained schedules in Pass 3 so that the *energy* produced by the *generation facility* during ramping to their *minimum loading point* is accounted for.
$10SSPRG^3_{k,h,b}$	The amount of synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 3 in association with *offer k*.
$10NSPRG^3_{k,h,b}$	The amount of non-synchronized *ten-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 3 in association with *offer k*.

$30RSPRG^3_{k,h,b}$	The amount of *thirty-minute operating reserve* that a qualified *generation facility* at bus *b* is scheduled to provide in hour *h* in Pass 3 in association with *offer k*.

6.6.2.7 Output Violation Variables

$ViolCost^3_h$	The cost incurred in order to avoid having the Pass 3 schedules for hour *h* violate specified constraints.
$SLdViol^3_h$	Projected load curtailment, that is, the amount of load that cannot be met using *offers* scheduled or committed in hour *h* in Pass 3.
$SGenViol^3_h$	The amount of additional load that must be scheduled in hour *h* in Pass 3 to ensure that there is enough load on the system to offset the must-run requirements of *generation facilities*.
$S10SViol^3_h$	The amount by which the overall synchronized *ten-minute operating reserve* requirement is not met in hour *h* of Pass 3 because the cost of meeting that portion of the requirement was greater than or equal to *P10SViol.*
$S10RViol^3_h$	The amount by which the overall *ten-minute operating reserve* requirement is not met in hour *h* of Pass 3 (above and beyond any failure to meet the synchronized *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P10RViol.*
$S30RViol^3_h$	The amount by which the overall *thirty-minute operating reserve* requirement is not met in hour *h* of Pass 3 (above and beyond any failure to meet the *ten-minute operating reserve* requirement) because the cost of meeting that portion of the requirement was greater than or equal to *P30RViol.*
$SREG10RViol^3_{r,h}$	The amount by which the minimum *ten-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 3 because the cost of meeting that portion of the requirement was greater than or equal to *PREG10RViol.*
$SREG30RViol^3_{r,h}$	The amount by which the minimum *thirty-minute operating reserve* requirement for region *r* is not met in hour *h* of Pass 3 because the cost of meeting that portion of the requirement was greater than or equal to *PREG30RViol.*

$SXREG10RViol^3_{r,h}$ The amount by which the *ten-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 3 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG10RViol.*

$SXREG30RViol^3_{r,h}$ The amount by which the *thirty-minute operating reserve* scheduled for region *r* exceeds the maximum required in hour *h* of Pass 3 because the cost of meeting the maximum requirement limit was greater than or equal to *PXREG30RViol.*

$SPreConITLViol^3_{f,h}$ The amount by which pre-contingency flows over *facility f* in hour *h* of Pass 3 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConITLViol.*

$SITLViol^3_{f,c,h}$ The amount by which flows over *facility f* that would follow the occurrence of contingency *c* in hour *h* of Pass 3 exceed the emergency limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PITLViol.*

$SPreConXTLViol^3_{z,h}$ The amount by which *intertie* flows over *facility z* in hour *h* of Pass 3 exceed the normal limit for flows over that *facility*, because the cost of alternative solutions that would not result in such an overload was greater than or equal to *PPreConXTLViol.*

$SURmpXTLViol^3_h$ The amount by which the total net scheduled import increase for hour *h* in Pass 3 exceeds the up ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

$SDRmpXTLViol^3_h$ The amount by which the total net scheduled import decrease in hour *h* of Pass 2 exceed the down ramp limits, because the cost of alternative solutions that would not result in violation was greater than or equal to *PRmpXTLViol.*

6.6.2.8 Output Shadow Prices

Shadow Prices of Constraints:

SPL^3_h	The Pass 3 shadow price measuring the rate of change of the objective function for a change in load at the *reference bus* in hour *h*.
$SPNormT^3_{f,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjNormMaxFlow_{f,h}$, on flows over transmission *facilities* in normal conditions for *facility f* in hour *h*.
$SPEmT^3_{f,c,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $AdjEmMaxFlow_{f,c,h}$, on flows over transmission *facilities* in emergency conditions for *facility f* in monitored contingency *c* in hour *h*.
$SPExtT^3_{z,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $MaxExtSch_{z,h}$, on flows over transmission *facilities* on the boundary between Ontario and other *control areas* for each constraint z in hour *h*.
$SPRUExtT^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $ExtUSC_h$, on the upward change of the sum of net imports over all *interties* from the previous hour to hour *h*.
$SPRDExtT^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the limit, $ExtDSC_h$, on the downward change of the sum of net imports over all *interties* from the previous hour to hour *h*.
$SP10S^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the total synchronized *ten-minute operating reserve* requirement, $TOT10S_h$, in hour *h*.
$SP10R^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the total *ten-minute operating reserve* requirement, $TOT10R_h$, in hour *h*.
$SP30R^3_h$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the total *thirty-minute operating reserve* requirement, $TOT30R_h$, in hour *h*.
$SPREGMin10R^3_{r,h}$	The Pass 3 shadow price measuring the rate of change of the objective function for a change in the minimum *ten-minute*

operating reserve requirement, $REGMin10R_{r,h}$, for region r in hour h.

$SPREGMin30R^3_{r,h}$ The Pass 3 shadow price measuring the rate of change of the objective function for a change in the minimum *thirty-minute operating reserve* requirement, $REGMin30R_{r,h}$, for region r in hour h.

$SPREGMax10R^3_{r,h}$ The Pass 3 shadow price measuring the rate of change of the objective function for a change in the maximum *ten-minute operating reserve* limit, $REGMax10R_{r,h}$, for region r in hour h.

$SPREGMax30R^3_{r,h}$ The Pass 3 shadow price measuring the rate of change of the objective function for a change in the maximum *thirty-minute operating reserve* limit, $REGMax30R_{r,h}$, for region r in hour h.

Shadow Price for Energy:

$\mathrm{LMP}^3_{\mathrm{h,b}}$ The Pass 3 locational marginal price for *energy* at each bus b in each hour h. It measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of supply at that bus in that hour in Pass 3.

$ExtLMP^3_{h,d}$ The Pass 3 locational marginal price for *energy* at each *intertie zone* sink and source bus d in each hour h. It measures the *offered* price of meeting an infinitesimal change in the amount of load at that bus in that hour, or equivalently, measures the value of an incremental amount of supply at that bus in that hour in Pass 3.

6.6.2.9 Energy Ramp Rates

Same as those in section 4.6.2.8.

6.7 Objective Function

6.7.1 The optimization of the objective function in Pass 3 is to maximize the expression:

$$\sum_{h=1,\dots,24}\left\{\begin{array}{l} \sum_{d\in DX, j\in J_d}\left(SHXL^3_{j,h,d}\cdot PHXL_{j,h,d} - SX10N^3_{j,h,d}\cdot PX10N_{j,h,d} - SX30R^3_{j,h,d}\cdot PX30R_{j,h,d}\right) \\ -\sum_{b\in B}\left[\begin{array}{l}\sum_{j\in J_b} SPRL^3_{j,h,b}\cdot PPRL_{j,h,b} \\ +\sum_{j\in J_b} \begin{array}{l}10NSPRL^3_{j,h,b}\cdot 10NPPRL_{j,h,b} + 10SSPRL^3_{j,h,b}\cdot 10SPPRL_{j,h,b} + \\ 30RSPRL^3_{j,h,b}\cdot 30RPPRL_{j,h,b}\end{array}\end{array}\right] \\ -\sum_{d\in DI, k\in K_d}\left(SHIG^3_{k,h,d}\cdot PHIG_{k,h,d} + SI10N^3_{k,h,d}\cdot PI10N_{k,h,d} + SI30R^3_{k,h,d}\cdot PI30R_{k,h,d}\right) \\ -\sum_{b\in B}\left[\begin{array}{l}\sum_{k\in K_b}\left(SPRG^3_{k,h,b}\cdot PPRG_{k,h,b}\right) \\ +\sum_{k\in K_b} \begin{array}{l}10SSPRG^3_{k,h,b}\cdot 10SPPRG_{k,h,b} + 10NSPRG^3_{k,h,b}\cdot 10NPPRG_{k,h,b} \\ + 30RSPRG^3_{k,h,b}\cdot 30RPPRG_{k,h,b}\end{array}\end{array}\right] \\ -ViolCost^3_h \end{array}\right\};$$

where $ViolCost^3{}_h$ is calculated as follows:

$$\begin{aligned} ViolCost^3_h = {} & SLdViol^3_h\cdot PLdViol - SGenViol^3_h\cdot PGenViol \\ & + S10SViol^3_h\cdot P10SViol + S10RViol^3_h\cdot P10RViol \\ & + S30RViol^3_h\cdot P30RViol \\ & + \sum_{r\in ORREG}\left(\begin{array}{l} SREG10RViol^3_{r,h}\cdot PREG10RViol \\ + SREG30RViol^3_{r,h}\cdot PREG30RViol \\ + SXREG10RViol^3_{r,h}\cdot PXREG10RViol \\ + SXREG30RViol^3_{r,h}\cdot PXREG30RViol \end{array}\right) \\ & + \sum_{z\in Z}\left(SPreConXTLViol^3_{z,h}\cdot PPreConXTLViol\right) \\ & + SURmpXTLViol^3\cdot PRmpXTLViol + SDRmpXTLViol^3\cdot PRmpXTLViol \\ & + \sum_{f\in F} SPreConITLViol^3_{f,h}\cdot PPreConITLViol \\ & + \sum_{f\in F, c\in C} SITLViol^3_{f,c,h}\cdot PITLViol. \end{aligned}$$

6.8 Constraints Overview

6.8.1 Resources not already committed in Pass 2 will not be scheduled and the constraints that require their inputs will be eliminated.

6.9 Bid/Offer Constraints Applying to Single Hours

6.9.1 Status Variables and Capacity Constraints

6.9.1.1 No schedule can be negative, nor can any schedule exceed the amount of capacity *offered* for that service. Therefore:

$$0 \leq SPRL^{3}_{j,h,b} \leq QPRL_{j,h,b};$$

$$0 \leq 10SSPRL^{3}_{j,h,b} \leq 10SQPRL_{j,h,b};$$

$$0 \leq 10NSPRL^{3}_{j,h,b} \leq 10NQPRL_{j,h,b};$$

$$0 \leq 30RSPRL^{3}_{j,h,b} \leq 30RQPRL_{j,h,b};$$

$$0 \leq SHXL^{3}_{j,h,d} \leq QHXL_{j,h,d};$$

$$0 \leq SX10N^{3}_{j,h,d} \leq QX10N_{j,h,d};$$

$$0 \leq SX30R^{3}_{j,h,d} \leq QX30R_{j,h,d};$$

$$0 \leq SHIG^{3}_{k,h,d} \leq QHIG_{k,h,d};$$

$$0 \leq SI10N^{3}_{k,h,d} \leq QI10N_{k,h,d}; \text{ and}$$

$$0 \leq SI30R^{3}_{k,h,d} \leq QI30R_{k,h,d};$$

for all *bids* j, *offers* k, hours h, buses b and *intertie zones* source/sink buses d.

6.9.1.2 In the case of *generation facilities*, in addition to restrictions on their schedules similar to those above, their schedules must be consistent with their operating status determined at the conclusion of Pass 2. To simplify the writing of subsequent constraints, we will define the following variable for buses where *generation facilities* are located:

$$OPRG^{3}_{h,b} = OPRG^{2}_{h,b}; \text{ and}$$

$$IPRG^{3}_{h,b} = IPRG^{2}_{h,b}$$

which will indicate whether a resource at bus b may be scheduled to operate or start in Pass 3 in hour h. Then:

$$0 \le SPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot QPRG_{k,h,b};$$

$$0 \le 10SSPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot 10SQPRG_{k,h,b};$$

$$0 \le 10NSPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot 10NQPRG_{k,h,b}; \text{ and}$$

$$0 \le 30RSPRG^3_{k,h,b} \le OPRG^3_{h,b} \cdot 30RQPRG_{k,h,b}$$

for all *offers* k, hours h, and buses b.

6.9.1.3 In the case of linked wheeling transactions (the export *bid* and the import *offer* have the same *NERC* tag identifier), the amount of scheduled export *energy* must be equal to the amount of scheduled import *energy*. Therefore:

$$\sum_{j \in J_d} SHXL^3_{j,h,dx} = \sum_{k \in k_d} SHIG^3_{k,h,di}$$

where dx and di are the respective buses of the export and import schedules associated with the wheeling transactions.

6.9.1.4 The minimum and/or maximum output of the *generation facilities* may be limited because of *outages* and/or de-ratings or in order for the units to provide *regulation* or voltage support. These constraints will take the form:

$$MinPRG_{h,b} \le MinQPRG_{h,b}(OPRG^3_{h,b}) + \sum_{k \in K_b} SPRG^3_{k,h,b} \le MaxPRG_{h,b}.$$

6.9.1.5 Similarly, the maximum level of load reduction is the mechanism by which a *dispatchable load* indicates any de-rating to its registered maximum load reduction level due to mechanical or operational adjustments to their *facility*. The constraint will take the form:

$$\sum_{j \in J_b} SPRL^3_{j,h,b} \le MaxPRL_{h,b}.$$

6.9.2 Operating Reserve Constraints

6.9.2.1 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled load (maximum load *bid* minus the load reductions). These conditions can be enforced by the following two constraints:

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq 30 \cdot ORRPRL_b \text{; and}$$

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq \sum_{j \in J_b} (QPRL_{j,h,b} - SPRL^3_{j,h,b}).$$

6.9.2.2 In addition, this next constraint ensures that the total(10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* ramp capability to increase load reduction (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8):

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq -\sum_{j \in J_b} \left[\left(QPRL_{j,h-1,b} - SPRL^3_{j,h-1,b} \right) - \left(QPRL_{j,h,b} - SPRL^3_{j,h,b} \right) \right] + 60 \cdot URRPRL_b.$$

6.9.2.3 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from committed *dispatchable load* cannot exceed the *dispatchable load's* Pass 3 scheduled consumption:

$$\sum_{j \in J_b} (10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} + 30RSPRL^3_{j,h,b}) \leq MaxPRL_{h,b} - \sum_{j \in J_b} SPRL^3_{j,h,b}.$$

6.9.2.4 The amount of 10-minute synchronized and 10-minute non-synchronized reserve that a *dispatchable load* is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_b} 10SSPRL^3_{j,h,b} + 10NSPRL^3_{j,h,b} \leq 10 \cdot ORRPRL_b.$$

6.9.2.5 The total reserve (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed *generation facility* cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum *offered* generation minus the *energy* schedule). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b})$$
$$\leq 30 \cdot ORRPRG_b \text{; and}$$

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b})$$
$$\leq \sum_{k \in K_b} (QPRG_{k,h,b} - SPRG^3_{k,h,b}).$$

6.9.2.6 In addition, this next constraint ensures that the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed *generation facility* cannot exceed its ramp capability (schedules for hour, h=0 are obtained from the initializing inputs listed in section 3.8). Ramping considerations from start ups or shut downs are not carried forward from one day to the next:

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 10RSPRG^3_{k,h,b})$$
$$\leq \sum_{k \in K_b} (SPRG^3_{k,h-1,b} - SPRG^3_{k,h,b}) + 60 \times URRPRG_b$$

and

$$\sum_{k \in K_b} (10SSPRG^3_{k,h,b} + 10NSPRG^3_{k,h,b} + 30RSPRG^3_{k,h,b}) + \sum_{k \in K_b} (SPRG^3_{k,h,b})$$
$$\leq [(h-n) * 60 + 30] \times URRPRG_b \times OPRG^3_{h,b}$$

where *n* is the hour of the last start before or in hour *h*

and

$$\sum_{k\in K_b}\left(10SSPRG^3_{k,h,b}+10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b}\right)+\sum_{k\in K_b}\left(SPRG^3_{k,h,b}\right) \le [(m-h)*60+30]\times DRRPRG_b\times OPRG^3_{h,b}$$

where *m* is the hour of the last shut down in or after hour *h*

6.9.2.7 Finally, the total (10-minute synchronized, 10-minute non-synchronized and 30-minute) from a committed *generation facility* cannot exceed the *it*s Pass 3 unscheduled capacity:

$$\sum_{k\in K_b}(10SSPRG^3_{k,h,b}+10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b}) \le MaxPRG_{h,b}-\sum_{k\in K_b}SPRG^3_{k,h,b}-MinQPRG_{h,b}.$$

6.9.2.8 The amount of *ten-minute operating reserve* (both synchronized and non-synchronized) that a *generation facility* is scheduled to provide cannot exceed the amount by which it can increase its output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k\in K_b}(10SSPRG^3_{k,h,b}+10NSPRG^3_{k,h,b})\le 10\cdot ORRPRG_b.$$

6.9.2.9 The total reserve (10-minute non-synchronized and 30-minute) from hourly exports cannot exceed its ramp capability over 30 minutes. It cannot exceed the total scheduled export. These conditions can be enforced by the following two constraints:

$$\sum_{j\in J_d}(SX10N^3_{j,h,d}+SX30R^3_{j,h,d})\le 30\cdot ORRHXL_d;$$

and

$$\sum_{j\in J_d}(SX10N^3_{j,h,d}+SX30R^3_{j,h,d})\le \sum_{j\in J_d}SHXL^3_{j,h,d}.$$

6.9.2.10 The amount of 10-minute non-synchronized reserve that hourly export is scheduled to provide cannot exceed the amount by which it can decrease its load over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{j \in J_d} SX10N^3_{j,h,d} \leq 10 \cdot ORRHXL_d .$$

6.9.2.11 The total reserve (10-minute non-synchronized and 30-minute) from hourly imports cannot exceed its ramp capability over 30 minutes. It cannot exceed the remaining capacity (maximum import *offer* minus scheduled *energy* import). These conditions can be enforced by the following two constraints:

$$\sum_{k \in K_d} (SI10N^3_{k,h,d} + SI30R^3_{k,h,d}) \leq 30 \cdot ORRHIG_d ;$$

and

$$\sum_{k \in K_d} (SI10N^3_{k,h,d} + SI30R^3_{k,h,d}) \leq \sum_{k \in K_d} (QHIG_{k,h,d} - SHIG^3_{k,h,d}).$$

6.9.2.12 The amount of 10-minute non-synchronized reserve that hourly import is scheduled to provide cannot exceed the amount by which it can increase the output over 10 minutes, as limited by its *operating reserve* ramp rate. This condition can be enforced by the following constraint:

$$\sum_{k \in K_d} SI10N^3_{k,h,d} \leq 10 \cdot ORRHIG_d .$$

6.10 Bid/Offer Inter-Hour/Multi-Hour Constraints

6.10.1 Ramping

6.10.1.1 *Energy* schedules for each resource cannot vary by more than an hour's ramping capacity for that resource. The *energy* schedule change in the hour in which the unit is scheduled to start or shut down depends on the unit ramp rate below its *minimum loading point*. Almost all non-quick start *generation facilities* will need one or more hours to reach their *minimum loading point* and to go down from *minimum loading point* to zero. Since non-committed *generation facilities* must be assigned zero output and committed units must operate at or above their *minimum loading point*, it is assumed that these units will be at their *minimum loading point* at the beginning of the first commitment hour and at the end of the hour before shut down.

6.10.1.2 The following three part constraint ensures that the *energy* schedules do not exceed the *generation facility's* ramp capability in the hours where the unit starts, stays on and shuts down.

Start Up Scenario ($OPRG^3_{h,b} = 1$, and $OPRG^3_{h-1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^3_{k,h,b} \leq \sum_{k \in K_b} 30 \times URRPRG_b$$

Continued On Scenario ($OPRG^3_{h-1,b} = OPRG^3_{h,b} = 1$)

$$\sum_{k \in K_b} \left(SPRG^3_{k,h-1,b}\right) - 60 \times DRRPRG_b \leq \sum_{k \in K_b} SPRG^3_{k,h,b}$$

$$\leq \sum_{k \in K_b} \left(SPRG^3_{k,h-1,b}\right) + 60 \times URRPRG_b$$

Shut Down Scenario ($OPRG^3_{h,b} = 1$, and $OPRG^3_{h+1,b} = 0$)

$$0 \leq \sum_{k \in K_b} SPRG^3_{k,h,b} \leq \sum_{k \in K_b} 30 \times DRRPRG_b$$

6.10.1.3 It should be noted that these ramp up/down rates apply to the operating range above the *minimum loading point* of the *generation facility*.

6.10.1.4 Similar logic is applied to *dispatchable loads* to arrive at the following constraint:

$$\sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^3_{j,h-1,b} \right) - 60 \cdot URRPRL_{h,b}$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^3_{j,h,b} \right)$$
$$\leq \sum_{j \in J_b} \left(QPRL_{j,h-1,b} - SPRL^3_{j,h-1,b} \right) + 60 \cdot DRRPRL_{h,b}.$$

6.10.1.5 The above two constraints apply for all hours from 1 to 24. In the above two constraints the variables related to hour zero belong to the last hour of the previous day and are obtained from the initializing assumptions.

6.10.1.6 The ramping rates in the ramping constraints must be adjusted to allow the resource to:

a) Ramp down from its lower limit in hour (*h-1*) to its upper limit in hour *h*.

b) Ramp up from its upper limit in hour (*h-1*) to its lower limit in hour *h*.

6.10.1.7 This will allow a solution to be obtained when changes to the upper and lower limits between hours are beyond the ramping capability of the resources.

6.10.1.8 In the above ramping constraints, a single ramp up and a single ramp down, $URRPRG_b$ and $DRRPRG_b$ for *generation facilities* and $URRPRL_b$ and $DRRPRL_b$ for *dispatchable loads* are used. The ramp rate is assumed constant over the full operating range of the *dispatchable load and generation facility*. However, this is not the case. *Dispatchable load bids and generator offers* will include multi-*energy* ramp rates. The multiple ramp rates are described in sections 4.10.2.8 and 4.10.2.9.

6.10.2 Energy Limited Resources

6.10.2.1 Constraints applying to *energy* limited resources are very similar to the constraints used in Pass 1. Therefore:

$$\sum_{h=1}^{1}\left(OPRG^3_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}SPRG^3_{k,h,b}\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^3_{k,1,b}+\sum_{k\in K_b}10NSPRG^3_{k,1,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^3_{k,1,b}\le EL_b;$$

$$\sum_{h=1}^{2}\left(OPRG^3_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}SPRG^3_{k,h,b}\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^3_{k,2,b}+\sum_{k\in K_b}10NSPRG^3_{k,2,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^3_{k,2,b}\le EL_b;$$

M

$$\sum_{h=1}^{24}\left(OPRG^3_{h,b}\cdot MinQPRG_{h,b}+\sum_{k\in K_b}SPRG^3_{k,h,b}\right)$$
$$+10ORConv\left(\sum_{k\in K_b}10SSPRG^3_{k,24,b}+\sum_{k\in K_b}10NSPRG^3_{k,24,b}\right)$$
$$+30ORConv\sum_{k\in K_b}30RSPRG^3_{k,24,b}\le EL_b$$

for all hours *h* and for all buses *b* at which *energy* limited resources are located. The factors *10ORConv* and *30ORConv* are applied to scheduled *ten-minute operating reserve* and *thirty-minute operating reserves* for *energy*-limited resources to convert MW into MWh. This factor is set to unity.

6.11 Constraints to Ensure Schedules Do Not Violate Reliability Requirements

6.11.1 Load

6.11.1.1 The total amount of withdrawals scheduled in Pass 3 at each bus *b* in each hour *h*, $With^3_{h,b}$, is the sum of:

- the portion of the load forecast for that hour that has been allocated to that bus; and

- all *dispatchable load bid*, net of the amount of load reduction scheduled (since the *dispatchable load* is excluded from the *demand* forecast by the DACP calculation engine), yielding:

$$With^3_{h,b} = LDF_{h,b} \cdot AFL_h + \left[\sum_{j \in J_b} \left(QPRL_{j,h,b} - SPRL^3_{j,h,b} \right) \right]; \text{ and}$$

the total amount of withdrawals scheduled in Pass 3 at each *intertie zone* sink bus *d* in each hour *h*, $With^3_{h,b}$, is the sum of:

- exports from Ontario to each *intertie zone* sink bus; and

- outflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose, yielding:

$$With^3_{h,d} = \sum_{j \in J_d} (SHXL^3_{j,h,d}) - \sum_{a \in A} ProxyUPOWt_{d,a} \cdot \min(0, PF_{h,a}).$$

6.11.1.2 The total amount of injections scheduled in Pass 3 at each bus *b* in each hour *h*, $Inj^3_{h,b}$, is the sum of:

- generation scheduled at that bus, yielding:

$$Inj^3_{h,b} = (OPRG^3_{h,b} + RAMPUP\_ENRG \cdot IPRG^3_{h+1,b}) MinQPRG_{h,b} + \sum_{k \in K_b} \left(SPRG^3_{k,h,b} \right); \text{ and}$$

the total amount of injections scheduled in Pass 3 at each *intertie zone* source bus *d* in each hour *h*, $Inj^3_{h,d}$, is the sum of:

- imports into Ontario from each *intertie zone* source bus; and

- inflows from Ontario associated with loop flows between Ontario and each *intertie zone*, allocated among the buses in the *intertie zones* using the distribution factors developed for that purpose:

$$Inj_{h,d}^{3} = \sum_{k \in K_d} (SHIG_{k,h,d}^{3}) + \sum_{a \in A} ProxyUPIWt_{d,a} \cdot \max(0, PF_{h,a}).$$

6.11.1.3 Injections and withdrawals at each bus must be multiplied by one plus the marginal loss factor to reflect the losses (or reduction in losses) that result when injections or withdrawals occur at locations other than the *reference bus*. These loss-adjusted injections and withdrawals must then be equal to each other, after taking into account the adjustment for any discrepancy between actual and marginal losses. Load reduction associated with the *demand* constraint violation will be subtracted from the total load and generation reduction associated with the *demand* constraint violation will be subtracted from total generation to ensure that the calculation engine will always produce a solution. These violation variables are assigned a very high cost to limit their use to infeasible cases.

$$\begin{aligned}&\sum_{b \in B} (1 + MglLoss_{h,b}) With_{h,b}^{3} + \sum_{d \in D} (1 + MglLoss_{h,b}) With_{h,d}^{3} - SLDViol_{h}^{3} \\ &\quad = \sum_{b \in B} (1 + MglLoss_{h,b}) Inj_{h,b}^{3} + \sum_{d \in D} (1 + MglLoss_{h,d}) Inj_{h,d}^{3} \\ &\quad\quad - SGenViol_{h}^{3} + LossAdj_{h}.\end{aligned}$$

6.11.2 Operating Reserve

6.11.2.1 Sufficient *operating reserve* must be provided on the system to meet system wide requirements for 10-minute synchronized reserve, *ten-minute operating reserve* and *thirty-minute operating reserve*, as well as all applicable regional minimum and maximum requirements for *operating reserve*.

6.11.2.2 Therefore, taking into consideration the potential not to meet these minimum and maximum requirements if the cost of meeting those requirements becomes too high:

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^{3}_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^{3}_{k,h,b}\right)+S10SViol^{3}_{h}$$
$$\geq TOT10S_h;$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^{3}_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^{3}_{k,h,b}\right)+S10RViol^{3}_{h}$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b} 10NSPRG^{3}_{k,h,b}\right)+\sum_{b\in B}\left(\sum_{j\in J_b} 10NSPRL^{3}_{j,h,b}\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d} SI10N^{3}_{k,h,d}\right)+\sum_{d\in D}\left(\sum_{j\in J_d} SX10N^{3}_{j,h,d}\right)$$
$$\geq TOT10R_h; \text{ and}$$

$$\sum_{b\in B}\left(\sum_{j\in J_b} 10SSPRL^{3}_{j,h,b}\right)+\sum_{b\in B}\left(\sum_{k\in K_b} 10SSPRG^{3}_{k,h,b}\right)+S30RViol^{3}_{h}$$
$$+\sum_{b\in B}\left(\sum_{k\in K_b}(10NSPRG^{3}_{k,h,b}+30RSPRG^{3}_{k,h,b})\right)$$
$$+\sum_{b\in B}\left(\sum_{j\in J_b}(10NSPRL^{3}_{j,h,b}+30RSPRL^{3}_{j,h,b})\right)$$
$$+\sum_{d\in D}\left(\sum_{k\in K_d}(SI10N^{3}_{k,h,d}+SI30R^{3}_{k,h,d})\right)$$
$$+\sum_{d\in D}\left(\sum_{j\in J_d}(SX10N^{3}_{j,h,d}+SX30R^{3}_{j,h,d})\right)$$
$$\geq TOT30R_h$$

for all hours h; and

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+SREG10RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^3_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^3_{j,h,b}\right)$$
$$\geq REGMin10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)-SXREG10RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b} 10NSPRG^3_{k,h,b}\right)+\sum_{b\in r}\left(\sum_{j\in J_b} 10NSPRL^3_{j,h,b}\right)$$
$$\leq REGMax10R_{r,h};$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)+SREG30RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^3_{j,h,b}+30RSPRL^3_{j,h,b})\right)$$
$$\geq REGMin30R_{r,h};\text{ and}$$

$$\sum_{b\in r}\left(\sum_{j\in J_b} 10SSPRL^3_{j,h,b}\right)+\sum_{b\in r}\left(\sum_{k\in K_b} 10SSPRG^3_{k,h,b}\right)-SXREG30RViol^3_{r,h}$$
$$+\sum_{b\in r}\left(\sum_{k\in K_b}(10NSPRG^3_{k,h,b}+30RSPRG^3_{k,h,b})\right)$$
$$+\sum_{b\in r}\left(\sum_{j\in J_b}(10NSPRL^3_{j,h,b}+30RSPRL^3_{j,h,b})\right)$$
$$\leq REGMax30R_{r,h}$$

for all hours h, and for all regions r in the set *ORREG.*

6.11.3 Internal Transmission Limits

6.11.3.1 The *IESO* must ensure that the set of DACP schedules produced by Pass 3 of the calculation engine would not violate any *security limits* in either the pre-contingency state or in any contingency. To develop the constraints to ensure that this occurs, the total amount of *energy* scheduled to be injected at each bus and the total amount of *energy* scheduled to be withdrawn at each bus will be used.

6.11.3.2 Then the pre-contingency limits on transmission within Ontario will not be violated if:

$$\sum_{b \in B} PreConSF_{b,f,h}(Inj_{h,b}^{3} - With_{h,b}^{3}) + \sum_{d \in D} PreConSF_{d,f,h}(Inj_{h,d}^{3} - With_{h,d}^{3}) - SPreConITLViol_{f,h}^{3} \leq AdjNormMaxFlow_{f,h}$$

for all *facilities* f and hours h.

6.11.3.3 Post-contingency limits on transmission *facilities* within Ontario will not be violated if:

$$\sum_{b \in B} SF_{b,f,c,h}(Inj_{h,b}^{3} - With_{h,b}^{3}) + \sum_{d \in D} SF_{d,f,c,h}(Inj_{h,d}^{3} - With_{h,d}^{3}) - SITLViol_{f,c,h}^{3} \leq AdjEmMaxFlow_{f,c,h}$$

for all *facilities* f, hours h, and monitored contingencies c.

6.11.4 Intertie Transmission Limits and Constraints on Net Imports

6.11.4.1 The calculation engine would not violate any *security limits* associated with *interties* between Ontario and *intertie zones*. To ensure this, we must calculate the net amount of *energy* scheduled to flow over each *intertie* in each hour and the amount of *operating reserve* scheduled to be provided by resources in that *control area*. This will be summed over all affected *interties*. The result will be compared to the limit associated with that constraint. Consequently:

$$\sum_{a\in A}\left[\begin{array}{l} EnCoeff_{a,z}\left(\sum_{d\in DI_a,k\in K_d}(SHIG^3_{k,h,d})+PF_{h,a}-\sum_{d\in DX_a,j\in J_d}\left(SHXL^3_{j,h,d}\right)\right)+ \\ 0.5(EnCoeff_{a,z}+1)\left[\begin{array}{l}\sum_{d\in DI_a,k\in K_d}\left(SI10N^3_{k,h,d}+SI30R^3_{k,h,d}\right) \\ +\sum_{d\in DX_a,j\in J_d}\left(SX10N^3_{j,h,d}+SX30R^3_{j,h,d}\right)\end{array}\right]\end{array}\right]$$
$$\le MaxExtSch_{z,h}$$

for all hours *h*, for all *intertie zones a* relevant to the constraint *z*

($EnCoeff_{a,z}\neq 0$), and for all constraints *z* in the set Z_{sch}.

6.11.4.2 In addition, changes in the net *energy* schedule over all *interties* cannot exceed the limits set forth by the *IESO* for hour-to-hour changes in those schedules. The net import schedule is summed over all *interties* for a given hour. It cannot exceed the sum of net import schedule for all *interties* for the previous hour plus the maximum permitted hourly increase. It cannot be less than the sum of the net import schedule for all *interties* for the previous hour minus the maximum permitted hourly decrease. Violation variables are provided for both the up and down ramp limits to ensure that the calculation engine will always find a solution. Therefore:

$$\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^3_{k,h-1,d})-\sum_{j\in J_d}(SHXL^3_{j,h-1,d})\right)-ExtDSC_h-SDRmpXTLViol^3_h$$
$$\le\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^3_{k,h,d})-\sum_{j\in J_d}(SHXL^3_{j,h,d})\right)$$
$$\le\sum_{d\in D}\left(\sum_{k\in K_d}(SHIG^3_{k,h-1,d})-\sum_{j\in J_d}(SHXL^3_{j,h-1,d})\right)+ExtUSC_h+SURmpXTLViol^3_h$$

for all hours *h* (schedules for hour, *h*=0 are obtained from the initializing inputs listed in section 3.8).

6.11.5 Intertie Schedule Limits Based on Pass 2 Outputs

6.11.5.1 Pass 3 will not reduce the amount of imported *energy* scheduled from each *intertie zone* in any hour. Additional imports of *energy* may be scheduled in Pass 3, Therefore, for imports that are not part of a linked wheeling transaction:

$$SHIG^{3}_{k,h,d} \geq SHIG^{2}_{k,h,d}$$

for all *offers* k, hours h and *intertie zones* source bus d, and:

6.11.5.2 Pass 3 will not increase the amount of exported *energy* scheduled from each *intertie zone* in any hour to the amount scheduled in Pass 2.

6.11.5.3 Therefore, for exports that are not part of a linked wheeling transaction:

$$SHXL^{3}_{j,h,d} \leq SHXL^{2}_{j,h,d}.$$

6.12 Shadow Prices

6.12.1 The *IESO* shall also determine *energy* and *operating reserve* prices in Pass 3 that will be *published* for informational purposes.

6.12.2 Shadow Energy Prices

6.12.2.1 The Pass 3 shadow price at each bus b in each hour h shall be calculated at buses in Ontario as:

$$LMP^{3}_{h,b} = \left(1 + MglLoss_{h,b}\right) \cdot SPL^{3}_{h} + \sum_{f \in F} \left(\begin{array}{l} PreConSF_{b,f,h} \cdot SPNormT^{3}_{f,h} \\ + \sum_{c \in C} SF_{b,f,c,h} \cdot SPEmT^{3}_{f,c,h} \end{array} \right)$$

6.12.3 Shadow Energy Prices at *Intertie Zones*

6.12.3.1 The Pass 3 shadow price at each *intertie zone* source/sink bus d in each hour h is calculated as:

$$\begin{aligned} ExtLMP^{3}_{h,d} \\ &= \left(1 + MglLoss_{h,d}\right) \cdot SPL^{3}_{h} + \sum_{f \in F} \left(\begin{array}{l} PreConSF_{d,f,h} \cdot SPNormT^{3}_{f,h} \\ + \sum_{c \in C} (SF_{d,f,c,h} \cdot SPEmT^{3}_{f,c,h}) \end{array} \right) \\ &+ \sum_{z \in Z_{sch}} (EnCoeff_{a,z} \cdot SPExtT^{3}_{z,h}) + SPRUExtT^{3}_{h} - SPRDExtT^{3}_{h} \end{aligned}$$

6.12.3.2 The first component of this calculation, the cost of meeting load at each *intertie zone* reflecting marginal losses incurred in transmitting *energy* from the *reference bus* to that *intertie zone*, is the same as the first component of the previous equation. The second component of this calculation determines the effect of congestion on internal transmission *facilities* on the price at each bus.

6.12.3.3 The last three components reflect the impact of limits on imports or exports, which are relevant for the calculation of prices at *intertie zones*. The first of the three components provides the effect of congestion resulting from *security limits* associated with *interties* between Ontario and *intertie zones*, for all constraints z in the set Z_{sch}. The last two components reflect the congestion cost resulting from the upward/downward limits of hour-to-hour net *energy* changes across all *interties*.

6.12.4 Shadow 30-Minute Reserve Prices

6.12.4.1 Shadow prices can also be calculated for each bus, reflecting the marginal contribution that each category of *operating reserve* would have if provided at that bus to increasing the value of the objective function. For each bus b, define $ORREG_b$ as the subset of $ORREG$ consisting of regions that include bus b. The Pass 3 price of *thirty-minute operating reserve* at a given bus b, $L30RP^3_{h,b}$, is the shadow price of the total *thirty-minute operating reserve* constraint, plus the shadow prices of all of the constraints requiring a minimum amount of *thirty-minute operating reserve* to be provided by resources in regions that include that bus, minus the shadow prices of all the constraints limiting the amount of *thirty-minute operating reserve* that can be provided by resources in regions that include that bus; given these definitions:

$$L30RP^3_{h,b} = SP30R^3_h + \sum_{r \in ORREG_b} SPREGMin30R^3_{r,h} - \sum_{r \in ORREG_b} SPREGMax30R^3_{r,h}.$$

6.12.5 Shadow 10-Minute Non-synchronized Reserve Prices

6.12.5.1 The Pass 3 price of 10-minute non-synchronized reserve at a given bus b, $L10NP^3_{h,b}$, is the shadow price of the total *ten-* and *thirty-minute operating reserve* constraints, plus the shadow prices of all of the constraints requiring a minimum amount of *ten-* or *thirty-minute* *operating reserve* to be provided by resources in regions that include that bus, minus the shadow prices of all the constraints limiting the amount of *ten-* or *thirty-minute operating reserve* that can be provided by resources in regions that include that bus:

$$L10NP^3_{h,b} = SP10R^3_h + SP30R^3_h + \sum_{r \in ORREG_b} \left(SPREGMin10R^3_{r,h} + SPREGMin30R^3_{r,h} \right) - \sum_{r \in ORREG_b} \left(SPREGMax10R^3_{r,h} + SPREGMax30R^3_{r,h} \right)$$

6.12.6 Shadow 10-Minute Synchronized Reserve Prices

6.12.6.1 Finally, the Pass 3 price of 10-minute synchronized reserve at a given bus *b,* $L10SP^3_{h,b}$, is the shadow price of the total *ten-* and *thirty-minute operating reserve* constraints and the total 10-minute synchronized reserve constraint, plus the shadow prices of all of the constraints requiring a minimum amount of *ten-* or *thirty-minute operating reserve* or 10-minute synchronized reserve to be provided by resources in regions that include that bus, minus the shadow prices of all the constraints limiting the amount of *ten-* or *thirty-minute operating reserve* or 10-minute synchronized reserve that can be provided by resources in regions that include that bus:

$$L10SP^3_{h,b} = SP10S^3_h + SP10R^3_h + SP30R^3_h + \sum_{r \in ORREG_b} \left(SPREGMin10R^3_{r,h} + SPREGMin30R^3_{r,h} \right) - \sum_{r \in ORREG_b} \left(SPREGMax10R^3_{r,h} + SPREGMax30R^3_{r,h} \right)$$

6.12.7 Shadow Operating Reserve Prices at *Intertie Zones*

6.12.7.1 Shadow *operating reserve* prices can also be calculated for *intertie zones*. These prices need to take into account the shadow prices of constraints in the set Z_{sch}, as some of these constraints will limit the amount of *operating reserve* that can be imported into Ontario. They do not need to take into account the shadow prices of constraints associated with lower limits on the amount of *operating reserve* that must be supplied within regions of Ontario or upper limits on the amount of *operating reserve* that may be supplied within regions of Ontario, since imported *operating reserve* will not affect either of these types of constraints. Nor do they need to take into account the shadow price for the hour-to-hour change in net *energy* flow over all *interties*, as these constraints will only affect the amount of *energy* that can be scheduled to flow into or out of Ontario.

6.12.7.2 The Pass 3 price of *thirty-minute operating reserve* at a given *intertie zone a*, $Ext30RP^3_{h,a}$, is the shadow price of the total *thirty-minute operating reserve* constraint, minus the product of:

- the impact that imports of *operating reserve* from that *intertie zone* have on each constraint limiting the import of *operating reserve* from that *intertie zone*, and
- the shadow price of that constraint, summed over all constraints:

$$Ext30RP^3_{h,a} = SP30R^3_h - \sum_{z \in Z_{sch}} 0.5(ENCoeff_{a,z} + 1)SPExtT^3_{z,h}.$$

6.12.7.3 The Pass 3 price of *ten-minute operating reserve* at a given *intertie zone a*, $Ext10RP^3_{h,a}$, is the shadow price of the total *ten-* and *thirty-minute operating reserve* constraints, minus the product of:

- the impact that imports of *operating reserve* from that *intertie zone* have on each constraint limiting the import of *operating reserve* from that *intertie zone*, and
- the shadow price of that constraint, summed over all constraints:

$$Ext10RP^3_{h,a} = SP10R^3_h + SP30R^3_h - \sum_{z \in Z_{sch}} 0.5(ENCoeff_{a,z} + 1)SPExtT^3_{z,h}.$$

6.12.7.4 There is no need to calculate a price for 10-minute synchronized reserve at *intertie zones*, since 10-minute synchronized reserve cannot be imported.

7. Combined-Cycle Modeling

7.1 Overview

7.1.1 *Registered market participants* with combined-cycle plants of one or more combustion turbines and one steam turbine may choose to have the associated *generation facilities* modeled as one or more *pseudo-units*. Each *pseudo-unit* comprises of a single combustion turbine and a share of the steam turbine capacity. Inputs for *pseudo-units* used by the DACP calculation engine are described in Chapter 7, section 2.2.6G.

7.2 Modeling by DACP Calculation Engine

7.2.1 The *pseudo-units* are independently scheduled in each pass subject to the optimization objective function described in sections 4.3, 5.3 and 6.3 respectively. However, the security assessment described in section 4.4 is performed for each *generation facility* of the combined-cycle plant.

7.2.2 As the security assessment function iterates with the scheduling function of the DACP calculation engine, the output relationship of each combustion turbine and its share of output from the steam turbine is respected. This output relationship is described as follows:

7.2.2.1 For a combined-cycle plant with *i* combustion turbines and one steam turbine, it is represented by *i pseudo-units*.

7.2.2.2 For each *pseudo-unit i*, let $pst_{i,k}$ represent the percentage of the *pseudo-unit*'s schedule that relates to the steam turbine in association with *offer k*.

7.2.2.3 Then for each *pseudo-unit i*, the percentage of the *pseudo-unit's* schedule that relates to the combustion turbine *i* is (100% - $pst_{i,k}$).

7.2.2.4 For a given *pseudo-unit* schedule $SPSU_{k,h}$ for hour *h* and *k* offers its associated combustion turbine schedule is:

$$\sum_{k} SPSU_{k,h} \times (100\% - pst_{i,k}).$$

7.2.2.5 And the steam turbine schedule of the *pseudo-unit* plant for hour *h* is: $\sum_{i}\sum_{k} SPSU_{k,h} \times pst_{i,k}$.

Appendix 7.6 – Local Market Power

1.1 Dispatch of Constrained Off Facilities and Constrained On Facilities

1.1.1 The *IESO* shall, pursuant to this Chapter 7, *dispatch* a *registered facility* as a *constrained on facility* or a *constrained off facility* when, without such action, the *reliability* of the *IESO-controlled grid* cannot be maintained due to a transmission flow constraint on the *IESO-controlled grid* or a *security limit.* The *IESO* shall *dispatch registered facilities* as *constrained on facilities* and *constrained off facilities* in such economic merit order as will enable it to meet its *reliability* obligations under these *market rules* at the lowest cost.

1.1.2 [Intentionally left blank – section deleted]

1.1.3 Subject to section 9.4.5 of Chapter 7 and sections 1.4.5.1 and 1.6.7.1, each *constrained on facility* or *constrained off facility* shall, in addition to such other *settlement* credits to which it may be entitled in accordance with Chapter 9, receive a congestion management *settlement* credit calculated in accordance with section 3.5.2 of Chapter 9.

1.2 Investigation of Local Market Power and Constrained Off Events

1.2.1 Subject to sections 1.2.1C, 1.2.2 or 1.2.6, where the *IESO* determines that a *constrained on event* or *constrained off event* may have occurred, the *IESO* shall conduct the analyses referred to in section 1.3 to establish whether local market power existed and as a preliminary step in determining whether the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3 is justified.

1.2.1A For purposes of establishing *designated constrained off watch zones* and for identifying persistent and significant *constrained off events* within *designated constrained off watch zones,* the *IESO* shall conduct the analysis set out in the applicable *market manual*.

The *market manual* shall include but not necessarily be limited to a description of:

- criteria for identifying *designated constrained off watch zones* and for revoking such designations;

- criteria for determining persistent and significant congestion management *settlement* credit payments for *constrained off events* within *designated constrained off watch zones*; and

- the manner for determining an initial estimated replacement price for the *investigated price*.

1.2.1B When developing the criteria referred to in section 1.2.1A, the *IESO* shall be guided by the following principles:

- areas within Ontario where nodal *energy* prices are materially different from the price of *energy* in either the *pre-dispatch schedule* or the *real-time schedule* are more likely to be *designated constrained off watch zones*; and

- *constrained off events* that occur more frequently over periods of time or that occur less frequently but involve larger congestion management *settlement* credit payments are more likely to be considered persistent and significant, justifying the price investigation analysis referred to in section 1.4.1.

When developing the initial estimated replacement price for the *investigated price* referred to in section 1.2.1A, the *IESO* shall be guided by the principle that the *market participant* should be financially indifferent to being constrained off relative to the profit it would have earned under the *market schedule*, with due consideration to the following:

- recent *offers* or *bids* submitted by the *market participant*;

- market prices in neighbouring jurisdictions;

- *market participant* costs as estimated through information provided by the *market participant*;

- in the case of energy limited resources, an assessment of opportunity costs; and

- any other information considered relevant by the *IESO*.

1.2.1C If after completing the analysis prescribed by section 1.2.1A, the *IESO* determines that a *market participant* received persistent and significant congestion management *settlement* credit payments for *constrained off events* in one or more *constrained off watch zones*, the *IESO* shall conduct the analysis referred to in section 1.4.1 to determine whether the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3.

1.2.1D The *IESO* shall monitor conditions on the *IESO-controlled grid* and publish any changes in the status of the *designated constrained off watch zones* before they take effect. *Market participants* may request a review of such designations, stating reasons for requesting the review, and the *IESO* shall undertake such review unless in its judgement the review is considered to be unwarranted.

1.2.2 The *IESO* shall not be required to conduct the analysis referred to in sections 1.2.1 or 1.2.1A if the *IESO* anticipates that:

1.2.2.1 the maximum adjustment to the congestion management *settlement* credit referred to in section 1.1.3 that may be effected on the basis of such analyses and of the analysis referred to in section 1.4.1 would not exceed the threshold amount *published* by the *IESO* pursuant to section 1.2.3; or

1.2.2.2 the impact of the price contained in the *energy bid* or the *energy offer* submitted by the *constrained on facility* or the *constrained off facility* is, in the *IESO's* opinion, not material.

1.2.3 The *IESO* shall determine and *publish* the threshold amount referred to in section 1.2.2.1, which shall be the minimum amount of an adjustment to a congestion management *settlement* credit referred to in section 1.1.3 that will, subject to sections 1.2.2.2 and 1.2.6, trigger an obligation on the *IESO* to conduct the analyses referred to in sections 1.2.1 or 1.2.1A.

1.2.4 [Intentionally left blank – section deleted]

1.2.5 [Intentionally left blank – section deleted]

1.2.6 Where the *IESO* cannot, for any reason, conduct the analyses referred to in section 1.3 in the manner described in that section, it may conduct such other analyses as it determines appropriate either prior to conducting the analysis described in section 1.4.1, if any, or as part of such analysis.

1.2.7 Where section 1.2.6 applies:

1.2.7.1 the *IESO* shall cease investigation of the *investigated price* where the *IESO* determines that the results of the analyses do not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3; or

1.2.7.2 the *IESO* shall conduct the analysis referred to in section 1.4.1 where the *IESO* determines that the results of the analyses referred to in section 1.2.6 reveal that the *investigated price* may justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3.

1.3 Local Market Power Screens

1.3.1 The *IESO* shall review the inputs and outputs of the *dispatch algorithm* for the *dispatch intervals* to which the *investigated price* relates, and such other information as the *IESO* determines appropriate, for the purpose of determining whether a transmission flow constraint on the *IESO-controlled grid* or a *security limit* resulted in a *constrained on event* or a *constrained off event.*

1.3.2 The *IESO* shall determine whether the *investigated price* falls within the range determined in accordance with section 1.3.8 using the *reference prices* referred to in section 1.3.3 and the factors derived from the methodology approved by the *IESO Board* pursuant to section 1.3.5.

1.3.3 For the purposes of section 1.3.2, the *reference prices* shall be:

1.3.3.1 the *historical reference price* representing *business days* between the hours of 07:00 and 23:00 EST for the *investigated facility*; or

1.3.3.1A the *historical reference price* representing all time periods other than those specified in section 1.3.3.1 for the *investigated facility*,

as the case may be depending on whether the *investigated price* was submitted for the time period indicated in section 1.3.3.1 or section 1.3.3.1A, referred to as P_h, or

1.3.3.1B where permitted by section 1.3.4, such alternative *reference price*, if any, as may be established by the *IESO Board* and published pursuant to section 1.3.4, referred to as P_a; and

1.3.3.2 the *market price* for *energy* determined for the *dispatch interval* to which the *investigated price* relates, referred to as P_m,

provided that,

1.3.3.3 if *dispatch data* that has been accepted by the *IESO*, as reflected in the *market schedules* for that *investigated facility,* is not available in respect of the *investigated facility* which is; i) a hydroelectric *generation facility* for at least ten of the thirty days; or ii) or for all other *facilities* at least fifteen of the ninety days, comprising the period over which the relevant *historical reference price* referred to in sections 1.3.3.1 and 1.3.3.1A is calculated, or

1.3.3.4 if the *investigated facility* is a *boundary entity* withdrawing *energy* from the *IESO-administered markets* at an *intertie* that has been designated by the *IESO* as an uncontested export *intertie*, being an *intertie*:

a. where at least ninety percent of the withdrawals over that *intertie* in the ninety days prior to such designation have been accounted for by one *market participant*, or

b. which is uncontested in accordance with criteria stipulated by the *IESO Board* (which criteria shall also specify the factors allowing revocation of the designation).

sections 1.3.3.1 and 1.3.3.1A shall not apply and only the *reference price* referred to in section 1.3.3.2 shall be used for the purposes of section 1.3.2.

1.3.4 The *IESO Board* may establish the alternative *reference price* referred to in section 1.3.3.1B based on an average of the price contained in all *energy offers* or *energy bids* submitted by the *registered market participant* for an *investigated facility* and accepted by the *IESO*, as reflected in the most recent *market schedules* for that *investigated facility*, during the time periods specified in section 1.3.3.1 or the time periods specified in section 1.3.3.1A as the case may be, in respect of a given increment or increments of supply or consumption. No such alternative *reference price* shall be used by the *IESO* for the purposes of section 1.3.3.1B until the manner of determination of such *reference price* and the conditions in which it may be applied have been *published* by the *IESO.*

1.3.5 The *IESO* shall publish the methodology, as determined by the *market surveillance panel* and approved by the *IESO Board*, for determining a pair of high end factors and a pair of low end factors for each type of *reference price* referred to in section 1.3.3, including the alternative *reference price* referred to in section 1.3.3.1B, if any.

1.3.5.1 [Intentionally left blank – section deleted]

1.3.5.2 [Intentionally left blank – section deleted]

1.3.6 The methodology referred to in section 1.3.5 for determining the pair of high end factors and the pair of low end factors for each type of *reference price* shall be established based on the concept that it is acceptable for the congestion management *settlement* credit referred to in section 1.1.3 to be larger as the number of consecutive or the number of cumulative hours that a *registered facility* may be *dispatched* as a *constrained on facility* or as a *constrained off facility* decrease. Accordingly:

1.3.6.1 one of each such pair of high end factors and one of each such pair of low end factors shall vary according to the number of consecutive hours that a *registered facility* was *dispatched* as a *constrained on facility* or a *constrained off facility* during the *constrained on event* or *constrained off event* being investigated; and

1.3.6.2 the other of each such pair shall vary according to the cumulative number of hours that a *registered facility* was *dispatched* as a *constrained on facility* or a *constrained off facility* in the ninety-day period preceding the *constrained on event* or *constrained off event* being investigated and during such *constrained on event* or *constrained off event*.

1.3.7 The methodology referred to in section 1.3.5 for determining the pair of high end factors and the pair of low end factors may differ for, and the resulting pairs of factors may also differ for, each of the *reference prices* referred to in section 1.3.3, including the alternative *reference price*, if any, referred to in section 1.3.3.1B. For each such *reference price*:

1.3.7.1 the high end factors shall decrease as either the number of consecutive hours or the number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively, increase, provided that neither of such factors shall be less than the value 1.0; and

1.3.7.2 the low end factors shall increase as either the number of consecutive hours or the number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively, increase, provided that such neither of such factors shall be greater than the value 1.0.

1.3.8 The *IESO* shall establish the range referred to in section 1.3.2 in respect of an *investigated price* as follows:

1.3.8.1 for the high end of the range the *IESO* shall:

a. calculate, for each applicable *reference price* referred to in section 1.3.3, high end values for each of the number of consecutive hours and the number of cumulative hours referred in sections 1.3.6.1 and 1.3.6.2, respectively, using the following equation:

reference price + absolute value (*reference price*) x (factor – 1)

where the factor used in the above equation is the high end factor determined for that type of *reference price* in accordance with sections 1.3.5 to 1.3.7 that corresponds to the appropriate number of consecutive hours or number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively;

b. select, in respect of each applicable *reference price*, the lesser of the high end values calculated pursuant to section 1.3.8.1(a); and

c. select the larger of the high end values based on P_m or P_h or, where the alternative *reference price* referred to in section 1.3.3.1B is used, based on P_m or P_a; and

1.3.8.2 for the low end of the range the *IESO* shall:

a. calculate, for each applicable *reference price* referred to in section 1.3.3, low end values for each of the number of consecutive hours and the number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively, using the following equation:

reference price + absolute value (*reference price*) x (factor – 1)

where the factor used in the above equation is the low end factor determined for that type of *reference price* in accordance with sections 1.3.5 to 1.3.7 that corresponds to the appropriate number of consecutive hours or number of cumulative hours referred to in sections 1.3.6.1 and 1.3.6.2, respectively;

b. select, in respect of each applicable *reference price*, the larger of the low end values calculated pursuant to section 1.3.8.2(a); and

c. select the lesser of the low end values based on P_m or P_h or, where the alternative *reference price* referred to in section 1.3.3.1B is used, based on P_m or P_a.

1.3.9 The *IESO* shall determine whether, in the *IESO's* opinion, there existed sufficient competition for the provision of the *physical services* that the *investigated facility* was to provide in being *dispatched* as a *constrained on facility* or a *constrained off facility*. The *IESO* shall determine whether sufficient competition existed based on the number of *market participants* and the MW quantity associated with, as applicable:

1.3.9.1 *energy offers,* not included in the *market schedule*, for a *generation facility* or an import that could have been constrained on; and

1.3.9.2 *energy bids,* included in the *market schedule,* for a *dispatchable load* or an export that could have been constrained off;

or,

1.3.9.3 *energy offers,* included in *the market schedule,* for a *generation facility* or an import that could have been constrained off; and

1.3.9.4 *energy bids,* not included in the *market schedule,* for a *dispatchable load* or an export that could have been constrained on;

for those *market participants* that could have effectively responded to *dispatch instructions* comparable to those issued for the *investigated facility*.

1.3.10 Where the *IESO* determines:

1.3.10.1 pursuant to section 1.3.1, that a transmission flow constraint on the *IESO-controlled grid* or a *security limit* did not result in a constrained *on event* or a *constrained off event*;

1.3.10.2 pursuant to section 1.3.2, that the investigated price falls within the range referred to in that section; or

1.3.10.3 pursuant to section 1.3.9, that sufficient competition existed for the provision of the physical services that the *investigated facility* was dispatched as a *constrained on facility* or a *constrained off facility* to provide,

the *IESO* shall, subject to section 1.8, cease investigation of the *investigated price.*

1.3.11 [Intentionally left blank – section deleted]

1.3.11.1 [Intentionally left blank – section deleted]

1.3.11.2 [Intentionally left blank – section deleted]

1.3.12 For the purpose of Appendix 7.6, local market power is established where the *IESO* determines:

1.3.12.1 pursuant to section 1.3.1, that a transmission flow constraint on the *IESO-controlled grid* or a *security limit* resulted in *constrained on event* or a *constrained off event*;

1.3.12.2 pursuant to section 1.3.2, that the *investigated price* falls outside of the range referred to in that section; and

1.3.12.3 pursuant to section 1.3.9, that sufficient competition did not exist for the provision of the *physical services* that the *investigated facility* was *dispatched* as a *constrained on facility* or a *constrained off facility* to provide.

If the *IESO* establishes that local market power exists, the *IESO* shall conduct the analysis referred to in 1.4.1 to determine whether the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3.

1.3.12.4 [Intentionally left blank – section deleted]

1.3.12.5 [Intentionally left blank – section deleted]

1.3.13 [Intentionally left blank – section deleted]

1.3.13.1 [Intentionally left blank – section deleted]

1.3.13.2 [Intentionally left blank – section deleted]

1.3.13.3 [Intentionally left blank – section deleted]

1.3.13.4 [Intentionally left blank – section deleted]

1.4 Price Investigation

1.4.1 Subject to section 1.4.2, the *IESO* shall conduct an analysis of such factors that the *IESO* considers relevant to a determination of whether the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, which factors may include:

1.4.1.1 the price, and variations in the price, of the fuel used by the *investigated facility;*

1.4.1.2 the degree to which the prices contained in the *energy offers* or *energy bids* submitted by the *registered market* participant for the *investigated facility* and accepted by the *IESO*, as reflected in the *market schedules* for that *investigated facility*, have varied over time;

1.4.1.3 [Intentionally left blank – section deleted]

1.4.1.4 market prices and variations in market prices in neighbouring jurisdictions;

1.4.1.5 opportunity costs for *energy* limited resources; and

1.4.1.6 for investigations of *constrained off events* in *designated constrained off watch zones* prescribed in section 1.2.1A, such other considerations as set out in the applicable *market manual*.

1.4.2 The *IESO* shall not be required to conduct the analysis referred to in section 1.4.1 and shall cease investigation of the *investigated price* if, in the *IESO*'s opinion:

1.4.2.1 the *IESO* does not have sufficient reliable information upon which to base the determination referred to in section 1.4.1;

1.4.2.2 the level of effort that would be required to conduct the analysis is large relative to the materiality of the anticipated impact of the *investigated price*; or

1.4.2.3 the conduct of the analysis would constitute an inefficient utilization of the *IESO's* resources, having regard to the *IESO*'s other activities and to the desire to allocate resources to the investigation of *energy offers* and *energy bids* that are most likely to require remedial action pursuant to this Appendix.

1.4.3 Where, based on the analysis conducted in section 1.4.1 and on the criteria specified in section 1.4A, the *IESO* determines that:

1.4.3.1 the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* shall, subject to section 1.8, cease investigation of the *investigated price*; or

1.4.3.2 the *investigated price* may justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* shall provide the *registered market participant* for the *investigated facility* with a reasonable opportunity to make representations as to why the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3. As part of its representations, the *registered market participant* may request that the *IESO* apply for the purpose of replacing the *investigated price* pursuant to section 1.4.5.1:

a. alternate high end or low end values in place of those prescribed by section 1.3.8, or

b. an alternate replacement price to the initial estimated replacement price referred to in section 1.2.1A.

1.4.4 Where, following a consideration of any representations made by the *registered market participant* for the *investigated facility* pursuant to section 1.4.3.2, the *IESO* determines that the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* shall, subject to section 1.8, cease investigation of the *investigated price.*

1.4.5 Where, following a consideration of any representations made by the *registered market participant* for the *investigated facility* pursuant to section 1.4.3.2 and based on the criteria specified in section 1.4A, the *IESO* determines that the *investigated price* justifies the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3:

1.4.5.1 the *IESO* shall replace the *investigated price* with the following as applicable, or such other value as may be agreed to by the *IESO* and the *market participant*:

a. in the case of a *constrained on generation unit* or a *constrained off dispatchable load*, the high end of the range determined in accordance with section 1.3.8.1;

b. in the case of a *constrained off generation unit* or a *constrained on dispatchable load*, the low end of the range determined in accordance with section 1.3.8.2;

c. [Intentionally left blank – section deleted]

d. in the case of persistent and significant *constrained off events* within *designated constrained off watch zones*, the initial estimated replacement price referred to in section 1.2.1A, or

1.4.5.2 the *IESO* may commence an inquiry pursuant to section 1.6.1.

1.4.5A Where section 1.4.5.1 applies, the *IESO* shall:

1.4.5A.1 re-calculate the congestion management *settlement* credit referred to in section 1.1.3 on the basis of the price referred to in section 1.4.5.1; and

1.4.5A.2 provide notice to the *registered market participant* for the *investigated facility* specifying:

a. the grounds and associated information upon which the *IESO* is relying in support of its intention to use, for *settlement* purposes, the re-calculated congestion management *settlement* credit referred to in section 1.4.5A.1;

b. an estimate of the replacement price for the *investigated price* referred to in section 1.4.5.1; and

c. the right of the *registered market participant* to request, within five *business days* of the date of receipt of the notice, an inquiry pursuant to section 1.6.1.

1.4.6 Where, following a consideration of any representations made by the *registered market participant* for the *investigated facility* pursuant to section 1.4.3.2 and the criteria specified in section 1.4A, the *IESO* determines that the *investigated price* may justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3, the *IESO* may commence an inquiry pursuant to section 1.6.1.

1.4.7 [Intentionally left blank – section deleted]

1.4.7.1 [Intentionally left blank – section deleted]

1.4.7.2 [Intentionally left blank – section deleted]

1.4.7.3 [Intentionally left blank – section deleted]

1.4.8 Where a *registered market participant* requests an inquiry pursuant to section 1.4.5A.2c within the time referred to in that section, the *IESO* shall not take any action pursuant to section 1.4.5.1 and shall conduct an inquiry pursuant to section 1.6.1.

1.4.9 Where a *registered market participant* does not request an inquiry pursuant to section 1.4.5A.2c within the time referred to in that section, the *IESO* shall use, for *settlement* purposes, the re-calculated congestion management *settlement* credit referred to in section 1.4.5A.1.

1.4A Criteria for Re-calculating Congestion Management Settlement Credits

1.4A.1 Having established in section 1.3 that local market power existed or that persistent and significant *constrained off events* occurred within *designated constrained off watch zones* pursuant to section 1.2.1A, the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3 shall be justified if the *IESO* establishes that the *investigated price* is not consistent with:

1.4A.1.1 the marginal costs of the *generation facility* that received the congestion management *settlement* credit;

1.4A.1.2 opportunity costs or replacement energy costs of a *generation facility*, *dispatchable load facility* or *boundary entity*; or

1.4A.1.3 value or benefits of consumption for a *dispatchable load facility or* an exporting *boundary entity,*

and such other additional values, benefits or costs as the *IESO* may determine relevant.

1.4A.2 Such values, benefits, and costs referred to in section 1.4A.1 will be based on information available to the *IESO* at the time of its decision under section 1.4, which may be:

1.4A.2.1 estimated information available to the *IESO*; or

1.4A.2.2 information provided by the *registered market participant* as part of its representations under section 1.4.3.2 or otherwise.

1.5 [Intentionally left blank – section deleted]

1.5.1 [Intentionally left blank – section deleted]

1.5.1.1 [Intentionally left blank – section deleted]

1.5.1.2 [Intentionally left blank – section deleted]

1.5.2 [Intentionally left blank – section deleted]

1.6 Inquiry

1.6.1 Where the *IESO* determines that an inquiry is required under section 1.4.5.2 or section 1.4.6 or an inquiry is requested by the *registered market participant* for the *investigated facility* under section 1.4.5A.2c, the *IESO* shall conduct an inquiry to determine whether the *investigated price* falls within the range determined in accordance with section 1.6.3 or 1.6.6, as the case may be, and shall notify the *registered market participant* for the *investigated facility* of the commencement of the inquiry. During such inquiry, the *IESO* shall provide the *registered market participant* for the *investigated facility* with a reasonable opportunity to make representations as to why the *investigated price* does not justify the re-calculation of the congestion management *settlement* credit referred to in section 1.1.3 including, but not limited to, representations:

1.6.1.1 as to the costs that should be considered for purposes of the determination referred to in section 1.6.3;

1.6.1.2 where section 1.6.6 applies, as to the costs or other information that should be considered for purposes of the determination referred to in that section; and

1.6.1.3 where applicable, as to the costs that should be considered for purposes of the adjustment referred to in section 1.6.4 and the revenues, operating income and forecasts or estimates referred to in section 1.6.5.

1.6.2 The *IESO* shall, for the purposes of determining the range referred to in section 1.6.1, notify the *registered market participant* for the *investigated facility* of the information required to be submitted by it for that purpose and shall use such information to the extent that the *IESO* determines that such information is complete and accurate. The *registered market participant* shall supply this information to the *IESO* by the date specified in the notification. Where the *IESO* determines that such information is incomplete or inaccurate, or where the *IESO* considers that the information received from the *registered market participant* is insufficient for the purpose of determining the range referred to in section 1.6.1, the *IESO* may refer the matter to the *dispute resolution panel* pursuant to section 2 of Chapter 3 and request, in the *notice of dispute*, that the *dispute resolution panel* complete the inquiry.

1.6.3 The *IESO* shall determine the range referred to in section 1.6.1 with respect to a *constrained on generation unit* or a *constrained off generation unit* in accordance with the following:

1.6.3.1 the low end of the range shall be the short-run marginal cost associated with that portion of the *generation unit's* output that was *dispatched* as a *constrained on generation unit* or a *constrained off generation unit* determined on the basis of:

a. fuel costs;

b. variable operating and maintenance costs;

c. opportunity costs; and

d. any other appropriate costs,

adjusted, where applicable and as the *IESO* may determine appropriate, by deducting an amount equal to the cycle costs incurred in circumstances where a *constrained off generation unit* was required to cease operation solely as a result of being *dispatched* as a *constrained off generation unit*. For the purposes of calculating the short-run marginal cost, the *IESO* may exclude any of the foregoing cost factors, or estimate any of these cost factors, in the event the *market participant* does not supply the necessary information as requested by the *IESO* pursuant to section 1.6.2; and

1.6.3.2 the high end of the range shall be 110 percent of the amount calculated in accordance with section 1.6.3.1, adjusted in accordance with one or both of the following as may be applicable and as the *IESO* may determine appropriate:

a. by adding an amount equal to the cycle costs incurred in circumstances where a *constrained on generation unit* was required to operate solely as a result of being *dispatched* as a *constrained on generation unit*; and

b. where section 1.6.4 applies, adding an amount equal to the *investigated facility's* fixed and embedded costs or such portion thereof as determined appropriate by the *IESO* in accordance with that section.

1.6.4 Where an investigated facility is a constrained on generation unit that, in the IESO's opinion based on the investigated facility's operating history:

1.6.4.1 has not recovered, during the twelve-month period prior to the *constrained on event* to which the *investigated price* relates:

a. the whole of the operating costs; and

b. such portion of the fixed and embedded costs as determined appropriate by the *IESO,*

associated with having been dispatched as a *constrained on generation unit* as a result of that *constrained on event*; or

1.6.4.2 in the case of a *generation unit*:

a. that commenced operations less than twelve months prior to the *constrained on event* in respect of which the *investigated price* was submitted; or

b. with respect to which the *constrained on event* to which the *investigated price* relates occurred less than twelve months following the *market commencement date*,

might not recover, during the twelve-month period beginning on the date of commencement of operations referred to in section 1.6.4.2(a) or the *market commencement date*, as the case may be,

the *IESO* may make the adjustment referred to in section 1.6.3.2(b) in such amount as determined appropriate by the *IESO*, based on the considerations referred to in section 1.6.5.

1.6.5 In determining whether to make the adjustment referred to in section 1.6.4 and in determining the amount of any such adjustment, the *IESO* shall:

1.6.5.1 consider the *investigated facility's* revenues and operating income associated with dispatch of the *investigated facility* prior to the *constrained on event* to which the *investigated price* relates; and

1.6.5.2 where section 1.6.4.2 applies consider:

a. the *investigated facility's* revenues and operating income associated with dispatch of the *investigated facility* prior to the *constrained on event* to which the *investigated price* relates; and

b. based on such forecasts or estimates as the *IESO* considers appropriate including, but not limited to, prorating the revenues and operating income referred to in section 1.6.5.2(a) over the period equal to the difference between (i) and (ii) referred to below in this section 1.6.5.2(b), the revenues and operating income that may be projected or estimated to be associated with *dispatch* of the *investigated facility* for a period equal to the difference between: (i) twelve months; and (ii) the period of time between the date of commencement of operations referred to in section 1.6.4.2(a) or the *market commencement date*, as the case may be, and the *constrained on event* to which the *investigated price* relates.

1.6.6 The *IESO* shall determine the range referred to in section 1.6.1 with respect to an *investigated facility* that is a *constrained on dispatchable load* or a *constrained off dispatchable load* in accordance with the following:

1.6.6.1 the low end of the range shall be 90 percent of the value or opportunity costs associated with that portion of the *facility's* consumption that was *dispatched* as a *constrained on dispatchable load* which may be determined on the basis of:

a. net profit or value associated with consumption, excluding the costs of purchasing *energy*;

b. opportunity costs, which may be the alternate cost for obtaining *energy* for consumption; and

c. any other appropriate value or benefits of consumption to the *market participant*,

adjusted, where applicable and as the *IESO* may determine appropriate, by adding an amount equal to the cycle costs incurred in circumstances where a *constrained on dispatchable load* was required to operate solely as a result of being *dispatched* as a *constrained on facility.* For the purposes of calculating the value or opportunity cost, the *IESO* may exclude any of the foregoing cost factors, or estimate any of these cost factors, in the event the *market participant* does not supply the necessary information as requested by the *IESO* pursuant to section 1.6.2.

1.6.6.2 the high end of the range shall be 110 percent of the amount calculated in accordance with section 1.6.6.1 and adjusted, as may be applicable and as the *IESO* may determine appropriate, by adding an amount equal to the cycle costs incurred in circumstances where the *facility* was *dispatched* as a *constrained off dispatchable load*.

1.6.7 Where the *investigated price* falls outside the range determined in accordance with section 1.6.3 or 1.6.6, as the case may be, the *IESO*:

1.6.7.1 shall replace the *investigated price* with a price determined in accordance with section 1.6.8 and revise, for *settlement* purposes, the congestion management *settlement* credit referred to in section 1.1.3 on the basis of such price;

1.6.7.2 [Intentionally left blank – section deleted]

1.6.7.3 shall provide the *registered market participant* for the *investigated facility* with written reasons describing the manner in which the range referred to in section 1.6.7 and the revision referred to in section 1.6.7.1 have been calculated.

1.6.8 The price at which the *IESO* shall, pursuant to section 1.6.7.1, replace the *investigated price* shall be determined as follows:

1.6.8.1 where the *investigated facility* is a *constrained on generation unit*, the amount determined pursuant to section 1.6.3.2;

1.6.8.2 where the *investigated facility* is a *constrained off generation unit*, the amount determined pursuant to section 1.6.3.1;

1.6.8.3 where the *investigated facility* is a *constrained off dispatchable load*, the amount that represents the high end of the range referred to in section 1.6.1, determined in accordance with the methodology developed pursuant to section 1.6.6; and

1.6.8.4 where the *investigated facility* is a *constrained on dispatchable load*, the amount that represents the low end of the range referred to in section 1.6.1, determined in accordance with the methodology developed pursuant to section 1.6.6.

1.6.9 [Intentionally left blank – section deleted]

1.6.10 Where the *investigated price* falls within the range calculated in accordance with section 1.6.3 or 1.6.6, as the case may be, the *IESO* shall not take the action referred to in section 1.6.7 and shall notify the *registered market participant* for the *investigated facility* accordingly.

1.7 Settlement

1.7.1 Where the *IESO* revises a *settlement credit* in accordance with section 1.4.5.1 or 1.6.7.1:

1.7.1.1 the revision shall be applied, in accordance with section 1.7.2, to the last *preliminary settlement statement* issued to:

a. the *metered market participant* for the *investigated facility* that is a *generation unit* or *dispatchable load*, or

b. the *registered market participant* for the *investigated facility* that is a *boundary entity*

for the current *billing period* for which such revised *settlement credit* is calculated; and

1.7.1.2 a consequential revision effected in accordance with section 1.7.2 shall, where applicable, be applied in accordance with section 4.8.2 of Chapter 9.

1.7.2 Where the *IESO* determines that a revision referred to in section 1.7.1.1 and a consequential revision referred to in section 1.7.1.2 are required to reflect alterations to payments due on a previous *invoice*, the *IESO* shall:

1.7.2.1 for the *market participant* for the *investigated facility* referred to in section 1.7.1.1, reflect the revision in the *market participant's* last preliminary *settlement statement* issued for the current *billing period* for which the revised *settlement* credit is calculated;

1.7.2.2 for the *market participant* for the *investigated facility* referred to in section 1.7.1.1, include in the *preliminary settlement statement* a debit adjustment reflecting *default interest* on the difference between:

a. the amount of the *settlement* credit as revised in accordance with section 1.4.5.1 or 1.6.7.1, and

b. the amount of the *settlement* credit that would otherwise have been applicable,

accrued:

c. from the *date* on which overpayment was made to the *market participant* for the *investigated facility* for the *constrained on event* or the *constrained off event* to which the *investigated price* relates,

d. to the *market participant payment date* to which the *preliminary settlement statement* relates; and

1.7.2.3 apply the amounts received pursuant to section 1.7.2.1 and 1.7.2.2 in accordance with section 4.8.2 of Chapter 9.

1.7.2.4 [Intentionally left blank]

1.7.2.5 [Intentionally left blank]

1.7.3 [Intentionally left blank]

1.7.3.1 [Intentionally left blank]

1.7.3.2 [Intentionally left blank]

1.7.4 [Intentionally left blank – section deleted]

1.8 No Prejudice to Other Investigations

1.8.1 Nothing in this Appendix shall preclude the *market assessment unit* or the *market surveillance panel* from conducting, in accordance with section 3 of Chapter 3, any monitoring or evaluation activity or analysis or any investigation with respect to or that involves an *energy bid* or an *energy offer* that has been the subject of an investigation or inquiry pursuant to this Appendix, provided that no *registered market participant* shall, as a result of such activity, analysis or investigation, be subject to the imposition of any financial sanction by the *IESO* other than the revision of a *settlement* credit effected in accordance with this Appendix.

1.9 Non-application

1.9.1 Notwithstanding any other provision of this Appendix, the *IESO* shall not commence or continue an investigation or an inquiry pursuant to this Appendix in respect of an *energy offer* or an *energy bid* submitted by a *constrained off facility* or a *constrained on facility* where it is determined that the *facility*:

1.9.1.1 is one with respect to which there exists a *reliability must-run contract* or a *contracted ancillary services* contract with the *IESO* that contains provisions fixing, by reference to a pre-determined amount or to a formula, the price at which *energy offers* or *energy bids* are to be submitted thereunder and the *investigated price* is consistent with such pre-determined amount or formula; and

1.9.1.2 was dispatched as a constrained on facility or a constrained off facility pursuant to and in accordance with such reliability must-run contract or such contracted ancillary services contract.

Appendix 7.7 – Radial Intertie Transactions

1.1 Applicable Configurations

1.1.1 A *registered facility* that is a *generation facility* that is connected electrically over a *radial intertie* to a neighbouring *control area* may only provide electricity or any *physical service* for delivery out of the *integrated power system* if it is, with the approval of the *IESO,* operating such *registered facility* in a *segregated mode of operation.*

1.2 Dispatch Data

1.2.1 A *market participant* that intends for a *registered facility* to operate in a segregated mode of operation shall maintain *dispatch data* that was submitted for that *registered facility* for each *dispatch hour* during which a *registered facility* will or is intended to operate in segregated mode of operation. The *market participant* may revise the applicable *dispatch data* in accordance with the timelines for submission of revised *dispatch data* specified in section 3.3 of Chapter 7.

1.2.2 Notwithstanding the provisions of section 3.3 of Chapter 7, if the *IESO*:

1.2.2.1 denies a Request for Segregation; or

1.2.2.2 revokes its approval to operate a *registered facility* in a *segregated mode of operation* or terminates the operation of a *registered facility* in a *segregated mode of operation* in accordance with section 1.3.6,

the *IESO* shall permit new or revised *dispatch data* to be submitted to the *IESO* in respect of the *registered facility* for the *dispatch hours* to which such denied request pertains.

1.3 Scheduling & Scheduling Approval

1.3.1 A registered *market participant* shall, within the time required by section 1.3.3, submit a *Request for Segregation* to the *IESO* for approval to operate its *registered facility* in a *segregated mode of operation* and shall submit an *outage* request, in accordance with the provisions specified in section 6.4 of Chapter 5 and the applicable *market manual*, to the *IESO* for the *registered facilities* intended to operate in a *segregated mode of operation.* The *registered market participant* shall make such a *Request for Segregation* in accordance with the applicable *market manual* and the information contained in such *Request for Segregation* shall include, but not be limited to:

1.3.1.1 the time at which operation in a *segregated mode of operation* is intended to commence;

1.3.1.2 the length of time that the applicable *registered facilities* are intended to operate in a *segregated mode of operation*; and

1.3.1.3 a list of the *registered facilities* that are intended to operate in a *segregated mode of operation*.

1.3.2 If a *registered market participant* wishes to revise the contents of a *Request for Segregation* it shall submit a new *Request for Segregation* and shall submit a new *outage* request to the *IESO* in accordance with section 1.3.1.

1.3.3 A *Request for Segregation* shall be made no earlier than 12:00 EST on the pre-dispatch day and no later than 2 hours prior to the start of the first *dispatch hour* to which such request pertains, unless otherwise agreed by the *IESO*. When the *Request for Segregation* is for the operation of a *registered facility* in a *segregated mode of operation* for more than one day the *IESO* may approve such operation for up to two *business days*.

1.3.4 Upon receipt of the *Request for Segregation* the *IESO* shall make a decision regarding a *Request for Segregation* as soon as practicable but no later than such time that allows the *transmitter*, referred to in section 1.3.5, a minimum of 90 minutes or such lesser time as agreed to by the *transmitter* to switch any applicable equipment or *facilities* required to permit implementation of the *segregated mode of operation* prior to the time set out in section 1.3.1.1, and shall notify the *registered market participant* of such decision. The *IESO*:

1.3.4.1 shall deny such *Request for Segregation* if:

a. such *Request for Segregation* pertains to a *registered facility* located in the province of Ontario and would threaten the reliability of the *IESO-controlled grid*; or

b. the *metering installation* for the *registered facility* to which such *Request for Segregation* relates does not comply with section 4.1A.1 of Chapter 6; or

c. such *Request for Segregation* pertains to a *registered facility* located outside the province of Ontario and would threaten the *security* of the *IESO-controlled grid*; and

1.3.4.2 may deny such *Request for Segregation* if the *metered market participant* for the *metering installation* for the *registered facility* to which such *Request for Segregation* relates has previously failed to comply with section 1.2.1.7 of Appendix 6.1 of Chapter 6 for a period in which such *registered facility* operated in a *segregated mode of operation.*

1.3.5 If the *IESO* approves a *Request for Segregation,* it shall direct the relevant *transmitter* to:

1.3.5.1 switch any applicable equipment or *facilities* required to permit implementation of the *segregated mode of operation* at the time referred to in section 1.3.1.1;

1.3.5.2 switch any applicable equipment or *facilities* required to cease implementation of the *segregated mode of operation* at the expiry of the time referred to in section 1.3.1.2.

1.3.6 The *IESO* may at any time revoke its approval to operate a *registered facility* in a *segregated mode of operation* or terminate the operation of a *registered facility* in a *segregated mode of operation,* as the case may be, for the reason described in section 1.3.4.1(b), where the *metered market participant* is failing to comply with section 1.2.1.7 of Appendix 6.1 of Chapter 6 in respect of the *metering installation* for such *registered facility* or where, in the *IESO's* opinion, such approval or such continued operation would threaten the *reliability* of a *local area* which forms part of the *IESO-controlled grid* or the *security* of the *integrated power system,* and shall notify the *registered market participant* accordingly. Where the *IESO* intends to revoke its approval to operate a *registered facility* in a *segregated mode of operation,* it shall revoke any direction issued pursuant to section 1.3.5. Where the *IESO* intends to terminate such operation, the *IESO* shall direct the relevant *transmitter* to switch any applicable equipment or *facilities* required to cease implementation of the *segregated mode of operation*. Where the *IESO* revokes its approval to operate a *registered facility* in a *segregated mode of* *operation* or terminates the operation of a *registered facility* in a *segregated mode of operation,* as the case may be, the *registered market participant* for that *registered facility* shall not be entitled to compensation for any costs, losses or damages from the *IESO* for such revocation or termination.

1.3.7 The *IESO* shall coordinate and confirm with the applicable *control area operator:*

1.3.7.1 the switching to be effected by the relevant *transmitter* in accordance with section 1.3.5 or 1.3.6; and

1.3.7.2 the names of the *registered facilities* that will operate in a *segregated mode of operation*.

1.3.8 The *IESO* shall not issue *dispatch instructions* to a *registered facility* in respect of any *dispatch hour* during which such *registered facility* is operating in a *segregated mode of operation*. All instructions relating to *dispatch* for the *registered facility* while operating in a *segregated mode of operation* shall be sent directly by the applicable *control area operator* to the *registered market participant*.

1.4 Settlements

1.4.1 The delivery of electricity or a *physical service* by a *registered facility* while operating in a *segregated mode of operation* shall be excluded from the *IESO's settlement process* and in no event shall the *IESO* be required to effect payment in respect of any electricity or *physical service* so delivered.

1.4.2 Notwithstanding section 1.4.1, a *registered market participant* that operates a *registered facility* in a *segregated mode of operation* shall submit such scheduling information to the *IESO* as may be necessary to enable the *IESO* to determine the amounts payable by the *registered market participant* for *export service* related to such operation.

1.4.3 Any costs incurred by a *transmitter* in complying with a direction issued pursuant to section 1.3.5 or 1.3.6 shall be borne by the *registered market participant* or the *transmitter* in the manner specified in their *connection agreement.*

1.4.4 The *registered market participant* shall be solely liable in respect of any positive or negative inadvertent accumulated while its *registered facilities* are operating in the *segregated mode of operation.*

Market Rules

Chapter 8
Physical Bilateral Contracts and Financial Markets

Connecting Today.
Powering Tomorrow.

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Table of Contents

1. Introductory Rules

1.1 Purpose and Application

1.1.1 This Chapter sets forth the rules governing:

1.1.1.1 the submission of physical bilateral contract data by market participants and the use of such physical bilateral contract data by the *IESO*; and

1.1.1.2 [Intentionally left blank – section deleted]

1.1.1.3 the sale and administration of *transmission rights* or *TRs* by the *IESO*.

1.1.2 The rules in this Chapter apply to:

1.1.2.1 the *IESO*; and

1.1.2.2 any *market participant* submitting *physical bilateral contract data* to the *IESO*, or holding or buying *transmission rights* or *TRs*.

2. Physical Bilateral Contract Data and Quantities

2.1 Overview

2.1.1 Any *market participant* (or any other person) may, subject to *applicable laws* and regulations, enter into, administer and settle *physical bilateral contract*s with another *market participant* (or any other person). Provided that such *physical bilateral contract*s are matters strictly between the parties and are not in any way to affect the operation of the *real-time markets* or the *physical markets* to be administered by the *IESO* pursuant to Chapter 7, such *physical bilateral contract*s:

2.1.1.1 may but need not be reported to the *IESO* for operational, *settlement* or any other purposes; and

2.1.1.2 are not subject in any way to these *market rules*.

2.1.2 Any *selling market participant* selling under a *physical bilateral contract* to a *buying market participant* may submit *physical bilateral contract data* to the *IESO* complying with the requirements of this section 2, and the *IESO* shall:

2.1.2.1 use such *physical bilateral contract data* and, if necessary, operational data to determine the *physical bilateral contract quantities* of *energy* sold by the *selling market participant* to the *buying market participant* in each hour at the location designated in the *physical bilateral contract data*;

2.1.2.2 determine, in respect of each of the *selling market participant* and the *buying market participant*, the value of the *physical bilateral contract quantity* referred to in section 2.1.2.1 for each applicable *metering interval* or *settlement hour*, as the case may be, based:

a. in the case of the *buying market participant*, on the *hourly Ontario energy price*, when the location specified pursuant to section 2.2.1 relates to a *non-dispatchable load*, a *self-scheduling generation facility,* a *self-scheduling electricity storage facility,* a *transitional scheduling generator* or an *intermittent generator*;

b. in the case of the *selling market participant*, on the 5-minute *energy market* price, when the location specified pursuant to section 2.2.1 relates to a *non-dispatchable load*, a *self-scheduling generation facility,* a *self-scheduling electricity storage facility,* a *transitional scheduling generator* or an *intermittent generator*;

c. in the case of each of the *buying market participant* and the *selling market participant*, on the 5-minute *energy market* price, when the location specified pursuant to section 2.2.1 relates to a *generation facility* or *electricity storage facility,* other than one referred to in section 2.1.2.2(a) or a *dispatchable load facility*; or

d. in the case of each of the *buying market participant* and the *selling market participant*, on the 5-minute *energy market* price, at the *intertie metering point* specified pursuant to section 2.2.1, when such location is an *intertie metering point*;

and apply such value in determining the *selling market participant's* and the *buying market participant's* respective net *energy market settlement* credit for the applicable *metering interval* or *settlement hour*, as the case may be, pursuant to section 3.3 of Chapter 9; and

2.1.2.3 [Intentionally left blank]

2.1.2.4 [Intentionally left blank]

2.1.2.5 [Intentionally left blank]

2.1.2.6 in the *settlement process* for each hour, allocate some or all of the various components of *hourly uplift* assessed on the *physical bilateral contract quantity* between the *buying market participant* and the *selling market participant* as specified in the *physical bilateral contract data*.

2.1.3 The *IESO* shall not, in any of its system operation, *physical market* operation or market *settlement processes*, accept, acknowledge, record or use any data with respect to any contracts to which it is not itself a party, except as specified in this section 2.

2.2 The Content of Bilateral Contract Data

2.2.1 Any *selling market participant* may submit to the *IESO physical bilateral contract data* defining *physical bilateral contract quantities* of *energy* that it is selling to a specified *buying market participant* in specified hours and at any location, so long as it is either:

2.2.1.1 a specified *delivery point* associated with an *RWM*; or

2.2.1.2 a specified *intertie metering point*.

2.2.2 A *selling market participant* may specify in its *physical bilateral contract data* that it will be responsible for some or all of the components of hourly uplift that the *buying market participant* would otherwise pay on the *physical bilateral contract quantities.*

2.2.3 A *selling market participant* may identify in its *physical bilateral contract data* a specific *primary RWM* or *intertie metering point* as the seller's location from which it is notionally transporting the *physical bilateral contract quantity*, it being understood that the seller's location shall have no effect on the valuation referred to in section 2.1.2, on operations described in Chapter 7 or on final *settlement amounts* as determined in accordance with Chapter 9.

2.3 The Form of Bilateral Contract Data

2.3.1 Subject to section 2.3.2, a *selling market participant* shall submit *physical bilateral contract data* in a form that has been approved by the *IESO*. Such *IESO*-approved forms shall include, but are not limited to, data files containing either of the following:

2.3.1.1 indication that the quantity of *energy* that the *selling market participant* is selling to a designated *buying market participant* in each hour, is 100% of the applicable *market participant's metering data* at the location designated in the *physical bilateral contract data* pursuant to section 2.2.1, provided that:

a. such location is one referred to in section 2.2.1.1; and

b. either the *selling market participant* or the *buying market participant* is the *metered market participant* in respect of the *RWM* or *RWMs* associated with such location; or

2.3.1.2 [Intentionally left blank]

2.3.1.3 the quantity of *energy*, in MWh, that the *selling market participant* is selling to the *buying market participant* in each hour at the location designated in the *physical bilateral contract data* pursuant to section 2.2.1.

2.3.2 A *selling market participant* shall submit *physical bilateral contract data* in only one of the two formats described in section 2.3.1.1 or section 2.3.1.3 pertaining to a particular location and a particular *buying market participant* for any *settlement hour* or combination of *settlement hours* within a single *trading day*.

2.3.3 A *selling market participant* shall only submit a single set of *physical bilateral contract data* pertaining to a particular location and a particular *buying market participant,* for any given *settlement hour* within a single *trading day* such that the most recent set of *physical bilateral contract data* submitted is the prevailing set used by the *IESO* in the *settlement process*.

2.4 Submitting and Revising Physical Bilateral Contract Data

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2.4.10A [Intentionally left blank]

2.4.11 A *selling market participant* submitting initial or revised *physical bilateral contract data* relating to a specified *dispatch day* for *settlement purposes* must do so:

2.4.11.1 no earlier than seven days prior to that *dispatch day*, using forms and procedures specified by the *IESO*;

2.4.11.2 on the same schedule and using the same *electronic information system* used for the submission of *dispatch data* for that *dispatch day* as described in section 3.2.1 of Chapter 7 or, if the *electronic information system* is not available, by such other means as may be specified by the *IESO* pursuant to section 3.2.2.3 of Chapter 7; and

2.4.11.3 within six *business days* after that *dispatch day*, using forms and procedures specified by the *IESO*.

2.4.11A A *selling market participant* submitting *physical bilateral contract data* that will not change from *trading week* to *trading week*, may, in the same form but in place of its *physical bilateral contract data* described in section 2.3, submit standing *physical bilateral contract data* which conforms to the same data submission requirements specified in section 2.4.11. Such standing *physical bilateral contract data* shall:

2.4.11A.1 define the *physical bilateral contract data* for each *dispatch hour* of each *dispatch day*;

2.4.11A.2 come into effect at the beginning of the second *dispatch day* after such *physical bilateral contract data* is submitted to the *IESO* by the *selling market participant*;

2.4.11A.3 remain in effect until the expiration date specified in the standing *physical bilateral contract data* unless earlier withdrawn or earlier revised by the *selling market participant*; and

2.4.11A.4 for the purposes of *settlement*, shall constitute the only *physical bilateral contract* between the *selling market participant* and the *buying market participant* at the particular location specified so long as such standing *physical bilateral contract data* is in effect or until such standing *physical bilateral contract data* is superseded pursuant to section 2.4.11B.

2.4.11B Where a *selling market participant* submits *physical bilateral contract data* pursuant to section 2.4.11A or section 2.3 pertaining to the same *buying market participant* at the same location specified in *physical bilateral contract data* previously submitted pursuant to section 2.4.11A or section 2.3, such *physical bilateral contract data* shall supersede any previously submitted *physical bilateral contract data* pertaining to the same *buying market participant* at the same location.

2.4.12 If the *IESO* issues a *notice of intent to suspend* or a *suspension order* to a *selling market participant*, section 6.3.4 of Chapter 3 shall apply and the *IESO* shall notify any *buying market participant* who is counterparty to any of *selling market participant's physical bilateral contracts* registered with the *IESO* of the *IESO's* actions.

2.4.13 If the *IESO* issues a *notice of intent to suspend* or a *suspension order* to a *buying market participant*, section 6.3.4 of Chapter 3 shall apply and the *IESO* shall notify any *selling market participant* who is a counterparty to any of the *buying market participant's physical bilateral contracts* registered with the *IESO* of the *IESO's* actions.

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4. The Transmission Rights Market

4.1 Purpose, Interpretation, and Transition

4.1.1 This section 4 sets forth:

4.1.1.1 the manner in which the *IESO* shall operate the *TR market* established for the purchase of *transmission rights* associated solely with transactions between the *IESO control area* and an adjoining *TR zone*;

4.1.1.2 the procedures pursuant to which persons may apply to the *IESO* for authorization to participate in the *TR market*;

4.1.1.3 the terms and conditions under which *transmission rights* may be assigned by *TR holders*;

4.1.1.4 the manner in which the *IESO* will conduct *TR auctions* for the purchase of *transmission rights* associated with injections and withdrawals between specified *TR zones*; and

4.1.1.5 the manner in which the *IESO* will determine *TR market clearing prices*.

4.1.2 A reference in this section 4 and in Appendices 8.1 and 8.2 to a *transmission right* shall, in the case of *long-term transmission rights* assigned by a *TR holder*, be deemed to include a reference to the right to the *settlement amounts* relating to one or more periods of one month under that *long-term transmission right*.

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4.1.6 The *IESO* may, for reasons of a failure in *TR participant* or *IESO* software, hardware or communication systems associated with a *TR auction*:

4.1.6.1 conduct a *TR auction* using contingency procedures, including but not limited to the contingency procedures defined in the applicable *market manual*;

4.1.6.2 conduct a *TR auction* and related activities along timelines other than those specified within this section 4; or

4.1.6.3 in the event that the *IESO* cannot conduct an effective *TR auction* in a commercially reasonable manner using contingency procedures and/or modified timelines, cancel all or part of a *TR auction*.

4.1.7 The *IESO* shall, as soon as practicable and prior to taking any action pursuant to section 4.1.6, notify all *TR participants* of any *TR auction* cancellation, and/or any contingency procedures, revised timelines and revised activity schedules which the *IESO* intend to implement.

4.1.8 *TR participants* shall comply with any applicable contingency procedures, revised activity schedules or revised timelines specified by the *IESO* under sections 4.1.6 and 4.1.7.

4.2 Denomination and Validity of Transmission Rights and TR Zones

4.2.1 Each *transmission right* shall be associated with a specified injection *TR zone* and a specified withdrawal *TR zone,* one of which shall be the *IESO control area* and the other of which shall be a *TR zone* other than the *IESO control area.*

4.2.2 Each *transmission right* shall be denominated in terms of 1 MW.

4.2.3 The period of validity of a *transmission right* shall be measured from the first hour in respect of which a *settlement amount* is to be paid to the *TR holder* under that *transmission right* to the last hour in respect of which a *settlement amount* is to be paid to the *TR holder* under that *transmission right.*

4.3 TR Holders

4.3.1 Subject to section 4.9.1, the *TR participant* that has purchased a *transmission right* in a *TR auction* shall be recognized by the *IESO* as the *TR holder* in respect of that *transmission right* as of the date on which the *IESO* receives payment for that *transmission right* from that *TR participant*.

4.4 Payments to TR Holders Under Transmission Rights

4.4.1 Subject to section 4.4.2, the amount owing by the *IESO* in respect of a *transmission right* that is valid for a given hour shall be calculated for each applicable *TR holder* by multiplying the amount referred to in section 4.4.1.1 with the amount referred to in section 4.4.1.2:

4.4.1.1 the greater of (i) zero and (ii) the *TR settlement price* at the withdrawal *TR zone* minus the *TR settlement price* at the injection *TR zone*; and

4.4.1.2 the number of *transmission rights* associated with such *TR zones* that are held by that *TR holder*.

4.4.2 Where the *transmission transfer capability* between a withdrawal *TR zone* and an injection *TR zone* has been reduced to zero by reason of the *outage* of the relevant *interconnection*, the amount owing by the *IESO* in respect of a *transmission right* associated with such *TR zones* that is valid for an hour during which such *transmission transfer capability* has been reduced to zero shall be calculated for each applicable *TR holder* as follows:

4.4.2.1 for the hour in which the reduction in *transmission transfer capability* first occurs, the amount owing shall be calculated in accordance with section 4.4.1; and

4.4.2.2 for each subsequent hour during which the reduction in *transmission transfer capability* subsists, including the hour in which the *transmission transfer capability* returns to an amount greater than zero, the amount owing shall be zero.

4.4.3 [Intentionally left blank]

4.5 Awarding of Transmission Rights

4.5.1 The total of all *transmission* rights awarded in a given round of a *TR* auction shall not exceed the fixed amount of *transmission rights* available for such round of a *TR auction* that is determined in accordance with section 4.6, 4.7 and 4.11.10, if applicable. *The IESO* shall determine the number of *transmission rights* awarded to each *TR bidder* in a given round of a *TR auction* using the objective function and other processes described in Appendix 8.1. Such number shall be between zero and the number of *transmission rights* that the *TR bidder* bid to purchase in that round.

4.5.2 The objective function described in Appendix 8.1 shall have as its mathematical objective the maximization of the benefit, measured in dollars, of the aggregate willingness of *TR bidders* to pay for *transmission rights* that they have been awarded in a given round of a *TR auction*. Such maximization of benefit will be net of any unawarded *transmission rights* as described in Appendix 8.1, if applicable.

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4.5.6 [Intentionally left blank – section deleted]

4.6 Simultaneous Feasibility

4.6.1 The *IESO* shall conduct a simultaneous feasibility test during each *TR auction* to ensure that the congestion rents collected by the *IESO* as described in section 4.18.1.1 shall, under most circumstances, be sufficient to cover any payment obligations owing by the *IESO* to *TR holders* under section 4.4.1 in respect of all *transmission rights* outstanding and all *transmission rights* to be offered during the *TR auction*.

4.6.2 For the purposes of the simultaneous feasibility test referred to in section 4.6.1, the *IESO* shall assume that each *transmission right* represents:

4.6.2.1 one MW of power injected at the injection *TR zone* associated with each *transmission right*; and

4.6.2.2 one MW of power withdrawn at the withdrawal *TR zone* associated with each *transmission right*.

4.6.3 The *IESO* shall, in conducting each simultaneous feasibility test referred to in section 4.6.1, use a forecast of available *transmission transfer capability* determined on the basis of the operating assumptions described in section 4.7.3.

4.6.4 A set of *transmission rights* shall pass the simultaneous feasibility test referred to in section 4.6.1 if all injections and withdrawals associated with such set of *transmission rights*, and every combination of subsets of such injections and withdrawals, could, if they represented power actually injected or withdrawn as described in section 4.6.2, be accommodated without causing the amount of power that passes over an *interconnection* between the *IESO control area* and an adjoining *TR zone* to exceed any limit applying to that *interconnection*.

4.7 Determination of Transmission Transfer Capabilities

4.7.1 The *IESO Board* shall establish a confidence level reflecting the degree to which the congestion rents collected by the *IESO* in a given period described in section 4.18.1.1 will be sufficient to cover the *IESO's* payment obligations to *TR holders* under section 4.4.1 for that period.

4.7.2 The *IESO* shall, in accordance with section 4.7.3, establish operating assumptions for the purposes of forecasting the *transmission transfer capability* to be used during each *TR auction.* Such *transmission transfer capability* forecasts shall be used to limit the number of *transmission rights* awarded in each auction for the purpose of achieving the confidence level established under section 4.7.1.

4.7.3 The *IESO* shall establish the operating assumptions referred to in section 4.7.2 in accordance with the following:

4.7.3.1 transmission line ratings shall be calculated on a seasonal basis based on *good utility practice*, shall be the same ratings as those used by the *IESO* in its real-time operations and may differ when the *IESO-controlled grid* is undergoing a *contingency event* relative to the ratings that would apply when the *IESO-controlled grid* is in a *normal operating state*;

4.7.3.2 the *facilities*, *interties* and conditions that are monitored by the *IESO* for *security* reasons in its real-time operations shall be emulated;

4.7.3.3 transmission lines, *facilities* and *interties* within the *IESO control area* shall be assumed to be in service except where a prolonged *planned outage* of a transmission line or *facility* is scheduled for the time during which *transmission rights* that are to be sold at the *TR auction* will be valid or where the *IESO* believes that a prolonged *forced outage* of a transmission line or *facility* is likely to occur for the time during which *transmission rights* that are to be sold at the *TR auction* will be valid;

4.7.3.4 phase angle regulators within the *IESO control area* and on *interconnections* between the *IESO control area* and adjoining *control areas* shall be assumed to be operating in a manner consistent with normal operations, having regard to the joint control of such *interconnections*, during the *TR auction*;

4.7.3.5 the transmission limits of the *IESO-controlled grid* shall be adjusted to reflect an estimate of the transmission reliability margin observed by the *IESO* in its real-time operations;

4.7.3.6 the ability of *control area operators* in *control areas* that are not included in the contract path of an *energy* transaction to curtail that transaction in accordance with applicable *reliability standards* shall be taken into account when estimating the amount of power that can be *reliably* transferred between the *IESO control area* and each adjoining *control area*;

4.7.3.7 parallel flows that result from events outside the *IESO control area* shall be taken into account when estimating the amount of power that can be *reliably* transferred between the *IESO control area* and each adjoining *control area;*

4.7.3.8 estimates of *transmission transfer capability* may be conservative but shall not be reduced below a level sufficient to define all *transmission rights* that have been awarded in previous *TR auctions* and that remain valid as at the date of the *TR auction*; and

4.7.3.9 the operating assumptions shall otherwise be permitted to vary depending on the length of time between the date of a given *TR auction* and the period of validity of the *transmission rights* to be offered in that *TR auction.*

4.8 Participation in TR Markets and Rules Applicable to TR Participants

4.8.1 No person may participate in the *TR market* nor be a *TR holder* unless that person has been authorized by the *IESO* as a *TR participant* in accordance with section 3 of Chapter 2 and this section 4.8.

4.8.2 No *TR participant* may be a *TR bidder* in a round of a *TR auction* unless the *TR participant* has, no less than five *business days* prior to the date on which the round of the *TR auction* is to be conducted, provided to the *IESO* a *TR market deposit*, in one or both of the forms set forth in section 4.8.2A, for the purpose of establishing that person's *bidding limit* in accordance with sections 4.14.1 or 4.20.2.2.

4.8.2A A *TR market deposit* shall be in one or both of the following forms:

4.8.2A.1 an irrevocable commercial letter of credit provided by a bank named in a Schedule to the *Bank Act*, (Canada) S.C. 1991, c. 46; or

4.8.2A.2 a cash deposit made with the *IESO* by or on behalf of the *TR participant.*

4.8.2B Where all or part of a *TR market deposit* is in the form of a standby letter of credit, the following provisions shall apply:

4.8.2B.1 the letter of credit shall provide that it is issued subject to either The Uniform Customs and Practice for Documentary Credits, 1993 Revision, ICE Publication No. 500 or The International Standby Practices 1998;

4.8.2B.2 the *IESO* shall be named as beneficiary in the letter of credit, the letter of credit shall be irrevocable and partial draws on the letter of credit shall not be prohibited;

4.8.2B.3 the only condition on the ability of the *IESO* to draw on the letter of credit shall be the delivery of a certificate of an officer of the *IESO* that a specified amount is owing by the *TR bidder* to the *IESO* and that, in accordance with the provisions of the *market rules*, the *IESO* is entitled to payment of that specified amount as of the date of delivery of the certificate;

4.8.2B.4 the letter of credit shall either provide for automatic renewal (unless the issuing bank advises the *IESO* at least thirty days prior to the renewal date that the letter of credit will not be renewed) or be for a term of at least one (1) year. Where the *IESO* is advised that a letter of credit is not to be renewed or the term of the letter of credit is to expire, the *TR bidder* shall arrange for and deliver additional *TR market deposits* if the *TR bidder* intends to continue to participate in the *TR market*. If such additional *TR market deposits* are not received by the *IESO* ten (10) *business days* before the expiry of a letter of credit, the *IESO* shall be entitled as of that time to payment of the full face amount of the letter of credit which amount, once drawn by the *IESO*, shall be treated as a *TR market deposit* in the form of cash; and

4.8.2B.5 by including a letter of credit as part of a *TR market deposit*, the *TR bidder* represents and warrants to the *IESO* that the issuance of the letter of credit is not prohibited in any other agreement, including without limitation, a negative pledge given by or in respect of the *TR bidder*.

4.8.3 [Intentionally left blank]

4.8.4 Notwithstanding any other provision of these *market rules*, a person that applies for authorization to participate in the *TR market* and that has not applied for authorization to participate, or is not participating in, any other *IESO-administered market* shall not be required to comply with any requirements for authorization other than those set forth in sections 4.8.1 to 4.8.3.

4.8.5 The following provisions of these *market rules* shall not apply to a person that is authorized by the *IESO* to participate only in the *TR market*:

4.8.5.1 [Intentionally left blank]

4.8.5.2 Chapters 4, 5, 6 and 7;

4.8.5.3 Chapter 8 other than this section 4; and

4.8.5.4 Chapter 10.

4.9 Assignment of Transmission Rights

4.9.1 A *TR holder* may assign to another *TR participant* its right to the *settlement amounts* under a *transmission right,* provided that such assignment shall only be recognized by the *IESO,* for *settlement* purposes, in accordance with section 4.9.5.

4.9.2 A *TR holder* that wishes the *IESO* to recognize, for *settlement* purposes, an assignment of its right to the *settlement amounts* under a *transmission right* shall apply to the *IESO* for recognition of the assignment in such form as shall be established by the *IESO*. The *IESO* shall verify whether the assignee is a *TR participant* and shall advise the assigning *TR holder* within two *business days* of the date of receipt of the application as to the results of such verification.

4.9.3 The *IESO* shall for *settlement purposes* recognize, in accordance with section 4.9.5, an assignment of the right to the *settlement amounts* under a *transmission right* unless the assignee is not a *TR participant.*

4.9.4 Where the *IESO* determines in accordance with section 4.9.3 that it shall not recognize, for *settlement* purposes, an assignment of the right to the *settlement* amounts under a *transmission right,* the *IESO* shall advise the assigning *TR holder* of the reasons for such determination.

4.9.5 Where the *IESO* recognizes, for *settlement* purposes, an assignment of the right to all *settlement amounts* under a *transmission right* in accordance with section 4.9.3, the assignee shall be deemed to be the *TR holder* in respect of the *settlement amounts* under that *transmission right* with effect from the *billing period* immediately following the date on which the *IESO* advises the assigning *TR holder* of the results of the *IESO's* verification pursuant to section 4.9.2 until such time as:

4.9.5.1 [Intentionally left blank – section deleted]

4.9.5.2 the right to the *settlement amounts* under the *transmission right* has been assigned to another *TR participant* and the *IESO* has recognized such assignment for *settlement* purposes in accordance with sections 4.9.2, and 4.9.3 and 4.9.5.

4.10 Short-Term Auctions

4.10.1 The *IESO* shall conduct a *short-term auction* between the 1st and 15th day of each month in which *transmission rights* valid for the following month shall be available.

4.10.2 Each *short-term auction* shall consist of only one round and shall offer *short-term transmission rights* valid for the immediately following month.

4.10.3 The first *short-term auction* conducted by the *IESO* shall constitute the *short-term auction* for the month immediately following the month during which the *market commencement date* occurred.

4.11 Long-Term Auctions

4.11.1 The first *long-term transmission rights* shall commence one month following the availability of the first *short-term transmission rights*. Following the initial *long-term auction*, the *IESO* shall thereafter conduct a *long-term auction* at least thirty days but not more than ninety days prior to the beginning of each subsequent quarter.

4.11.2 Each *long-term auction* conducted by the *IESO;*

4.11.2.1 shall offer *transmission rights* that are valid for a period of one year, commencing on the first day of the quarter immediately succeeding the quarter in which the *long-term auction* occurs; and

4.11.2.2 Any residual *transmission rights* from a *long-term auction* shall, subject to section 4.7, be offered as *short-term transmission rights* in the manner described in section 4.10.

4.11.3 [Intentionally left blank – section deleted]

4.11.4 [Intentionally left blank – section deleted]

4.11.5 Each *long-term auction* referred to in section 4.11.2 shall consist of multiple rounds. In each case:

4.11.5.1 the number of rounds shall be determined by the *IESO* on the basis of the *IESO's* assessment of the appropriate balance between providing *TR participants* with opportunities for price discovery and the administrative burden on the *IESO* and *TR participants* of conducting varying numbers of rounds;

4.11.5.2 each round shall be conducted independently of all others;

4.11.5.3 *TR market clearing prices* shall be determined for each round; and

4.11.5.4 *transmission rights* shall be awarded in each round on the basis of the *TR market clearing prices* determined for that round.

4.11.6 [Intentionally left blank]

4.11.7 The *IESO* shall, for each of the first three *long-term auctions* that it conducts, apportion the available *transmission transfer capability* forecasted in accordance with the operating assumptions established in respect of each such *long-term auction* pursuant to section 4.7.2, adjusted to account for all outstanding *transmission rights*, among *transmission rights* having a period of validity of one month and *transmission rights* having a period of validity of one year in such manner as the *IESO* determines appropriate.

4.11.8 [Intentionally left blank – section deleted]

4.11.9 [Intentionally left blank – section deleted]

4.11.10 For each *long-term auction* that is conducted in multiple rounds in accordance with section 4.11.5, the *transmission transfer capability* that is used to define the *transmission rights* in accordance with sections 4.11.7 and 4.11.8 shall be allocated within each of the rounds as follows:

4.11.10.1 the portion of *transmission transfer capability* allocated to each round shall increase with each successive round; and

4.11.10.2 the portion of *transmission transfer capability* allocated to the final round shall be at least three times the portion of *transmission transfer capability* allocated to the first round.

4.12 Pre-auction Publication

4.12.1 The *IESO* shall *publish*, at least thirty days prior to each *TR auction*:

4.12.1.1 hourly prices determined on the basis of the last projected *market price* for *energy published* for that hour pursuant to section 5.5.1 of Chapter 7 for each *TR zone* during the preceding twelve months or, in the case of a *TR auction* conducted less than twelve months following the *market commencement date*, since the *market commencement date*;

4.12.1.2 the *TR market clearing price* for each *transmission right* sold during any *TR auctions* conducted in the preceding eighteen months or, in the case of a *TR auction* conducted less than eighteen months following the *market commencement date*, since the *market commencement date*;

4.12.1.3 actual and scheduled hourly flows over each *interconnection* during the preceding twelve months or, in the case of a *TR auction* conducted less than twelve months following the *market commencement date*, since the *market commencement date*;

4.12.1.4 the hourly *transmission transfer capability* of each *interconnection* during the preceding twelve months or, in the case of a *TR auction* conducted less than twelve months following the *market commencement date*, since the *market commencement date* or from such earlier period as such information may be available provided that such information need not cover a period in excess of twelve months; and

4.12.1.5 identification of any *transmission transfer capability* limits, parallel flow assumptions and other applicable constraints that may limit the number of *transmission rights* that can be awarded in the *TR auction*, and the operating assumptions established in respect of the *TR auction* pursuant to section 4.7.2.

4.12.1.6 [Intentionally left blank]

4.13 TR Bids and TR Laminations

4.13.1 A *TR participant* may submit no more than one *TR bid* with respect to a given injection *TR zone* and withdrawal *TR zone* for each round of any *TR auction*. A *TR bid* shall conform to the following requirements:

4.13.1.1 The *TR bid* shall indicate the name of the *TR bidder*, the injection *TR zone* and the withdrawal *TR zone* for each *transmission right* that the *TR bidder* is bidding to purchase, and the round of the *TR auction* to which the *TR bid* relates;

4.13.1.2 Each *TR bid* must contain at least 1 and may contain up to 20 *TR laminations* for an injection *TR zone* and withtrawal *TR zone;*

4.13.1.3 The price in each *TR lamination* shall be a positive amount, be expressed in dollars and whole cents per MW, and represent the maximum price that the *TR bidder* is bidding to purchase the quantity of *transmission rights* identified in the *TR lamination*;

4.13.1.4 The quantity in each *TR lamination* shall be a positive amount, not exceed the total amount of *transmission rights* available in the relevant round of the *TR auction*, be expressed in whole numbers, and represent the maximum quantity of *transmission rights* that the *TR bidder* is bidding to purchase at the price identified in the *TR lamination*; and;

4.13.1.5 If a *TR bid* is composed of multiple *TR laminations*, such *TR laminations* shall be in monotonically increasing quantities with decreasing prices.

4.13.1.6 [Intentionally left blank – section deleted]

4.13.2 [Intentionally left blank – section deleted]

4.13.3 [Intentionally left blank – section deleted]

4.13.4 [Intentionally left blank]

4.13.5 *TR bids* shall be submitted to the *IESO* no earlier than 09:00 EST on the date that is two *business days* prior to the date on which a round of a *TR auction* is to be conducted and no later than 17:00 EST on the day before the date on which the round of the *TR auction* is to be conducted.

4.13.6 [Intentionally left blank – section deleted]

4.13.7 *TR bids* shall be submitted to the *IESO* using the *electronic information system* and the communication protocol described in the applicable *market manual*.

4.13.8 The *IESO* shall:

4.13.8.1 stamp each *TR bid* with the time that it was received by the *IESO*;

4.13.8.2 confirm receipt of each *TR bid* within the time specified in the applicable *market manual* using the communication protocol referred to in section 4.13.7; and

4.13.8.3 *publish* and notify *TR participants* of alternative means of submitting and confirming receipt of *TR bids* when the communication protocol referred to in section 4.13.7 is unavailable.

4.13.9 The *IESO* shall reject any *TR bid* that does not comply with the rules set forth in this section 4.13 and shall provide the *TR participant* submitting a rejected *TR bid* of the reasons for such rejection.

4.13.10 A *TR participant* that does not receive from the *IESO* confirmation of receipt of a *TR bid* in accordance with section 4.13.8.2 shall immediately contact the *IESO* by telephone, facsimile or other means specified in the applicable *market manual* seeking confirmation of receipt.

4.13.11 A *TR participant* shall, if requested by the *IESO*, resubmit a *TR bid* by such means as may be specified by the *IESO* in the request.

4.14 Bidding Limits

4.14.1 Subject to section 4.20.2.2, the *IESO* shall establish, for each *TR participant* that intends to be a *TR bidder* in a *TR auction*, a *bidding limit* equal to ten times the amount or value of the *TR market deposit* provided to the *IESO* by that *TR participant* pursuant to section 4.8.2.

4.14.2 The *IESO* shall refuse to accept a *TR bid* from a *TR bidder* where the price multiplied by the quantity of any *TR lamination* within the *TR bid* equals a value which exceeds the *TR bidder's* remaining *bidding limit* after accounting for all other accepted *TR bids* from such *TR bidder* in the relevant *TR auction*.

4.14.3 Where a *TR bidder* has been awarded a *transmission right* in a *TR auction* and the *TR market deposit* provided by the *TR bidder* pursuant to section 4.14.1 consists in whole or in part of a cash deposit, the *IESO* shall apply the cash deposit to offset any amounts owing to the *IESO* by that *TR bidder* under section 4.17.1 for the purchase of the *transmission right.*

4.14.4 Where the amount of a cash deposit provided by a *TR participant* as a *TR market deposit* pursuant to section 4.14.1 exceeds the amount owing to the *IESO* by that *TR participant* under section 4.17.1 for the purchase of *transmission rights* in respect of a given *TR auction*, the *IESO* shall, if so requested by the *TR participant* at the time at which the cash deposit was so provided, include such excess as a credit on the *invoice* submitted to the *TR participant* for that *TR auction*. Where the *TR participant* has not so requested that such a credit be effected, the excess shall be held by the *IESO* and shall form part of that *TR participant's TR market deposit* for purposes of a subsequent *TR auction* in which the *TR participant* wishes to participate.

4.14.5 Where a *TR participant* has provided to the *IESO* a *TR market deposit,* in a form other than a cash deposit, pursuant to section 4.14.1 in respect of a given *TR auction*, the *IESO* shall, upon receipt of payment in full by the *TR participant* of the net amount of any *invoice* submitted to the *TR participant* for that *TR auction* and subject to the terms of the *TR market deposit*:

4.14.5.1 if so requested by the *TR participant* at the time at which the *TR market deposit* was so provided, return the *TR market deposit* to the *TR participant*; or

4.14.5.2 if the *TR participant* did not make the request referred to in section 4.14.5.1, hold the *TR market deposit,* which *TR market deposit* shall form part of that *TR participant's TR market deposit* for purposes of a subsequent *TR auction* in which the *TR participant* wishes to participate.

4.15 TR Market Clearing Prices

4.15.1 The *IESO* shall determine a *TR market clearing price* for each *transmission right* in each round of a *TR auction* in accordance with section 4.15.2, independent of the calculation of the *TR market clearing prices* for *transmission rights* in other rounds of the same *TR auction*.

4.15.2 The *TR market clearing price* for a given *transmission right* in a given round of a *TR auction* shall be equal to the lowest *bid* price of all *TR laminations* that were awarded *transmission rights*, as determined by Appendix 8.1.

4.15.2.1 [Intentionally left blank – section deleted]

4.15.2.2 [Intentionally left blank – section deleted]

4.15.2.3 [Intentionally left blank – section deleted]

4.16 Post-Auction Notification and Publication

4.16.1 The *IESO* shall, as soon as practicable and no later than the end of the next business day following the conclusion of a round of a *TR auction*, and in any event prior to the time at which *TR bids* may be submitted in respect of the next round of the *TR auction*, notify each *TR bidder* of the following:

4.16.1.1 the number of *transmission rights* awarded to the *TR bidder* during that round;

4.16.1.2 the *TR market clearing price* of each *transmission right* awarded to the *TR bidder* during that round;

4.16.1.3 the injection *TR zone* and the withdrawal *TR zone* in respect of each *transmission right* awarded to the *TR bidder* during that round; and

4.16.1.4 the period for which each *transmission right* awarded to the *TR bidder* during that round is valid.

4.16.2 [Intentionally left blank – section deleted]

4.16.3 The *IESO* shall, as soon as practicable and no later than the end of the next business day following the conclusion of a round of a *TR auction*, and in any event prior to the time at which *TR bids* may be submitted in respect of the next round of the *TR auction*, *publish* the following:

4.16.3.1 the *TR market clearing price* for each *transmission right* sold during that round;

4.16.3.2 the number of *transmission rights* sold during that round;

4.16.3.3 the injection *TR zone* and withdrawal *TR zone* for each *transmission right* sold during that round; and

4.16.3.4 the period of validity of each *transmission right* sold during that round.

4.17 Payment for Purchase of Transmission Rights

4.17.1 The amount payable to the *IESO* by a successful *TR bidder* in respect of *transmission rights* awarded to that successful *TR bidder* in a given round of a *TR auction* shall be the aggregate of the *TR market clearing price* of each *transmission right* awarded to that successful *TR bidder* in that round.

4.17.2 [Intentionally left blank – section deleted]

4.18 TR Clearing Account

4.18.1 The *IESO* shall establish and maintain a *TR clearing account* and shall:

4.18.1.1 credit to the *TR clearing account*, in respect of each *settlement hour*, the net congestion rents calculated in accordance with section 3.6.2 of Chapter 9;

4.18.1.1A credit to the *TR clearing account* the amounts referred to in sections 4.20.1A and 4.20.1B;

4.18.1.2 subject to section 4.19.5, credit to the *TR clearing account* the net revenues received from the sale of *transmission rights* in a *TR auction* in accordance with section 4.19.4;

4.18.1.3 debit from the *TR clearing account* any amounts required to be paid to *TR holders* pursuant to section 4.4.1;

4.18.1.4 debit from the *TR clearing account* any amounts required to be paid to successful *TR offerors* pursuant to section 4.19.6;

4.18.1.5 debit from the *TR clearing account* any amounts authorized to be debited and used to offset *transmission services charges* in accordance with section 4.18.2; and

4.18.1.6 credit to the *TR clearing account* any *transmission rights settlement* credits adjusted under section 6.6.10A.2 of Chapter 3.

4.18.2 Subject to section 4.18.3, the *IESO Board* may, at such times as it determines appropriate, authorize the debit of funds from the *TR clearing account* in accordance with section 3.6.3 of Chapter 9 for the purpose of using those funds to offset *transmission services charges*.

4.18.3 The *IESO Board* shall establish a reserve threshold for the *TR clearing account.*

4.19 Settlement

4.19.1 All amounts payable to *TR holders* under *transmission rights* in accordance with section 4.4.1 shall be *settled* by the *IESO* in accordance with section 6 of Chapter 9.

4.19.2 Payments required to be made by the *IESO* to *TR holders* in accordance with section 4.4.1 shall be funded by means of debits from the *TR clearing account.* Where the aggregate amount payable to *TR holders* in a given *billing period* under section 4.4.1 exceeds all funds available in the *TR clearing account*, the shortfall shall be funded by the borrowing of short-term funds in accordance with section 6.16.5 of Chapter 9.

4.19.3 Where the aggregate amount payable to *TR holders* in a given *billing period* under section 4.4.1 is less than the congestion rents collected during that *billing period* as described in section 4.18.1.1, the excess shall be used first, to repay any short-term funds borrowed by the *IESO* on account of a shortfall referred to in sections 4.19.2 and 4.19.6, second, subject to section 4.19.5A, to reimburse *market participants* for funds recovered by the *IESO* under Chapter 9, section 6.16.6.2, on a prorated basis according to, and in an amount that does not exceed, the amount so recovered, third, to replenish the reserve threshold specified in section 4.18.3, and the balance shall remain in the *TR clearing account*.

4.19.4 All amounts payable to the *IESO* on account of the purchase of *transmission rights* in accordance with section 4.17.1 in respect of all rounds of a given *TR auction* shall be settled by the *IESO* in accordance with section 6 of Chapter 9.

4.19.5 In respect of a given *TR auction*, the aggregate amount received by the *IESO* in respect of the purchase of *transmission rights* shall be used first to repay any short-term funds borrowed by the *IESO* on account of a shortfall referred to in sections 4.19.2, second, subject to section 4.19.5A, to reimburse *market participants* for funds recovered by the *IESO* under Chapter 9, section 6.16.6.2, on a prorated basis according to, and in an amount that does not exceed, the amount so recovered, third, to replenish the reserve threshold specified in section 4.18.3, and the balance shall remain in the *TR clearing account*.

4.19.5A In the event that the *IESO* cannot, after taking all reasonable steps to do so, locate *market participants* from which funds were recovered by the *IESO* under Chapter 9, section 6.14.5.2, any amount that would otherwise be distributed to such *market participants* under sections 4.19.3 and 4.19.5 shall remain in the *TR clearing account.*

4.19.6 [Intentionally left blank – section deleted]

4.20 Default in Payment

4.20.1 Where a successful *TR bidder* fails to remit to the *IESO* any payment due on account of a *transmission right* awarded to that *TR bidder* during a *TR auction* on the applicable *market participant payment date*:

4.20.1.1 the *transmission right* shall not be issued to the *TR bidder*; and

4.20.1.2 the *TR bidder* shall forfeit:

a. its *TR market deposit*; or

b. that portion of its *TR market deposit* that is equal to 10% of the value of all *transmission rights* awarded to the *TR bidder* during the applicable *TR auction*,

whichever is the lesser.

4.20.1A Where section 4.20.1.2 applies and the *TR market deposit* is in the form of a cash deposit, the *IESO* may draw upon the cash deposit and credit the *TR clearing account* with the amount of the penalty or may invoice the *market participant* for the amount of the penalty, as the case may be, and may remit to the *TR bidder* the difference, if any, between such amount and the amount of the *TR market deposit.*

4.20.1B Where section 4.20.1.2 applies and the *TR market deposit* is in the form of an irrevocable letter of credit, the *IESO* may claim and realize upon the letter of credit in respect of the amount referred to in section 4.20.1.2(a) or 4.20.1.2(b), as the case may be, and shall credit to the *TR clearing account* the proceeds of such realization.

4.20.2 Where a successful *TR bidder* has defaulted in payment of any amount due on account of a *transmission right* awarded to that *TR bidder* during a given *TR auction*, the *IESO* may impose one or both of the following conditions on the participation by that *TR bidder* in a subsequent *TR auction*:

4.20.2.1 require the *TR bidder* to provide a *TR market deposit* in the form of a cash deposit only; or

4.20.2.2 establish the *TR bidder's bidding limit* for that *TR auction* as an amount that is less than ten times the amount or value of the *TR market deposit* provided by that *TR bidder* in respect of that *TR auction*.

Market Rules

Chapter 8 Physical Bilateral Contracts and Financial Markets - Appendices

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Appendix 8.1 – Mathematical Formulation of the TR Objective Function and Constraints

1.1 This Appendix describes the objective function and additional processes used to determine the number of *transmission rights* to be awarded to each *TR bidder,* as described in section 4.5.1 of Chapter 8, and the *TR market clearing price* in a given round of a *TR auction.*

1.2 The objective function, outlined in section 1.3, describes the maximization of the benefit of awarded *TR laminations* net of any unawarded *transmission rights* as determined in accordance with section 1.4(e), if applicable. *Transmission rights* are awarded in quantities to *TR bidders* ranging from zero up to the maximum quantity of their *TR lamination*. The total amount of *transmission rights* awarded to all *TR bidders* in a round of a *TR auction* will not exceed the total number of *transmission rights* available in such round of the *TR auction*. *Transmission rights* will be awarded optimally from highest price to lowest price of the *TR laminations* received for the relevant round of the *TR auction* unless and until such time as there are multiple *TR laminations* that share the same price and cannot all be fully awarded based on the available *transmission rights*, which shall be resolved in accordance with section 1.4. If there are insufficient *transmission rights* available to award the entire quantity of a *TR lamination* and section 1.4 does not apply, such *TR bidder* shall be awarded the remainder of the *transmission rights* available.

1.3 The objective for each injection *TR zone* and withdrawal *TR zone* for each round of a given *TR auction* is to maximize the following function:

$$Z = \sum_{i} \mathrm{p}_i * q_\mathrm{i}$$

where:

(a) ‘Z’ is the benefit as described in section 4.5.2 of Chapter 8 for the relevant round of the *TR auction;*

(b) ‘i’ is an index into the set of all *TR laminations* received for the relevant round of the *TR auction;*

(c) ‘p_i’ is the price of *TR lamination ‘i’*, submitted in accordance with section 4.13.1.3 of Chapter 8*;*

(d) ‘q_i’ is the quantity of awarded *transmission rights* associated with *TR lamination ‘i’,* submitted in accordance with section 4.13.1.4 of Chapter 8, where the quantity of awarded *transmission rights* is determined as follows, as applicable:

(i) the sum of all q_i is less than or equal to the fixed amount of *transmission rights* available for such round of a *TR auction* that is determined in accordance with section 4.6, 4.7, and 4.11.10, if applicable, of Chapter 8;

(ii) where *TR lamination ‘i’* is the highest price *TR lamination* for such *TR bidder* and has an associated price is equal to or greater than the *TR market clearing price* for such round of the *TR auction*, the entire quantity of the *TR lamination* or a portion thereof as determined in accordance with section 1.4, or, where section 1.4 does not apply, the portion that will result in all available *transmission rights* being awarded;

(iii) for *TR laminations ‘i’* with a price that is equal to or greater than the *TR market clearing price* for such round of the *TR auction,* other than the one referred to in (ii) for the same *TR bidder*, the quantity that is incremental to the *TR bidder’s* previous *TR lamination*, as ranked from highest to lowest price, or a portion thereof as determined in accordance with section 1.4, or, where section 1.4 does not apply, the portion that will result in all available *transmission rights* being awarded; and

for *TR laminations ‘i’* with a price that is less than the *TR market clearing price* for such round of the *TR auction,* such quantity shall be zero.

1.4 Where multiple *TR laminations* share the same price and cannot all be fully awarded based on the available *transmission rights*, the awarding of remaining available *transmission rights* will be determined in accordance with the following:

(a) First, the *IESO* will award to each tied *TR bidder* their proportional share of the remaining *transmission rights* available, rounded down to nearest whole number. Each *TR bidders* proportional share will be determined based on the quantity of their tied *TR lamination* relative to the amount of all tied *TR laminations*, where the quantity of a tied *TR lamination* that is not the *TR bidders* highest priced *TR lamination* will be the quantity that is incremental to the *TR bidder’s* previous *TR lamination*, as ranked from highest to lowest price;

(b) second, if there continues to be a remainder of *transmission rights* within the relevant round of the *TR auction,* such remainder shall be awarded in accordance with the following:

(i) The *IESO* will rank all such *TR bidders* from the highest to lowest based on the difference between the proportional quantity determined in section 1.4(a) prior to being rounded down and the proportional quantity determined in section 1.4(a) that was awarded to such *TR bidder*; and

(ii) The *IESO* will award one *transmission right* to each such *TR bidder* in sequence from highest to lowest ranking until either there are no more remaining *transmission rights* to be awarded or one or more such *TR bidders* is tied in their ranking and there are insufficient remaining *transmission rights* to award to them all;

(c) third, where there are still remaining *transmission rights* following the completion of section 1.4(b), such remainder shall be awarded in accordance with the following:

(i) The *IESO* will rank the *TR bidders* whom tied, as contemplated under section 1.4(b)(ii), from highest to lowest based on the quantity of *transmission rights* in their *TR lamination* that is incremental to the *TR bidder's* previous *TR lamination*, as ranked from highest to lowest price, if applicable; and

(ii) The *IESO* will award one *transmission right* to each such *TR bidder* in sequence from highest to lowest ranking until either there are no more remaining *transmission rights* to be awarded or one or more such *TR bidders* is tied in their ranking and there are insufficient remaining *transmission rights* to award to them all;

(d) fourth, where there are still remaining *transmission rights* following the completion of section 1.4(c), such remainder shall be awarded in accordance with the following:

(i) The *IESO* will rank the *TR bidders* whom tied, as contemplated under section 1.4(c)(ii), from earliest to latest based on the timestamps of the date and time, to the second, reflecting the time when the *TR bidder* submits the relevant *TR laminations*; and

(ii) The *IESO* will award one *transmission right* to each such *TR bidder* in sequence from earliest to latest ranking until either there are no more remaining *transmission rights* to be awarded or one or more such *TR bidders* is tied in their ranking and there are insufficient remaining *transmission rights* to award to them all;

(e) finally, where the remainder of transmission rights within the relevant round of the TR auction are unable to be awarded in accordance with section 1.4(d), such remainder shall not be awarded to any TR bidder.

Market Rules

Chapter 9

Settlements and Billing

Connecting Today.
Powering Tomorrow.

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Table of Contents

1. Introductory Rules

1.1 Application and Purpose

1.1.1 This chapter applies to:

1.1.1.1 the *IESO*; and

1.1.1.2 *market participants*.

1.1.2 This chapter sets out the respective rights and obligations of the *IESO* and of *market participants* in determining, billing for and effecting payment in respect of financial obligations arising from the *IESO-administered markets*, other provisions of the *market rules*, and *applicable law* including without limitation the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998*, and any regulations enacted thereunder including, but not limited to the following:

1.1.2.1 [Intentionally left blank – section deleted]

1.1.2.2 the *energy market*;

1.1.2.3 the *operating reserve market*;

1.1.2.4 congestion management;

1.1.2.5 *transmission rights* (*TRs*);

1.1.2.6 [Intentionally left blank – section deleted]

1.1.2.7 operating deviations;

1.1.2.8 *ancillary services* and *reliability must-run contracts*;

1.1.2.9 *transmission services charges* and connection charges collected by the *IESO*;

1.1.2.10 [Intentionally left blank – section deleted]

1.1.2.11 the *IESO* administration charge;

1.1.2.12 penalties and fines;

1.1.2.13 [Intentionally left blank – section deleted]

1.1.2.14 rebates and other payments arising from market power mitigation measures;

1.1.2.15 the day-ahead commitment process;

1.1.2.16 forecasting services relating to *variable generation*;

1.1.2.17 *capacity obligations*; and

1.1.2.18 ramp-down *settlement* amount.

1.2 Regulated Settlement Amounts and Related Payment Charges

1.2.1 Notwithstanding any other provision within the *market rules*, the *IESO* shall, with respect to determining, collecting and remitting applicable *settlement amounts*, comply with the relevant provisions of *applicable law* including without limitation the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, and any regulations enacted thereunder, as amended from time to time.

1.2.1.1 [Intentionally left blank – section deleted]

1.2.1.2 [Intentionally left blank – section deleted]

1.2.2 [Intentionally left blank – section deleted]

1.2.3 Notwithstanding any other provision within the *market rules*, *market participants* shall remit to the *IESO* such applicable *settlement amounts* and other payments as may be required under the relevant provisions of *applicable law* including without limitation the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998* and any regulations enacted thereunder, as amended from time to time.

1.2.3.1 [Intentionally left blank – section deleted]

1.2.3.2 [Intentionally left blank – section deleted]

2. Settlement Data Collection and Management

2.1 Metering and Metering Responsibilities

2.1.1 Subject to section 2.1.1A, every *meter* utilised for determining *settlement amounts* according to this Chapter must be a *registered wholesale meter (RWM).*

2.1.1A Nothing in section 2.1.1 shall be construed as requiring the *IESO* to determine *settlement amounts* on the basis of an *RWM* in circumstances where:

2.1.1A.1 it is permitted to use another *meter* for this purpose pursuant to section 3.1.4A;

2.1.1A.2 in circumstances where the *IESO* has determined that determination of *settlement amounts* using a *metering installation* whose registration has expired is required for the efficient operation of the *IESO-administered markets*;

2.1.1A.3 [Intentionally left blank – section deleted]

2.1.1A.4 the *IESO* has not permitted the use of the *RWM* for determining *settlement amounts* for the reason specified section 4.2.2A of Chapter 6;

2.1.1A.5 [Intentionally left blank – section deleted]

2.1.1A.6 the *IESO* is determining *settlement amounts* related to *capacity obligations* using measurement data submitted by *capacity market participants* with an *hourly demand response resource*.

2.1.2 A single *metered market participant* must be designated for each *RWM* that is not an *intertie metering point*.

2.1.3 The same *metered market participant* must be designated for all *primary RWMs,* other than *intertie metering points*, for which any *metering data* will be allocated to any single *registered facility*.

2.1.4 [Intentionally left blank – section deleted]

2.1.5 The *IESO* shall be responsible for *metering data* and its allocation with respect to all *intertie metering points*. The *IESO*, in accordance with operating agreements with other *control areas*, shall:

2.1.5.1 to the extent required to fulfill its obligations under this Chapter, interpret and apply the protocols governing interchanges between the *IESO-controlled grid* and other *control areas*;

2.1.5.2 provide to the *settlement process* the *interchange schedule data* described in section 2.5; and

2.1.5.3 determine the allocated quantities called for by section 3.1.9 based on scheduled *intertie* flows even when these differ from actual flows as determined by *metering data*.

2.1.6 [Intentionally left blank – section deleted]

2.1.6.1 [Intentionally left blank]

2.1.6.2 [Intentionally left blank]

2.1A Station Service

2.1A.1 The *market participant* responsible for registering a *facility* consuming *transmission station service* or *connection station service* shall:

2.1A.1.1 identify to the *IESO* the fraction of the *energy* withdrawn at that *facility* supplied from the *IESO-controlled grid* which is not such *station service*; and

2.1A.1.2 ensure that the consumption of the *energy* referred to in section 2.1A.1.1 is measured by an *RWM* that complies with the requirements of Chapter 6.

2.1A.2 For *settlement* purposes, *transmission station service* shall be treated as a transmission loss.

2.1A.3 Where *connection station service* is not separately metered by an *RWM*, the *energy* consumption associated with *connection station service* shall be estimated and submitted by the *market participant* responsible for registering the relevant *connection facility* in accordance with the equations and procedures described in the applicable *market manuals*, which estimate shall be stamped by a registered professional engineer and shall be subject to audit by the *IESO*.

2.1A.4 For *settlement* purposes, *connection station service* shall be treated as follows:

2.1A.4.1 where the *energy consumption* associated with *connection station service* is included in the *energy consumption* measured by an *RWM*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

a. amongst those *market participants* whose *facilities* are *connected* to the relevant *connection facility* in the proportions provided by the *metering service provider* for that *RWM*, and the provision of such proportions shall constitute certification by such *metering service provider* that such proportions have been agreed between the *metering service provider* and all *market participants* whose *facilities* are *connected* to the relevant *connection facility*.

b. [Intentionally left blank – section deleted]

2.1A.4.2 where the *energy consumption* associated with *connection station service* is not included in the *energy consumption* measured by an *RWM*, the sum of the *energy* associated with that *connection station service* and with site specific losses shall be apportioned:

a. amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* in the proportions provided by the *metering service provider* for each *RWM* measuring the flow of *energy* taken from the *connection facility*. The proportions provided by each *metering service provider* shall reflect agreement amongst all applicable *metering service providers* and shall only be accepted by the *IESO* if the proportions provided by all applicable *metering service providers* sum to one. The provision of such proportions shall constitute certification by each such *metering service provider* that it has reached agreement with all other applicable *metering service providers* in respect of such proportions; or

b. where one or more of the *metering service providers* referred to in section 2.1A.4.2(a) has not provided the *IESO* with the proportions referred to in that section, amongst those *market participants* whose *facilities* are connected to the relevant *connection facility* on the basis of the number of *load serving breakers* serving each such *market participant.*

2.1A.5 A *metering service provider* who provides to the *IESO* factors for apportioning *connection station service* and site specific losses pursuant to section 2.1A.4.1(a) or 2.1A.4.2(a) may, no more than once in each calendar year or more frequently if required by the registration of a new *RWM*, submit to the *IESO* revised proportions for the purposes of apportioning the *energy* referred to in section 2.1A.4. The provision of such revised proportions shall constitute certification by such *metering service provider* as to the agreement referred to in section 2.1A.4.1(a) or 2.1A.4.2(a), as the case may be.

2.1A.6 For greater certainty, nothing in section 2.1A.4 shall be construed as permitting the apportionment of *connection station service* and site specific losses to a *market participant* in respect of a *facility* that is an *embedded load facility,* an *embedded generation facility,* or an *embedded electricity storage facility.*

2.1A.6A Where the sum of *energy* associated with *connection station service* and with site specific losses is apportioned by the *IESO* pursuant to section 2.1A.4.2(b) by reason of the failure of all applicable *metering service providers* to reach agreement as to the proportions referred to in sections 2.1A.4.1(a) or 2.1A.4.2(a) as the case may be, any *market participant* that is the subject of such apportionment may submit the matter to the dispute resolution process set forth in section 2 of Chapter 3 and shall, in the *notice of dispute*:

2.1A.6A.1 name all other *market participants* which are the subject of the same apportionment as *respondents*; and

2.1A.6A.2 request that the arbitrator determine an alternative apportionment.

2.1A.6B Where an *arbitrator* determines an alternative apportionment pursuant to section 2.1A.6A, the *metering service provider* for each applicable *RWM* shall, within 5 *business days* of the date of the award of the *arbitrator*, file with the *IESO* proportions for apportioning the sum of *energy* associated with *connection station service* and with site specific losses that reflect such alternative apportionment.

2.1A.7 Subject to section 2.1A.9, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by a *generation unit* passing through the *metering installation* net of all applicable *generation station service*, the costs associated with *generation station service* shall, for *settlement* purposes, be apportioned:

2.1A.7.1 amongst those *generation units* consuming such *generation station service* in the proportions provided by the *metering service provider* for the relevant *metering installation*; or

2.1A.7.2 where the *metering service provider* has not provided the proportions referred to in section 2.1A.7.1, equally amongst all such *generation units*,

provided that, in either case such apportionment results in a totalization of the applicable *RWMs* that is identical to the totalization of the *meters* required to meet the monitoring requirements of section 7.3, 7.3A, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4.

2.1A.7A Subject to section 2.1A.9A, where *metering data* from a *metering installation* does not reflect the amount of *energy* injected by an *electricity storage unit* passing through the *metering installation* net of all applicable *electricity storage station service*, the costs associated with *electricity storage station service* shall, for *settlement* purposes, be apportioned:

2.1A.7A.1 amongst those electricity storage units consuming such electricity storage station service in the proportions provided by the metering service provider for the relevant metering installation; or

2.1A.7A.2 where the *metering service provider* has not provided the proportions referred to in section 2.1A.7A.1, equally amongst all such *electricity storage units*, provided that, in either case such apportionment results in a totalization of the applicable *RWMs* that is identical to the totalization of the *meters* required to meet the monitoring requirements of section 7.3, 7.3A, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4.

2.1A.8 A *metering service provider* who provides the *IESO* with proportions pursuant to section 2.1A.7.1 may submit up to two requests in a calendar year to the *IESO* to have such proportions revised, provided that the giving of effect to such revisions shall be subject to the mutual agreement of the *metering service provider* and the *IESO*.

2.1A.9 If the consumption of *generation station service* results in:

2.1A.9.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 3.1.9, accruing at the location of a *generation unit* which is part of an eligible *generation facility* within the meaning of section 2.1A.13 in circumstances where the injection of *energy* by that *generation facility* as a whole exceeds the withdrawal of *energy* by that *generation facility* as a whole during a given *metering interval*; and

2.1A.9.2 such accrual of AQEW results in *hourly uplift,* non-hourly *settlement amounts,* or both, accruing at the location referred to in section 2.1A.9.1 during any *metering interval* within an *energy market billing period*, the *metered market participant* for that *generation facility* shall, subject to section 2.1A.10, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.1A.9.2.

2.1A.9A If the consumption of *electricity storage station service* results in:

2.1A.9A.1 an allocated quantity of *energy* withdrawn or AQEW, as described in section 3.1.9, accruing at the location of an *electricity storage unit* which is part of an eligible *electricity storage facility* within the meaning of section 2.1A.13A in circumstances where the injection of *energy* by that *electricity storage facility* as a whole exceeds the withdrawal of *energy* by that *electricity storage facility* as a whole during a given *metering interval*; and

2.1A.9A.2 such accrual of AQEW results in *hourly uplift,* non-hourly *settlement amounts,* or both, accruing at the location referred to in section 2.1A.9.1 during any *metering interval* within an *energy market billing period*, the *metered market participant* for that *electricity storage facility* shall, subject to section 2.1A.10, be reimbursed the *hourly uplift* and non-hourly *settlement amounts* referred to in section 2.1A.9A.2.

2.1A.10 No reimbursement will be provided to a *metered market participant* pursuant to section 2.1A.9 or 2.1A.9A in respect of amounts attributable to the following:

2.1A.10.1 transmission services charges;

2.1A.10.2 any applicable penalties, awards or adjustments reflected in the *invoice* issued to the *metered market participant*; or

2.1A.10.3 any other *settlement amounts* where such a reimbursement:

a. is prohibited by *applicable law* or the *market rules*; or

b. where the *settlement amount* is collected by the *IESO* pursuant to an obligation imposed upon it by *applicable law,* is not permitted by such *applicable law.*

2.1A.11 [Intentionally left blank – section deleted]

2.1A.12 [Intentionally left blank – section deleted]

2.1A.13 For the purposes of section 2.1A.9.1, a *generation facility* may be designated by the *IESO* as an eligible *generation facility* where the *generation facility*:

2.1A.13.1 is comprised of two or more *registered facilities*:

a. [Intentionally left blank – section deleted]

b. that have the same metered market participant.

2.1A.13.2 is located within the *IESO control area*; and

2.1A.13.3 has associated with it *generation station service* that serves more than one *registered facility* included within that *generation facility*.

2.1A.13A For the purposes of section 2.1A.9A.1, an *electricity storage facility* may be designated by the *IESO* as an eligible *electricity storage facility* where the *electricity storage facility*:

2.1A.13A.1 is comprised of two or more *registered facilities* that have the same metered market participant;

2.1A.13A.2 is located within the *IESO control area*; and

2.1A.13A.3 has associated with it *electricity storage station service* that serves more than one *registered facility* included within that *electricity storage facility*.

2.1A.14 The *IESO* shall recover any amount reimbursed pursuant to section 2.1A.9 or 2.1A.9A described in section 4.8.1.6.

2.2 Metering Data Recording and Collection Frequency

2.2.1 All *metering data* must be recorded for each *metering interval* except as otherwise provided in section 2.2.2 or elsewhere in these *market rules.*

2.2.2 A *RWM* that serves only *non-dispatchable load, self-scheduling generation facilities, self-scheduling electricity storage facilities, transitional scheduling generators* or *intermittent generators* need not record any *metering data* regarding *energy* (in MWh) or reactive *energy* (in MVARh) for *metering intervals* but must record such *metering data* for each *settlement hour*. *Metering data* regarding demand or power (in MW) shall be recorded by such *RWMs* for such *intervals* as the *IESO* may specify in the applicable *market manual*.

2.2.3 An *intertie metering point* shall record *metering data* in a manner consistent with the applicable interchange protocol.

2.2.4 *Metering data* shall be collected by or delivered to the *IESO* in accordance with Appendix 9.1 or in accordance with such other schedule as the *IESO* may determine from time to time.

2.3 Collection and Validation of Metering Data

2.3.1 The *IESO* shall collect or receive *metering data* directly from *RWM*s, in such other manner as may be specified in Appendix 9.1 and from such other processes as may be appropriate. Such *metering data* will initially be “raw” data that have not been validated or corrected by the *VEE process.*

2.3.2 The raw *metering data* collected by or delivered to the *IESO* shall be subjected to the *VEE process* described in Appendix 9.1. The *VEE process* shall:

2.3.2.1 convert raw *metering data* into validated, corrected or estimated "*settlement* ready" *metering data* suitable for use in determining *settlement amounts*;

2.3.2.2 operate according to the *settlement* schedule specified in section 6;

2.3.2.3 detect errors in *metering data* resulting from improper operational conditions and/or hardware/software malfunctions, including failures of or errors in metering or communication hardware, and from *metering data* exceeding pre-defined variances or tolerances; and

2.3.2.4 use operational system data, including historical generation and load patterns and data collected by or delivered to the *IESO*, as appropriate, for validating raw *metering data*, and for editing, estimating and correcting *metering data* found to be erroneous or missing.

2.3.2A While undergoing the *VEE process, metering data* from a given registered *metering installation* in respect of a given *trading day* or, where applicable, estimates thereof, shall bear appropriate flags and shall be accessible by electronic means by any person referred to in section 10.1.3 of Chapter 6 on the day following such *trading day.*

2.3.3 Subject to section 2.3.4, all *metering data* in respect of a given registered *metering installation* for a given *trading day* used for determining *settlement amounts* pursuant to this Chapter shall be "*settlement* ready" *metering data* that has been validated and corrected by the *VEE process*. Such "*settlement* ready" *metering data* shall be accessible by electronic means by any person referred to in section 10.1.3 of Chapter 6 no later than five *business days* following such *trading day*, providing that the applicable *metering service provider* has resolved any trouble call pertaining to such *metering data.*

2.3.4 *Metering data* used for determining *settlement amounts* pursuant to this Chapter shall, where applicable, be adjusted to reflect the estimation or deeming provisions set forth in sections 11.1.4 and 11.1.6, respectively, of Chapter 6.

2.4 [Intentionally left blank – section deleted]

2.4.1 [Intentionally left blank – section deleted]

2.4.1.1 [Intentionally left blank]

2.4.1.2 [Intentionally left blank]

2.4.1.3 [Intentionally left blank]

2.4.1.4 [Intentionally left blank]

2.4.2 [Intentionally left blank – section deleted]

2.4.2.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]

2.4.2.2 [Intentionally left blank – section deleted]

2.4.3 [Intentionally left blank – section deleted]

2.4.3.1 [Intentionally left blank – section deleted]

2.4.3.2 [Intentionally left blank – section deleted]

2.4.4 [Intentionally left blank – section deleted]

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2.4.5.1 [Intentionally left blank – section deleted]

a. [Intentionally left blank – section deleted]
b. [Intentionally left blank – section deleted]
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2.4.5.2 [Intentionally left blank – section deleted]

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2.4.9 [Intentionally left blank – section deleted]

2.4.9.1 [Intentionally left blank – section deleted]

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a. [Intentionally left blank – section deleted]

b. [Intentionally left blank – section deleted]

2.4.10 [Intentionally left blank – section deleted]

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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* 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.

2.5 Collection of Interchange Schedule Data

2.5.1 The *IESO* shall, in co-operation with other *control area operators, security coordinators* and *interconnected transmitters* and in accordance with applicable interchange protocols, determine the following *interchange schedule data* for each *settlement hour*:

2.5.1.1 the total scheduled flows of *energy*, and of any other physical quantity or *physical service* traded in the *IESO-administered markets*, across each transmission interface between the *IESO-controlled grid* and an *intertie zone*; and

2.5.1.2 the allocation of each scheduled *intertie* flow among *market participants*.

2.5.2 The *IESO settlement process* shall use the *interchange schedule data* to determine *settlement amounts* even though the total scheduled flows on all *interties* may be either more or less than actual physical flows as measured by all *intertie metering points*. The *IESO* shall manage deviations between scheduled and actual *intertie* flows in accordance with interchange protocols with other *control areas* and the requirements of applicable *standards authorities*, with any resulting financial gains or losses ultimately accruing or charged to *market participants* through the *hourly uplift***.**

2.5.3 The *IESO* shall *publish* the total scheduled and actual flows of *energy* between the *IESO-controlled grid* and each *intertie zone*.

2.6 Collection of Physical Bilateral Contract Data

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*.

2.6.2 *Physical bilateral contract quantities* shall not be included in the quantities of *energy* used to determine *settlement amounts* related to *energy*, although they may be used to determine other *settlement amounts* as provided in this Chapter.

2.6.3 *Physical bilateral contract quantities* must specify total quantities for each *settlement hour*, not quantities for metering intervals within a *settlement hour*. The *IESO* shall divide hourly *physical bilateral contract quantities* into equal interval quantities when necessary for determining *settlement amounts* as provided for in section 3.1.6.

2.6.4 The *IESO* shall submit directly to the *settlement process* the *physical bilateral contract quantities* submitted by each *market participant* for each *settlement hour* as provided in section 3.1.6.

2.7 Collection of Transmission Right (TR) Data

2.7.1 The *IESO* shall implement, in accordance with Chapter 8, *TR auctions* that will result in an allocation among *market participants* of *transmission rights)* associated with the transactions referred to in section 4.1.1.1 of Chapter 8 and conveying rights to *settlement amounts* based on differences in *energy* prices between the specified injection *TR zone* and the specified withdrawal *TR zone* with which each *TR* is associated.

2.7.2 The *IESO* shall submit to the *settlement process* by the sixth *business day* after each *dispatch day* the following data related to *TRs*:

2.7.2.1 the quantities, in MW, of *TRs* held by each *TR holder* with respect to each applicable pair of specified injection and withdrawal *TR* zones for each *settlement hour* of such *dispatch day*; and

2.7.2.2 the total proceeds from the sale of *TR*s in respect of all rounds of a *TR auction* that is concluded on such *dispatch day*.

2.8 [Intentionally left blank – section deleted]

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2.8.2 [Intentionally left blank – section deleted]

2.8.3 [Intentionally left blank – section deleted]

2.9 Collection of Ancillary Service Data

2.9.1 The *IESO* shall submit to the *settlement process* the data from *contracted ancillary service* contracts and from the daily *dispatch* process necessary to determine *contracted ancillary service* payments.

2.10 Collection of Market Price and Other Settlement Data

2.10.1 The *IESO* shall submit to the *settlement process* all *market prices* determined by the *IESO* according to the provisions of Chapter 7, and all *metering data* and other *operating results* available to the *IESO* as may be needed by the *settlement process* for determining *settlement amounts* pursuant to this Chapter.

2.11 Settlement Record Retention, Confidentiality, and Reliability

2.11.1 Subject to section 2.11.3, the *IESO* shall retain all *settlement* records for a period adequate to support the *settlement* audit referred to in section 6.19, matters described in section 6.8.12.4, and/or a *dispute outcome*, but in no case for less than seven years.

2.11.2 The *IESO* shall periodically review the period for which *settlement* records are retained and shall, if required and subject to section 2.11.3, take such steps as may be required to effect a change in such period.

2.11.3 The period for which *settlement* records are retained shall comply with the requirements of any regulatory authority having jurisdiction over the *IESO* or *market participants*.

2.11.4 *Settlement* and supporting data for each *trading day* of a *billing period* shall be made available by direct electronic means to the relevant *market participant* as soon as the data become available to the *IESO*. The data shall remain available via electronic access until the earlier of 60 days from the end of the *billing period* and the date on which invoicing and payment activities for that *billing period* have been completed.

2.11.5 The *IESO* shall safeguard any *settlement* information that is *confidential information* in accordance with section 5 of Chapter 3.

2.11.6 The *IESO* shall assure that back-up computer and communication systems are available for the *settlement process* and shall, in accordance with section 6.1, use such back-up systems in the event that equipment failure or an emergency evacuation makes the primary systems referred to in section 6.1.1 unavailable.

3. Determination of Hourly Settlement Amounts

3.1 Hourly Settlement Variables and Data

3.1.1 The *IESO* shall determine hourly *settlement amounts* for the *hourly markets* using the hourly price and quantity variables and data described in this section 3.1.

3.1.2 [Intentionally left blank – section deleted]

Day-Ahead Commitment Process Variables, Data and Information

3.1.2A The *IESO* shall determine the following day-ahead quantities from the *schedule of record,* and provide them directly to the *settlement process*:

$DA\_DQSI_{k,h}^{i,t}$ = *schedule of record* quantity scheduled for injection by *market participant* ‘k’ for an import transaction at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

$DA\_DQSI_{k,h}^{m,t}$ = *schedule of record* quantity scheduled for injection by *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h'

$DA\_DQSW_{k,h}^{i,t}$ = *schedule of record* quantity scheduled for withdrawal by *market participant* 'k' for an export transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$DA\_ELMP_{h}^{m,t}$ = day-ahead constrained schedule intertie price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'

$DA\_ILMP_{h}^{m,t}$ = day-ahead constrained schedule intertie price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

3.1.2B The *IESO* shall provide directly to the *settlement process*:

3.1.2B.1 information to identify *market participants* which are deemed to have accepted in accordance with section 5.8.4 of Chapter 7 a day-ahead production cost guarantee for their *generation facility*;

3.1.2B.2 information to identify any event in which the *IESO* de-commits a *generation facility* between the release and *publication* of the *schedule of record* and the end of its committed schedule in the *schedule of record* where the *market participant* has been deemed to have accepted in accordance with section 5.8.4 of Chapter 7 a day-ahead production cost guarantee for that *facility*;

3.1.2B.3 exemptions from the day-ahead import failure charge described in section 3.8B, for any applicable import transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2B.4 exemptions from the day-ahead export failure charge described in section 3.8D, for any applicable export transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2B.5 exemptions from the day-ahead linked wheel failure charge described in section 3.8E, for any applicable linked wheel transactions scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.8B; and

3.1.2B.6 exemptions from the day-ahead *generator* withdrawal charge described in section 3.8F, for any applicable *registered facility* scheduled in the *schedule of record* where such exemptions have been determined in accordance with chapter 7, section 7.5.3.

3.1.2B.7 the following information:

$DA\_BE_{k,h}^{m,t}$ = *energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$DA\_BE_{k,h}^{i,t}$ = *energy offers* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$DA\_BL_{k,h}^{i,t}$ = *energy bids* submitted in day-ahead, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$DA\_SNLC_{k,h}^{m}$ = as-offered speed-no-load cost associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *delivery point* 'm'

$DA\_SUC_{k,h}^{m}$ = as-offered *start-up cost* associated with *three-part offers* for a given *settlement hour* 'h' for *market participant* 'k' at *delivery point* 'm'

$MLP_{k,h}^{m,t}$ = minimum output of *energy* the *market participant* 'k' at *delivery point* 'm' can maintain without ignition support in *metering interval* 't' of *settlement hour* 'h'

$OPCAP_{k,h}^{m,t}$ = de-rated *generation capacity* submitted by *market participant* 'k' at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'

3.1.2C The *IESO* shall determine from the *pre-dispatch schedule* and the *pre-dispatch* projected *market schedule,* and provide directly to the *settlement process* the following *pre-dispatch prices* and quantities:

$PD\_DQSI_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for injection by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$PD\_DQSW_{k,h}^{i,t}$ = *pre- dispatch* constrained quantity scheduled for withdrawal by *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

$PD\_EMP_{h}^{m,t}$ = *pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h'

In instances where this variable is provided to the s*ettlement process* on an hourly basis as determined in section 3.9, it shall be deemed to apply uniformly to all *metering intervals* 't' in *settlement hour* 'h'

$PD\_ELMP_{h}^{m,t}$ = *pre-dispatch* constrained schedule *intertie* price at the *delivery point* 'm' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'

$PD\_ILMP_{h}^{m,t}$ = *pre-dispatch* constrained schedule *intertie* price at the *delivery point* 'm' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

3.1.2D The *IESO* shall provide directly to the *settlement process*:

3.1.2D.1 exceptions from the real-time import failure charge set out in section 3.8C.2 for any applicable import transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;3.1.2D.2 exceptions from the real-time export failure charge set out in section 3.8C.4 for any applicable export transactions scheduled in the *pre-dispatch schedule* where such exceptions have been determined in accordance with chapter 7, section 7.5.8B;

3.1.2D.3 the adjustment of amounts provided for in section 6.6.10A.2 of Chapter 3;

3.1.2D.4 any applicable price bias adjustment factors, as described in section 3.8C.7, utilised in the calculation of the:

a. real-time import failure charge; or

b. real-time export failure charge;

that are in effect as of the *settlement hour* in which such *settlement amounts* are calculated by the *IESO*; and

3.1.2D.5 the following information:

$PD\_BE_{k,h}^{i,t}$ = *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

$PD\_BL_{k,h}^{i,t}$ = *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

3.1.3 The *IESO* shall determine *energy market* prices and quantities as provided in Chapter 7 and shall provide the following variables and data from the *energy market,* determined in accordance with section 3.1.4A, directly to the *settlement process*:

$MQSI_{k,h}^{m,t}$ = market quantity scheduled for injection in the *market schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$MQSW_{k,h}^{m,t}$ = market quantity scheduled for withdrawal in the *market schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$DQSI_{k,h}^{m,t}$ = *dispatch* quantity scheduled for injection in the *real-time schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h' determined on the basis of the *dispatch instructions* issued to *market participant* 'k' for that *metering interval*

$DQSW_{k,h}^{m,t}$ = *dispatch* quantity scheduled for withdrawal in the *real-time schedule* by *market participant* 'k' at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h' determined on the basis of the *dispatch instructions* issued to *market participant* 'k' for that *metering interval*

$TMQSI_h^{m,t}$ = total market quantity scheduled for injection in the *market schedule* by all *market participant*s at location m or *intertie metering point* 'm' in *metering interval* 't' of *settlement hour* 'h'

= $\sum_k MQSI_{k,h}^{m,t}$, with k = all *market participants*

$EMP_h^{m,t}$ = *energy market* price at *delivery point* 'm' in *metering interval* 't' of *settlement hour* 'h'

$ICP_h^{i,t}$ = where $i \in M$ such that M is the set of all *delivery points* 'm' and *intertie metering points* 'm'

$EMP_h^{i,t}$ = *energy market price* at intertie *metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'

= $ICP_h^{i,t} + EMP_h^{m,t}$ subject to the constraints outlined in sections 8.2.2.4 and 8.2.2.5 of Chapter 7.

= where m is any *delivery point* while uniform pricing exists.

= where $i \in M$ such that M is the set of all *delivery points* 'm' and *intertie metering points* 'm'.

$HOEP_h$ = hourly Ontario energy price in settlement hour 'h'

= $\sum_{m,t} EMP_h^{m,t}/12$,
with t = all *metering intervals* in *settlement hour* 'h'
m = all *primary RWM*s

$x_h^{m,t}$ = a *settlement* floor price for *energy* applicable to *intertie metering point* 'm' *metering interval* 't' in *settlement hour* 'h', as set in the applicable *market manual*. The need for a *settlement* floor price other than *MMCP* shall remain in effect only until floor prices for *energy offers* from *registered market participants* that are *variable generators* or nuclear *generators* go into effect.

3.1.4 The *IESO* shall determine *operating reserve market* prices and quantities in a process integrated with the *energy market*, as provided in Chapter 7. For each of the two types "r" of *class r reserves*, the *IESO* shall provide directly to the *settlement process* the following variables and data, determined in accordance with section 3.1.4A:

$PROR_{r,h}^{m,t}$ = *market price* (in $/MW) of class r reserve in *metering interval* ‘t’ of *settlement hour* ‘h’ at *delivery point* ‘m’ or *intertie metering point* ‘m’

$PROR_{r,h}^{i,t}$ = *market price* (in $/MW) of class r reserve in *metering interval* ‘t’ of *settlement hour* ‘h’ at *intertie metering point* ‘i’

= where i ∈ M such that M is the set of all *delivery points* ‘m’ and *intertie metering points* ‘m’.

= $ICP_{r,h}^{i,t} + PROR_{r,h}^{m,t}$ subject to the constraints outlined in sections 8.2.2.6 and 8.2.2.7 of Chapter 7.

= where m is any *delivery point* while uniform pricing exists.

$ICP_{r,h}^{i,t}$ = *intertie congestion price* for class r reserve at *intertie metering point* ‘i’ in *metering interval* ‘t’ of *settlement hour* ‘h’

= where i ∈ M such that M is the set of all *delivery points* ‘m’ and *intertie metering points* ‘m’.

$SQROR_{r,k,h}^{m,t}$ = scheduled quantity (in MW) of *class r reserve* for *market participant* ‘k’ in *metering interval* ‘t’ of *settlement hour* ‘h’ at location m or *intertie metering point* ‘m’ as described in the *market schedule*

$DQSR_{r,k,h}^{m,t}$ = dispatch quantity (in MW) of class r reserve for *market participant* ‘k’ at location m in *metering interval* ‘t’ or *intertie metering point* ‘m’ of *settlement hour* ‘h’ as determined on the basis of the *dispatch instructions* issued to *market participant* ‘k’ for that *metering interval*

3.1.4A For the purposes of sections 3.1.3, 3.1.4 and 3.5.2, “location m” in respect of *market participant* ‘k’ shall mean the location of:

3.1.4A.1 the relevant *meter* used by *market participant* ‘k’ to meet the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 in respect of *registered facility* k/m, where such requirements apply in respect of *registered facility* k/m; or

3.1.4A.2 the *RWM* for *registered facility* k/m, where the monitoring requirements of section 7.3, 7.4, 7.5 or 7.6, as the case may be, of Chapter 4 do not apply in respect of *registered facility* k/m.

3.1.5 [Intentionally left blank – section deleted]

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 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 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'

3.1.7 The *IESO* shall offer a service whereby the *selling market participant* in a *physical bilateral contract* or the selling *market participant* under a financial bilateral contract may assume responsibility for components of the buying or *buying market participant's settlement* obligations other than those for *energy*.

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* or *intertie metering point* 'm' to *primary* or *intertie metering point* 'n' for *settlement hour* 'h'

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* 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*, *self-scheduling electricity storage 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* 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* 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 or intertie metering point 'm' in metering interval 't' of settlement hour 'h'

3.1.10 The *IESO* shall provide the following *capacity auction* information and provide them directly to the *settlement process*:

$CARC_k^m$ = the quantity of *energy* (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant 'k'* at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual*;

$CACP^z$ = the *capacity auction clearing price* (in $/MW per day) for the relevant *trading day* in electrical zone 'z'.

$CACP^z_h$ = the *capacity auction clearing price* for *settlement hour* 'h' (in $/MWh) within the *availability window* in electrical zone 'z', determined by taking the *capacity auction clearing price* for the applicable *obligation period* and electrical zone and dividing by the number of *settlement hours* within the *availability window* of the relevant *trading day* within the *obligation period.*

$CAEO^m_{k,h}$ = the quantity of *auction capacity* for *settlement hour* 'h' (in MW) made available by *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* of the *availability window* determined as the lesser of the *resource's energy offers* (in MW) submitted in the day-ahead commitment process, pre-dispatch, and *real-time market*, as applicable.

$CARC_k^m$ = the quantity (in MW) of the *hourly demand response resource's demand response contributors* total registered capability for *capacity market participant* 'k' at *delivery point* 'm', as registered with the *IESO* in accordance with the applicable *market manual;*

$CBOC^m_k$ = the buy-out capacity is an amount (in MW) by which the *capacity obligation* for the *obligation period* for *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' is being reduced as per the *capacity market participant's* election pursuant to section 4.7J.3 of Chapter 9.

$CCO^m_{k,h}$ = the *capacity obligation* (in MW) for the *obligation period* per *capacity auction resource* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *settlement hour* 'h', as may be adjusted pursuant to the *market rules*.

$CICAP^m_k$ = the *cleared ICAP* (in MW) for *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, as determined in accordance with the applicable *market manual*.

$CNPF_{tm}$ = for a given *energy market billing period* 'tm', the non-performance factor as listed in Section 7.1 of Market Manual 12.

$DREBQ^m_{k,h}$ = the quantity (in MW) of *auction capacity* made available by an *hourly demand response resource* or *capacity dispatchable load resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' of the *availability window*, determined as the lesser of the *resource's energy bids* submitted in the day-ahead commitment process, pre-dispatch, and *real-time energy market*, as applicable, and where such value exceeds the $CARC_k^m$ for the *resource* in the relevant *energy market billing period*, the $DREBQ^m_{k,h}$ shall equal such $CARC_k^m$.

$DRSQty^m_{k,h}$ = the quantity of *energy* (in MW) scheduled for withdrawal in the *real-time market* by *market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' of the *availability window*, as described in all *real-time schedules* for such *settlement hour*.

$HDRBP^m_{k,h}$ = the price component (in \$/MWh) of the *energy bid* submitted in the *real time market* for *hourly demand response resource* by *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h' within the *availability window.*

$HDRDC^{m}_{k,h}$ = the delivered capacity (in MWh) by *hourly demand response resource* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' within the *activation window* of the applicable test activation, calculated as follows:

$$\text{Min}(\text{Curtailed MW}^{m}{}_{k,h}\,, \sum_{t=1}^{12}(\frac{\text{Min}(\text{TBQ}^{m}{}_{k,h}, \text{CARC}_{k^{m}}, \text{CCO}^{m}{}_{\text{k,h}})}{12}) - DQSW^{m,t}_{k,h})$$

Where:

(a) "Curtailed $MW^{m}_{k,h}$" is the difference (in MWh) between baseline value, calculated in accordance with the applicable *market manual*, and actual consumption measurement data by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as calculated in accordance with the applicable *market manual*.

(b) "$TBQ^{m}_{k,h}$" is the offered quantity of *energy* (in MW) contained in the last lamination of the *price quantity pair* of the *energy bid* submitted in the *real time market* by *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h'.

HDRTAPR = the out of market test activation rate (in $/MWh), as set out in the applicable *market manual.*

$OCMW^{i}_{k}$ = the *over committed capacity* (in MW) of a *generator-backed capacity import resource* for *capacity market participant* 'k' at *intertie metering point* 'i', as determined by the *IESO*.

RAC^{m}_{k} = the available capacity (in MW) of a *capacity auction resource* at *delivery point* or *intertie metering point* 'm' for *capacity market participant* 'k' in the applicable *obligation period*, and is determined in accordance with the following:

(a) For *capacity dispatchable load resources* and *hourly demand response resources*:

$RAC^{m}_{k} = MIN(DREBQ^{m}_{k,h}, (1.15* CCO^{m}_{k,h}), CICAP^{m}_{k}, CARC_{k}^{m})$

Where:

(i) $CARC_k^m$ is only applicable to *virtual hourly demand response resources*

(b) For *capacity generation resources*, *system-backed capacity import resources*, *generator-backed capacity import resources* and *capacity storage resources*:

$$RAC^m_k = MIN(CAEO^m_{h,k}, (1.15 * CCO^m_{k,h}), CICAP^m_k)$$

3.1.11 The *IESO* shall, in accordance with the applicable *market manual,* determine the required *settlement* data for *registered market participants* that submitted *dispatch data* for *facilities* operating as *pseudo-units,* using the information submitted under Chapter 7, sections 2.2.6G and 2.2.6J, and shall provide this *settlement* data directly to the *settlement process*.

3.2 [Intentionally left blank – section deleted]

3.2.1 [Intentionally left blank – section deleted]

3.3 Hourly Settlement Amounts in the Real-Time Energy Market

3.3.1 The hourly net *energy market settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$NEMSC_{k,h}$") shall be determined by the appropriate equations set forth in section 3.3.2 and where applicable, in accordance with section 2.1.2 of Chapter 8.

3.3.2 For *market participant* 'k', $NEMSC_{k,h}$ shall be the sum, over all *metering intervals* 't' in *settlement hour* 'h' and all *RWMs* and *intertie metering points*, of the *settlement amounts* determined for each *metering interval* and *RWMs* or *intertie metering point*, as follows:

3.3.2.1 in respect of a *dispatchable facility* or an *intertie metering point* associated with:

- an injecting boundary entity;
- a withdrawing *boundary entity* where the associated *intertie congestion price* is less than zero; or,
- a withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7 section 3.5.8.2:

$$NEMSC_{k,h} = \Sigma_{t,m} (EMP_h^{m,t} \times ((AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t}) + \Sigma_{s,b} (BCQ_{s,k,h}^{m,t} - BCQ_{k,b,h}^{m,t})))$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *RWMs* relating to a *dispatchable facility* and all *intertie metering points* associated with: i) any injecting *boundary entities*; ii) any withdrawing *boundary entities* where the associated *intertie congestion price* is less than zero; and, iii) any withdrawing *boundary entity* conducting a wheeling through transaction that is linked as per Chapter 7 section 3.5.8.2

s = all *selling market participants*

b= all *buying market participants*

and

3.3.2.1A in respect of an *intertie metering point* associated with a withdrawing *boundary entity* where that *intertie congestion price* is not less than zero:

$$NEMSC_{k,h} = \Sigma_{t,m} ((MAX (x_h^{m,t}, EMP_h^{m,t})) \times AQEW_{k,h}^{m,t})$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *intertie metering points* where the *intertie congestion price* is not less than zero

and

3.3.2.2 in respect of a *non-dispatchable load facility*, *a self-scheduling generation facility*, a *self-scheduling electricity storage facility*, a *transitional scheduling generator* or *intermittent generator*.

$$NEMSC_{k,h} = HOEP_h \times \Sigma_{t,m} (AQEI_{k,h}^{m,t} - AQEW_{k,h}^{m,t} + \Sigma_s BCQ_{s,k,h}^{m,t}) - \Sigma_{n,b,t} (EMP_h^{n,t} \times BCQ_{k,b,h}^{n,t})$$

where:

m = all *RWMs* relating to a *non-dispatchable load facility,* a *self-scheduling generation facility,* a *self-scheduling electricity storage facility,* a *transitional scheduling generator* or *intermittent generator*

n = all *RWMs* and *intertie metering point*s

s = all *selling market participant*s

b= all *buying market participants*

t = all *metering interval*s in *settlement hour* 'h'

3.3.3 [Intentionally left blank]

3.4 Hourly Settlement Amounts for Operating Reserve and Charges

3.4.1 The hourly *operating reserve settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$ORSC_{k,h}$") shall be determined by the following equation:

$$ORSC_{k,h} = \sum_{m,t,r} PROR_{r,h}^{m,t} \times AQOR_{r,k,h}^{m,t}$$

where:
m = all *primary RWMs* and *intertie metering points*
t = all *metering intervals* in *settlement hour* 'h'
r1 = 10-minute spinning *operating reserve*
r2 = 10-minute non-spinning *operating reserve;* and
r3 = 30-minute *operating reserve*.

3.4.2 The *IESO* shall apply the non-accessibility charge specified in section 7.4.2.1 of Chapter 7, and a *market participant* shall be subject to such non-accessibility charge, for every *dispatch interval* where the *market participant* is scheduled to provide *operating reserve* but was not dispatched to increase *energy generation* or reduce energy withdrawal pursuant to section 7.4.3 Chapter 7, and where the total scheduled *operating reserve* is greater than the total accessible *operating reserve* as determined by:

$$\sum_R AQOR_{rn,k,h}^{m,t} > TAOR_{k,h}^{m,t} \text{ and } \sum_R AQOR_{rn,k,h}^{m,t} > 0$$

Where:

R: is the set of all classes of *operating reserve*

For *operating reserve* provided by a *dispatchable load*:

$$TAOR_{k,h}^{m,t}=Max\left(0,AQEW_{k,h}^{m,t}-MC_{m}^{h,t}\right)$$

$MC_{m}^{h,t}$ = minimum consumption level and is equal to the quantity in the *price-quantity pair* where the *bid* price is *MMCP*

For *operating reserve* provided by a *generator* other than aggregated *facilities*:

$$TAOR_{k,h}^{m,t}=Max\left(0,MAX\_CAP_{k,h}^{m,t}-AQEI_{k,h}^{m,t}\right)$$

$MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch* scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each *dispatch interval*

3.4.2.1 Where *operating reserve* is scheduled to be provided by aggregated *facilities,* a *market participant* shall be subject to a non-accessibility charge for every *dispatch interval* where the *market participant* is scheduled to provide *operating reserve* but was not dispatched to increase *energy generation* pursuant to section 7.4.3 of Chapter 7, and where the total scheduled *operating reserve* is greater than the total accessible *operating reserve* as determined by:

$$\sum_{R}^{M} AQOR_{rn,k,h}^{m,t} > TAOR\_CA_{k,h}^{M,t}, \text{ and } \sum_{R}^{M} AQOR_{rn,k,h}^{m,t} > 0$$

Where:

R: is the set of all classes of *operating reserve*

M: is set of all *delivery points* ‘m’ that are compliance aggregated

Total accessible *operating reserve* (TAOR) for aggregated *generators:*

$$TAOR\_CA_{k,h}^{M,t}=Max\left(0,\sum^{M}\left(MAX\_CAP_{k,h}^{m,t}-AQEI_{k,h}^{m,t}\right)\right)$$

$MAX\_CAP_{k,h}^{m,t}$ = the maximum limit used in determining the *real-time schedule* in the *dispatch* scheduling and pricing process as described in Chapter 7, Appendix 7.5 for each *dispatch interval*

3.4.3 Where it is determined that a non-accessibility charge is to be applied to a *market participant* pursuant to section 3.4.2, the non-accessibility charge shall be calculated for each class of *operating reserve* as follows:

For synchronized *ten-minute operating reserve*:

$$\mathrm{ORSCB}_{r1,k,h}^{m,t} = \mathrm{Min}\left(0, \left(\mathrm{TAOR}_{k,h}^{m,t} - \mathrm{AQOR}_{r1,k,h}^{m,t}\right) \times \mathrm{PROR}_{r1,h}^{m,t}\right)$$

For non-synchronized *ten-minute operating reserve*:

$$\mathrm{ORSCB}_{r2,k,h}^{m,t} = \mathrm{Min}\left(0, \left(\mathrm{Max}\left(0, \mathrm{TAOR}_{k,h}^{m,t} - \mathrm{AQOR}_{r1,k,h}^{m,t}\right) - \mathrm{AQOR}_{r2,k,h}^{m,t}\right) \times \mathrm{PROR}_{r2,h}^{m,t}\right)$$

For *thirty-minute operating reserve*:

$$\mathrm{ORSCB}_{r3,k,h}^{m,t} = \mathrm{Min}\left(0, \left(\mathrm{Max}\left(0, \mathrm{TAOR}_{k,h}^{m,t} - \mathrm{AQOR}_{r1,k,h}^{m,t} - \mathrm{AQOR}_{r2,k,h}^{m,t}\right) - \mathrm{AQOR}_{r3,k,h}^{m,t}\right) \times \mathrm{PROR}_{r3,h}^{m,t}\right)$$

Where:

$AQOR_{rn,k,h}^{m,t}$: Allocated quantity in MW of *class r reserve* for *market participant* ‘k’ at *RWM* ‘m’ in *metering interval* ‘t’ of *settlement hour* ‘h’;

$PROR_{rn,h}^{m,t}$: *Market price* in \$/MW of *class r reserve* in *metering interval* ‘t’ of *settlement hour* ‘h’ at *RWM* ‘m’;

r1 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

r2 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

r3 denotes *thirty-minute operating reserve*.

3.4.3.1 Where it is determined that a non-accessibility charge is to be applied to a *market participant* pursuant to section 3.4.2.1, the amount of non-accessible *operating reserve* shall be determined for each class of *operating reserve* as follows:

For aggregated *generators* scheduled to provide synchronized *ten-minute operating reserve*:

$$\mathrm{ORIA\_CA}_{\mathrm{r1,k,h}}^{\mathrm{M,t}} = \mathrm{Min}\left(0, \mathrm{TAOR\_CA}_{\mathrm{k,h}}^{\mathrm{M,t}} - \sum^{\mathrm{M}} \mathrm{AQOR}_{\mathrm{r1,k,h}}^{\mathrm{m,t}}\right)$$

For aggregated *generators* scheduled to provide non-synchronized *ten-minute operating reserve*:

$$ORIA\_CA_{r2,k,h}^{M,t} = Min\left(0, Max\left(0, TAOR\_CA_{k,h}^{M,t} - \sum^{M} AQOR_{r1,k,h}^{m,t}\right) - \sum^{M} AQOR_{r2,k,h}^{m,t}\right)$$

For aggregated *generators* scheduled to provide *thirty-minute operating reserve*:

$$ORIA\_CA_{r3,k,h}^{M,t} = Min\left(0, Max\left(0, TAOR\_CA_{k,h}^{M,t} - \sum^{M} AQOR_{r1,k,h}^{m,t} - \sum^{M} AQOR_{r2,k,h}^{m,t}\right) - \sum^{M} AQOR_{r3,k,h}^{m,t}\right)$$

Where:

$AQOR_{rn,k,h}^{m,t}$: Allocated quantity in MW of *class r reserve* for *market participant* 'k' at *RWM* 'm' in *metering interval* 't' of *settlement hour* 'h';

r1 denotes the *ten-minute operating reserve* that is synchronized with the *IESO-controlled grid*;

r2 denotes *ten-minute operating reserve* that is not synchronized with the *IESO-controlled grid*; and

r3 denotes *thirty-minute operating reserve*.

3.4.3.2 The non-accessibility charge calculated pursuant to section 3.4.2.1 will be divided among individual aggregate *facilities* on a pro-rated based on the percentage of total inaccessible *operating reserve* attributed to it as determined as follows:

$$ORCF_{rn,k,h}^{m,t} = \frac{ORIA_{rn,k,h}^{m,t}}{\sum^{M1} ORIA_{rn,k,h}^{m,t}}$$

M1: is the set of delivery point 'm' where a resource has operating reserve scheduled for OR class 'rn'.

For synchronized *ten-minute operating reserve*:

$$ORIA_{r1,k,h}^{m,t} = Min\left(0,\left(TAOR_{k,h}^{m,t}\text{-}AQOR_{r1,k,h}^{m,t}\right)\right)$$

For non-synchronized *ten-minute operating reserve*:

$$ORIA_{r2,k,h}^{m,t} = Min\left(0,\left(Max\left(0,TAOR_{k,h}^{m,t}\text{-}AQOR_{r1,k,h}^{m,t}\right)\text{-}AQOR_{r2,k,h}^{m,t}\right)\right)$$

For *thirty-minute operating reserve*:

$$ORIA_{r3,k,h}^{m,t} = Min\left(0,\left(Max\left(0,TAOR_{k,h}^{m,t}\text{-}AQOR_{r1,k,h}^{m,t}\text{-}AQOR_{r2,k,h}^{m,t}\right)\text{-}AQOR_{r3,k,h}^{m,t}\right)\right)$$

Where:

Total inaccessible *operating reserve* for *generators:*

$$ORIA_{rn,k,h}^{m,t} = Min\left(0,TAOR_{k,h}^{m,t}\text{-}\sum_{R} AQOR_{rn,k,h}^{m,t}\right)$$

Total accessible *operating reserve* for *generators*:

$$TAOR_{k,h}^{m,t} = Max\left(0,MAX\_CAP_{k,h}^{m,t}\text{-}AQEI_{k,h}^{m,t}\right)$$

3.4.3.3 The non-accessibility charge calculated pursuant to section 3.4.3.2 will be calculated for an individual aggregate *facility* as follows:

$$ORSCB_{rn,k,h}^{m,t} = ORIA\_CA_{rn,k,h}^{M,t} \times ORCF_{rn,k,h}^{m,t} \times PROR_{rn,h}^{m,t}$$

Where:

$PROR_{rn,h}^{m,t}$: *Market price* in $/MW of *class r reserve* in *metering interval* ‘t’ of *settlement hour* ‘h’ at *RWM* ‘m’.

3.5 Hourly Settlement Amounts for Congestion Management

3.5.1 The *dispatch instructions* provided by the *IESO* to *market participant* ‘k’ will sometimes instruct k to deviate from its *market schedule* in ways that, based on *market participant* ‘k’s *offers* and *bids*, imply a change to *market participant* ‘k’s net operating profits relative to the operating profits implied by *market participant* ‘k’s *market schedule*. When this occurs and *market participant* ‘k’ responds to the *IESO*’s *dispatch instructions*, *market participant* ‘k’ shall, subject to Appendix 7.6 of Chapter 7, receive as compensation a *settlement* credit equal to the change in implied operating profits resulting from such response, calculated in accordance with section 3.5.2. If *market participant* ‘k’ does not fully or accurately respond to its *dispatch instructions* from the *IESO*, the compensation paid to *market participant* ‘k’ shall be altered as set forth in this section 3.5, or as otherwise specified by the *IESO*.

3.5.1A A *registered market participant* for a *registered facility* that is a *dispatchable load* or an *electricity storage facility* withdrawing *energy* is not entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 where that *registered facility’s* DQSW is less than the corresponding MQSW at that location for the same *metering interval* as the result of that *registered facility’s* own equipment or operational limitations, if:

3.5.1A.1 that *registered facility* does not fully or accurately respond to its *dispatch instructions*; or

3.5.1A.2 the ramping capability of that *registered facility*, as represented by the ramp rate set out in the *offers* or *bids,* is below the threshold for the *IESO* to modify *dispatch instructions* and thereby prevents changes to the *dispatch*;

and then the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

3.5.1B A *market participant* shall not be *invoiced* congestion management *settlement* credits for an export transaction if that transaction attracted the congestion management *settlement* credits under the following conditions:

3.5.1B.1 the net *interchange schedule* limit is binding in the *market schedule* on an economic export transaction in pre-dispatch, and subsequently, in accordance with section 6.1.3 of Chapter 7, the *IESO* increases the quantity of that transaction in the *real-time schedule*; or

3.5.1B.2 the net *interchange schedule* limit is binding in the *market schedule* on an uneconomic export transaction in pre-dispatch, and subsequently, in accordance with section 6.1.3 of Chapter 7, the *IESO* decreases the quantity of that transaction in the *real-time schedule*.

The amount of congestion management *settlement* credits referred to in this section is limited to the portion of the transaction that is modified by the *IESO*.

3.5.1C [Intentionally left blank – section deleted]

3.5.1D A *registered market participant* for a *registered facility* that is a *dispatchable load* or an *electricity storage facility* withdrawing energy, shall not be entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 for *settlement hour* 'h' where:

3.5.1D.1 the *price-quantity pairs* contained in the *energy bid* associated with that *registered facility* for *settlement hour* 'h' are not identical to the *price-quantity pairs* in the *energy bid* associated with the same *registered facility* for the applicable preceding *settlement hour* or following *settlement hour*;

3.5.1D.2 the change in *energy bid* as referred to in section 3.5.1D.1 results in a change in the quantity scheduled in the *market schedule* for that *registered facility* as described in the applicable *market manual*;

3.5.1D.3 the change in *energy bid* as referred to in section 3.5.1D.1 results in the ramping of the that *registered facility* as described in the applicable *market manual*; and

3.5.1D.4 that *registered facility's* DQSW is less than the corresponding MQSW at that locaton for any *metering interval* falling within *settlement hour* 'h'.

3.5.1E For the purpose of calculating congestion management *settlement* credits for *variable generators* that are *registered market participants*:

3.5.1E.1 if the *registered facility* is required to follow *dispatch instructions* issued by the *IESO* for any given *dispatch intervals,* the corresponding congestion management *settlement* credits for those *dispatch intervals* shall be calculated using the *market schedule* quantity determined in accordance with section 6.4.2.9A of Chapter 7; and

3.5.1E.2 except as noted in section 3.5.1F, the *market participant* shall not be eligible for congestion management *settlement* credits in *dispatch intervals* where the *registered facility* is issued a *release notification* by the *IESO* in accordance with section 7.1, which remains in effect for any *dispatch interval*.

3.5.1F For the purpose of calculating congestion management *settlement* credits for *variable generators* that are *registered market participants,* if the *registered facility* is subject to a *release notification* for a given *dispatch interval*, and for that *dispatch interval* the *registered facility's* $MQSI_{k,h}^{m,t}$ is less than the corresponding $DQSI_{k,h}^{m,t}$ for the same *dispatch interval* as a result of the *market participant's energy offers* being partially or fully uneconomic in the unconstrained schedule relative to the constrained schedule, the congestion management *settlement* credits for that *dispatch interval* shall be calculated pursuant to section 3.5.2A using the difference between the operating profit based on the *market schedule* quantity $MQSI_{k,h}^{m,t}$ determined in accordance with section 6.4.2.9B of Chapter 7 and the operating profit calculated based on the allocated quantity of *energy* injected (AQEI) for the same *dispatch interval*.

3.5.1G A *registered market participant* for a *registered facility* that is a *dispatchable generation facility* or an *electricity storage facility* injecting *energy*, shall not be entitled to a congestion management *settlement* credit determined in accordance with section 3.5.2 for any *dispatch interval 't'* within *settlement hour* 'h' where:

3.5.1G.1 the registered facility is not a quick-start facility;

3.5.1G.2 the *IESO* has identified the *dispatch interval* as part of consecutive

ramp-down *dispatch intervals* resulting in the shutdown of the *registered facility,* including those where the *registered facility* does not fully or accurately respond to its *dispatch instructions*, in accordance with the applicable *market manual*; and

3.5.1G.3 the *registered facility's* $MQSI_{k,h}^{m,t}$ is less than the corresponding

$DQSI_{k,h}^{m,t}$ for the same *dispatch interval*.

A *registered facility* subject to the withholding or recovery of a congestion management *settlement* credit for a *dispatch interval* under this section shall receive a ramp-down *settlement* amount for the applicable *dispatch interval* in accordance with section 3.5A.

3.5.2 Subject to sections 3.5.1A, 3.5.1D, 3.5.1E, 3.5.1F, 3.5.1G, 3.5.6, 3.5.6A, 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6F, 3.5.6G, 3.5.9, 3.5.10 and 3.5.11 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* or an *electricity storage facility* 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 $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$
B is matrix BE, BR_r, 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.

$OPR_{k,h}$ 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.

$OPL_{k,h}$ represents that component of the congestion management *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to a constraint on the withdrawal of *energy* by a *dispatchable load* or an *electricity storage facility* subject to section 3.5.1. $OPL_{k,h}$ utilizes the negative of each output from each component Operating Profit (OP) function so as to correct for negative revenue streams (owing to withdrawals of *energy*).

$OPL_{k,h}$ is calculated as follows:

$$OPL_{k,h} = \sum_{m,t}\left[\begin{array}{l} -1\times OP(EMP_h^{m,t}, MQSW_{k,h}^{m,t}, BL) - \\ MAX\left(-1\times OP(EMP_h^{m,t}, DQSW_{k,h}^{m,t}, BL), -1\times OP(EMP_h^{m,t}, AQEW_{k,h}^{m,t}, BL)\right) \end{array}\right]$$

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

3.5.2A For purposes of section 3.5.1F, for *variable generators* that are *registered market participants*, the $OPE_{k,h}$ equation in section 3.5.2 shall be calculated as follows:

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

3.5.3 [Intentionally left blank]

3.5.4 Subject to section 5.3.4 of Chapter 5, during instances where $CMSC_{k,h}$ is calculated at an *intertie metering point* at which a *market participant* is conducting an import or export transaction for a *physical service* that is subject to a *constrained off event* that is reflected in *dispatch instructions* issued by the *IESO* as a result of a request initiated by an entity other than the *IESO*, the *IESO* shall not calculate any portion of $CMSC_{k,h}$ pertaining to the affected transaction for those *metering intervals* within *settlement hour* 'h' in which such conditions exist, and for greater certainty, during any *metering interval* in which:

3.5.4.1 $MQSI_{k,h}^{m,t}$ is not equal to $DQSI_{k,h}^{m,t}$ as a result of such a *constrained off event*;

3.5.4.2 $MQSW_{k,h}^{m,t}$ is not equal to $DQSW_{k,h}^{m,t}$ as a result of such a *constrained off event*; or

3.5.4.3 $SQROR_{r,k,h}^{m,t}$ is not equal to $DQSR_{r,k,h}^{m,t}$ as a result of such a *constrained off event*;

and irrespective of whether or not a *constrained on event* or a *constrained off event* was affecting the transaction in any preceding *metering interval*.

3.5.5 A DQSI, DQSW or DQSR, quantity as the case may be, that departs from its corresponding *market schedule* quantity due to the circumstances described in section 3.5.4 shall be denoted as such within the supporting data provided to the affected *market participant* as part of the content of *settlement statements* described in sections 6.5.4.1 and 6.5.4.3.

3.5.6 The *IESO* shall adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *offer price* that:

3.5.6.1 is associated with a *generation facility,* an injecting *electricity storage facility,* or is associated with an injecting *boundary entity*; and

3.5.6.2 is less than a specified lower limit where such limit is the lesser of 0.00 $/MWh and the *energy market price* for the applicable *dispatch interval*;

to that lower limit.

3.5.6A The *IESO* may adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *bid* price that:

3.5.6A.1 is associated with a *dispatchable load facility* or is associated with a withdrawing *boundary entity* or a withdrawing *electricity storage facility*;

3.5.6A.2 is less than the prices determined by the *IESO* in accordance with the applicable *market manual*; and

3.5.6A.3 is less than the *energy market price* in the applicable Ontario or *intertie zone* for the applicable *dispatch interval*;

to the lesser of the prices determined by the *IESO* in accordance with the applicable *market manual* and the *energy market price* in the applicable Ontario or *intertie zone*.

3.5.6B A *registered market participant* for a *registered facility* that is a *dispatchable generation facility*, who:

- increases the *offer* price associated with the *generation facility minimum loading point* for its *minimum generation block run-time* so that under Chapter 7 section 5.7.1.4 the *registered market participant* for the *generation facility* is no longer eligible for the applicable guarantee; and
- has received a manual constraint from the *IESO* for the *generation facility* under Chapter 7 section 6.3A.2 or 6.3A.4;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, associated with that *offer* price increase for *settlement hour* ‘h’, where *settlement hour* ‘h’ falls within the *generation facility minimum generation block run-time*. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6C A *registered market participant* for a *registered facility* that is a dispatchable *generation facility* or a dispatchable *electricity storage facility* that can inject who, for *settlement hour* ‘h’:

- is unable to comply with a *dispatch instruction* under section7.5.3 of Chapter 7, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; and/or
- requests that the *IESO* apply a constraint to the *dispatchable generation facility or the dispatchable electricity storage facility that can inject* to prevent endangering the safety of any person, equipment damage, or violation

of any *applicable law*, excluding constraints applied under Chapter 7 sections 6.3A.2 or 6.3A.4;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, resulting from the above actions for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6D A *registered market participant* for a *registered facility* that is a *dispatchable generation facility* and is fuelled by a related *generation facility*, who, for *settlement hour* 'h':

- has received a constraint from the *IESO* for the *dispatchable generation facility* as per the applicable *market manual*; and
- submits or has submitted an *offer* price for that *dispatchable generation facility* for *settlement hour* 'h' greater than a specified limit defined in the applicable *market manual*;

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit or ramp-down *settlement* amount, determined in accordance with section 3.5.2 or 3.5A respectively, associated with that *offer* price for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit or ramp-down *settlement* amount in accordance with section 3.5.6E.

3.5.6E The *IESO* may recover congestion management *settlement* credits or ramp-down *settlement* amounts in accordance with sections 3.5.6B, 3.5.6C, 3.5.6D, 3.5.6G and Section 21.5 of Chapter 7. In this situation, the *IESO* shall:

- notify the *market participant* of its intent to recover that *congestion management settlement credit* or ramp-down *settlement amount*; and
- notify the *market participant* of the time, which shall not be less than five *business days* from the date of receipt of the notice, within which the *market participant* may make written representations in response to the *IESO's* intent.

On receiving a response from the *market participant* within the specified time period, or upon expiry of the specified time period within which no response is received from the *market participant*, the *IESO* shall either:

- determine the amount of the congestion management *settlement* credit or ramp-down *settlement* amount to recover and notify the *market participant* accordingly; or

- gather further information as the *IESO* determines appropriate to determine the amount of the congestion management *settlement* credit or ramp-down *settlement* amount to recover and notify the *market participant* accordingly of the determination.

The *IESO* shall redistribute any payments that are recovered in accordance with section 4.8.2.

3.5.6F Where the *energy market price* for the applicable *dispatch interval* is less than zero, the *IESO* may adjust, in the matrices specified in section 3.5.2 and for the purposes of determining the applicable congestion management *settlement* credit payments, any *bid* price that:

3.5.6F.1 is associated with a withdrawing *boundary entity* at an *intertie* that is not import congested; and

3.5.6F.2 is greater than the *energy market price* in the applicable *intertie zone* for the applicable *dispatch interval;*

to the prices determined by the *IESO* in accordance with the applicable *market manual*.

3.5.6G A *registered market participant* for a *registered facility* that is a *dispatchable load*, or a dispatchable *electricity storage facility* that can withdraw, who, for *settlement hour* 'h':

- is unable to comply with a *dispatch instruction* under section 7.5.3 of Chapter 7, to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law*; and/or

- requests that the *IESO* apply a constraint to the *dispatchable load facility* or the dispatchable *electricity storage facility* that can withdraw to prevent endangering the safety of any person, equipment damage, or violation of any *applicable law;*

subject to section 3.5.6E, is not entitled to any inappropriate congestion management *settlement* credit, determined in accordance with section 3.5.2, resulting from the above actions for *settlement hour* 'h'. The *IESO* may recover such congestion management *settlement* credit in accordance with section 3.5.6E.

3.5.7 [Intentionally left blank – section deleted]

3.5.7A A *registered market participant* for a *constrained on generation unit* is not entitled to a congestion management *settlement* credits determined in accordance with section 3.5.2 for that *facility* up to *minimum loading point* if the congestion management *settlement* credit is earned as a result of constraints applied under Chapter 7, section 5.8.5 for hours in the day after the *dispatch day*. In this case, the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2 of Chapter 9.

3.5.8 Notwithstanding any other provision in the *market rules*, a *market participant* shall not be eligible for any congestion management *settlement* credit payments for a wheeling through transaction where the *market participant* effects the transaction by linking an *energy offer* and *energy bid* under section 3.5.8.2 of Chapter 7.

3.5.9 The *IESO* may limit, withhold or recover any congestion management *settlement* credits or ramp-down *settlement* amounts that result from the acceptance by the *IESO* of the replacement *energy* referred to in section 3.3.4C of Chapter 7 and shall redistribute any recovered payments in accordance with section 4.8.2. Any applicable congestion management *settlement* credits or ramp-down *settlement* amounts for replacement *energy* accepted by the *IESO* shall be limited as set out in the applicable *market manual* to an *IESO* estimate of what would have been received by the original *facility* had it not experienced the *forced outage.*

3.5.10 In accordance with the applicable *market manual*, a *market participant* shall not be entitled to any congestion management *settlement* credits determined in accordance with section 3.5.2 and attributable to a *constrained off event* associated with an *energy* offer or an *energy* bid from a *boundary entity* for an injection into or withdrawal from the *IESO-controlled grid,* where the *constrained off event* appears in the *pre-dispatch schedule* identified in section 6.1.3 of Chapter 7. In this case, the *IESO* may withhold or recover such congestion management *settlement* credits and shall redistribute any recovered payments in accordance with section 4.8.2.

3.5.11 A *market participant* shall not be eligible for any congestion management *settlement* credit payments in respect of an *energy* bid from a *boundary entity* for a *called capacity export*. The *IESO* may withhold or recover any congestion management *settlement* credits paid in respect of *called capacity exports* and shall redistribute any recovered payments in accordance with section 4.8.2.

3.5A Hourly Settlement Amounts for Ramp-Down

3.5A.1 Subject to section 3.5A.2, the ramp-down *settlement* amount for any *dispatch interval* 't' identified in section 3.5.1G for market *participant* 'k' within *settlement hour* 'h'("$RDSA_{k,h}$") shall be the lesser of:

- the congestion management *settlement* credit for *dispatch interval* 't' which was withheld or recovered under section 3.5.1G; and
- the ramp-down compensation ("$RDC_{k,h}^{m,t}$") as determined by the following equation:

Let 'BE' be a matrix of n *price-quantity pairs* offered by *market participant* 'k' to supply *energy* during the *settlement hour* immediately before the hour in which ramp-down begins, adjusted by a factor as specified in the applicable *market manual*.

Let OP(P,Q,B) be a 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 BE such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

Using the terms below, let $RDC_{k,h}^{m,t}$ be expressed as follows:

$$RDC_{k,h}^{m,t} = MAX\left[0, \left[\begin{array}{l} OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE) - \\ MAX\left(OP(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE), OP(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE)\right) \end{array}\right]\right]$$

3.5A.2 The *IESO* may recover the hourly ramp-down *settlement* amount determined in accordance with section 3.5A.1 pursuant to sections 3.5.6B, 3.5.6C, 3.5.6D and 3.5.6E, as applicable.

3.6 Hourly Settlement Amounts for Transmission Rights and Charges

3.6.1 The *TR settlement* credit for *market participant* 'k' in *settlement hour* 'h' ("$TRSC_{k,h}$") shall, other than where section 4.4.2.2 of Chapter 8 applies, be determined by the following equation:

$$TRSC_{k,h} = \max[0, \Sigma_{j,i}\ (1/12) \times QTR_{k,h}^{\ i,j} \times \Sigma_t\ (EMP_h^{\ j,t} - EMP_h^{\ i,t})]$$

where:

j = all *primary RWM's* and *intertie metering points*

i = all *primary RWM's* and *intertie metering points*

3.6.2 The contribution to the *transmission charge reduction fund* in *settlement hour* 'h' ("$TCRF_h$") shall be the net congestion rentals collected by the *IESO* (the negative of the net *energy market settlement* credit paid to *market participants*) less the net payments from the *IESO* to *market participants* under *TRs*, or:

$$TCRF_h = \Sigma_{t,m}\ (EMP_h^{m,t} - EMP_h^{REF,t}) \times \Sigma_k\ (AQEW_{k,h}^{m,t} - AQEI_{k,h}^{m,t}) - \Sigma_k\ TRSC_{k,h}$$

where:

t = all *metering intervals* in *settlement hour* 'h'

m = all *primary* RWMs and *intertie metering points*

k = all *market participants*

$EMP_h^{REF,t}$ = *energy market price* at the reference bus in metering interval 't' of *settlement hour* 'h'. Until such time that locational pricing is implemented in the *IESO-administered markets*, the uniform *energy market price* is the *energy market price* at the reference bus.

3.6.3 Disbursements from the *TR clearing account* authorised by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be used by the *IESO* in accordance with section 4.7.

3.6.4 Any net revenues received from the sale of a *TR* in a *TR auction,* along with the hourly balance accrued in the *transmission charge reduction fund,* shall be credited to the *TR clearing account* and shall be used in accordance with the provisions of section 3.6.3 and of Chapter 8.

3.7 [Intentionally left blank – section deleted]

3.7.1 [Intentionally left blank – section deleted]

3.7.2 [Intentionally left blank – section deleted]

3.8 Hourly Settlement Amounts for Operating Deviations

3.8.1 The *IESO* may adjust by means of a debit the *settlement statement* of any *market participant* who is compensated in the market for providing *operating reserve* from a specific *registered facility* that operates in a way that does not provide the service for which it has been paid. Such debits in any *settlement hour* may represent either the decreased value of services provided in that same *settlement hour*, or the value of *operating reserve* services deemed not to have been provided in earlier *dispatch hours* as a result of failure to perform when called in the later *dispatch hour* associated with that *settlement hour*. The hourly *settlement* debits for failure to provide *energy* from *operating reserve* when it is called are set forth in this section 3.8.

3.8.2 An *operating reserve* shortfall *settlement* debit may be assessed on any *market participant* 'k' responsible for a *registered facility* at *RWM* m, which will be *registered facility* "k/m" for the purpose of this section 3.8.2 and of section 3.8.4, that is scheduled by the *IESO* to provide *class r reserve* of class 1or 2 (i.e., *ten-minute reserve* or *thirty-minute reserve*) and then fails to provide *energy* from that class of *operating reserve* when instructed to do so by the *IESO* according to these *market rules*. The amount of *market participant* 'k's *operating reserve* shortfall *settlement* debit for *class r reserve* for *settlement hour* 'h' ("$ORSSD_{k,r,h}$") is determined as follows:

3.8.2.1 the *energy* shortfall fraction for *class r reserve* for *registered facility* k/m in *metering interval* 't' of *settlement hour* 'h' ("$ORESF_{k,r,h}^{m,t}$") is defined as follows:

where *operating reserve* is provided from a *generator,* or from an *electricity storage participant* injecting *energy* :

$$ORESF_{k,r,h}^{m,t} = MAX\ [(SE_{k,h}^{m,t} - AQEI_{k,h}^{m,t})/SE_{k,h}^{m,t},\ 0]$$

where *operating reserve* is provided from a *dispatchable load* or from an *electricity storage participant* withdrawing *energy*:

$$ORESF_{k,r,h}^{m,t} = MAX\ [(AQEW_{k,h}^{m,t} - SE_{k,h}^{m,t})\ /\ AQEW_{k,h}^{m,t},\ 0]$$

in either of the above cases:

$ORESF_{k,r,h}^{m,t}$ shall be 0 if:

a. $SE_{k,h}^{m,t}=0$;

b. no class r reserve is activated for registered facility k/m, at RWM m during metering interval ‘t’ of settlement hour ‘h’; or

c. $ORESF_{k,r,h}^{m,t}$ is less than the value established by the *IESO Board* and *published* in accordance with section 3.8.2.4.

Where:

$SE_{k,h}^{m,t}$ = total scheduled *energy*, including activated *operating reserve*, from *registered facility* k/m at *RWM* m, determined on the basis of the *dispatch instructions* for *metering interval* ‘t’ of *settlement hour* ‘h’.

3.8.2.2 define $\Sigma_{T,H}\ ORRSC_{k,r,H}^{m,T}$ = total *settlement* credits for *class r reserve* (including congestion management *settlement* credits related to *class r reserve*) during the lesser of:

a. where *registered facility* k/m has not been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour*, all *metering intervals* during the current *settlement hour* and all of the *metering intervals* within the 719 *settlement hours* preceding the current *settlement hour*; or

b. where *registered facility* k/m has been activated to provide *operating reserve* during the 719 *settlement hours* preceding the current *settlement hour* all *metering intervals* between the current *metering interval*, including the current *metering interval* and the most recent *metering interval* preceding the current *metering interval*, in which the *market participant* ‘k’ received a *dispatch instruction* for the activation of *class r reserve* from *registered facility* k/m.

3.8.2.3 $ORSSD_{k,r,h}$ is defined as follows:

a. where the most recent *dispatch instruction* issued to the *market participant* for the activation of *class r reserve* prior to the current *metering interval* was issued within the 719 *settlement hours* preceding the current *settlement hour* and resulted in $ORESF_{k,r,h}^{m,t}$ that exceeded the value referred to in section 3.8.2.4,

$ORSSD_{k,r,h} = \sum_{m,t} [ORESF_{k,r,h}^{m,t} \times \Sigma_{T,H} (ORRSC_{k,r,H}^{m,T})]$; or

b. in all other cases,

$$ORSSD_{k,r,h} = \sum_{m,t} [ORESF_{k,r,h}^{m,t} \times \sum_{T,H} (ORRSC_{k,r,H}^{m,T})/2]$$

where:

t = all *metering intervals* in *settlement hour* 'h' in which $ORESF_{k,r,h}^{m,t}$ exceeds the value referred to in section 3.8.2.4

T = all *metering intervals* referred to in section 3.8.2.2 (a), or 3.8.2.2 (b) as the case may be

H = all *settlement hours* referred to in section 3.8.2.2 (a), or 3.8.2.2 (b) as the case may be

m = all RWMs serving market participant 'k's registered facilities

3.8.2.4 For the purposes of section 3.8.2.1(c), the *IESO Board* shall establish, and the *IESO* shall *publish,* a value below which $ORESF_{k,r,h}^{m,t}$ shall be set at zero. Where the *IESO Board* revises such value:

a. any such revised value shall be *published* by the *IESO*; and

b. the revised value shall not be used for the purposes of calculating $ORESF_{k,r,h}^{m,t}$ until 31st *trading day* following the date of publication.

3.8.3 [Intentionally left blank]

3.8.4 [Intentionally left blank]

3.8.4.1 [Intentionally left blank]

3.8.4.2 [Intentionally left blank]

3.8.4.3 [Intentionally left blank]

3.8.5 [Intentionally left blank]

3.8A Hourly Settlement Amounts for Intertie Offer Guarantees

3.8A.1 The *market prices* determined by the *real-time market schedule* provided by the *IESO* used for the *settlement* of a *boundary entity* associated with an *intertie metering point* will sometimes deviate from:

in the case of an import transaction not scheduled in the *schedule of record*, its accepted *offer* prices in the *pre-dispatch market schedule* (the "*projected market schedule*") in ways that, based on the *real-time dispatch process*, imply a change to *market participant* 'k's net operating profits relative to the operating profits implied by the *pre-dispatch market schedule* for that *boundary entity*; or

in the case of an import transaction scheduled in the *schedule of record*, its accepted *offer* prices in the *schedule of record* in ways that, based on the *real-time dispatch process*, imply a change to *market participant* 'k's net operating profits relative to the operating profits implied by the *schedule of record* for that *boundary entity*.

When this occurs but subject to section 3.8A.3, *market participant* 'k' associated with that *boundary entity* for *settlement hour* 'h' shall receive as compensation:

3.8A.1.1 in the case of an import transaction not scheduled in the *schedule of record*, a *real-time intertie offer* guarantee ($RT\_IOG_{k,h}$) *settlement* credit for the import of *energy* into the *IESO-administered markets* equal to the cumulative losses resulting from a negative change in implied operating profits over the course of each *settlement hour*, resulting from such *settlement*, calculated in accordance with section 3.8A.2; or

3.8A.1.2 in the case of an import transaction scheduled in the *schedule of record*, the larger of a real-time *intertie offer* guarantee *settlement* credit ($RT\_IOG_{k,h}$) or the day-ahead *intertie offer* guarantee *settlement* credit ($DA\_IOG_{k,h}$) for the import of *energy* into the *IESO-administered markets* equal to the cumulative losses resulting from a negative change in implied operating profits over the course of each *settlement hour*, resulting from such *settlement*, calculated in accordance with section 3.8A.2 or 3.8A.2B as the case may be.

Real-Time Intertie Offer Guarantee

3.8A.2 The real-time *intertie offer* guarantee *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$RT\_IOG_{k,h}$") shall be determined by the following equation:

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

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $EMP_h^{i,t}$: the real-time 5-minute *energy market price* at the applicable *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

'Q' is $MQSI_{k,h}^{i,t}$: the market quantity scheduled for injection in the *market schedule* by *market participant* 'k' at *intertie metering point* 'i' in *metering interval* 't' of *settlement hour* 'h'

'B' is matrix $BE_{k,h}^{i,t}$ of N price-quantity pairs offered by *market participant* 'k' to supply *energy* from a particular *boundary entity* associated with an *intertie metering point* 'i' in the *IESO-administered markets*, during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by offered price where offered prices are in column 1 and offered quantities are in column 2.

Using the terms below, let $RT\_IOG_{k,h}$ be expressed as follows:

$$RT\_IOG_{k,h} = EIM_{k,h}$$

Where:

$EIM_{k,h}$ represents that component of the real-time *intertie offer* guarantee *settlement* credit for *market participant* 'k' during *settlement hour* 'h' attributable to import of *energy* into the *IESO-administered markets* at all relevant *intertie metering points* 'i' in accordance with the rationale referred to in section 3.8A.1 and is calculated as follows:

$$EIM_{k,h} = \sum_I (-1) \bullet MIN\left[0, \sum_T OP(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE)\right]$$

Such that:

I is the set of all relevant *intertie metering points* 'i'

T is the set of all *metering intervals* 't' in *settlement hour* 'h'

$EMP_h^{i,t}$ is the real-time 5-minute *energy market price* at the applicable *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

Day-Ahead Intertie Offer Guarantee

3.8A.2A The day-ahead *intertie offer* guarantee *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$DA\_IOG_{k,h}$") shall be determined for import transactions that are not part of a day-ahead linked wheel.

3.8A.2B The day-ahead *intertie offer* guarantee *settlement* credit for *market participant* 'k' for *settlement hour* 'h' ("$DA\_IOG_{k,h}$") shall be determined by the following equation:

$DA\_BE_{k,h}^{i,t}$ is the offer matrix of N price-quantity pairs for the eligible import transaction scheduled in the *schedule of record* for *market participant* 'k' during *metering interval* 't' for settlement hour 'h' at *intertie metering point* 'i' arranged in ascending order by offered price where offered prices are in column 1 and offered quantities are in column 2.

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

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} \left[B[n,1] \cdot (B[n,2] - B[n-1,2])\right] - \left[(Q - B[s^*,2]) \cdot B[s^*+1,1]\right]$$

Where:

s* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $EMP_h^{i,t}$: the real-time 5-minute *energy market price* at the applicable *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'

'Q' is the minimum of:

$DA\_DQSI_{k,h}^{i,t}$: the *schedule of record* constrained quantity scheduled for injection by *market participant* 'k' for an import transaction at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h'; or

$DQSI_{k,h}^{i,t}$: the real-time constrained quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’;

‘B’ is matrix $DA\_BE_{k,h}^{i,t}$: *energy offers* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2;

such that the day-ahead *intertie offer* guarantee is formulated as follows:

The principles for the settlement of the day-ahead *intertie offer* guarantee are as follows:

1. Component 1: Any shortfall in payment on the real-time import flow of the *schedule of record* will be based upon the real-time revenue received for that amount of *energy* in comparison with the costs submitted in the importer’s day-ahead *offer*;
2. Component 2: For the portion of *schedule of record* that is not implemented in the real-time *dispatch* schedule, the day-ahead *intertie offer* guarantee will guarantee the cost incurred of arranging the import (where the real-time *offer* price is less than day ahead *offer* price) or subtract any revenue gained (where the real-time *offer* price is greater than the day-ahead *offer* price) [1]; and
3. Component 3: Any income from real-time congestion management *settlement* credit (CMSC) included in an importer’s *schedule of record* delivered in real-time will be used to reduce the day-ahead *intertie offer* guarantee payment.

The Day-Ahead Intertie Offer Guarantee is calculated as follows:

$$DA\_IOG_{k,h} = \mathrm{MAX}\left[0, \sum_{T}\left(DA\_IOG\_COMP1_{k,h}^{i,t} + DA\_IOG\_COMP2_{k,h}^{i,t} - DA\_IOG\_COMP3_{k,h}^{i,t}\right)\right]$$

Where:

T = set of all *metering intervals* ‘t’ in the set of all *settlement hour* ‘h’

[1] Where the real-time *offer* is equal to the day-ahead *offer*, the cost/gain is equal to zero (0).

Component 1

Component 1 includes any shortfall in payment on the delivered real-time *dispatch* of the *schedule of record* based upon the real-time revenue received for that amount of *energy* in comparison with the costs as represented in the importer's day-ahead *offer*. Component 1 is calculated as follows:

$DA\_IOG\_COMP1_{k,h}^{i,t}$ = As-offered day-ahead costs for the minimum of the importer's *schedule of record* and the real-time constrained schedule for the interval minus all real-time revenue received over the interval for that amount of *energy*

$$DA\_IOG\_COMP1_{k,h}^{i,t} = (-1)\times OP\left(EMP_{h}^{i,t}, MIN\left(DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}\right), DA\_BE_{k,h}^{i,t}\right)$$

Component 2

If, as a result of economic selection, a portion of the *schedule of record* is not implemented in the real-time *dispatch* schedule, the day-ahead *intertie offer* guarantee:

Guarantees the cost of arranging the delivery if the real-time *offer* is less than the day-ahead *offer*; or

Subtracts any gain where the real-time *offer* is greater than the day-ahead *offer*.

If there are no real-time *energy offers* submitted by the *market participant* for any portion of the day-ahead constrained schedule, the real-time *energy offers* for that portion of *energy* will be set to MMCP (*Maximum Market Clearing Price*) for the purposes of calculating Component 2.

If the real-time *energy offers* for any portion of the day-ahead constrained schedule is below \$0.00 \$/MWh (i.e. negative), the real-time *energy offers* for that portion of *energy* will be set to \$0.00 \$/MWh for the purposes of calculating Component 2.

Component 2 is calculated as follows:

$DA\_IOG\_COMP2_{k,h}^{i,t}$ = As-offered day-ahead costs for the difference between:

- the minimum of the importer's *schedule of record* quantity, or the real-time constrained schedule; and
- the minimum of the importer's *schedule of record* quantity.

over the interval minus all real-time *energy offers* (with a minimum limit of zero) over the interval for that amount of *energy*

$$DA\_IOG\_COMP2_{k,h}^{i,t} = XDA\_BE_{k,h}^{i,t} - MAX\left(0, XBE_{k,h}^{i,t}\right)$$

Where:

Let $XBE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{s*}\right) \times P_{s*+1}$$

where matrix (B) is *energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

Let $XDA\_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{d*}\right) \times P_{d*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price quantity pair* where offered prices ‘P’ are in column 1 and offered quantities ‘Q’ are in column 2

c*	=	the highest indexed row of matrix $XDA\_BE_{k,h}^{i,t}$ such that $Q_{c*} \le \min[DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t},] \le Q_n$ and where $Q_{c*-1} = \min[DA\_DQSI_{k,h}^{i,t}, DQSI_{k,h}^{i,t}]$ and where if $Q_{c*} < Q_{c*-1}$, let $Q_{c*} = Q_{c*-1}$
d*	=	the highest indexed row of matrix XDA_BEk,hi,t such that Qd* ≤ DA_DQSIk,hi,t ≤ Qn
p*	=	the highest indexed row of matrix XBEk,hi,t such that Qp* ≤ min[DA_DQSIk,hi,t, DQSIk,hi,t] ≤ Qn and where Qp*-1 = min[DA_DQSIk,hi,t, DQSIk,hi,t] and where if Qp* < Qp*-1, let Qp* = Qp*-1
s*	=	the highest indexed row of matrix $XBE_{k,h}^{i,t}$ such that $Q_{s*} \le DA\_DQSI_{k,h}^{i,t} \le Q_n$

Component 3

The DA-IOG payment for an import will be reduced by the income received from real time congestion management *settlement* credit (CMSC) for the importer's *schedule of record* delivered in real-time.

The importer's *schedule of record* will be measured against both the real-time constrained schedule and the real-time unconstrained schedule to determine the amount of revenue from CMSC that should be included in the day-ahead *intertie offer* guarantee calculation.

For any interval, there are six possible orderings of the amount of an importer's capacity that may be included in the *schedule of record*, the real-time unconstrained schedule and the real-time constrained schedule. Table 0-1: Ordering of Importer's Capacity and Day-Ahead Intertie Offer Guarantee Component 3 summarizes the six possible orderings and the inclusion of Component 3 in the day-ahead *intertie offer* guarantee calculation.

For the purposes of determining the applicable CMSC in Component 3, the o*ffer price* is subject to Section 3.5.6.

Table 0-1: Ordering of Importer's Capacity and Day-Ahead Intertie Offer Guarantee Component 3

Scenario	Ordering	Component 3 - CMSC Included?
1	DQSI >= MQSI >= DA_DQSI	N
2	MQSI >= DQSI >= DA_DQSI	N
3	DQSI > DA_DQSI > MQSI	Y (Partial CMSC)
4	MQSI > DA_DQSI > DQSI	Y (Partial CMSC)
5	DA_DQSI >= DQSI > MQSI	Y (All CMSC)
6	DA_DQSI >= MQSI > DQSI	Y (All CMSC)

Component 3 is calculated as follows :

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = Income received from real time congestion management *settlement* credits (CMSC) for the importer's *schedule of record* delivered in real-time over the interval

Component 3 is only calculated when the real-time CMSC for the same interval is a value other than zero.

Scenario 1

$DA\_IOG\_COMP3_{k,h}^{i,t} = 0$

Scenario 2

$DA\_IOG\_COMP3_{k,h}^{i,t} = 0$

Scenario 3

$$DA\_IOG\_COMP3_{k,h}^{i,t} = OP\left(EMP_h^{i,t}, MQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - OP\left(EMP_h^{i,t}, DA\_DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right)$$

Scenario 4

$$DA\_IOG\_COMP3_{k,h}^{i,t} = OP\left(EMP_h^{i,t}, DA\_DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right) - OP\left(EMP_h^{i,t}, DQSI_{k,h}^{i,t}, BE_{k,h}^{i,t}\right)$$

Scenario 5

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Scenario 6

$DA\_IOG\_COMP3_{k,h}^{i,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Intertie Offer Guarantee Settlement

3.8A.3 The cumulative *intertie offer* guarantee *settlement* credits payable to a *market participant* for any and all applicable *settlement hours* in the *real-time market* for an *energy billing period* shall be adjusted by the *IESO* in accordance with section 3.8A.4 to nullify such credits where:

3.8A.3.1 that *market participant* has submitted one or more *energy offers* and one or more *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; or

3.8A.3.2 the *market assessment unit* has determined that the *market participant* has an agreement or arrangement to share the *intertie offer* guarantee *settlement* credit with one or more other *market participants* and they have submitted one or more *energy offers* and one or more *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; or

3.8A.3.3 the *market participant* has one or more import transactions in the *schedule of record* at an *intertie metering point* and where:

the same import transaction is subsequently scheduled in the corresponding *metering interval* of the corresponding *settlement hour* in the *real-time market*; and

the *market participant* submits one or more *schedule of record* and/or real-time *energy bids* as contemplated by section 3.5.8.1 of Chapter 7 for the same *dispatch interval*; and

at least one of such *energy offers* and one of such *energy bids* is scheduled; and

where the export transaction of such *energy bid* is settled at the *energy market* price at the *intertie metering point* and not a *settlement* floor price as set out in section 3.3.2.1A.

For certainty, any *market participant* shall have recourse to the dispute resolution provisions of section 2 of Chapter 3 if it believes that the *market assessment unit* did not have reasonable grounds for making the determination that the *market participant* had any such agreement or arrangement with another *market participant* as described in section 3.8A.3.2.

3.8A.4 The combined day-ahead and real-time *intertie offer* guarantees and intertie offer guarantee *settlement* credit offset ("IOG Offset") process is as follows. Any adjustment made by the *IESO* under section 3.8A.3 shall be applied with respect to any export transaction in the constrained schedule for *market participant* 'k' in each *settlement hour* 'h' for which *market participant* 'k' is entitled to receive a real-time or day-ahead *intertie offer* guarantee *settlement* credit meeting the conditions set out in section 3.8A.3. The total amount offset shall be limited by the cumulative quantity of the export transactions expressed in the constrained schedule for that *settlement hour* and shall not exceed the total combined real-time and day-ahead *intertie offer* guarantee *settlement* credits received for the *settlement hour*. Where the cumulative quantity of the export transactions expressed in the constrained schedule for the *settlement hour* is less than the cumulative quantity of imports triggering real-time and day-ahead *intertie offer* guarantee *settlement* credits for that same *settlement hour*, the real-time and day-ahead *intertie offer* guarantee *settlement* credits will be offset in ascending order from the import transaction with the smallest real-time and/or day-ahead *intertie offer* guarantee *settlement* rate to the import transaction attracting the largest real-time and/or largest day-ahead *intertie offer* guarantee *settlement* rate and only up until the point at which the total quantity of import transactions equals the total quantity of export transactions, and may be expressed as described in the general rule that follows.

The offset process described in this section shall apply to:

real-time *intertie offer* guarantee *settlement* credits meeting the criteria of section 3.8A.3.1; or

real-time *intertie offer* guarantee *settlement* credits or day-ahead *intertie offer* guarantee *settlement* credits meeting the criteria of section 3.8A.3.3.

For the purposes of this calculation all applicable real-time or day-ahead *intertie offer* guarantee *settlement* credits meeting the criteria described above, attributable to *market participant* ‘k’ for *settlement hour* ‘h’ shall be arranged in ascending order by rate (dollars per megawatt per transaction), and subject to the following decision rules:

a. [Intentionally left blank – section deleted]

b. Where a day-ahead *intertie offer* guarantee *settlement* credit is associated with the import transaction, but no real-time *intertie offer* guarantee *settlement* credit was applicable, the day-ahead *intertie offer* guarantee *settlement credit* will be included;

c. Where a real-time *intertie offer* guarantee *settlement* credit is associated with the import transaction, but no day-ahead *intertie offer* guarantee *settlement* credit is applicable, the real-time *intertie offer* guarantee *settlement* credit will be included;

The ordering of these *settlement amounts* is described in terms of a general rule as follows:

Let $MI_{k,h}^{t}$ [N,13] be an N by 13 matrix of N pairs of import quantities scheduled for injection by *market participant* 'k' in the real-time *dispatch schedule* and/or the constrained schedule from the DACP *schedule of record* in the *settlement hour* 'h' ($DA\_DQSI_{k,h}^{i}$ and/or $DQSI_{k,h}^{i}$ as the case may be) paired with the corresponding day-ahead *intertie offer* guarantee, the component of the real-time *intertie offer* guarantee *settlement* credit, DA-IOG rate, RT-IOG rate, DA Offset DQSW, DA-Offset Flag, Settlement rate, (gross) IOG$, RT Offset DQSW, IOG Offset $, (net) IOG $ for all *intertie metering points* 'i' arranged in ascending order by *settlement* rate in each row. Columns 1 through 4 are original inputs to the matrix, while columns 5 through 13 are derived.

The general rules to settle IOG are as follows:

Note: $MI_{k,h}$ [N,13] matrix has been transposed such that the columns are on the rows.

Event Type	General Rule
Matrix $MI_{k,h}$ [Row 'n', Column 1]	$DA\_DQSI_{k,h}^{i}$ Associated with the settlement amount in column 3
Matrix $MI_{k,h}$ [Row 'n', Column 2]	$DQSI_{k,h}^{i}$ Associated with the settlement amount in column 3 and 4
Matrix $MI_{k,h}$ [Row 'n', Column 3]	$DA\_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 4]	$RT\_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 5]	$MI_{k,h}$ [n,5] {$DA\_IOG\_RATE_{k,h}^{i}$}=

	$DA\_IOG_{k,h}^{i}$ / MIN($DA\_DQSI_{k,h}^{i}$, $DQSI_{k,h}^{i}$)
Matrix $MI_{k,h}$ [Row 'n', Column 6]	$MI_{k,h}$ [n,6] {$RT\_IOG\_RATE_{k,h}^{i}$}= $RT\_IOG_{k,h}^{i}$ / $DQSI_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 7]	$MI_{k,h}$ [n,7] {$DA\_OFFSET\_DQSW_{k,h}^{i}$}
Matrix $MI_{k,h}$ [Row 'n', Column 8]	$MI_{k,h}$ [n,8] { $DA\_OFFSET\_FLAG_{k,h}^{i}$ } = "Y" or "N" Such that: $DA\_OFFSET\_FLAG_{k,h}^{i}$ = "Y" when {$DA\_OFFSET\_DQSW_{k,h}^{i}$}> 50% of MIN{$DA\_DQSI_{k,h}^{i}$,$DQSI_{k,h}^{i}$ }
Matrix $MI_{k,h}$ [Row 'n', Column 9]	$MI_{k,h}$ [n,9] {$IOG\_SETTLEMENT\_RATE_{k,h}^{i}$} = $RT\_IOG\_RATE_{k,h}^{i}$ if $DA\_OFFSET\_FLAG_{k,h}^{i}$ = "Y" ; OR $MI_{k,h}^{i}$ [n,9] {$IOG\_SETTLEMENT\_RATE_{k,h}^{i}$} = MAX[$DA\_IOG\_RATE_{k,h}^{i}$, $RT\_IOG\_RATE_{k,h}^{i}$] if $DA\_OFFSET\_FLAG_{k,h}^{i}$ = "N"; Subject to: $MI_{k,h}$ [n,9] >= $MI_{k,h}$ [n-1,9]; $MI_{k,h}$ [1,9] = MIN[$MI_{k,h}$ [1 to N,9]]; [$MI_{k,h}$ [1 to N,9]] <> 0
Matrix $MI_{k,h}$ [Row 'n', Column 10]	$MI_{k,h}^{i}$ [n,10] {$IOG\$_{k,h}^{i}$} = the $DA\_IOG\$_{k,h}^{i}$ or $RT\_IOG\$_{k,h}^{i}$ associated with the Settlement Rate $_{k,h}^{i}$ (i.e. $RT\_IOG\_RATE_{k,h}^{i}$ or MAX($DA\_IOG\_RATE_{k,h}^{i}$,$RT\_IOG\_RATE_{k,h}^{i}$))
Matrix $MI_{k,h}$ [Row 'n', Column 11]	$MI_{k,h}$ [n,11] {$RT\_OFFSET\_DQSW_{k,h}^{i}$ }
Matrix $MI_{k,h}$ [Row 'n', Column 12]	$MI_{k,h}$ [n,12] {$IOG\_OFFSET_{k,h}^{i}$ }

Matrix $MI_{k,h}$ [Row 'n', Column 13]	$MI_{k,h}$ [n,13] {$Net\_IOG_{k,h}^{i}$ } = $MI_{k,h}$ [n,10] {$IOG\$_{k,h}^{i}$} - $MI_{k,h}^{i}$ [n,12] {$IOG\_OFFSET_{k,h}^{i}$ }

The outcomes from the general rules are as follows

	A	B	C	D
Event Type	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is not offset Day Ahead	An import transaction scheduled day ahead receiving a DA-IOG but no RT-IOG and is offset Day Ahead	An import transaction scheduled only in the real-time and receiving a RT-IOG but no DA-IOG	An import transaction scheduled both in the day ahead and in the real-time receiving DA-IOG and RT-IOG.
Matrix $MI_{k,h}$ [Row 'n', Column 1]	$DA\_DQSI_{k,h}^{i}$	$DA\_DQSI_{k,h}^{i}$	NULL	$DA\_DQSI_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 2]	$DQSI_{k,h}^{i}$	$DQSI_{k,h}^{i}$	$DQSI_{k,h}^{i}$	$DQSI_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 3]	$DA\_IOG_{k,h}^{i}$	$DA\_IOG_{k,h}^{i}$	$DA\_IOG_{k,h}^{i}$ = NULL	$DA\_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 4]	$RT\_IOG_{k,h}^{i}$ = NULL	$RT\_IOG_{k,h}^{i}$ = NULL	$RT\_IOG_{k,h}^{i}$	$RT\_IOG_{k,h}^{i}$
Matrix $MI_{k,h}$ [Row 'n', Column 5]	{$DA\_IOG\_RATE_{k,h}^{i}$}	{$DA\_IOG\_RATE_{k,h}^{i}$}	NULL	{$DA\_IOG\_RATE_{k,h}^{i}$}
Matrix $MI_{k,h}$ [Row 'n', Column 6]	{$RT\_IOG\_RATE_{k,h}^{i}$}= NULL	{$RT\_IOG\_RATE_{k,h}^{i}$}= NULL	{$RT\_IOG\_RATE_{k,h}^{i}$}	{$RT\_IOG\_RATE_{k,h}^{i}$}
Matrix $MI_{k,h}$ [Row 'n', Column 7]	{$DA\_OFFSET\_DQSW_{k,h}^{i}$} = 0	{$DA\_OFFSET\_DQSW_{k,h}^{i}$} > 0	NULL	{$DA\_OFFSET\_DQSW_{k,h}^{i}$} >= 0

	A	B	C	D
Matrix $MI_{k,h}$ [Row ‘n’, Column 8]	$\{DA\_OFFSET\_FLAG_{k,h}^{i}\}$ = “N”	$\{DA\_OFFSET\_FLAG_{k,h}^{i}\}$ = “Y”	NULL	$\{DA\_OFFSET\_FLAG_{k,h}^{i}\}$ = “Y” or “N”
Matrix $MI_{k,h}$ [Row ‘n’, Column 9]	$MI_{k,h}$ [n,9] $\{IOG\_SETTLEMENT\_RATE_{k,h}^{i}\} = \{DA\_IOG\_RATE_{k,h}^{i}\}$	NULL	$MI_{k,h}$ [n,9] $\{IOG\_SETTLEMENT\_RATE_{k,h}^{i}\} = \{RT\_IOG\_RATE_{k,h}^{i}\}$	$MI_{k,h}$ [n,9] $\{IOG\_SETTLEMENT\_RATE_{k,h}^{i}\} = \{RT\_IOG\_RATE_{k,h}^{i}\}$ or $MAX(DA\_IOG\_RATE_{k,h}^{i}, RT\_IOG\_RATE_{k,h}^{i})$
Matrix $MI_{k,h}$ [Row ‘n’, Column 10]	$MI_{k,h}$ [n,10] $\{IOG\$_{k,h}^{i}\} = DA\_IOG\$_{k,h}^{i}$	NULL	$MI_{k,h}$ [n,10] $\{IOG\$_{k,h}^{i}\} = RT\_IOG\$_{k,h}^{i}$	$MI_{k,h}$ [n,10] $\{IOG\$_{k,h}^{i}\} = \{RT\_IOG\$_{k,h}^{i}\}$ or $MAX(DA\_IOG\$_{k,h}^{i}, RT\_IOG\$_{k,h}^{i})$
Matrix $MI_{k,h}$ [Row ‘n’, Column 11]	$MI_{k,h}$ [n,11] $\{RT\_OFFSET\_DQSW_{k,h}^{i}\} >= 0$	NULL	$MI_{k,h}$ [n,11] $\{RT\_OFFSET\_DQSW_{k,h}^{i}\} >= 0$	$MI_{k,h}$ [n,11] $\{RT\_OFFSET\_DQSW_{k,h}^{i}\} >= 0$
Matrix $MI_{k,h}$ [Row ‘n’, Column 12]	$MI_{k,h}$ [n,12] $\{IOG\_OFFSET_{k,h}^{i}\} >= 0$	NULL	$MI_{k,h}$ [n,12] $\{IOG\_OFFSET_{k,h}^{i}\} >= 0$	$MI_{k,h}$ [n,12] $\{IOG\_OFFSET_{k,h}^{i}\} >= 0$
Matrix $MI_{k,h}$ [Row ‘n’, Column 13]	$MI_{k,h}$ [n,13] $\{Net\_IOG_{k,h}^{i}\}$ = $MI_{k,h}$ [n,10] $\{IOG\$_{k,h}^{i}\}$ - $MI_{k,h}$ [n,12] $\{IOG\_OFFSET_{k,h}^{i}\}$	NULL	$MI_{k,h}$ [n,13] $\{Net\_IOG_{k,h}^{i}\}$ = $MI_{k,h}$ [n,10] $\{IOG\$_{k,h}^{i}\}$ - $MI_{k,h}$ [n,12] $\{IOG\_OFFSET_{k,h}^{i}\}$	$MI_{k,h}$ [n,13] $\{Net\_IOG_{k,h}^{i}\}$ = $MI_{k,h}$ [n,10] $\{IOG\$_{k,h}^{i}\}$ - $MI_{k,h}$ [n,12] $\{IOG\_OFFSET_{k,h}^{i}\}$

The Day-Ahead IOG rate (DA_IOG RATE$_{k,h}^{i}$) column 5, at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the day ahead constrained import schedule value in columns 1 (DA_DQSI$_{k,h}^{i}$) and real time import schedule value in column 2 (DQSI$_{k,h}^{i}$) and the DA_IOG$_{k,h}^{i}$ value in Column 3 of each unique row 'n' in matrix MI$_{k,h}$ as follows:

DA_IOG RATE$_{k,h}^{i}$	=	$\mathrm{IF}\left[\mathrm{DA\_IOG}_{k,h}^{i} \text{ is not NULL}, \frac{\mathrm{DA\_IOG}_{k,h}^{i}}{\mathrm{MIN}(\mathrm{DA\_DQSI}_{k,h}^{i}, \mathrm{DQSI}_{k,h}^{i})}, 0\right]$

The Real-Time IOG rate (RT_IOG_RATE$_{k,h}^{i}$) column 6 at an *intertie metering point* 'i' in *settlement hour* 'h' is calculated using the real-time constrained import schedule of column 2 and the RT_IOG$_{k,h}^{i}$ value of Column 4 of each unique row 'n' in matrix MI$_{k,h}$ as follows:

RT_IOG RATE$_{k,h}^{i}$	=	$\mathrm{IF}\left[\mathrm{RT\_IOG}_{k,h}^{i} \text{ is not NULL}, \frac{\mathrm{RT\_IOG}_{k,h}^{i}}{\mathrm{DQSI}_{k,h}^{i}}, 0\right]$

The matrix is arranged in ascending order on DA_IOG_RATE$_{k,h}^{i}$ (Column 5) from the lowest rate to the highest rate.

The day-ahead export schedule quantity offset by *market participant* 'k' at an *intertie metering point* 'i' in *settlement hour* 'h' (DA_OFFSET_DQSW$_{k,h}^{i}$) column 7 is calculated using the day ahead constrained import schedule value in columns 1 (DA_DQSI$_{k,h}^{i}$), real time import schedule value in column 2 (DQSI$_{k,h}^{i}$) and the day ahead constrained export schedule value for the *market participant* for an hour as follows:

DA_DQSW_REM$_{k,h}$	=	$\left[\mathrm{MAX}\left[0, \left(\sum^{I} \mathrm{DA\_DQSW}_{k,h}^{I} - \sum_{i=1}^{n} \mathrm{DA\_OFFSET\_DQSW}_{k,h}^{i}\right)\right]\right]$

DA_OFFSET_DQSW$_{k,h}^{i}$	=	$\mathrm{MIN}\left[\mathrm{DA\_DQSI}_{k,h}^{i}, \mathrm{DQSI}_{k,h}^{i}, \mathrm{DA\_DQSW\_REM}_{k,h}\right]$

Where:

I = set of all *intertie metering points* ‘i’

n = The number of day ahead import transactions with DA_OFFSET_DQSW at each pass.

The day-ahead IOG offset flag ($DA\_OFFSET\ FLAG_{k,h}^{i}$) column 8 at an *intertie metering point* ‘i’ in *settlement hour* ‘h’ is calculated using the values in column 7 $DA\_OFFSET\_DQSW_{k,h}^{i}$, columns 1 ($DA\_DQSI_{k,h}^{i}$) and real time import schedule value in column 2 ($DQSI_{k,h}^{i}$) of each unique row ‘n’ in matrix $MI_{k,h}$ as follows:

$DA\_OFFSET\_FLAG_{k,h}^{i}$	=	$IF\left(DA\_OFFSET\_DQSW_{k,h}^{i} > [50\% \times MIN\left(DA\_DQSI_{k,h}^{i}, DQSI_{k,h}^{i}\right)], Y, N\right)$

The IOG offset rate ($IOG\_SETTLEMENT\_RATE_{k,h}^{i}$) column 9 at an *intertie metering point* ‘i’ in *settlement hour* ‘h’ is calculated using the values in Column 5 ($DA\_IOG\_RATE_{k,h}^{i}$) and Column 6 ($RT\_IOG\_RATE_{k,h}^{i}$) of each unique row ‘n’ in matrix $MI_{k,h}$ as follows:

$IOG\_SETTLEMENT\_RATE_{k,h}^{i}$	=	$IF\left[DA\_OFFSET\_FLAG_{k,h}^{i}=Y, RT\_IOG\_RATE_{k,h}^{i}, MAX(RT\_IOG\_RATE_{k,h}^{i}, DA\_IOG\_RATE_{k,h}^{i})\right]$
		Subject to: $MI_{k,h}\ [n,9] >= MI_{k,h}\ [n-1,9]$; $MI_{k,h}\ [1,9] = MIN[MI_{k,h}\ [1\ to\ N,9]]$; $[MI_{k,h}\ [1\ to\ N,9]] <> 0$

The IOG dollar amount ($IOG\$_{k,h}^{i}$) column 10 at an *intertie metering point* ‘i’ in *settlement hour* ‘h’ is the IOG dollar amount associated with the rate used in Column 9 ($IOG\_SETTLEMENT\_RATE_{k,h}^{i}$).

The matrix is arranged in ascending order of ($IOG\_SETTLEMENT\_RATE_{k,h}^{i}$) (Column 9) from the lowest rate to the highest rate.

The real-time export schedule quantity offset by *market participant* ‘k’ at an *intertie metering point* ‘i’ in *settlement hour* ‘h’ ($RT\_OFFSET\_DQSW_{k,h}^{i}$) column 11 is calculated using the real-time constrained import schedule values in column 2 ($DQSI_{k,h}^{i}$) and the real time constrained export schedule value for the *market participant* for an hour as follows:

$RT\_DQSW\_REM_{k,h}$	=	$\left[MAX\left[0,\left(\sum^{I} DQSW^{i}_{k,h} - \sum_{i=1}^{n} RT\_OFFSET\_DQSW^{i}_{k,h}\right)\right]\right]$

$RT\_OFFSET\_DQSW_{k,h}{}^{i}$	=	$MIN\left[DQSI^{i}_{k,h}, RT\_DQSW\_REM_{k,h}\right]$

Where:

I = set of all *intertie metering points* 'i'

n = The number of day ahead import transactions with DA_OFFSET_DQSW at each pass.

The IOG offset *settlement amount* for *market participant* 'k' at an *intertie metering point* 'i' in *settlement hour* 'h' ($IOG\_OFFSET_{k,h}{}^{i}$) column 12 is calculated using column 9 ($IOG\_SETTLEMENT\_RATE_{k,h}{}^{i}$) and column 11($RT\_OFFSET\_DQSW_{k,h}{}^{i}$) as follows:

$IOG\_OFFSET_{k,h}{}^{i}$	=	$\left(IOG\_SETTLEMENT\_RATE^{i}_{k,h} \times RT\_OFFSET\_DQSW^{i}_{k,h}\right)$

The IOG *settlement amount* for *market participant* 'k' at an *intertie metering point* 'i' in *metering settlement hour* 'h' ($NET\_IOG_{k,h}{}^{i,}$) column 13 is calculated using column10 ($IOG\$_{k,h}{}^{i}$) and column 12 ($IOG\_OFFSET_{k,h}{}^{i}$) as follows:

$NET\_IOG_{k,h}{}^{i}$	=	$\left(IOG\$^{i}_{k,h} - IOG\_OFFSET^{i}_{k,h}\right)$

3.8A.5 [Intentionally left blank – section deleted]

3.8A.6 [Intentionally left blank – section deleted]

Day-Ahead Intertie Offer Guarantee Adjustments

3.8A.7 [Intentionally left blank – section deleted]

3.8A.8 [Intentionally left blank – section deleted]

3.8A.9 [Intentionally left blank – section deleted]

3.8B Day Ahead Import Failure Charge

3.8B.1 The *IESO* shall apply the day-ahead import failure charge specified in section 3.8B.2 to a *market participant* for any quantity of *energy* scheduled for injection at an *intertie metering point* scheduled in the *schedule of record* where:

3.8B.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for injection in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;* and,

3.8B.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B of these *market rules*; and

3.8B.1.3 the import transaction is not part of a day-ahead linked wheel.

3.8B.2 For all import transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8B.1, the day-ahead import failure charge shall be formulated as follows:

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

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} [B[n,1] \cdot (B[n,2] - B[n-1,2])] - [(Q - B[s^*,2]) \cdot B[s^*+1,1]]$$

Where:

s* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $PD\_EMP_h^{m,t}$: pre-dispatch projected *energy market price* applicable to all *delivery* points 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h;

'Q' is $DA\_ISD_{k,h}^{i,t}$ as defined below; and

'B' is $DA\_BE_{k,h}^{i,t}$: energy offers submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market* *participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2; or ‘B’ is $PD\_BE_{k,h}^{i,t}$: energy *offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2.

the *offer* matrix of *price-quantity pairs* for the applicable import transaction that was submitted by *market participant* ‘k’ and scheduled in the *pre-dispatch of record* during *metering interval* ‘t’ for *settlement hour* ‘h’ of the *real-time trading day*

and,

Let $DA\_ISD_{k,h}^{i,t}$ be the day-ahead import scheduling deviation quantity calculated for *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ as determined by the formula:

DA import scheduling deviation quantity ($DA\_ISD_{k,h}^{i,t}$)	=	MAX (day-ahead import transaction quantity – pre-dispatch import transaction quantity, 0)
$DA\_ISD_{k,h}^{i,t}$	=	MAX ($DA\_DQSI_{k,h}^{i,t}$ – $PD\_DQSI_{k,h}^{i,t}$, 0) Where: $DA\_DQSI_{k,h}^{i,t}$ is the *schedule of record* quantity scheduled for injection by *market participant* ‘k’ for an import transaction at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’; and $PD\_DQSI_{k,h}^{i,t}$ is the pre-dispatch quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

Let $XPD\_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times (Q_n - Q_{n-1})\right] + (Q - Q_{s*}) \times P_{s*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

p* = the highest indexed row of matrix $XPD\_BE_{k,h}^{i,t}$ such that $Q_{p*} \leq PD\_DQSI_{k,h}^{i,t} \leq Q_n$ and where $Q_{p*-1} = PD\_DQSI_{k,h}^{i,t}$ and where if $Q_{p*} < Q_{p*-1}$, let $Q_{p*} = Q_{p*-1}$

s* = the highest indexed row of matrix $XPD\_BE_{k,h}^{i,t}$ such that $Q_{s*} \leq DA\_DQSI_{k,h}^{i,t} \leq Q_n$

Let $XDA\_BE_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1})\right] + (Q - Q_{d*}) \times P_{d*+1}$$

where matrix (B) is *energy offers* submitted in the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

c* = the highest indexed row of matrix $XDA\_BE_{k,h}^{i,t}$ such that $Q_{c*} \leq PD\_DQSI_{k,h}^{i,t} \leq Q_n$ and where $Q_{c*-1} = PD\_DQSI_{k,h}^{i,t}$ and where if $Q_{c*} < Q_{c*-1}$, let $Q_{c*} = Q_{c*-1}$

d* = the highest indexed row of matrix $XDA\_BE_{k,h}^{i,t}$ such that $Q_{d*} \leq DA\_DQSI_{k,h}^{i,t} \leq Q_n$

Such that the day-ahead import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$DA\_IFC_{k,h}$ = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x MINIMUM of:

[MAXIMUM of:

[[The sum of all revenues implied by each import transaction valued at the *pre-dispatch energy market price* in the Ontario zone for the difference in quantity scheduled in pre-dispatch and the quantity scheduled in the *schedule of record*.

Minus:

Those costs represented through the *offers* for the import transaction scheduled in the *schedule of record*] or zero],

[MAXIMUM of:

[the pre-dispatch *offer* to increase quantity scheduled in pre-dispatch to quantity scheduled day-ahead minus the day-ahead *offer* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*] or zero],

[day-ahead import scheduling deviation quantity times the MAXIMUM of (zero or the pre-dispatch *energy market price* in the Ontario zone)]]

$DA\_IFC_{k,h}$ =

$$\sum_{I,T} (-1) \times MIN\Big[MAX\Big(0, OP\big(PD\_EMP_h^{m,t}, DA\_DQSI_{k,h}^{i,t}, DA\_BE_{k,h}^{i,t}\big) - OP\big(PD\_EMP_h^{m,t}, PD\_DQSI_{k,h}^{i,t}, DA\_BE_{k,h}^{i,t}\big),$$

$$MAX\big(0, XPD\_BE_{k,h}^{i,t} - XDA\_BE_{k,h}^{i,t}\big), \big(MAX(0, PD\_EMP_h^{m,t}) \times DA\_ISD_{k,h}^{i,t}\big)\Big]$$

Where:

$DA\_BE_{k,h}^{i,t}$ *are energy offers* submitted into the schedule of record, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2;

$PD\_BE_{k,h}^{i,t}$ are *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price-quantity pair* where offered prices are in column 1 and offered quantities are in column 2;

$PD\_EMP_h^{m,t}$ is the $PD\_EMP_h^{m,t}$;

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i'.

3.8C Real-Time Import and Real-Time Export Failure Charges

3.8C.1 The real-time import failure charge and the real-time export failure charges referred to in section 7.5.8B of Chapter 7 are *settlement amounts* that shall be determined in sections 3.8C.2 and 3.8C.3 and in sections 3.8C.4 and 3.8C.5 respectively.

Real-time Import Failure Charge

3.8C.2 The *IESO* shall assess a *market participant* with a real-time import failure charge for any quantity of *energy* scheduled for injection at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.2.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for injection in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8C.2.2 the *IESO* has not determined, nor has the *market participant*-demonstrated to the satisfaction of the *IESO,* that the failure was due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8C.3 For all import transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.2, the real-time import failure charge shall be formulated as follows:

Let $RT\_ISD_{k,h}^{i,t}$ be the real-time import scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Import Scheduling Deviation Quantity	**=**	MAX (*pre-dispatch* import transaction quantity – real-time import transaction quantity, 0)
$RT\_ISD_{k,h}^{i,t}$	**=**	MAX ($PD\_DQSI_{k,h}^{i,t}$ - $DQSI_{k,h}^{i,t}$, 0)

such that the real-time import failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$RT\_IFC_{k,h}$ **=** For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between: the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for imports in effect for the *settlement hour* minus the *pre-dispatch* projected *energy market price* in the Ontario zone

times :

real-time import scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the real-time import scheduling deviation quantity times the maximum of the real-time *energy market price* in the Ontario zone or zero]

$$RT\_IFC_{k,h} = \sum^{I,T} (-1) \times MIN\left[MAX\left[0,(EMP_h^{m,t} + PB\_IM_h^{\ t} - PD\_EMP_h^{m,t}) \times RT\_ISD_{k,h}^{\ i,t}\right], MAX(0, EMP_h^{m,t}) \times RT\_ISD_{k,h}^{\ i,t}\right]$$

where:

$PD\_EMP_h^{m,t}$ is the pre-dispatch projected *energy market price* applicable to all *delivery points* ‘m’ in the Ontario zone during *metering interval* ‘t’ of *settlement hour* ‘h’;

$EMP_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* ‘m’ in the Ontario zone during *metering interval* ‘t’ of *settlement hour* ‘h’;

$PB\_IM_h^t$ is the price bias adjustment factor for import transactions in effect during *metering interval* ‘t’ of *settlement hour* ‘h’;

‘I’ is the set of all *intertie metering points* ‘i’;

‘T’ is the set of all metering intervals in settlement hour ‘h’.

Real-time Export Failure Charge

3.8C.4 The *IESO* shall assess a *market participant* with a real-time export failure charge for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* in the constrained *pre-dispatch schedule* where:

3.8C.4.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity for withdrawal in the constrained *real-time schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point*; and,

3.8C.4.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure was due to bona fide and legitimate reasons described in chapter 7, section 7.5.8B.

3.8C.5 For all export transactions scheduled in the constrained *pre-dispatch schedule* and meeting the criteria set out in section 3.8C.4, the real-time export failure charge shall be formulated as follows:

Let $RT\_ESD_{k,h}^{i,t}$ be the real-time export scheduling deviation quantity calculated for *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' as determined by the formula:

Real-time Export Scheduling Deviation Quantity **=** MAX (*pre-dispatch* export transaction quantity – real-time export transaction quantity, 0)

$$RT\_ESD_{k,h}^{i,t} = MAX\,(PD\_DQSW_{k,h}^{i,t} - DQSW_{k,h}^{i,t}, 0)$$

such that the real-time export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$RT\_EFC_{k,h}$ **=** For all *intertie metering points*:

-1 x [MAXIMUM of:

[[The difference between the *pre-dispatch* projected *energy market price* in the Ontario zone minus the real-time *energy market price* in the Ontario zone adjusted by the prevailing price bias adjustment factor for exports in effect for the *settlement hour*]

times :

real-time export scheduling deviation quantity.]

or zero,]

subject to: a maximum value of the:

real-time export scheduling deviation quantity times the maximum of the pre-dispatch *energy market price* in the Ontario zone or zero]

$$RT\_EFC_{k,h} = \sum^{I,T} (-1) \times MIN\left[MAX\left[0, (PD\_EMP_h^{m,t} - EMP_h^{m,t} - PB\_EX_h^{t}) \times RT\_ESD_{k,h}^{i,t}\right], MAX(0, PD\_EMP_h^{m,t}) \times RT\_ESD_{k,h}^{i,t}\right]$$

where:

$PD\_EMP_h^{m,t}$ is the *pre-dispatch* projected *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$EMP_h^{m,t}$ is the real-time 5-minute *energy market price* applicable to all *delivery points* 'm' in the Ontario zone during *metering interval* 't' of *settlement hour* 'h'

$PB\_EX_h^{t}$ is the price bias adjustment factor for export transactions in effect during *metering interval* 't' of *settlement hour* 'h'

'I' is the set of all *intertie metering points* 'i'

'T' is the set of all metering intervals in settlement hour 'h'

3.8C.6 Where any import transaction scheduled in the *pre-dispatch schedule of record* and subsequently scheduled at the same *intertie metering point* in the *real-time market* is subject to both the day ahead import failure charge of section 3.8B and the real-time import failure charge of section 3.8C, the *market participant* shall be assessed with the greater of these charges but not both.

3.8C.7 The *IESO* shall determine, in accordance with the applicable *market manual*, any applicable price bias adjustment factors to be used in the calculation of the real-time import failure charge and the real-time export failure charge. The price bias adjustment factor shall compensate for systematic differences between the pre-dispatch and real-time price.

3.8C.8 The *IESO* shall *publish* all applicable price bias adjustment factors in advance of the *settlement hours* to which such factors apply.

3.8C.9 [Intentionally left blank – section deleted]

3.8D Day Ahead Export Failure Charge

3.8D.1 The *IESO* shall apply the day-ahead export failure charge specified in section 3.8D.2 to a *market participant* for any quantity of *energy* scheduled for withdrawal at an *intertie metering point* scheduled in the *schedule of record*

where:

3.8D.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for withdrawal in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;*

3.8D.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B; and

3.8D.1.3 the export transaction is not part of a day-ahead linked wheel.

3.8D.2 For all export transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8D.1, the day-ahead export failure charge shall be formulated as follows:

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

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} P_n \cdot (Q_n - Q_{n-1}) - (Q - Q_{s^*}) \cdot P_{s^*+1}$$

Using matrix notation for parameter 'B' this may be expressed as follows:

$$OP(P,Q,B) = P \cdot Q - \sum_{n=1}^{s^*} \left[B[n,1] \cdot (B[n,2] - B[n-1,2])\right] - \left[(Q - B[s^*,2]) \cdot B[s^*+1,1]\right]$$

Where:

s* is the highest indexed row of B such that $Q_{s^*} \leq Q \leq Q_n$ and where, $Q_0=0$

'P' is $PD\_EMP_h^{m,t}$: *pre-dispatch* projected *energy market price* applicable to all *delivery* points 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

'Q' is $DA\_ESD_{k,h}^{i,t}$ as defined below; and

'B' is $DA\_BL_{k,h}^{i,t}$: *energy bids* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2; or

'B' is $PD\_BL_{k,h}^{i,t}$: *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *delivery point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered *price in e*ach *price quantity pair* where offered price*s 'P' are i*n column 1 and offered quantities 'Q' are in column 2

the *offer* matrix of *price-quantity pairs* for the applicable export transaction that was submitted by *market participant* 'k' and scheduled in the *schedule of record* during *metering interval* 't' for *settlement hour* 'h' of the *real-time trading day*

and,

Let $XDA\_BL_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\sum_{n=c^*}^{d^*} P_n \times (Q_n - Q_{n-1}) + (Q - Q_{d^*}) \times P_{d^*+1}$$

where matrix (B) is *energy bids* submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

c*	=	the highest indexed row of matrix $XDA\_BL_{k,h}^{i,t}$ such that $Q_{c^*} \leq PD\_DQSW_{k,h}^{i,t} \leq Q_n$ and where $Q_{c^*-1} = PD\_DQSW_{k,h}^{i,t}$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$
d*	=	the highest indexed row of matrix $XDA\_BL_{k,h}^{i,t}$ such that $Q_{d^*} \leq DA\_DQSW_{k,h}^{i,t} \leq Q_n$

Let $XPD\_BL_{k,h}^{i,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_i \times (Q_n - Q_{n-1})\right] + (Q - Q_{s^*}) \times P_{s^*+1}$$

where matrix (B) *energy bids* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *intertie metering point* 'i' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

p*	=	the highest indexed row of matrix $XPD\_BL_{k,h}^{i,t}$ such that $Q_{p^*} \leq PD\_DQSW_{k,h}^{i,t} \leq Q_n$ and where $Q_{p^*-1} = PD\_DQSW_{k,h}^{i,t}$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$
s*	=	the highest indexed row of matrix $XPD\_BL_{k,h}^{i,t}$ such that $Q_{s^*} \leq DA\_DQSW_{k,h}^{i,t} \leq Q_n$

Such that the day-ahead export failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$DA\_EFC_{k,h}$ = For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x MINIMUM of:

[MAXIMUM of:

[-1 x [The sum of all revenues implied by each export transaction valued at the *pre-dispatch energy market price* in the Ontario zone for the difference in quantity scheduled in pre-dispatch and the quantity scheduled in the *schedule of record*.

Minus:

Those costs represented through the *offers* for the export transaction scheduled in the *schedule of record*]

or zero],

[MAXIMUM of:

[the day-ahead *bid* to increase quantity scheduled in pre-dispatch to quantity scheduled day-ahead minus the pre-dispatch *bid* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*]

or zero]

MAXIMUM of (zero or the day-ahead *bid* to increase quantity scheduled in pre-dispatch to quantity scheduled in the *schedule of record*)]

$DA\_EFC_{k,h}$ =

$$\sum_{I,T}(-1) \times \mathrm{MIN}\Big[\mathrm{MAX}\Big(0,(-1) \times \mathrm{OP}\big(\mathrm{PD\_EMP}_{h}^{m,t}, \mathrm{DA\_DQSW}_{k,h}^{i,t}, \mathrm{DA\_BL}_{k,h}^{i,t}\big) - (-1) \times \mathrm{OP}\big(\mathrm{PD\_EMP}_{h}^{m,t}, \mathrm{PD\_DQSW}_{k,h}^{i,t}, \mathrm{DA\_BL}_{k,h}^{i,t}\big)\Big), \mathrm{MAX}\big(0, \mathrm{XDA\_BL}_{k,h}^{i,t} - \mathrm{XPD\_BL}_{k,h}^{i,t}\big), \mathrm{MAX}\big(0, \mathrm{XDA\_BL}_{k,h}^{i,t}\big)\Big]$$

Where:

$DA\_BL_{k,h}^{i,t}$ are energy bids submitted into the *schedule of record*, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered *price in e*ach *price quantity pair* where offered prices *‘P’ are i*n column 1 and offered quantities ‘Q’ are in column 2;

$PD\_BL_{k,h}^{i,t}$ are *energy* bids submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’ arranged in ascending order by the offered *price in e*ach *price quantity pair* where offered prices *‘P’ are i*n column 1 and offered quantities ‘Q’ are in column 2;

$PD\_EMP_{h}^{m,t}$ is the *pre-dispatch* projected *energy market price* applicable to all *delivery* points 'm' in the Ontario zone in *metering interval* 't' of *settlement hour* 'h';

‘T’ is the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’;

‘I’ is the set of all *intertie metering points* ‘i’.

3.8E Day Ahead Linked Wheel Failure Charge

3.8E.1 The *IESO* shall apply the day-ahead linked wheel failure charge specified in section 3.8E.2 to a *market participant* for any quantity of *energy* scheduled for a linked wheel at an *intertie metering point* scheduled in the *schedule of record*

where:

3.8E.1.1 the *market participant* fails either in whole or in part to schedule a *dispatch* quantity scheduled for a linked wheel in the *pre-dispatch schedule* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *intertie metering point;* and,

3.8E.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is due to bona fide and legitimate reasons as described in chapter 7, section 7.5.8B.

3.8E.2 For all linked wheel transactions scheduled in the *schedule of record* and meeting the criteria of section 3.8E.1, the day-ahead linked wheel failure charge shall be formulated as follows:

Day-ahead linked wheel scheduling deviation ($DA\_LWSD_{k,h}^{i,t}$)	=	MAX[(day-ahead import – hour-ahead pre-dispatch import), (day-ahead export – hour-ahead pre-dispatch export)]
$DA\_LWSD_{k,h}^{i,t}$	=	$MAX[(DA\_DQSI_{k,h}^{i,t} - PD\_DQSI_{k,h}^{i,t}), (DA\_DQSW_{k,h}^{i,t} - PD\_DQSW_{k,h}^{i,t})]$ Where: $DA\_DQSI_{k,h}^{i,t}$ is *schedule of record* quantity scheduled for injection by *market participant* ‘k’ at *delivery point* ‘m’ during *metering interval* ‘t’ of *settlement hour* ‘h’; $PD\_DQSI_{k,h}^{i,t}$ is the *pre-dispatch* constrained quantity scheduled for injection by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’; $DA\_DQSW_{k,h}^{i,t}$ is the *schedule of record* quantity scheduled for withdrawal by *market participant* ‘k’ at *delivery point* ‘m’ during *metering interval* ‘t’ of *settlement hour* ‘h’; and $PD\_DQSW_{k,h}^{i,t}$ is the *pre-dispatch* constrained quantity scheduled for withdrawal by *market participant* ‘k’ at *intertie metering point* ‘i’ during *metering interval* ‘t’ of *settlement hour* ‘h’

Day-ahead price spread ($DA\_PS_{k,h}^{i,t}$)	=	day-ahead constrained schedule *intertie* price of the sink for the export transaction minus day-ahead constrained *intertie* price of the source for the import transaction
$DA\_PS_{k,h}^{i,t}$	=	$DA\_ELMP_{k,h}^{m,t} – DA\_ILMP_{k,h}^{m,t}$ Where: $DA\_ELMP_h^{i,t}$ is the day-ahead constrained schedule *intertie* price at the *intertie metering point* 'i' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'; and $DA\_ILMP_h^{i,t}$ is the day-ahead constrained *intertie* price at the *intertie metering point* 'i' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'
Pre-dispatch price spread ($PD\_PS_{k,h}^{i,t}$)	=	pre-dispatch constrained schedule *intertie* price of the sink for the export transaction – pre-dispatch constrained *intertie* price of the source for the import transaction
$PD\_PS_{k,h}^{i,t}$	=	$PD\_ELMP_h^{m,t} – PD\_ILMP_h^{m,t}$ Where: $PD\_ELMP_h^{i,t}$ is the *pre-dispatch* constrained schedule intertie price at the *intertie metering point* 'i' of the sink for the export transaction during *metering interval* 't' of *settlement hour* 'h'; and $PD\_ILMP_h^{i,t}$ is the *pre-dispatch* constrained intertie price at the *intertie metering point* 'i' of the source for the import transaction during *metering interval* 't' of *settlement hour* 'h'

Such that the day-ahead linked wheel failure charge for *market participant* 'k' during *settlement hour* 'h' for all *intertie metering points* 'i' may be formulated with the above components as follows:

$DA\_LWFC_{k,h}$	=	For all *intertie metering points* and all *metering intervals* during the *settlement hour*:

-1 x [The day-ahead linked wheel scheduling deviation quantity.

Multiplied by:

MAXIMUM of:

The day-ahead price spread less the pre-dispatch price spread or zero],

$$DA\_LWFC_{k,h} = \sum_{I,T} (-1) \times \left[\left(DA\_LWSD_{k,h}^{i,t}\right) \times MAX\left[0, \left(DA\_PS_{k,h}^{i,t} - PD\_PS_{k,h}^{i,t}\right)\right]\right]$$

Where:

'T' is the set of all *metering intervals* 't' in *settlement hour* 'h';

'I' is the set of all *intertie metering points* 'i'.

3.8E.3 If a day-ahead linked wheel failure charge specified in section 3.8E.2 applies to a linked wheel where a real-time import failure charge specified in section 3.8C.3 and/or a real-time export failure charge specified in section 3.8C.5 applies to the same linked wheel, a charge shall apply to the *market participant* equal to the lesser of:

3.8E.3.1 the day-ahead linked wheel failure charge specified in section 3.8E.2; and

3.8E.3.2 the sum of the real-time import failure charge and the real-time export failure charge, both subject to the scheduling deviation quantity between the *schedule of record* and the *pre-dispatch schedule*, as follows:

$RT\_EFC\_DALW_{k,h}^{i} + RT\_IFC\_DALW_{k,h}^{i}$

Where:

$RT\_EFC\_DALW_{k,h}^{i}$	=	real-time export failure charge for the export portion of the day-ahead linked wheel for the quantity failure from day-ahead to Pre-dispatch

$RT\_EFC\_DALW_{k,h}^{i}$	=	$\sum^{T}(-1) \times MIN\Big[MAX\Big[0,(PD\_EMP_{h}^{m,t} - EMP_{h}^{m,t} - PB\_EX_{h}^{t}) \times MAX\big((DA\_DQSW_{k,h}^{i,t} - PD\_DQSW_{k,h}^{i,t}),0\big)\Big], MAX(0, PD\_EMP_{h}^{m,t}) \times MAX\big((DA\_DQSW_{k,h}^{i,t} - PD\_DQSW_{k,h}^{i,t}),0\big)\Big]$

$RT\_IFC\_DALW_{k,h}^{i}$	=	real-time import failure charge for the import portion of the day-ahead linked wheel for the quantity failure from day-ahead to Pre-dispatch

$RT\_IFC\_DALW_{k,h}^{i}$	=	$\sum^{T}(-1) \times MIN\Big[MAX\Big[0,(EMP_{h}^{m,t} + PB\_IM_{h}^{t} - PD\_EMP_{h}^{m,t}) \times MAX\big((DA\_DQSI_{k,h}^{i,t} - PD\_DQSI_{k,h}^{i,t}),0\big)\Big], MAX(0, EMP_{h}^{m,t}) \times MAX\big((DA\_DQSI_{k,h}^{i,t} - PD\_DQSI_{k,h}^{i,t}),0\big)\Big]$

3.8F Day-Ahead Generator Withdrawal Charge

3.8F.1 The *IESO* shall apply the day-ahead *generator* withdrawal charge specified in section 3.8F.2 to a *market participant* who was deemed to have accepted the day-ahead production cost guarantee in accordance with Section 5.8.4 of Chapter 7 for any quantity of *energy* scheduled for injection at a *metering point* scheduled in the *schedule of record* where:

3.8F.1.1 the *market participant* withdraws their commitment scheduled in the *schedule of record* in the corresponding *metering interval* of the corresponding *settlement hour* at the same *metering point;* and, 3.8F.1.2 the *IESO* has not determined, nor has the *market participant* demonstrated to the satisfaction of the *IESO,* that the failure is to prevent endangering the safety of any person, damage to equipment, or violation of any *applicable law*.

3.8F.2 The day-ahead *generator* withdrawal charge shall be formulated as follows:

If withdrawal notification is received at or 4 hours prior to the first withdrawal hour in real time (PD – 4), then the Withdrawal Charge is calculated as follows:

$$DA\_GWC_{k,start\ event} = MIN\left(0, \sum_{i=1}^{n} (-1) \times OP\left(MIN\left(PD\_EMP_{h}^{m,t}, EMP_{h}^{m,t}\right), MLP_{k,h}^{m,t}, DA\_BE_{k,h}^{m,t}\right)\right)$$

Where:

n = the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ for the total number of hours with a *schedule of record* that are withdrawn

start event = the set of hours with a contiguous *schedule of record*

If withdrawal notification is received later than PD-4 or if the *market participant* does not notify the *IESO* of their intent to withdraw and does not inject for the hours committed in the *schedule of record*, then the withdrawal charge is calculated as follows:

$$DA\_GWC_{k,start\ event} = MIN\left(0, \sum_{i=1}^{n} (-1) \times OP\left(EMP_{h}^{m,t}, MLP_{k,h}^{m,t}, DA\_BE_{k,h}^{m,t}\right)\right)$$

Where:

n = the set of all *metering intervals* ‘t’ in *settlement hour* ‘h’ for the total number of hours with a *schedule of record* for the start event that are withdrawn

start event = the set of hours with a contiguous *schedule of record*

3.9 Hourly Uplift Settlement Amounts

3.9.1 The hourly *settlement amounts* defined by the preceding provisions of this section 3 will result in an hourly *settlement* deficit that shall be recovered from *market participants* as a whole through the *hourly uplift*. The total *hourly uplift settlement amount* for *settlement hour* ‘h’ (“$HUSA_h$”) shall be determined according to the following equation:

$$HUSA_h = \sum_K \left(NEMSC_{k,h} + ORSC_{k,h} + CMSC_{k,h} + RDSA_{k,h} + TRSC_{k,h} + IOG_{k,h}\right) + TCRF_{k,h} - \sum_K \left(\sum_R ORSSD_{k,r,h} + \sum_R ORSCB_{r,k,h} + DA\_IFC_{k,h} + RT\_IFC_{k,h} + DA\_EFC_{k,h} + RT\_EFC_{k,h} + DA\_LWFC_{k,h}\right)$$

over all ‘k’ *market participants*

$NEMSC_{k,h}$ = net *energy market settlement* credit for *market participant* ‘k’ in *settlement hour* ‘h’

$ORSC_{k,h}$ = *operating reserve market settlement* credit for *market participant* ‘k’ in *settlement hour* ‘h’

$CMSC_{k,h}$ = congestion management *settlement* credit for *market participant* ‘k’ in *settlement hour* ‘h’

$RDSA_{k,h}$ = ramp-down *settlement* amount for *market participant* ‘k’ in *settlement hour* ‘h’

$TRSC_{k,h}$ = *transmission rights settlement* credit for *market participant* ‘k’ in *settlement hour* ‘h’

$IOG_{k,h}$ = intertie offer guarantee settlement credit for the *market participant* ‘k’ in *settlement hour* ‘h’

$DA\_IFC_{k,h}$= day-ahead import failure charge for the *market participant* ‘k’ in *settlement hour* ‘h’

$RT\_IFC_{k,h}$ = real-time import failure charge for the *market participant* ‘k’ in *settlement hour* ‘h’

$DA\_EFC_{k,h}$= day-ahead export failure charge for the *market participant* ‘k’ in *settlement hour* ‘h’

$RT\_EFC_{k,h}$= real-time export failure charge for the *market participant* ‘k’ in *settlement hour* ‘h’

$DA\_LWFC_{k,h}$= day-ahead linked wheel failure charge for the *market participant* 'k' in *settlement hour* 'h'

$TCRF_{k,h}$ = transmission charge reduction fund contribution in *settlement hour* 'h'

$ORSSD_{k,r,h}$ = *operating reserve settlement* debit for *operating deviations* for *class r reserve* for *market participant* 'k' in *settlement hour* 'h'

$ORSCB_{r,k,h}$ = *operating reserve* non-accessibility charge for *class r reserve* for *market participant* 'k' in *settlement hour* 'h'

3.9.2 The *IESO* shall allocate *hourly uplift* on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* within each *settlement hour* in which an *hourly uplift settlement amount* accrues.

3.9.3 *Hourly uplift* and non-hourly *settlement amounts* shall be disaggregated on *settlement statements* in such manner as shall be determined by the *IESO.*

3.9.4 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:

the day-ahead *intertie offer* guarantee *settlement* ($DA\_IOG_{k,h}$)*;* or
the day-ahead import failure charge ($DA\_IFC_{k,h}$),

in the *hourly uplift settlement amount,* the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.1 or 4.8.2 respectively commencing with the activation of the day-ahead commitment process.

3.9.5 Until such time that the *IESO* has the software capability to include the following *settlement amounts*:

the real-time import failure charge ($RT\_IFC_{k,h}$)*;* or
the real-time export failure charge ($RT\_EFC_{k,h}$),

in the *hourly uplift settlement amount,* the *IESO* shall recover or distribute such *settlement amounts* as non-hourly *settlement amounts* under the provisions of section 4.8.2.

4. Non-hourly Settlement Amounts

4.1 Transmission Tariff Charges

4.1.1 The *IESO* shall collect from *transmission customers*, and distribute to *transmitters*, *transmission services charges* approved by the *OEB* in accordance with Chapter 10.

4.2 Ancillary Service Payments

4.2.1 The *IESO* shall have the authority to negotiate *reliability must-run contracts* with *registered market participants* or prospective *registered market participants* regarding the operation of *reliability must-run resources* in accordance with section 9 of Chapter 7. Where such *reliability must-run contracts* provide both for payments from the *energy market* and *operating reserve market* pursuant to section 3 and additional payments for making *physical services*, other than *contracted ancillary services*, available to those markets, any such additional payments required to be made in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.2 The *IESO* shall contract for *certified black start facilities* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for such *certified black start facilities* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.3 The *IESO* shall contract for *regulation* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for *regulation* in a given *energy market billing period* shall be recovered from *market participants* through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*.

4.2.3A [Intentionally left blank – section deleted]

4.2.4 The *IESO* shall contract for *reactive support service* and *voltage control service* adequate to permit the *IESO* to meet its obligations under Chapter 5. The costs to the *IESO* of contracting for such *reactive support service* and *voltage control service* in a given *energy market billing period* shall be recovered in accordance with the following:

4.2.4.1 *market participants* shall pay for such costs through a uniform charge, in $/MWh, imposed on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and at all *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*;

4.2.4.2 there shall be no power factor requirements or penalties associated with electrical power flowing out of Ontario through *intertie metering points*; and

4.2.4.3 there shall be no separate compensation from the *IESO* for *reactive support service* and *voltage control service* from equipment such as capacitor banks, reactor banks, and synchronous condensers owned by *transmitters*. Any compensation for providing such *ancillary services* shall be included in the *transmission services charges* to the extent provided by the *OEB*.

4.2.5 Subject to sections 9.4.2 and 9.4.4 of Chapter 7, no compensation shall be paid for *ancillary services* provided pursuant to the *connection* requirements of Chapter 4.

4.2.6 [Intentionally left blank]

4.3 [Intentionally left blank]

4.4 [Intentionally left blank – section deleted]

4.4.1 [Intentionally left blank – section deleted]

4.5 IESO Administration Charge, Penalties, and Fines

4.5.1 The *IESO* shall determine a methodology for calculating and allocating an *IESO administration charge.*

4.5.2 [Intentionally left blank – section deleted]

4.6 [Intentionally left blank – section deleted]

4.6.1 [Intentionally left blank – section deleted]

4.7 TR Clearing Account Disbursements

4.7.1 Disbursements from the *TR clearing account* ordered by the *IESO Board* pursuant to section 4.18.2 of Chapter 8 shall be distributed among *market participants* based on the proportionate share of all *transmission service charges* paid during *energy market billing periods* immediately preceding the current *energy market billing period,* in accordance with this section 4.7.

4.7.1.1 The portion of the total disbursements from the *TR clearing* account allotted to *market participants* that have paid provincial transmission charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of energy withdrawn from the *IESO-controlled grid* at all *RWMs* excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.7.2 and 4.7.3.

4.7.1.2 The portion of the total disbursements from the *TR clearing account* allotted to *market participants* that have paid *export transmission service* charges shall be disbursed to *market participants* on an individual basis as a non-hourly *settlement amount* according to each *market participant's* proportionate quantity of *energy* withdrawn from the *IESO-controlled grid* at all *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board,* in the manner described in sections 4.7.2 and 4.7.3.

4.7.2 The portion of any disbursement from the *TR clearing account* payable to *market participant* 'k' in the current *energy market billing period* shall be calculated as follows:

$$TRCAC_k = \frac{TRCAD}{\sum_{K,H}^{M,T} AQEW_{k,h}{}^{m,t}} \times \sum_{H}^{M,T} AQEW_{k,h}{}^{m,t}$$

For *market participants* that have paid provincial transmission service charges in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*:

$TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} (AQEW_{k,h}{}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t})$

For *market participants* that have paid *export transmission service* charges in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board***:**

$$TRCAC_k = TRCAD_E \times \sum_H{}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

$$TRCAD_L = (\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAD$$

$$TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAD$$

$TRCAC_k$ = the *TR clearing account* credit payable to *market participant* 'k' in the current *energy market billing period*

TRCAD = the total dollar value of all disbursements from the *TR clearing account* authorised by the *IESO Board* in the current *energy market billing period*

$TRCAD_L$ = the portion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period* allocated to *market participants* that have paid provincial transmission service charges "C" in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

$TRCAD_E$ = the portion of the total dollar value of all disbursements from the *TR clearing account* authorized by the *IESO Board* in the *current energy market billing period* allocated to *market participants* that have paid *export transmission service* charges "C1" in the *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

M = the set of all *RWMs* 'm' excluding *intertie metering points* during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

I = *intertie metering points* 'i' during *energy market billing periods* immediately preceding the current *energy market billing period*, as determined by the *IESO Board*

K = the set of all *market participants* ‘k’ during *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

T = the set of all *metering intervals* ‘t’ in *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

H = the set of all *settlement hours* ‘h’ in *energy market billing periods* immediately preceding the current *energy market billing period,* as determined by the *IESO Board*

C = the set of all monthly service charge types ‘c’ as follows: 650,651,652

C1 = the set of all monthly export transmission charge types ‘c’ as follows: 653

4.7.3 Where a *$TRCAC_k$* is payable to a former *market participant*, the *IESO* will endeavour to distribute the *$TRCAC_k$* as specified in the applicable *market manual*. If the *IESO* cannot distribute a *$TRCAC_k$* to a former *market participant* as specified in the applicable *market manual,* such amounts shall remain in the *TR clearing account* for subsequent debits in accordance with section 4.18.1 of Chapter 8.

4.7A [Intentionally left blank – section deleted]

4.7A.1 [Intentionally left blank – section deleted]

4.7A.1.1 [Intentionally left blank – section deleted]

4.7A.1.2 [Intentionally left blank – section deleted]

4.7A.2 [Intentionally left blank – section deleted]

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 2.2B, 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 synchronization 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 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*.

4.7B.1.2 the applicable *combined guaranteed costs* for the specified submission to which the revenues determined in accordance with 4.7B.1.1 apply. Subject to section 4.7B.1.3, the *combined guaranteed costs* will be calculated by the *IESO* and will be the sum of the following costs:

4.7B.1.2A the submitted eligible costs, determined in accordance with section 4.7B.5 and section 2.2B.6 of Chapter 7, as applicable; and

4.7B.1.2B the *offer* price associated with the real-time *dispatch* multiplied by the *energy* injected, to a maximum of the *minimum loading point,* during the period from the beginning of the *minimum generation block run-time* until the earlier of:

- the end of the period representing *minimum generation block run-time*; or
- the end of the period representing *minimum run-time*.

4.7B.1.2.C [Intentionally left blank – section deleted]

4.7B.1.3 the elements of the *combined guaranteed costs* in section 4.7B.1.2A shall be deemed to be zero where a *market participant* is also eligible for the start-up cost component of a day-ahead production cost guarantee attributable to the same start-up event.

4.7B.2 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7B.1.1 is greater than or equal to the *combined guaranteed costs* referred to in section 4.7B.1.2, then no additional payments are made in respect of the eligible *generation facility* by the *IESO.*

4.7B.3 If for each eligible *generation facility* the sum of the revenues calculated pursuant to section 4.7B.1.1 is less than the *combined guaranteed costs* referred to in section 4.7B.1.2, then the *IESO* shall calculate that difference and shall include that amount in the form of additional payments made in respect of the eligible *generation facility*.

4.7B.4 A *real-time* generation cost guarantee shall not be paid for a *generation unit* with respect to costs incurred or revenues accrued by that *generation unit* for which a day-ahead production cost guarantee applies under section 4.7D.

4.7B.4A A real-time generation cost guarantee shall not be paid where a *generation unit* has committed its *capacity* to an external *control area* and:

4.7B.4A.1 the external *control area operator* has called a *called capacity export* prior to the *generation unit* being scheduled for the real-time generation cost guarantee in accordance with section 5.7 of Chapter 7; or

4.7B.4A.2 the external *control area operator* has called a *called capacity export* after the *generation unit* has been scheduled for the real-time generation cost guarantee in accordance with section 5.7 of Chapter 7 and the *IESO* is restricting other transactions on *interconnected systems* in accordance with section 2.3 and 5.7 of Chapter 5, while maintaining the *called capacity export* transaction.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

Calculating Eligible Costs:

4.7B.5 The *IESO* shall calculate the submitted eligible costs described in section 2.2B.5 of Chapter 7, as follows and as further specified in the applicable *market manual*:

4.7B.5.1 The incremental fuel cost is equal to the fuel price multiplied by the fuel quantity where:

Fuel price =

- pre-approved price, adjusted by the applicable foreign exchange rate, if any; plus
- pre-approved services price adder; plus
- pre-approved cap and trade price adder, if applicable.

Fuel quantity =

- submitted *start volume*; plus

- submitted *start volume* multiplied by the pre-approved compressor volume adder fuel percentage, except for purposes of calculating cap and trade costs.

4.7B.5.2 The incremental operating and maintenance cost is equal to:

- electricity consumption cost, equal to the pre-approved electricity consumption price multiplied by the pre-approved electricity consumption quantity; plus
- pre-approved operating consumables cost adder; plus
- pre-approved planned maintenance cost adder, adjusted by the applicable foreign exchange rate, if any.

4.7C [Intentionally left blank – section deleted]

4.7C.1 [Intentionally left blank – section deleted]

4.7C.2 [Intentionally left blank – section deleted]

4.7C.3 [Intentionally left blank – section deleted]

4.7D Day-Ahead Production Cost Guarantee Payments

4.7D.1 The *IESO* shall determine on a *per-start* basis, for each *generation unit* that has met the criteria set out in chapter 7, sections 5.8.4, a day-ahead production costs guarantee consisting of the following components:

a. Component 1 is any shortfall in payment on the delivered real-time *dispatch* of the *schedule of record* and will be based upon the real-time revenue received for that amount of *energy* in comparison with the value as represented in the *generator's* day-ahead *offer* for incremental *energy* and *speed-no-load costs*;

b. Component 2 is the value of arranging the delivery (where the real-time *offer* is less than the day-ahead *offer*), or any gain (where the real-time *offer* is greater than the day-ahead *offer*)[2] for the portion of *schedule of record* quantity that is not implemented in the real-time *dispatch* schedule;

c. Component 3 is any income from real-time *energy* congestion management settlement credit (CMSC) included in a *generator's*

[2] Where the real-time *offer* is equal to the day-ahead *offer*, the value/gain is equal to zero (0).

schedule of record delivered in real-time and will be used to reduce the day-ahead production cost guarantee payment;

d. Component 4 is any income from real-time *operating reserve* in a *generator's schedule of record* that was not dispatched in real-time and will be used to reduce the day-ahead production cost guarantee payment; and

e. Component 5 is the as-offered *start-up cost* (as-offered value of bringing an off-line *generator* on-line to *minimum loading point*).

4.7D.2 The *IESO* shall determine the type of schedule and which components described in Section 4.7D.1 are included in the day-ahead production cost guarantee, for each *generation unit,* as follows:

a. Variant 1: If the *generation unit* is not operating from the previous *dispatch day* into the current *dispatch day*, the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 5. Variant 1 occurs when:

- the *generation unit* is not operating at the end of the previous DACP dispatch day (Day-1 HE 24 indicates off-line status); or
- the *generation unit* is operating at the end of the previous DACP dispatch day (Day-1, HE 24 indicates on-line status) but it is not operating into the current DACP dispatch day (Day 0, HE 1 indicates off-line status); or
- the *generation unit* is scheduled to start later in the current DACP dispatch day.

b. Variant 2: If the *generation unit* is operating from the previous *dispatch day* into the current *dispatch day*, to complete its *minimum generation block run-time* the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 4 but does not include Component 5. The day-ahead production costs guarantee calculation also includes a clawback for Component 1 and Component 3

c. Variant 3: If a *generation unit* is operating from the previous *dispatch day* into the current *dispatch day* and has completed its *minimum generation block run-time* in the previous *dispatch day*, the day-ahead production costs guarantee calculation for the current *dispatch day* includes Components 1 through 4 but does not include Component 5. Variant 3 occurs when:

- the *generation unit* is operating from the previous DACP *dispatch day* (Day-1, HE 24 indicates on-line status) into the current DACP *dispatch day* (Day 0, HE 1 indicates on-line status) and has completed its *MGBRT* in the previous DACP *dispatch day*; or
- the *generation unit* is operating from the previous DACP *dispatch day* (Day-1, HE 24 indicates on-line status) into the current DACP *dispatch day*, (Day 0, HE 1 indicates on-line status) and has not completed its *MGBRT* and is scheduled in the current DACP *dispatch day* for hours in excess of completing its *MGBRT* from the previous DACP *dispatch day*. Variant 3 in the current DACP *dispatch day* is only for the hours in excess of completing the *MGBRT* hours for the start from the previous DACP *dispatch day*.

4.7D.3 The *IESO* shall calculate the day-ahead production cost guarantee components 1 through 4 for each interval in the *schedule of record* where the *generator* is injecting into the *IESO-controlled grid*.

4.7D.4 The *IESO* shall calculate the day-ahead production cost guarantee components based on the type of schedule described in Section 4.7D.2 as follows:

Component 1 – Variants 1, 2 and 3

Component 1 includes any shortfall in payment for the minimum of the *generator's schedule of record*, real-time constrained schedule and the allocated quantity of *energy* injected based upon the real-time revenue received for that amount of *energy* in comparison with the costs as represented in the *generator's* day-ahead *offer*. Component 1 is calculated as follows:

$PCG\_COMP1_{k,h}^{m,t}$ = All day-ahead costs excluding as-offered *start-up costs* for the minimum of the *generator's schedule of record*, real-time constrained scheduled and the allocated quantity of *energy* injected over the interval minus all real-time revenue received over the interval for that amount of *energy*

$$PCG\_COMP1_{k,h}^{m,t} = (-1)\times OP\left(EMP_{h}^{m,t}, MIN\left(DA\_DQSI_{k,h}^{m,t}, DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t}\right), DA\_BE_{k,h}^{m,t}\right) + \frac{DA\_SNLC_{k,h}^{m}}{12}$$

Component 1 Clawback – Variant 2

Component 1 Clawback recovers the day-ahead production cost guarantee Component 1 paid up to the *minimum loading point* for the remaining hours of *MGBRT*. Component 1 Clawback– Variant 2 is calculated as follows:

$PCG\_COMP1\_CB_{k,h}^{m,t}$ = All day-ahead costs excluding as-offered *start-up costs* up to the minimum of the *generation facility's minimum loading point* and the allocated quantity of energy injected over the interval minus all real-time revenue received over the interval for that amount of *energy*

$$PCG\_COMP1\_CB_{k,h}^{m,t} = \begin{array}{c}(-1)\times OP\left(EMP_{h}^{m,t}, MIN\left(AQEI_{k,h}^{m,t}, MLP_{k,h}^{m,t}\right), DA\_BE^{m,t}\right)\\ +\dfrac{DA\_SNLC_{k,h}^{m}}{12}\end{array}$$

Component 2 – Variants 1, 2 and 3

If, as a result of economic selection, a portion of the *schedule of record* is not implemented in the real-time *dispatch* schedule, the day-ahead production cost guarantee:

Guarantees the cost of arranging the delivery if the real-time *offer price* is less than the day-ahead *offer price*; or

Subtracts any gain where the real-time *offer price* is greater than the day-ahead *offer price*.

In the absence of a forced de-rating or a scheduled de-rating, if there are no real-time *energy offers* for any portion of the day-ahead constrained schedule, the real-time *energy offers* for that portion of *energy* will be set to MMCP (*Maximum Market Clearing Price*) for the purposes of calculating Component 2.

If the real-time *energy offers* for any portion of the day-ahead constrained schedule is below \$0.00 \$/MWh (i.e. negative), the real-time *energy offers* for that portion of *energy* will be set to \$0.00 \$/MWh for the purposes of calculating Component 2.

Component 2 is calculated as follows:

$PCG\_COMP2_{k,h}^{m,t}$ = As-offered day-ahead costs excluding as-offered *start-up costs* for the difference between:

- the minimum of the *generator's schedule of record*, the de-rated value of the *generation facility* or the maximum of the real-time constrained schedule and the allocated quantity of *energy* injected; and
- the minimum of the *generator's schedule of record* and the de-rated value of the *generation facility*

over the interval minus all real-time *energy offers* (with a minimum limit of zero) over the interval for that amount of *energy*

$$PCG\_COMP2_{k,h}^{m,t} = XDA\_BE_{k,h}^{m,t} - MAX\left(0, XBE_{k,h}^{m,t}\right)$$

Where:

Let $XBE_{k,h}^{m,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=p^*}^{s^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{s^*}\right) \times P_{s^*+1}$$

where matrix (B) is *energy offers* submitted in real-time, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at m*etering point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

Let $XDA\_BE_{k,h}^{m,t}$ be the function which calculates the area under the curve created by an n x 2 matrix (B) of offered *price-quantity pairs*:

$$\left[\sum_{n=c^*}^{d^*} P_n \times \left(Q_n - Q_{n-1}\right)\right] + \left(Q - Q_{d^*}\right) \times P_{d^*+1}$$

where matrix (B) is *energy offers* submitted in pre-dispatch, represented as an N by 2 matrix of *price-quantity pairs* for each *market participant* 'k' at *metering point* 'm' during *metering interval* 't' of *settlement hour* 'h' arranged in ascending order by the offered price in each *price quantity pair* where offered prices 'P' are in column 1 and offered quantities 'Q' are in column 2

c* = the highest indexed row of matrix $XDA\_BE_{k,h}^{m,t}$ such that $Q_{c^*} \leq \min[DA\_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})] \leq Q_n$ and where $Q_{c^*-1} = \min[DA\_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})]$ and where if $Q_{c^*} < Q_{c^*-1}$, let $Q_{c^*} = Q_{c^*-1}$

d* = the highest indexed row of matrix $XDA\_BE_{k,h}^{m,t}$ such that $Q_{d^*} \leq \min[DA\_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}] \leq Q_n$

p*	=	the highest indexed row of matrix $XBE_{k,h}^{m,t}$ such that $Q_{p^*} \leq \min[DA\_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})] \leq Q_n$ and where $Q_{p^*-1} = \min[DA\_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}, \max(DQSI_{k,h}^{m,t}, AQEI_{k,h}^{m,t})]$ and where if $Q_{p^*} < Q_{p^*-1}$, let $Q_{p^*} = Q_{p^*-1}$
s*	=	the highest indexed row of matrix $XBE_{k,h}^{m,t}$ such that $Q_{s^*} \leq \min[DA\_DQSI_{k,h}^{m,t}, OPCAP_{k,h}^{m,t}] \leq Q_n$

Component 3 – Variants 1, 2 and 3

The day-ahead production cost guarantee payment for a *generator* will be reduced by the income received from real time congestion management settlement credits (CMSC) for the *generator's schedule of record* delivered in real-time.

The *generator's schedule of record* will be measured against both the real-time constrained schedule and the real-time unconstrained schedule to determine the amount of revenue from congestion management settlement credits that should be included in the day-ahead production cost guarantee calculation.

For any interval, there are six possible orderings of the amount of a *generation facility's* capacity that may be included in the *schedule of record*, the real-time constrained schedule and the real-time unconstrained schedule. The table below summarizes the six possible orderings and the inclusion of Component 3 in the day-ahead production cost guarantee calculation.

For the purposes of determining the applicable CMSC in Component 3, the o*ffer price* is subject to Section 3.5.6.

Table: Ordering of Generator's Capacity and Day-Ahead Production Cost Guarantee Component 3

Scenario	Ordering	Component 3 - CMSC Included?
1	DQSI >= MQSI >= DA_DQSI	N
2	MQSI >= DQSI >= DA_DQSI	N
3	DQSI > DA_DQSI > MQSI	Y (Partial CMSC)
4	MQSI > DA_DQSI > DQSI	Y (Partial CMSC)
5	DA_DQSI >= DQSI > MQSI	Y (All CMSC)
6	DA_DQSI >= MQSI > DQSI	Y (All CMSC)

Component 3 is calculated as follows :

$PCG\_COMP3_{k,h}^{m,t}$ = Income received from real time congestion management *settlement* credits (CMSC) for the *generator's schedule of record* delivered in real-time over the interval

Component 3 is only calculated when:

- the real-time CMSC ($TD_{k,h,105}^{m,t}$) for the same interval is a value other than zero; and
- the mathematical sign of (DQSI-MQSI) is equal to the mathematical sign of (AQEI-MQSI).

Scenario 1

$PCG\_COMP3_{k,h}^{m,t} = 0$

Scenario 2

$PCG\_COMP3_{k,h}^{m,t} = 0$

Scenario 3

$$PCG\_COMP3_{k,h}^{m,t} = OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) - MAX\left(OP\left(EMP_h^{m,t}, DA\_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right)$$

Scenario 4

$$PCG\_COMP3_{k,h}^{m,t} = OP\left(EMP_h^{m,t}, DA\_DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right) - MAX\left(OP\left(EMP_h^{m,t}, DQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)\right)$$

Scenario 5

$PCG\_COMP3_{k,h}^{m,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Scenario 6

$PCG\_COMP3_{k,h}^{m,t}$ = Congestion management *settlement* credit calculated as per Section 3.5.

Component 3 Clawback – Variant 2

Component 3 Clawback – Variant 2 recovers the congestion management *settlement* credits (CMSC) paid up to the *minimum loading point* for the remaining hours of MGBRT. Component 3 Clawback – Variant 2 is calculated as follows:

$PCG\_COMP3\_CB_{k,h}^{m,t}$ = Income received from real time congestion management *settlement* credits (CMSC) from the minimum of *generation units minimum loading point* and the allocated quantity of energy injected to the real-time unconstrained schedule over the interval

Component 3 Clawback - Variant 2 is only calculated when:

- the *schedule of record* is not less than both the real-time constrained schedule and the real-time unconstrained schedule and the event is a constrained-on event (i.e. Scenarios 3 and 5);
- the *minimum loading point* is greater than the real-time unconstrained schedule; and
- Component 3 ($PCG\_COMP3_{k,h}^{m,t}$) for the same interval is a value other than zero.

Scenario 1

$PCG\_COMP3\_CB_{k,h}^{m,t} = 0$

Scenario 2

$PCG\_COMP3\_CB_{k,h}^{m,t} = 0$

Scenario 3

In Scenario 3, the clawback ($PCG\_COMP3\_CB_{k,h}^{m,t}$) is only calculated when the *minimum loading point* is greater than the real-time unconstrained schedule.

$$PCG\_COMP3\_CB_{k,h}^{m,t} = MAX\left(OP\left(EMP_h^{m,t}, MLP_{k,h}^{m,t}, BE_{k,h}^{m,t}\right), OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right.\right. - OP\left(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t}\right)$$

Scenario 4

$PCG\_COMP3\_CB_{k,h}^{m,t} = 0$

Scenario 5

In Scenario 5, the clawback ($PCG\_COMP3\_CB_{k,h}^{m,t}$) is only calculated when the *minimum loading point* is greater than the real-time unconstrained schedule.

$$PCG\_COMP3\_CB_{k,h}^{m,t} = MAX\left(OP(EMP_h^{m,t},MLP_{k,h}^{m,t},BE_{k,h}^{m,t}),OP\left(EMP_h^{m,t}, AQEI_{k,h}^{m,t},BE_{k,h}^{m,t}\right)\right) - OP(EMP_h^{m,t}, MQSI_{k,h}^{m,t}, BE_{k,h}^{m,t})$$

Scenario 6

$$PCG\_COMP3\_CB_{k,h}^{m,t} = 0$$

Component 4 – Variants 1, 2 and 3

The day-ahead production cost guarantee payment for a *generator* will be reduced by the income received from real-time *operating reserve* for the *generator's schedule of record* not dispatched in real-time.

Component 4 is calculated as follows:

$PCG\_COMP4_{k,h}^{m,t}$ = net income received from real-time *operating reserve* over the interval for the *generator's schedule of record* not dispatched in real-time

$$PCG\_COMP4_{k,h}^{m,t} = OP(PROR_{r1,h}^{m,t}, 30R\_SQROR_{r1,k,h}^{m,t}, BR_{k,h}^{m,t}) + OP(PROR_{r2,h}^{m,t}, 10NS\_SQROR_{r2,k,h}^{m,t}, BR_{k,h}^{m,t}) + OP(PROR_{r3,h}^{m,t}, 10S\_SQROR_{r3,k,h}^{m,t}, BR_{k,h}^{m,t})$$

Where:

r1 = *30-minute operating reserve*

r*2* = 10-minute non-spinning *operating reserve*

r*3* = 10-minute spinning *operating reserve*

$$30R\_SQROR_{r1,k,h}^{m,t} = MAX\left[0,MIN\left(DA\_DQSI_{k,h}^{m,t}-MQSI_{k,h}^{m,t},SQROR_{r1,k,h}^{m,t}\right)\right]$$

$$10NS\_SQROR_{r2,k,h}^{m,t} = MAX\left[0,MIN\left(DA\_DQSI_{k,h}^{m,t}-MQSI_{k,h}^{m,t}-30R\_SQROR_{r1,k,h}^{m,t},SQROR_{r2,k,h}^{m,t}\right)\right]$$

$$10S\_SQROR_{r3,k,h}^{m,t} = MAX\left[0,MIN\left(DA\_DQSI_{k,h}^{m,t}\text{-}MQSI_{k,h}^{m,t}\text{-}30R\_SQROR_{r1,k,h}^{m,t}\text{-}10NS\_SQROR_{r2,k,h}^{m,t},SQROR_{r3,k,h}^{m,t}\right)\right]$$

x^* = the highest indexed row of matrix $BR_{r1,k,h}^{m,t}$, such that $QR_{x^*} \leq \max[0,\min(DA\_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t}, SQROR_{r1,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

y^* = the highest indexed row of matrix $BR_{r2,k,h}^{m,t}$ such that $QR_{y^*} \leq \max[0,\min(DA\_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t} - 30R\_SQROR_{r1,k,h}^{m,t}, SQROR_{r2,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

z^* = the highest indexed row of matrix $BR_{r3,k,h}^{m,t}$, such that $QR_{z^*} \leq \max[0,\min(DA\_DQSI_{k,h}^{m,t} – MQSI_{k,h}^{m,t} - 30R\_SQROR_{r1,k,h}^{m,t} - 10NS\_SQROR_{r1,k,h}^{m,t}, SQROR_{r3,k,h}^{m,t})] \leq QR_n$ and where $QR_0 = 0$

Component 5 – Variant 1

Component 5 is the as-offered *start-up cost* incurred to bring an off-line *generation unit* through all the unit specific start-up procedures, including synchronization and ramp up to *minimum loading point*. Component 5 is calculated as follows:

$PCG\_COMP5_{k,h}^{m,t}$ = As-offered *start-up cost* submitted by the *market participant* for the DACP start event.

The rules for calculating Component 5 are as follows:

- **Scenario 1:** If the *market participant* achieves *minimum loading point* within the first 6 intervals[3] of the start of the DACP scheduled period, the full as-offered start-up cost is considered.
- **Scenario 2:** If the *generation unit* achieves *minimum loading point* between the start of the 7th interval and before the start of the 18th interval of the start of the DACP scheduled period, the as-offered start-up cost is calculated on a fractional basis. The as-offered start-up cost is calculated based on the number of 5-minute intervals the resource takes to achieve *minimum loading point* between the start of the 7th interval and before the start of the 18th interval.
- **Scenario 3:** If the *generation unit* achieves *minimum loading point* after the 17th interval of the start of the DACP scheduled period (i.e. 18th interval and onwards), the as-offered *start-up cost* is not considered.

[3] The duration of an interval is 5 minutes.

Scenario 1

$PCG\_COMP5_{k,h}^{m,t} = DA\_SUC_{k,h}^{m}$

Scenario 2

$$PCG\_COMP5_{k,h}^{m,t} = DA\_SUC_{k,h}^{m} - \left(DA\_SUC_{k,h}^{m} \times \frac{1}{DA\_INT} \times SUC\_INT\right)$$

Where

$DA\_INT = 12$

SUC_INT = number of 5-minute intervals between Interval 7 and 18 the *market participant* takes to achieve *minimum loading point*.

Scenario 3

$PCG\_COMP5_{k,h}^{m,t} = 0$

Component 5 – Variants 2 and 3

Component 5 is not calculated for Variants 2 and 3.

4.7D.5 If for each DACP start event for each eligible *generation unit* the sum of the revenues referred to in section 4.7D.4 is greater than or equal to the sum of the costs referred to in section 4.7D.4, then the *IESO* shall make no additional payments in respect of the eligible *generation facility*.

4.7D.6 Subject to section 4.7D.7, if for each DACP start event for each eligible *generation unit* the sum of the revenues referred to in section 4.7D.4 is less than the sum of the costs referred to in section 4.7D.4, then the *IESO* shall include that amount in the form of additional payments made in respect of the eligible *generation facility*.

4.7D.7 A *generation unit* shall not be eligible for additional payments determined in accordance with section 4.7D.6 when:

- the *generation unit's* online status in Day-1, HE24 is attributed to any *pre-dispatch schedule* other than a *schedule of record;* and
- the *generation unit* receives a Variant 3 type *schedule of record* beginning in Day0, HE1 pursuant to section 4.7D.2.c for the purpose of ramping down the *generation unit* to offline status; and
- the *generation unit* would have otherwise not been economic in HE1 of Day 0.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

4.7D.8 A day-ahead production cost guarantee shall not be paid where a *generation unit* has committed its capacity to an external *control area* and:

4.7D.8.1 the external *control area operator* has called a *called capacity export* prior to the *generation unit* being scheduled for the day-ahead production cost guarantee in accordance with section 5.8 of Chapter 7; or

4.7D.8.2 the external *control area operator* has called a *called capacity export* after the *generation unit* has been scheduled for the day-ahead production cost guarantee in accordance with section 5.8 of Chapter 7 and the *IESO* is restricting other transactions on *interconnected systems* in accordance with section 2.3 and 5.7 of Chapter 5, while maintaining the *called capacity export* transaction.

The *IESO* may withhold or recover such payments made in respect of the *generation unit* and shall redistribute any recovered payments in accordance with section 4.8.2.

4.7E Day-Ahead Fuel Cost Compensation Settlement Amount

4.7E.1 In the event that the *IESO*, in order to maintain reliable operation of the *IESO-controlled grid* requires a *generation facility*:

a. that was included in the *schedule of record*; and

b. for which the *registered market participant* for the *generation facility* is deemed to have accepted the day-ahead production cost guarantee in accordance with Section 5.8.4 of Chapter 7;

either to de-synchronize from the *IESO-controlled grid* prior to the end of its commitment scheduled in the ***s**chedule of record* or not to synchronize to the *IESO-controlled grid*, the *market participant* may, in accordance with chapter 7 section 6.3B, claim, in the manner specified in the applicable *market manual*, reimbursement of financial losses related to the procurement of fuel for operation at its commitment scheduled in the *schedule of record* and which was not ultimately utilized by that *generation facility*.

4.7E.2 Where the *IESO* determines that claims made under section 4.7E.1 are valid, such compensation claims will be applied to the *market participant's settlement statement* for the last *trading day* of each *real-time market billing period* after the determination has been made.

4.7E.3 All claims made to the *IESO* pursuant to section 4.7E.1 may be subject to audit by the *IESO* which may obligate the *market participant* to demonstrate or otherwise make a binding declaration that the financial loss being claimed was not mitigated through the actions of:

a. the *market participant*;

b. an *affiliate* or subsidiary of the *market participant*; or

c. any other party that may have a commercial relationship with the *market participant* where that commercial relationship involves compensation of any kind that is directly related to the mitigation of the financial loss being claimed.

4.7E.4 The cumulative *settlement amounts* payable to *market participants* for each real-time *energy market billing period* under the provisions of section 4.7E.2 shall be recovered from *market participants* in accordance with section 4.8.1.12.

4.7F [Intentionally left blank – section deleted]

4.7F.1 [Intentionally left blank – section deleted]

4.7F.2 [Intentionally left blank – section deleted]

4.7F.3 [Intentionally left blank – section deleted]

4.7G Forecasting for Variable Generation

4.7G.1 The *IESO* may contract for forecasting services relating to *variable generation*.

4.7H [Intentionally left blank – section deleted]

4.7H.1 [Intentionally left blank – section deleted]

4.7H.2 [Intentionally left blank – section deleted]

4.7H.3 [Intentionally left blank – section deleted]

4.7I [Intentionally left blank – section deleted]

4.7I.1 [Intentionally left blank – section deleted]

4.7I.2 [Intentionally left blank – section deleted]

4.7I.3 [Intentionally left blank – section deleted]

4.7J Capacity Obligations

Capacity Obligation Availability Payments

4.7J.1 The *capacity auction* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CAAP^{m}_{k}$") shall be calculated for each *energy market billing period* and disbursed to *capacity market participants* who have a *capacity obligation* during the relevant *obligation period* and which shall be calculated as follows:

$$CAAP^{m}_{k} = \Sigma^{H}\ CCO^{m}_{k,h} \times CACP^{z}_{h}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *business days* in the relevant *energy market billing period*.

4.7J.2 [Intentionally left blank – section deleted]

Capacity Obligation Availability Charges

4.7J.2.1 The *capacity auction* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *trading day* ("$CAAC^{m}_{k}$") shall be collected from such *capacity market participants* in accordance with the following:

4.7J.2.1A In regard to a *capacity market participant* participating with an *hourly demand response resource* or a *capacity dispatchable load resource*, the *capacity auction* availability charge *settlement amount* shall be calculated for each *trading day* for which it fails for any *settlement hour* of the *availability window* during such *trading day* to submit a *demand response energy bid* in an amount that is greater than or equal to its *capacity obligation* in the day-ahead commitment process and maintain such *energy bid* through the *real-time market.* Where a *capacity market participant* participating with an *hourly demand response resource* does not receive a standby notice, the *demand response energy bid* is instead required to be maintained until 7:00 am EST of the relevant *trading day*. The *capacity auction* availability charge *settlement amount* is calculated as follows:

$$CAAC^{m}_{k} = \Sigma^{H} (-1) \times Max(0, CCO^{m}_{k,h} - DREBQ^{m}_{k,h}) \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*;

(b) If the *capacity market participant* did not submit a *demand response energy bid* for its *hourly demand response resource* or *capacity dispatchable load resource*, as the case may be, for *settlement hour* 'h' in the day-ahead commitment process or failed to maintain such *energy bid* through the *real-time market* or until 7:00 am EST as the case may be, $DREBQ^{m}_{k,h}$ = 0;

(c) In regards to *hourly demand response resource*, if the *demand response energy bids* submitted for *settlement hour* 'h' does not form part of *energy bids* spanning at least four consecutive *settlement hours*, $DREBQ^{m}_{k,h}$ = 0;

(d) If the *demand response energy bid* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *demand response energy bid* submitted in the *real-time market* for the same *settlement hour*, $DREBQ^{m}_{k,h}$ shall be equal to the lesser of the two *demand response energy bids*; and

(e) Notwithstanding any of the foregoing, $DREBQ^{m}_{k,h}$ shall not exceed the $CARC^{m}_{k}$ for the *hourly demand response resource*.

4.7J.2.1B For a *capacity market participant* participating with a *capacity generation resource*, *system-backed capacity import resource*, *generator-backed capacity import resource*, or *capacity storage resource*, the *capacity auction* availability charge *settlement amount* shall be calculated for each *trading day* it fails for any *settlement hour* of an *availability window* during such *trading day* to submit *energy offer* in an amount that is greater than or equal to its *capacity obligation* in the day-ahead commitment process and maintain such *energy offer* as follows: (a) for *system-backed capacity import resources* or *generator-backed capacity import resources,* through to pre-dispatch; (b) for *capacity storage resources,* through the *real-time market;* and (c) for *capacity generation resources,* in accordance with the applicable *market manual*. The *capacity auction* availability charge *settlement amount* is calculated as follows:

$$CAAC^{m}_{k} = \Sigma^{H} (-1) \times Max(0, CCO^{m}_{k,h} - CAEO^{m}_{k,h}) \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* during the relevant *trading day*;

(b) If the *capacity market participant* did not submit an *energy offer* in the day-ahead commitment process or maintain such *energy offer* through to pre-dispatch or the *real-time market*, as the case may be, for *settlement hour* 'h', $CAEO^{m}_{h,k} = 0$;

(c) If the *energy offer* submitted in the day-ahead commitment process for *settlement hour* 'h' is not equal to the *energy offers* submitted in pre-dispatchor the *real-time market* for the same *settlement hour*, the $CAEO^{m}_{k,h}$ shall be equal to the lesser of any such *energy offers*; and

(d) If a *capacity storage resource* receives a non-zero *energy dispatch instruction* within the relevant *availability window,* the $CAEO^{m}_{k,h}$ for the remaining *settlement hours* of the *availability window* after receiving such non-zero *energy dispatch instruction* shall be equal to the *energy offer* applicable to the *settlement hour* in which they receive such non-zero *energy dispatch instruction.*

Capacity Obligation Dispatch Charges

4.7J.2.2 Subject to section 19.4.5 and 7.5.3 of Chapter 7, the *capacity auction* dispatch charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' ("$CADC^{m}_{k,h}$") shall be calculated and collected from such *capacity market participant* participating with a commercial or industrial *hourly demand response resource* for each *settlement hour* of an *availability window* in which the *hourly demand response resource* fails to comply with an activation notice, as determined in accordance with section 4.7J.2.2.1, and which shall be calculated in accordance with the following:

$$CADC^{m}_{k,h} = (-1) \times DRSQty^{m}_{k,h} \times CACP^{z}_{h} \times CNPF_{tm}$$

Where:

(a) 'h' is a *settlement hour* in which the *hourly demand response resource* failed to comply with its activation notice, as determined in accordance with the applicable *market manual*.

(b) 'tm' is the *energy market billing period* that corresponds to *settlement hour* 'h'.

4.7J.2.2.1 A commercial or industrial *hourly demand response resource* is determined to have failed to comply with an activation notice if the following condition is true:

$$C\&I\_HDR\_BL^{m,t}_{k,h} - HDR\_AC^{m,t}_{k,h} < 85\% \times (TBQ^{m,t}_{k,h} - DQSW_{k,h}^{m,t})$$

Where:

(a) "$C\&I\_HDR\_BL^{m,t}_{k,h}$" is the amount calculated pursuant to the applicable *market manual*.

(b) "$HDR\_AC^{m,t}_{k,h}$" is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *metering interval* 't' of *settlement hour* "h", as determined in accordance with the submitted measurement data and AQEW, as the case may be.

(c) "$TBQ^{m,t}_{k,h}$" has the same meaning as ascribed to the same variable within the definition of $HDRDC^{m}_{k,h}$ in section 3.1.10.

Capacity Obligation Administration Charges

4.7J.2.3 The *capacity auction* administration charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAADM^{m}_{k}$") shall be calculated and collected from each *capacity market participant* participating with a virtual *hourly demand response resource* or a *generator-backed capacity import resource* for each *energy market billing period* in which such *capacity market participant* fails to provide timely, accurate and complete data, including measurement data to the *IESO* in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CAADM^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Charges

4.7J.2.4 The *capacity auction* capacity charge *settlement amount* for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' in the relevant *energy market billing period* ("$CACC^{m}_{k}$") shall be calculated and collected from each *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to deliver its *cleared ICAP* within the applicable threshold, as set out in the applicable *market manual,* in response to a *capacity auction capacity test*, and which shall be calculated as follows:

$$CACC^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

4.7J.2.5 [Intentionally left blank – section deleted]

4.7J.2.6 [Intentionally left blank – section deleted]

Capacity Obligation Capacity Import Call Failure Charges

4.7J.2.7 Subject to section 7.5.8A of Chapter 7, the *capacity auction* capacity import failure *settlement amount* for *capacity market participant* 'k' participating with a *generator-backed capacity import resource* at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period* ("$CACIF^{m}_{k}$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which such *capacity market participant* fails to satisfy its *capacity obligation* in response to a *capacity import call*, as determined in accordance with the applicable *market manual*, and which shall be calculated as follows:

$$CACIF^{m}_{k} = (-1) \times CAAP^{m}_{k}$$

Where:

(a) '$CAAP^{m}_{k}$' is the *capacity auction* availability payment *settlement amount*, calculated in accordance with section 4.7J.1, for *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' for the relevant *energy market billing period*.

Capacity Obligation Capacity Deficiency Charges

4.7J.2.8 The *capacity auction* capacity deficiency *settlement amount* for *capacity market participant* 'k' at *intertie metering point* 'i' for the relevant *energy market billing period* ("$CACD^{i}_{k}$") shall be calculated and collected from such *capacity market participant* for each *energy market billing period* in which the *IESO* has determined that all or a portion of the *capacity market participant's capacity obligation* is *over committed capacity*, and which shall be calculated and collected for the entire *obligation period* in accordance with the following:

$$CACD^{i}_{k} = \sum^{H} (-1.5) \times OCMW^{i}_{k} \times CACP^{z}_{h}$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* within the relevant *energy market billing period*.

4.7J.2.8.1 If the *IESO* determines that all or a portion of the *capacity market participant's capacity obligation* is *over committed capacity*, the *capacity market participant's capacity obligation* shall be reduced by the amount of *over committed capacity* effective as of the first *trading day* of the subsequent *energy market billing period*. If such reduction in the *capacity market participant's capacity obligation* for such resource results in such *capacity obligation* being less than one MW, the remainder of the *capacity market participant's capacity obligation* for such resource is forfeited effective as of the first *trading day* of the subsequent *energy market billing period*.

Capacity Obligation In-Period Cleared UCAP Adjustment Charge

4.7J.2.9 The *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *energy market billing period* ("$CAIPA^{m}_{k}$") shall be calculated and collected from such *capacity market participant* for i) the *energy market billing period* in which the *IESO* provided notice to the *capacity market participant* that the *hourly demand response resource's* average hourly capacity delivered over the four hour testing period was less than 90% of its *cleared UCAP*; ii) each prior *energy market billing period* of the relevant *obligation period* included as an adjustment to the next scheduled *recalculated settlement statement* for such *energy market billing period*; and iii) if the *capacity market participant* has filed a *notice of disagreement* in regards to the outcome of a *capacity auction capacity test,* each subsequent *energy market billing period* of the relevant *obligation period*. The *capacity obligation* in-period UCAP adjustment charge *settlement amount* is calculated as follows:

$$CAIPA^{m}_{k} = (-1 \times Max\ (0, (CAAP^{m}_{k} \times (UCAP\ Adjustment) + \sum^{H} CAAC^{m}_{k,h}))$$

Where:

(a) $CAAP^{m}_{k}$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1.

(b) $CAAC^{m}_{k,h}$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for *settlement hour* 'h', as calculated pursuant to section 4.7J.2.1.

(c) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *energy market billing period.*

(d) 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response resource's* delivered performance during a *capacity auction capacity test*, as determined in accordance with the applicable *market manual*. If the *capacity market participant* has filed a *notice of disagreement* in regards to the outcomes of the *capacity auction capacity test* in accordance with section 6.8, and but for filing such *notice of disagreement* the *capacity market participant* would have forfeited any of its *capacity obligation* pursuant to section 19.4.18 of Chapter 7, then the UCAP Adjustment shall equal 100%.

Capacity Obligation Buy-Out Charges

4.7J.3 A *capacity market participant* or a *capacity auction participant* may elect to be subject to a *capacity obligation* buy-out charge *settlement amount* for all, or a portion of, their *capacity obligation* in accordance with the applicable *market manual*. Upon the *IESO's* acceptance of a buy-out request, the *capacity market participant's capacity obligation* shall be reduced to reflect the approved buy-out and the *IESO* shall calculate the *capacity obligation* buy-out *settlement amount* for such *capacity market participant* 'k' at *delivery point* or *intertie metering point* 'm' ("$CABOC^{m}_{k}$") which shall be calculated as follows:

$$CABOC^{m}_{k} = 50\% \text{ x } \Sigma^{H} \text{ } CBOC^{m}_{k} \text{ x } CACP^{z}_{h} \text{ x } (1 - CNPF_{tm})$$

Where:

(a) 'H' is the set of all *settlement hours* within the *availability window* of all *trading days* from the buy-out effective date to the end of the *commitment period*.

(b) 'tm' is the *energy market billing period* that corresponds to the relevant *settlement hour*.

Measurement Data Audit

4.7J.4 At any time, the *IESO* may audit any submitted measurement data and supporting information and a *capacity market participant* shall provide such information in the time and manner specified by the *IESO*. If, as a result of such an audit, the *IESO* determines that actual measurement data and supporting information differed from the submitted measurement data and supporting information, the *IESO* shall recover from or distribute to a *capacity market participant* any resulting over or under payment, as applicable.

Capacity Obligation Dispatch Test Activation and Capacity Obligation Emergency Activation Payment

4.7J.5 Subject to section 4.7J.5.3, the *IESO* shall calculate and disburse a *capacity auction dispatch test* payment *settlement amount* or *capacity auction* emergency activation payment *settlement amount* for a valid *capacity auction dispatch test* or emergency activation, respectively, of an *hourly demand response resource* to the applicable *capacity market participant*, in accordance with the following:

4.7J.5.1 in regards to *capacity auction dispatch tests*, the c*apacity auction dispatch test* payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CATAP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CATAP^{m}_{k,h} = HDRTAPR \text{ X } HDRDC^{m}_{k,h}$$

4.7J.5.2 in regards to *emergency operating state* activation, the *capacity auction emergency operating state* activation payment *settlement amount* for *capacity market participant* 'k' participating with an *hourly demand response resource* at *delivery point* 'm' in *settlement hour* 'h' ("$CAEOP^{m}_{k,h}$") shall be determined for each applicable *settlement hour* within the activation window as follows:

$$CAEOP^{m}_{k,h} = Max(0, HDRBP^{m}_{k,h} - Max(0,HOEP_{h})) \text{ X } HDRDC^{m}_{k,h}$$

4.7J.5.3 If measurement data for any *metering interval* within a *settlement hour* was not submitted to the *IESO* in accordance with the applicable *market manual,* the *capacity market participant* shall not be eligible to receive a *capacity auction* test activation payment *settlement amount* or a *capacity auction emergency operating state* activation payment *settlement amount* for such *settlement hour*.

Capacity Obligation Availability Charges True-Up Payment

4.7J.6 The *capacity obligation* availability charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CAACT^m_k$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which (i) the *capacity market participant* was subject to an availability charge pursuant to section 4.7J.2.1 or 4.7J.2.1A; and (ii) the *capacity market participant offered* an amount of capacity in excess of the *capacity obligation* of its *capacity auction resource* for at least one *settlement hour* within the *availability window* of the applicable *obligation period*. The *capacity auction* availability charge true-up *settlement amount* shall be calculated as follows:

$$CAACT^m_k = (\text{Min}\ ((-1) \times \sum^{TM} ((\sum^{D} CAAC^m_k) + \text{UCAP Adjustment} \times CAAP^m_k + CAIPA^m_k), \sum^{H} \text{Max}\ (0,(RAC_k - CCO_{k,h}) \times CACP_h \times CNPF_{tm}))$$

Where:

(a) $CAAC^m_k$ is the *capacity obligation* availability charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *trading day,* as calculated as the sum of the *capacity obligation* availability charge *settlement amount* of each *settlement hour* within the relevant *availability window* determined pursuant to section 4.7J.2.1;

(b) 'UCAP Adjustment' is a de-rate (in %) based on the *hourly demand response* resource's delivered performance during a *capacity auction capacity test* performed during the relevant *obligation period*, as determined in accordance with the applicable *market manual*;

(c) $CAAP^m_k$ is the *capacity obligation* availability payment *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.1;

(d) $CAIPA^m_k$ is the *capacity obligation* in-period *cleared UCAP* adjustment charge *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' for the relevant *energy market billing period*, as calculated pursuant to section 4.7J.2.9;

(e) 'D' is the set of all *trading days* within the relevant *energy market billing period*;

(f) 'tm' is the *energy market billing period* associated with *settlement hour* 'h' within the relevant *obligation period;*

(g) 'TM' is the set of all *energy market billing periods* within the relevant *obligation period;* and

(h) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period.*

Capacity Obligation Capacity Auction Charges True-up Payment

4.7J.7 The *capacity obligation* charge true-up *settlement amount* for *capacity market participant* 'k' at *delivery point* 'm' in the relevant *obligation period* ("$CACT^{m}_{k}$") shall be calculated and disbursed to such *capacity market participant* for each *obligation period* in which the *capacity market participant* has a *capacity obligation*. The *capacity obligation* charge true-up *settlement amount* shall be calculated as follows*:*

$$CACT^{m}_{k} = -1 \text{x} Min\ (0, (\sum_{H} TD_{C,k,h}{}^{m} + \sum_{H} TD_{P,k,h}{}^{m}))$$

Where:

(a) $TD_{C,k,h}{}^{m}$ is the total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where:

a. 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.2.1, 4.7J.2.1A, 4.7J.2.3, 4.7J.2.4, 4.7J.2.7, 4.7J.2.8, and 4.7J.2.9.

(b) $TD_{P\ k,h}{}^{m}$ is the total dollar value of all *settlement amounts* 'P' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *obligation period*, where:

a. 'P' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1 and 4.7J.6

(c) 'H' is the set of all *settlement hours* 'h' within the *availability window* of the relevant *obligation period*.

Capacity Auction Uplift

4.7J.8 The *capacity auction* uplift *settlement amount* for *market participant* 'k' at *delivery point* 'm' in the *energy market billing period* ("CAU^{m}_{k}") will be calculated and collected from or disbursed to *market participants* for load facilities, as defined in *Ontario Regulation 429/04*, for each *energy market billing period*. The *capacity auction* uplift *settlement amount* shall be determined in accordance with sections 4.7J.8.1 and 4.7J.8.2. In calculating the *capacity auction* uplift *settlement amount* in this section 4.7J.8, the following subscripts and superscripts shall have the following meanings unless otherwise specified:

(a) 'H' is the set of all *settlement hours* 'h' in the relevant *energy market billing period;*

(b) 'M' is the set of all *delivery points* 'm' of *market participant* 'k';

(c) 'Class B Load' as defined in the applicable *market manual*;

(d) '$EGEI_k$' as defined in the applicable *market manual.*

4.7J.8.1 for *market participants* that are classified as a 'Class A Market Participants' in respect of the relevant load facility, as defined in *Ontario Regulation 429/04*, in accordance with *applicable law,* the *capacity auction* uplift *settlement amount* for such load facility shall be calculated as follows:

$$CAU^m_k = \Sigma_{H,M} (TD_{C,k,h}{}^m * PDF_k)$$

Where:

(a) '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where:

(i) 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(b) 'PDF_k' is the Peak Demand Factor for 'Class A Market Participant' or Distributor 'k' for the relevant *energy market billing period*, as determined in accordance with *applicable law,* where if the 'Class A Market Participant' or Distributor 'k' ceases to be a 'Class A Market Participant' in respect of the relevant load facility during the relevant *energy market billing period,* the PDF_k shall be pro-rated accordingly.

4.7J.8.2 for *market participants* that are classified as 'Class B Market Participants' in respect of the relevant load facility, as defined in *Ontario Regulation 429/04*, in accordance with *applicable law,* the *capacity auction* uplift *settlement amount* for such load facility shall be calculated in accordance with the following:

(a) for Fort Frances Power Corporation Distribution Inc.:

$$CAU^m_k = (\Sigma_{H,M}\ TD_{C,k,h}{}^m - TD_{C1350,k,h}{}^m) \text{ x } MAX((\ \Sigma_H{}^{M,T}\ AQEW_{k,h}{}^{m,t} + EGEI_k - EEQ),0)\ /\ \text{Class B Load}$$

Where:

(i) '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(ii) '$TD_{C1350,k,h}{}^m$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

(iii) 'EEQ' as defined in the applicable *market manual;*

(b) *market participants* that are classified as 'Class B Market Participants' in respect of the relevant load facility in accordance with *applicable law*:

$$CAU^m_k = (\Sigma_{H,M}\ TD_{C,k,h}{}^m - TD_{C1350,k,h}{}^m) \text{ x } MAX((\Sigma_H{}^{M,T}\ AQEW_{k,h}{}^{m,t} + EGEI_k - GA\_AQEW_{g,k,h,M}{}^{m,t} - PGS_{h,M}),0)\ /\ \text{Class B Load}$$

Where:

(i) '$TD_{C,k,h}{}^m$' is total dollar value of all *settlement amounts* 'C' for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period*, where 'C' is the set of the *settlement amounts* applied in accordance with MR Ch. 9 ss. 4.7J.1, 4.7J.2, 4.7J.3, 4.7J.5, 4.7J.6, and 4.7J.7.

(ii) '$TD_{C1350,k,h}^{m}$' is total dollar value of *settlement amounts* applied pursuant to section 4.7J.8.1 for *capacity market participant* 'k' at *delivery point* 'm' in *settlement hour* 'h' in the relevant *energy market billing period;*

(iii) '$GA\_AQEW_{g,k,h,M}^{m,t}$' as defined in the applicable *market manual*.

(iv) '$PGS_{h,M}$' as defined in the applicable *market manual*.

4.8 Additional Non-Hourly Settlement Amounts

4.8.1 The *IESO* shall, at the end of each *energy market billing period,* recover from *market participants,* on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period,* the following amounts:

4.8.1.1 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 5.3.4 of Chapter 4;

4.8.1.2 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 5.3.4 of Chapter 5;

4.8.1.3 any out-of-pocket expenses paid in that *energy market billing period* by the *IESO* pursuant to section 6.7.4 of Chapter 5;

4.8.1.4 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 8.4A.9 of Chapter 7;

4.8.1.5 any costs incurred in that *energy market billing period* by the *IESO* to acquire *emergency energy* pursuant to section 2.3.3A of Chapter 5;

4.8.1.6 any reimbursement paid in that *energy market billing period* by the *IESO* pursuant to section 2.1A.14;

4.8.1.7 [Intentionally left blank – section deleted]

4.8.1.8 [Intentionally left blank – section deleted]

4.8.1.9 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 4.7B.3;

4.8.1.10 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 4.7C;

4.8.1.11 any compensation paid in that *energy market billing period* by the *IESO* pursuant to section 8.2.6 of Chapter 5;

4.8.1.12 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7D;

4.8.1.13 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7E; and

4.8.1.14 [Intentionally left blank – section deleted]

4.8.1.15 [Intentionally left blank – section deleted]

4.8.1.16 any compensation paid in that *energy market billing period* by the *IESO* under section 4.7G.

4.8.2 The *IESO* shall, at the end of each *energy market billing period*, distribute to *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all *metering intervals* and *settlement hours* within that *energy market billing period*, the following amounts:

4.8.2.1 any compensation received by the *IESO* for the provision of *emergency energy* pursuant to section 4.4A.1 of Chapter 5;

4.8.2.2 any compensation received by the *IESO* as a result of a local market power investigation as set out in sections 1.7.1 and 1.7.2 of Appendix 7.6;

4.8.2.3 [Intentionally left blank – section deleted]

4.8.2.4 [Intentionally left blank – section deleted]

4.8.2.5 any payments recovered by the *IESO* in accordance with sections 3.5.1A and 3.5.6E;

4.8.2.6 any adjustments made by the *IESO* in accordance with section 3.5.6;

4.8.2.7 [Intentionally left blank – section deleted]

4.8.2.8 any proceeds from the day-ahead import failure charge that are not distributed as a component of *hourly uplift* under section 3.9.4;

4.8.2.9 any proceeds from the real-time import failure charge or the real- time export failure charge that in accordance with section 3.9.5 are not distributed as a component of *hourly uplift*;

4.8.2.10 any proceeds from the recovery of congestion management *settlement* credits or other *settlement amounts* in accordance with section 6.6.10A.2 of Chapter 3, excluding any payments recovered under section 4.18.1.6 of Chapter 8;

4.8.2.11 any recovery of day-ahead *intertie offer* guarantee payments pursuant to section 3.3A.13 of Chapter 7;

4.8.2.12 [Intentionally left blank – section deleted]

4.8.2.13 any recovery of payments made by the *IESO* under section 3.5.9;

4.8.2.14 any proceeds from the day-ahead *generator* withdrawal charge under section 3.8F;

4.8.2.15 any recovery of payments made by the *IESO* under section 3.5.10;

4.8.2.16 any recovery of payments made by the *IESO* under sections 4.7B.4A, 4.7D.7 or 4.7D.8;

4.8.2.17 any recovery of payments made by the *IESO* under section 3.5.7A; and

4.8.2.18 any recovery of payments made by the *IESO* under section 3.5.11.

4.8.3 The *IESO* shall, at the end of each *energy market billing period,* recover from *market participants,* in the manner specified in the applicable *market manual,* the following amounts:

4.8.3.1 [Intentionally left blank – section deleted];

4.8.3.2 [Intentionally left blank – section deleted];

4.8.3.3 any compensation for *capacity market participants* paid in that *energy market billing* period by the *IESO* pursuant to section 4.7J.

4.8.3.4 any funds borrowed by the *IESO* and any associated interest costs incurred by the *IESO* in the preceeding *energy market billing period* pursuant to section 6.16.6.2.

4.8.4 The *IESO* shall distribute to *market participants*, in the manner specified in the applicable *market manual*, the following amounts:

4.8.4.1 [Intentionally left blank – section deleted];

4.8.4.2 [Intentionally left blank – section deleted];

4.8.4.3 any adjustments to *capacity market participant* payments pursuant to section 4.7J.

5. Market Power Mitigation

5.1 Settlement of Market Power Mitigation Rebate

5.1.1 Any payment received by the *IESO* pursuant to the terms of any agreement:

5.1.1.1 to which the *IESO* is required by its *licence* to be a party;

5.1.1.2 which incorporates the terms of a directive issued by the *Minister* to the *Ontario Energy Board* pursuant to subsection 28(1) of the *Ontario Energy Board Act, 1998*; and

5.1.1.3 which provides for the payment to the *IESO* of a rebate of certain *settlement amounts*,

shall be distributed in accordance with the *IESO licence*, as amended from time to time.

5.1.2 [Intentionally left blank]

5.1.3 [Intentionally left blank]

5.1.4 [Intentionally left blank]

5.1.5 [Intentionally left blank]

5.1.6 [Intentionally left blank]

6. Settlement Statements

6.1 Communication of Settlement Information

6.1.1 All communications between *market participants* and the *IESO* relating to the *settlement* process shall be effected using the *electronic information system* and other such means of communication as may be specified in applicable *market manuals*.

6.1.2 If there is a failure of a communication system and it is not possible to communicate in accordance with the *electronic information system* or where applicable, the means of communication specified in the applicable *market manuals*, then the *IESO* or the *market participant*, as the case may be, shall communicate information relating to the *settlement process* by facsimile or other alternative means specified by the *IESO*.

6.2 Settlement Schedule and Payments Calendar

6.2.1 By November 1 of each year, the *IESO* shall *publish* the *IESO Settlement Schedule & Payments Calendar* or *SSPC* for the following calendar year showing the dates referred to in sections 6.3.2 to 6.3.23 as fixed dates within such calendar year.

6.2.2 If the *IESO* becomes aware of any change required to the *SSPC*, the *IESO* shall *publish* an updated *SSPC* to reflect the necessary changes. The *IESO* shall use reasonable efforts to provide *market participant*s with at least two weeks' notice of any changes to the *SSPC*.

6.2.3 The *SSPC* is *published* by the *IESO* for *market participant* ease of reference and the applicable dates that are binding on the *IESO* and *market participant*s are the dates determined in accordance with sections 6.3.1 to 6.3.23. Notwithstanding anything to the contrary, any reference in these *market rules* to the *SSPC* shall be deemed to be references to the dates specified in accordance with sections 6.3.1 to 6.3.23.

6.3 Settlement Cycles

6.3.1 Subject to section 6.3.24 to 6.3.33, section 6.3.2 to 6.3.23 set out the applicable dates for the *settlement process* and issuance of *settlement statements* and *invoices*.

TR auctions

6.3.2 The *preliminary settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued two *business days* after the *trading day*.

6.3.3 After the *preliminary settlement statement* referred to in section 6.3.2 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.4 The *final settlement statement* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued six *business days* after the *trading day*.

6.3.5 After the *final settlement statement* referred to in section 6.3.4 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.6 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a) or as otherwise required, *recalculated settlement statements* for each *trading day* for all rounds of any *TR auction* that is concluded on such *trading day* shall be issued at the following times:

a. the first *recalculated settlement statement* shall, where applicable, be issued on the last *business day* of the month immediately following the month of the *trading day* to which the *recalculated settlement statement* relates;

b. the *final recalculated settlement statement* shall be issued on the last *business day* of the month that is 22 months after the month of the *trading day* to which the *final recalculated settlement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement*; and

c. notwithstanding the foregoing, and at the *IESO*'s sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlement statement* referred to in section 6.3.6(a)-(b), an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* in the preceding 23-month period.

6.3.7 After a *recalculated settlement statement* referred to in section 6.3.6 is issued, each *market participant* shall have two *business days* in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.8 The *IESO* shall issue one invoice to each *market participant*, covering all *trading days* within a *billing period*, on the same business day it issues the *final settlement statement* for the last *trading day* of that *billing period*.

6.3.9 The *market participant payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.10 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant*'s payments in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.11 The *IESO payment date* for all rounds of any *TR auction* that is concluded during such *billing period* shall be the second *business day* after the corresponding *market participant payment date*.

6.3.12 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant* in respect of all rounds of any *TR auction* that is concluded in each *billing period* reach each *market participant*'s *settlement account* no later than the *close of banking business* (of the bank at which the *market participant*'s *settlement account* is held) on the *IESO payment date*.

Real-Time Markets

6.3.13 The *preliminary settlement statement* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the *trading day*.

6.3.14 After the *preliminary settlement statement* referred to in section 6.3.13 is issued, each *market participant* shall have six *business day*s to notify the *IESO* of errors or omissions in the *preliminary settlement statement* in accordance with section 6.8.

6.3.15 The *final settlement statement* for each *trading day* in the *real-time market*s and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued ten *business days* after the issuance of the *preliminary settlement statement* for that *trading day*.

6.3.16 After the *final settlement statement* referred to in section 6.3.15 is issued, each *market participant* shall have six *business day*s in which to notify the *IESO* of errors or omissions in the *final settlement statement* in accordance with section 6.8.

6.3.17 Where an adjustment is required pursuant to sections 6.8.9.2(b), 6.8.9.2(c), 6.9.1.2(b), 6.9.1.2(c), or 6.10.4.1(a), or as otherwise required, *recalculated settlement statements* for each *trading day* in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.3.2, shall be issued at the following times:

a. the first *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is one month after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the first *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

b. the second *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is two months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the second *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

c. the third *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is five months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the third *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

d. the fourth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eight months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fourth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

e. the fifth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is eleven months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the fifth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

f. the sixth *recalculated settlement statement* shall, where applicable, be issued on the same date as the *invoice* for the month that is seventeen months after the month which contains the trading day to which the *recalculated settlement* *statement* relates. For greater certainty, the sixth *recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month;

g. the *final recalculated settlement statement* shall be issued on the same date as the *invoice* for the month that is 23 months after the month which contains the *trading day* to which the *recalculated settlement statement* relates. For greater certainty, the *IESO* shall always issue the *final recalculated settlement statement* and the *final recalculated settlement statement* is issued on the same date for all the *trading day*s of a given month; and

h. notwithstanding the foregoing, and at the *IESO*'s sole discretion, the *IESO* may issue, either in lieu of or in addition to the *recalculated settlements statements* referred to in section 6.3.17(a)-(g), an ad hoc *recalculated settlement statement* at any time up to and including the scheduled date to issue the *final recalculated settlement statement* for the relevant *trading day*. An ad hoc *recalculated settlement statement* may relate to any *trading day* that was first invoiced in the preceding 23-month period.

6.3.18 After a *recalculated settlement statement* referred to in section 6.3.17 is issued, other than in respect of a *final recalculated settlement statement*, each *market participant* shall have six *business day*s in which to notify the *IESO* of errors or omissions in the *recalculated settlement statement* in accordance with section 6.8.

6.3.19 The *IESO* shall issue one *invoice* to each *market participant*, covering all *trading day*s within a *billing period*, and such other information specified in accordance with section 6.12.1, on the same day it issues the *preliminary settlement statement* for the last *trading day* of that *billing period*.

6.3.20 The *market participant payment date* for each *real-time market billing period* and for each *TR market billing period* shall be the second *business day* following the issuance of the *invoice*.

6.3.21 Each *market participant* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the *market participant*'s payments for each *real-time market billing period* and for each *TR market billing period* reach the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date*.

6.3.22 The *IESO payment date* for each *real-time market billing period* and for each *TR market billing period* shall be the second *business day* after the *market participant payment date*.

6.3.23 The *IESO* shall initiate the *electronic funds transfer* process in accordance with the provisions of section 6.14 so as to ensure that the sums owing to each *market participant*, *forecasting entity*, and to each *transmitter* for each *real-time market billing period* and for each *TR market billing period* reach the *market participant*'s *settlement account* or the *transmitter*'s *transmission services settlement account*, as the case may be, no later than the *close of banking business* (of the bank at which the *market participant*'s *settlement account* or the *transmitter*'s *transmission services settlement account* is held) on the *IESO payment date*.

Delays

6.3.24 The *IESO* may delay the issuance of *settlement statement*s for a *trading day* to a date later than that provided for in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, where, in the *IESO*'s opinion significant inaccuracies exist in the *settlement statements* such as to justify such delay.

6.3.25 Where the *IESO* delays the issuance of one or more *settlement statement*s for a *trading day* pursuant to section 6.3.24:

6.3.25.1 the issuance of *settlement statement*s for any immediately succeeding *trading day*s that would otherwise be required pursuant to sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be, to be issued prior to the date referred to in section 6.3.26.1 shall be delayed to that date or to such later date(s) as may be determined and published by the *IESO*; and

6.3.25.2 the date by which *market participant*s must notify the *IESO* of errors or omissions in any delayed *settlement statement*s for each of the *trading day*s referred to in section 6.3.25.1 shall be delayed by the same number of days which the *settlement statement* to which the date relates is delayed.

6.3.26 Where the *IESO* delays the issuance of a *settlement statement* for a *trading day* pursuant to section 6.3.24, the *IESO* shall publish notice of such delay, which notice shall indicate:

6.3.26.1 the date on which such *settlement statement* shall be issued in lieu of the date referred to in sections 6.3.2, 6.3.4, 6.3.6, 6.3.13, 6.3.15, and 6.3.17, as the case may be;

6.3.26.2 the date by which *market participants* must notify the *IESO* of errors or omissions in such *settlement statement*s, determined in accordance with section 6.3.25.2; and

6.3.26.3 whether the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27.

6.3.27 Where the *IESO* determines that it will be unable to issue *invoice*s calculated in accordance with section 6.12.1 in respect of a given *energy market billing period* on or within one *business day* of the applicable date determined in accordance with section 6.3.8 or 6.3.19, the *IESO* shall, within two *business days* of the applicable date, issue to each *market participant* an estimated *invoice* for such *energy market billing period* in a net amount determined in accordance with section 6.3.29.

6.3.28 Where the *IESO* intends to invoke the estimated *invoice* procedure referred to in section 6.3.27 or to delay the issuance of *invoice*s pursuant to section 6.3.33, the *IESO* shall *publish* a notice indicating whether the *IESO* intends, in accordance with section 6.3.31, to delay each of the *market participant payment date* and the *IESO payment date* associated with such *invoice*s or estimated *invoice*s.

6.3.29 The amount of an estimated *invoice* issued to a *market participant* pursuant to section 6.3.27 shall, subject to section 6.3.30, be determined in accordance with the following:

6.3.29.1 The amount referred to in section 6.4.2.1, shall be equal to the aggregate of:

6.3.29.1.1 the net total amount for that *market participan*t for all *trading day*s that occurred during the *energy market billing period* prior to the date on which the issuance of *preliminary settlement statements* commenced to be delayed pursuant to section 6.3.24 or 6.3.25.1, as the case may be;

6.3.29.1.2 for each *trading day* in the *energy market billing period* that occurred subsequent to the date referred to in section 6.3.29.1, the net total amount for that *market participant* as set forth in the *final settlement statement*s issued to that *market participant* in the preceding *energy market billing period*, commencing with the *final settlement statement* issued for the last *trading day* of such preceding *energy market billing period* and using a number of *final settlement statement*s equal to the number of *trading day*s in the current *energy market billing period* occurring subsequent to the date referred to in section 6.3.29.1; and

6.3.29.1.3 for greater certainty, any net total amount for that *market participant* reflected on a *recalculated settlement statement* which would have otherwise been included on the *invoice* for the relevant *energy market billing period* shall not be reflected on the estimated *invoice*.

6.3.29.2 The amount referred to in section 6.4.2.1, shall be equal to the aggregate of:

6.3.29.2.1 the net total amount for that *market participant* reflected on the relevant post-auction report issued pursuant to section 4.16.1 of Chapter 8 for the aggregate of the amounts for the purchase of *TRs* by the *market participant* in all rounds of any *TR auction* that is concluded within the relevant financial market *billing period*.

6.3.30 Where the data required to determine the amount of an estimated *invoice* in accordance with section 6.3.29.1 is not readily available at the relevant time, the *IESO* shall issue to each applicable *market participant* an estimated *invoice* in an amount equal to:

6.3.30.1 the net amount of the *invoice* issued to the *market participant* for the preceding *energy market billing period* minus any amounts on such *invoice* included on a *recalculated settlement statement*; or

6.3.30.2 zero, if no *invoice* was issued to the *market participant* for the preceding *energy market billing period*.

6.3.31 Where the *IESO* issues estimated *invoice*s pursuant to section 6.3.28 or delays the issuance of *invoice*s pursuant to section 6.3.33 in respect of a given *energy market billing period*, the *IESO* may, where the delay resulting in the need to issue an estimated *invoice* or to delay the issuance of the *invoice*s has or is likely to have an adverse effect on the operation of the *IESO settlement clearing account*, delay each of the *market participant payment date* and the *IESO payment date* associated with such estimated *invoice* or delayed *invoice* by one *business day* relative to the periods referred to in sections 6.3.9 or 6.3.15, or sections 6.3.11 or 6.3.17, respectively.

6.3.32 Where the *IESO* issues to a *market participant* an estimated *invoice* in respect of a given *energy market billing period* pursuant to section 6.3.27, the *IESO* shall adjust the *invoice* issued to the *market participant* for the next *energy market billing period* to reflect any net difference between the amount of the estimated *invoice* and the amount that would have been set forth on the *market participant*'s *invoice* had the *invoice* been calculated in accordance with section 6.12.1 rather than estimated in accordance with section 6.3.27, including adding any net amounts reflected on any *recalculated settlement statement*s for the same *energy market billing period*.

6.3.33 Where the *IESO* determines that:

6.3.33.1 it will be unable to issue *invoice*s calculated in accordance with section 6.12.1 in respect of a given *energy market billing period* on the applicable date specified in the accordance with sections 6.3.8 or 6.3.19 by reason of the delay in issuance of *settlement statement*s referred to in section 6.3.24 or 6.3.25.1, or for any other reason; and

6.3.33.2 it is able to issue such *invoice*s within one *business day* of the applicable date specified in accordance with sections 6.3.8 or 6.3.19 such that the estimated *invoice* procedure referred to in sections 6.3.27 to 6.3.32 does not apply,

the *IESO* may delay the issuance of such *invoice*s for such *energy market billing period* for a period of up to one *business day* relative to the applicable date specified in accordance with sections 6.3.8 or 6.3.19, as the case may be.

6.4 Settlement Statement Process

6.4.1 The *IESO* shall issue *settlement statement*s to each *market participant* to cover each trading day in accordance with section 6.5, section 6.6 and section 6.7, and shall provide the *settlement* data included in such *settlement statements* into the *settlement process*.

6.4.2 For each *settlement statement*, the *IESO* shall calculate a net *settlement amount* for each *market participant* for the *trading day*. The net *settlement amount* shall be comprised of:

6.4.2.1 the aggregate of the trading amounts from each transaction in each *settlement hour* in the *trading day*; and

6.4.2.2 the aggregate of the amounts for the purchase of *TR*s in all rounds of any *TR auction* that is concluded on the *trading day*,

adjusted to reflect any fees payable by the *market participant* and any other adjustment amounts payable or receivable pursuant to these *market rules.*

6.4.3 The net *settlement amount* referred to in section 6.4.2 shall be a positive or negative dollar amount for each *market participant* and:

6.4.3.1 where the net *settlement amount* for a *market participant* is negative, the absolute value of the *settlement amount* shall be an amount payable by the *market participant* to the *IESO*; or

6.4.3.2 where the net *settlement amount* for a *market participant* is positive, the *settlement amount* shall be an amount receivable by the *market participant* from the *IESO*.

6.4.4 *Settlement statements* shall be considered issued to *market participant*s when issued in accordance with the applicable *market manuals*.

6.4.5 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive a *preliminary settlement statement*, *final settlement statement*, or *final recalculated settlement statement* on the date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in section 6.3.25.1 and 6.3.26. Each *market participant* shall be deemed to have received such *settlement statements* on the relevant date specified in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, unless it notifies the *IESO* to the contrary within two *business days* of date specified for issuance of such *settlement statement* in accordance with sections 6.3.2 to 6.3.23.

6.4.6 In the event that a *market participant* notifies the *IESO* that it has failed to receive a *settlement statement* on the date specified for that *settlement statement* in accordance with sections 6.3.2 to 6.3.23 or, where applicable, on any of the dates referred to in sections 6.3.25.1 and 6.3.26, the *IESO* shall re-send such *settlement statement*, in which case the *settlement statement* shall be considered to have been received on the date the re-sent *settlement statement* is sent to the *market participant*.

6.5 Preliminary Settlement Statement Coverage

6.5.1 The *IESO* shall issue to each *market participant* separate *preliminary settlement statements* to cover:

6.5.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.5.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.5.1.1,

6.5.1.3 any adjustments which may be required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, 6.5.1.4 in accordance with the timelines set forth in sections 6.3.2, 6.3.13, 6.3.24 and 6.3.25.1, as may be applicable.

6.5.2 *Preliminary settlement statements* related to each *market participant* for all rounds of any *TR auction* that is concluded on a given *trading day* shall include, in electronic format, for each *settlement hour* of the relevant *trading day* or for each such *TR auction*, as the case may be, referenced by applicable *charge type*:

6.5.2.1 the *hourly Ontario energy price* in that *settlement hour*;

6.5.2.2 the payment for the *settlement hour*, either from the *market participant* to the *IESO*, or from the *IESO* to the *market participant*;

6.5.2.3 all fees, charges, credits and payments applicable to the *market participant* in respect of the purchase of a *TR* in all rounds of such *TR auction*; and

6.5.2.4 for each type of charge listed, the total *trading day's* charges and a *billing period*-to-date total.

6.5.3 *Preliminary settlement statements* related to each *market participant* for the *real-time markets* and for the *TR market,* other than in respect of the element referred to in section 6.5.2, shall include the *settlement amounts,* prices and quantities described in section 6.5.4, presented as follows:

6.5.3.1 for each hourly *settlement amount* referred to in section 3, by *metering interval* or *settlement hour*, as the case may be, depending upon the manner of calculation of the *settlement amount* as described in section 3;

6.5.3.2 for each non-hourly *settlement amount* referred to in section 4 or 5 that is required to be calculated over or in respect of a given *billing period*, by *billing period*, provided that such non-hourly *settlement amount*s shall be included only in the *preliminary settlement statement* issued in respect of the last *trading day* of a *billing period*; and

6.5.3.3 for each non-hourly *settlement amount*, other than those referred to in section 6.5.3.2, by *metering interval*, *settlement hour*, or *trading day*, as the case may be, depending upon the time period over or with respect to which the relevant *settlement amount* is required to be calculated pursuant to section 4, or 5.

6.5.4 The *preliminary settlement statement*s referred to in section 6.5.3 shall be in electronic format and shall set forth, for the *market participant* to whom the *preliminary settlement statement* is issued and referenced by applicable charge type:

6.5.4.1 the *energy* injected or withdrawn by each of that *market participant*'s *registered facilities* as determined in each of the *market schedule* and the *real-time schedule*.

6.5.4.2 the allocated quantities of *energy* withdrawn or injected by each of that *market participant*'s *registered facilities*.

6.5.4.3 the aggregate quantity of each class of *operating reserve* provided by each of that *market participant*'s *registered facilities* as determined in each of the *market schedule* and the *real-time schedule*.

6.5.4.4 the aggregate quantities or capacities, as the case may be, of each *contracted ancillary service* scheduled and provided from each of that *market participant*'s *registered facilities*;

6.5.4.5 the *physical bilateral contract quantities* for that *market participant*;

6.5.4.6 the availability payments to be made in each *billing period* under *reliability must-run contracts* to each of that *market participant*'s *reliability must-run resources*;

6.5.4.7 details of performance incentive payments or penalties applicable to the *market participant*;

6.5.4.8 the *energy market price* applying to each of that *market participant*'s *registered facilities*;

6.5.4.9 the applicable 5-minute price for each class of *operating reserve* for each of that *market participant*'s *registered facilities*;

6.5.4.10 detailed calculations of applicable *transmission services charges*, and the *market participant*'s share of these;

6.5.4.11 the total of each type of *contracted ancillary service* charges, and the *market participant*'s share of these;

6.5.4.12 all *real-time market* fees, charges and payments applicable to the *market participant* and the basis for deriving those fees, charges or payments;

6.5.4.13 for each type of charge listed, the total *trading day*'s charges and a *billing period*-to-date total; and

6.5.4.14 all *TR market* fees, charges, credits and payments applicable to the *market participant*.

6.6 Final Settlement Statement Coverage

6.6.1 The *IESO* shall issue to each *market participant* separate *final settlement statements* to cover:

6.6.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*;

6.6.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.6.1.1; and

6.6.1.3 adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10,

6.6.1.4 in accordance with the timelines set forth in sections 6.3.4, 6.3.14, 6.3.24, and 6.3.25.1, as may be applicable.

6.6.2 The *final settlement statement* shall be in the same form as the *preliminary settlement statement* and shall include all of the information provided in the *preliminary settlement statement*, as amended following the validation procedure set forth in section 6.8 and 6.9, where applicable.

6.6.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, *final settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *final settlement statement*.

6.6.4 Each *market participant* that receives a *final settlement statement* is required to pay any net debit amount shown in the *final settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *final settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of such debit or credit.

6.7 Recalculated Settlement Statement Coverage

6.7.1 The *IESO* shall, when applicable, issue to each *market participant* separate *recalculated settlement statements* to cover adjustments required pursuant to the *market rules*, including section 6.8, section 6.9, matters identified in section 6.8.12.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10 in respect of:

6.7.1.1 transactions in all rounds of any *TR auction* that is concluded on a given *trading day*; and

6.7.1.2 transactions in the *real-time markets* and in the *TR market*, other than in respect of the element referred to in section 6.7.1.1,

6.7.1.3 accordance with the timelines set forth in sections 6.3.6, 6.3.17, 6.3.24, 6.3.25.1, as may be applicable.

6.7.2 The *recalculated settlement statement* shall be in the same form as the *final settlement statement* and shall include all of the information provided in the most recently issued *settlement statement* for the *trading day* for which the *recalculated settlement statement* relates, as amended following the validation procedure set forth in section 6.8 and 6.9 and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, where applicable.

6.7.3 In accordance with the provisions of sections 6.8.9, 6.8.11, 6.9.1.2, 6.9.4, and the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, where applicable, *recalculated settlement statements* shall include any required adjustments as a credit or debit to each affected *market participant* resulting from *settlement* disagreements that have been resolved prior to the issue date of the applicable *recalculated settlement statement*.

6.7.4 Each *market participant* that receives a *recalculated settlement statement* is required to pay any net debit amount shown in the *recalculated settlement statement* on the corresponding *market participant payment date* and shall be entitled to receive any net credit amount shown in the *recalculated settlement statement* on the corresponding *IESO payment date*, whether or not there is any outstanding disagreement regarding the amount of such debit or credit.

6.8 Market Participant Validation of Settlement Statements

6.8.1 Each *market participant* shall review all of its *settlement statements* upon receipt. Subject to the terms of this section 6.8, a *market participant* may register a disagreement with the *IESO* with respect to any *settlement statement* other than a *final recalculated settlement statement* by filing a *notice of disagreement* in accordance with the timelines set forth in sections 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be.

6.8.2 Subject to section 6.8.12, if a *market participant* disagrees with any item or calculation set forth in a *preliminary settlement statement* that it has received, or considers that there is an omission in such *preliminary settlement statement,* it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4.

6.8.3 Subject to section 6.8.12, if a *market participant* disagrees with an item or calculation set forth on a *final settlement statement* or a *recalculated settlement statement*, other than a *final recalculated settlement statement*, that:

a. differs in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag;

b. is an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day* and is identified as associated with an adjustment flag; or

c. the *market participant* considers that there is an omission in such *settlement statement*, including where the *IESO* does not issue a *recalculated settlement statement* because it has determined an adjustment is not necessary and the *market participant* disagrees with such determination, it may provide the *IESO* with a *notice of disagreement* in such form as may be established by the *IESO* and in accordance with section 6.8.4. For greater certainty, a *market participant* shall not provide a *notice of disagreement* to the *IESO* if the item or calculation on a *final settlement statement* or *recalculated settlement statement* with which the *market participant* disagrees is not captured by sections (a) or (b) above.

6.8.4 *Notices of disagreement* shall relate to only one *settlement statement* and shall include at least the following information:

6.8.4.1 the date of issuance of the *settlement statement* in question;

6.8.4.2 the *dispatch day* in question;

6.8.4.3 the item(s) or omission(s) in question;

6.8.4.4 clearly state, with supporting material, the reasons for the disagreement;

6.8.4.5 where applicable and with supporting material, the proposed adjustment to the data used to calculate any relevant *settlement amount* on the *settlement statement*; and

6.8.4.6 where applicable and with supporting material, the proposed correction to any calculation of the relevant *settlement amount* on the *settlement statement.*

6.8.5 Where a *notice of disagreement* includes a proposed adjustment to:

6.8.5.1 *physical bilateral contract data*; or

6.8.5.2 any data of a comparable nature which may be identified by the *IESO* from time to time,

the *IESO* shall notify any other *market participant* to whom items 6.8.5.1 or 6.8.5.2 relates of such proposed adjustment prior to taking any action under section 6.8.9.

6.8.6 The *notice of disagreement* issued by the *market participant* shall be acknowledged by the *IESO* upon receipt.

6.8.7 The issuance of a *notice of disagreement* shall not remove the obligation of the *market participant* to settle any *invoice* based on the *preliminary settlement statement*, *final settlement statement* or *recalculated settlement statement*.

6.8.8 Subject to section 6.8.12 the *IESO* shall use the information provided in and with a *notice of disagreement*, and any other information available to the *IESO,* to consider the subject-matter of the disagreement and determine the necessary corrections, if any.

6.8.9 Following the determination described in section 6.8.8, the *IESO* shall inform the *market participant* of its determination, provide the *market participant* the opportunity to respond within ten *business days*, and, after considering any such response, take one of the following actions:

6.8.9.1 if the *IESO* concludes that no adjustment or correction is required in the *settlement statement,* it shall take no further action; or

6.8.9.2 if the *IESO* concludes that an adjustment or correction is required, take one of the following actions:

a. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the *notice of disagreement* is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* concludes an adjustment is required after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement.* For clarity, where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; or

c. if the *notice of disagreement* is with respect to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, the *IESO* shall make the adjustment in the next scheduled *recalculated settlement statement*.

6.8.10 If the *IESO* does not make its determination before the date for issuing any subsequent *settlement statements,* as applicable, the *IESO* shall issue such *settlement statements* without taking into account the disagreement.

6.8.11 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.8 shall, subject to section 6.18.3, be included as:

6.8.11.1 a debit or credit in the *final settlement statement*, or

6.8.11.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period allocation* to a *recalculated settlement statement,* or a subsequant *preliminary settlement statement* where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

6.8.12 No *market participant* may submit a *notice of disagreement*, and any such *notice of disagreement* shall not be valid and any adjustment resulting from such *notice of disagreement* shall be void, if the *notice of disagreement*:

6.8.12.1 is submitted to the *IESO* after the time specified in 6.3.3, 6.3.5, 6.3.7, 6.3.14, 6.3.16, 6.3.18, and 6.3.25.2, as the case may be;

6.8.12.2 relates to an issue which falls outside the permitted scope of such *notice of disagreement* outlined in sections 6.8.2 or 6.8.3, as the case may be;

6.8.12.3 relates to a *final recalculated settlement statement*;

6.8.12.4 relates to a compliance and enforcement action described in section 6 of Chapter 3, or matters relating to section 3.5.6B, section 3.5.6C, section

3.5.6D, section 3.5.6G, section 3.5.9, section 3.8.1, section 3.8.2, or section 4.7E of Chapter 9, section 2.2B.2 of Chapter 7 or Appendix 7.6 of Chapter 7;

6.8.12.5 relates to a dispute referred to in section 2.1A.6A of Chapter 9;

6.8.12.6 relates to an adjustment made on a *settlement statement* reflecting a dispute outcome;

6.8.12.7 relates to a matter described in the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10;

6.8.12.8 relates to the calculation of:

a. the 5-minute *energy market* price for any *dispatch interval* in a given settlement hour;

b. the 5-minute *market price* for any class of *operating reserve* for any *dispatch interval* in a given *settlement hour*; or

c. the hourly Ontario energy price for a given *settlement hour*; or

6.8.12.9 relates to a matter which the *market participant* has already submitted a *notice of disagreement*, including in regards to an earlier *settlement statement*.

6.8.13 Subject to the processes outlined in section 10.4 of Chapter 6 and section 6C of Chapter 10, *market participants* that fail to submit a *notice of disagreement* in accordance with section 6.8 in regards to a *settlement statement* shall have no further recourse in regards to the amount of any *settlement amount* contained on such *settlement statement*.

6.8.14 Nothing in section 6.8.12 shall prevent a *market participant* from submitting, or the *IESO* from making a determination in regards to, a *notice of disagreement* that relates to the manner in which any of the elements noted in sections 6.8.12.8 have been applied for purposes of the calculation of the *market participant's* net *settlement amount.*

6.8.15 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.8.9 or the *IESO* has not made its determination prior to the earlier of either (i) the date that is 23 months after the date on which the relevant *trading day* was first *invoiced*; or (ii) twelve months after the date the *notice of disagreement* was issued by the *market participant*, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1. Additionally, if a *market participant* disagrees with an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, the *market participant* may pursue their disagreement through the dispute resolution procedure described in section 6.10.1.

6.9 IESO Validation of Settlement Statements

6.9.1 Subject to section 6.9.2, if the *IESO* becomes aware of a possible error within an *IESO* system or *settlement process* that a *market participant* would not have reasonably been able to identify and address through section 6.8 and which may result in *settlement amounts* being calculated incorrectly, the *IESO* shall use the information available to the *IESO* to consider the possible error and take one of the following steps:

6.9.1.1 if the *IESO* concludes that no material adjustment or correction is required, it shall take no further action; and

6.9.1.2 if the *IESO* concludes that a material adjustment or correction is required, take one or more of the following actions:

a. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination prior to the issuance of the corresponding *final settlement statement*, the *IESO* shall adjust the corresponding *final settlement statement* accordingly;

b. if the correction is with respect to an item or calculation on a *preliminary settlement statement* and the *IESO* makes its determination after the issuance of the corresponding *final settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statements*. For clarity, where the correction relates to a trading date prior to the *IESO* commencing the issuance of *recalculated settlement statements*, the *IESO* shall make the adjustment on a subsequent *preliminary settlement statement*; and

c. if the correction is with respect to an item or calculation on any other *settlement statement*, the *IESO* shall make the adjustment on one or more *recalculated settlement statement*.

6.9.2 Notwithstanding section 6.9.1 and commencing with *settlement amounts* which were invoiced or should have been invoiced on or after *RSS commencement date*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amounts* which were invoiced, or should have been invoiced, more than 23 months before the day on which the *IESO* issues the *settlement statement* referred to in section 6.9.1.2. Notwithstanding the foregoing, where entitlement to a *settlement amount* is prescribed by *applicable law*, the *IESO* shall not take any action or make any correction under section 6.9 in regards to any *settlement amount* if a limitation period applicable to such *settlement amount* prescribed in *applicable law* has lapsed.

6.9.3 If the *IESO* does not make its determination before the date for issuing the any *settlement statements*, as applicable, the *IESO* shall issue such *settlement statements* without taking into account the error being considered.

6.9.4 Any changes required to be made in a *final settlement statement* or *recalculated settlement statement* as a result of the validation process described in this section 6.9 shall, subject to section 6.18.3, be included as:

6.9.4.1 a debit or credit in the *final settlement statement*, or

6.9.4.2 if the *IESO* has already issued the relevant *final settlement statement* prior to the determination of the required change, as an *adjustment period allocation,* to a *recalculated settlement statement,* or a subsequant *preliminary settlement statement* where the *notice of disagreement* relates to a *trading date* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* issued for each affected *market participant*. If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement.*

6.9.5 If a *market participant* disagrees with the *IESO*'s conclusion and action taken in accordance with section 6.9.1.2, the *market participant* may pursue their disagreement through the *market participant* validation procedure described in section 6.8, or, if the adjustment is made on a *final recalculated settlement statement* or on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued, through the dispute resolution procedure described in section 6.10.1.

6.9.6 Notwithstanding the foregoing, nothing in this section 6.9 limits the *IESO*'s ability to apply an adjustment related to matters described in section 6.8.12.4, including as a *current period adjustment* to a *preliminary settlement statement* issued more than two years after the *invoice* for the relevant *trading day* was issued.

6.10 Dispute Resolution

6.10.1 Subject to section 6.10.2, if a *market participant* wishes to initiate a dispute in regards to matters described in section 6.8.15, section 6.9.5, section 6.8.12.4, or in regards to a *final recalculated settlement statement,* it may submit the matter to the dispute resolution process set forth in section 2 of Chapter 3.

6.10.2 In regards to matters described in section 6.10.1, no *market participant* may submit a *notice of dispute*, and any such *notice of dispute* shall not be valid, if:

6.10.2.1 in regards to disputes pertaining to *settlement statements* other than a *final recalculated settlement statement,* the *notice of dispute* relates to a matter which, pursuant to section 6.8.2, section 6.8.3, or section 6.8.12, except for section 6.8.12.4, is not an item or calculation for which the the *market participant* is permitted to submit a *notice of disagreement*, unless the only reason that a *market participant* is not permitted to submit a *notice of disagreement* is because the new or adjusted item or calculation is not identified as associated with an adjustment flag;

6.10.2.2 in regards to disputes pertaining to a *final recalulated settlement statement,* the *notice of dispute* relates to a matter:

a. which does not differ in amount from the same item or calculation set forth on an earlier *settlement statement* corresponding to the same *trading day*;

b. is not an item or calculation which is new and not set forth on an earlier *settlement statement* corresponding to the same *trading day*;

c. is not an item or calculation which the *market participant* considers that there is an omission in such *settlement statement*; or

d. described in sections 6.8.12.5 to 6.8.12.9.

6.10.2.3 subject to section 2.5.1B of Chapter 3, the *notice of dispute* was submitted by the *market participant*:

a. in regards to matters described in section 6.8.15 where the *IESO* has made its determination, more than twenty *business days* after either the *IESO* notifies the *market participant* in accordance with section 6.8.9.1 or issues the relevant *settlement statement* in accordance with section 6.8.9.2, as the case may be;

b. in regards to matters described in section 6.8.15 where the *IESO* has not made its determination, prior to the date referred to in section 6.8.15;

c. in regards to matters described in section 6.9.5 where the adjustment is made on an ad hoc *recalculated settlement statement* issued after the date when the sixth *recalculated settlement statement* is scheduled to be issued, more than twenty *business days* after the *IESO* issues the ad hoc *recalculated settlement statement;*

d. in regards to disputes pertaining to a *final recalculated settlement statement*, more than twenty *business days* after the *IESO* issues the *final recalculated settlement statement*;

e. in regards to matters described in section 6.8.12.4, except for a compliance and enforcement action described in section 6 of Chapter 3, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed;

f. in regards to a compliance and enforcement action described in section 6 of Chapter 3, outside of the applicable timeline set forth in section 2.5.1A of Chapter 3; and

g. in regards to an item or calculation on a *final settlement statement* or a *recalculated settlement statement*, which is either new and not set forth on an earlier *settlement statement* or differs from the same item or calculation set forth on an earlier *settlement statement* but such item or calculation is not identified as associated with an adjustment flag, more than twenty *business days* after the *IESO* issues the *settlement statement* containing the amounts being disputed.

6.10.3 Following the resolution of a dispute, the *IESO* shall arrange to have the *dispute outcome* carried out as soon as is reasonably practicable following the resolution of the dispute, subject to the availability of data and of the *IESO's* resources.

6.10.4 To implement a *dispute outcome*, the *IESO* shall:

6.10.4.1 for the *market participant* that originally filed the *notice of dispute* that resulted in the *dispute outcome*, reflect the amounts to be debited or credited in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits on the next scheduled *recalculated settlement statement*; or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on the *final recalculated settlement statement*, the *IESO* shall reflect such credits or debits on a subsequent *preliminary settlement statement* issued for the *market participant*.

6.10.4.2 ensure any credit adjustment made to such *market participant*, being a refund of payments already made, shall include interest at the *default interest rate* from the date the overpayment was received to the time that the repayment is credited to the relevant *market participant settlement account*;

6.10.4.3 arrange to have all net adjustments for each *market participant*, and any interest on such net adjustments, placed into the *IESO adjustment account*; and

6.10.4.4 for any other *market participant* affected by the *dispute outcome*, reflect the incremental dollar amount determined in section 6.10.4.1 as a debit or credit in accordance with the following:

a. if the dispute is resolved prior to the issuance of the *final recalculated settlement statement* and the *IESO* has sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as an *adjustment period allocation* on the next scheduled *recalculated settlement statement.* If, after making all reasonable efforts to do so, the *IESO* cannot recover these amounts from or distribute these amounts to a former *market participant*, such amounts shall then be included as a c*urrent period adjustment* to a subsequent *preliminary settlement statement;*or

b. if the dispute is resolved after the issuance of the *final recalculated settlement statement,* the dispute relates to a *trading day* prior to the *IESO* commencing the issuance of *recalculated settlement statements,* or the *IESO* does not have sufficient time to implement the *dispute outcome* on a *recalculated settlement statement*, the *IESO* shall reflect such credits or debits as a c*urrent period adjustment* on a subsequent *preliminary settlement statement* issued for the *market participant.*

6.10.4.5 Notwithstanding the section 6.10.4.1(a) and 6.10.4.4(a), where *dispute outcome* requires an adjustment within a specified time period and the next scheduled *recalculated settlement statements* follows such time period, the *IESO* shall issue an ad hoc *recalculated settlement statements* to reflect such adjustments within the required timeframe.

6.11 Responsibility of the IESO

6.11.1 In carrying out its *settlement* responsibilities, the *IESO* shall operate in a non-discriminatory manner.

6.11.2 The *IESO* shall not be a counter-party to any trade transacted through the *real-time markets*.

6.12 Settlement Invoices

6.12.1 Unless the *IESO* has invoked the estimated *invoice* procedure pursuant to section 6.3.27, each *invoice* issued by the *IESO* to a *market participant* shall be based on all of the *settlement statements* issued to the *market participant* since their last *invoice* was issued except for any that may pertain to the next *billing period*, as more particularly described in the applicable *market manual*. In each *invoice*, other than an estimated *invoice* issued pursuant to section 6.3.27:

6.12.1.1 each line item shall correspond to a distinct commodity or service bought or sold over the *billing period*; and

6.12.1.2 the *charge type* appearing on the *invoice* shall allow *invoice* line items to be cross-referenced to the relevant *settlement statements.*

6.12.2 The *IESO* shall, on the days specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33, issue an *invoice* to each *market participant* showing:

6.12.2.1 the dollar amounts which are to be paid by or to the *market participant*, according to *settlement statements* as specified in section 6.12.1 or as estimated pursuant to section 6.3.27;

6.12.2.2 the *market participant payment date* by which such amounts (if any) are to be paid by the *market participant* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account*);

6.12.2.3 the *IESO payment date* by which the *IESO* is to make payments (if any) to the *market participant* no later than the *close of banking business* (of the bank at which the *market participant settlement account* is held); and

6.12.2.4 details of the *IESO settlement clearing account*, including the bank name, account number and *electronic funds transfer* instructions, to which any amounts owed by the *market participant* are to be paid in accordance with section 6.12.2.2.

6.12.3 *Invoices* shall be considered issued to *market participants* when issued by the *IESO* in accordance with the applicable *market manuals*.

6.12.4 It is the responsibility of each *market participant* to notify the *IESO* if it fails to receive an *invoice* on the date specified for the issuance of such *invoice* accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33. Each *market participant* shall be deemed to have received its *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* unless it notifies the *IESO* to the contrary.

6.12.5 In the event that a *market participant* notifies the *IESO* that it has failed to receive an *invoice* on the relevant date specified in accordance with sections 6.3.8 and 6.3.19 or, where applicable, on either of the dates referred to in section 6.3.27 or section 6.3.33*,* the *IESO* shall re-send the appropriate *invoice* and the *invoice* shall be considered received on the date the re-sent *invoice* is sent to the *market participant.*

6.13 Payment of Invoices

6.13.1 Subject to section 6.13.2, each *market participant* shall pay the full net *invoice* amount by the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31 and 6.3.33, regardless of whether or not the *market participant* has initiated or continues to have a dispute respecting the net amount payable.

6.13.2 A *market participant* may pay at an earlier date than the *market participant payment date* specified in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33 in accordance with the following:

6.13.2.1 notification must be given to the *IESO* before submitting such prepayment or before converting an existing overpayment by the *market participant* into a prepayment;

6.13.2.2 the prepayment notification shall specify the dollar amount prepaid;

6.13.2.3 a prepayment shall be made by the *market participant* into the *IESO prepayment account* designated by the *IESO*;

6.13.2.4 on any *market participant payment date,* the *IESO* may initiate the transfer of necessary funds from the *IESO prepayment account* to the *IESO settlement clearing account* to discharge, up to the amount of the prepayment, that *market participant*'s outstanding payment obligations arising in relation to that *market participant payment date;* and

6.13.2.5 subject to section 5.6.3 of Chapter 2, and notwithstanding section 4.18.1.2 of Chapter 8, funds held in an *IESO prepayment account* on behalf a *market participant* may be applied by the *IESO* to any outstanding financial obligations of that *market participant* to the *IESO* for transactions carried out in the *IESO-administered markets.*

6.13.3 With respect to *transmission services charges*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *transmitter's transmission services settlement account* sufficient funds to pay in full the *transmission services charges* falling due to that *transmitter* on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33.

6.13.4 With respect to the *IESO administration charge*, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account sufficient funds to pay in full the *IESO administration charge* falling due on any *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 in priority to any other payments to be made on that *IESO payment date* or on subsequent days out of the *IESO settlement clearing account.*

6.13.5 With respect to the smart metering charge*,* the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account only those funds that were received in the *IESO settlement clearing account* in payment of the smart metering charge*.* The smart metering charge is the fee approved by the *OEB* to recover costs incurred by the *IESO* solely as a result of the *IESO* acting as the Smart Metering Entity and its responsibilities related to the smart metering initiative.

6.13.6 The *IESO* shall, on the *IESO payment date* specified in accordance with sections 6.3.11 and 6.3.22 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* determine the amounts available in the *IESO settlement clearing account* for distribution to *market participant*s or the *forecasting entity*, and shall, if necessary, borrow funds in accordance with the provisions of section 6.16 if necessary to enable the *IESO settlement clearing account* to clear no later than 11:00 am on the *IESO payment date*.

6.14 Funds Transfer

6.14.1 All payments by *market participant*s in respect of *settlement* matters shall be made to the *IESO settlement clearing account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.2 All payments by the *IESO* to *market participants* in respect of settlement matters shall be made to each *market participant's market participant settlement account* or to each *transmitter's transmission services settlement account* via *electronic funds transfer* and shall be effected by the dates and times specified in this Chapter.

6.14.3 In the event of failure of any *electronic funds transfer* system affecting the ability of either a *market participant* or the *IESO* to make payments, the affected party shall arrange for alternative means of payment so as to ensure that payment is effected by the dates and times specified in this Chapter.

6.14.4 No *market participant* shall include in any *electronic funds transfer* amounts attributable to more than one *invoice* or prepayment, unless such *electronic funds transfer* is in such form as may be specified in the applicable *market manual.*

6.14.5 The *IESO* shall be entitled to and shall rely on the information contained in or accompanying an *electronic funds transfer* received pursuant to section 6.14.4 for the purpose of allocating the aggregate amount of an *electronic funds transfer* referred to in that section and, notwithstanding section 13 of Chapter 1:

6.14.5.1 the *IESO* shall not be liable to any person in respect of the allocation of:

a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2; and

6.14.5.2 the *market participant* providing the *IESO* with such information shall indemnify and hold harmless the *IESO* in respect of any claims, losses, liabilities, obligations, actions, judgements, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation by the *IESO* of:

a. the aggregate amount of an *electronic funds transfer* when effected in accordance with such information or with section 6.14.6.1; or

b. the amount of any associated overpayment or underpayment effected in accordance with section 6.14.6.2.

6.14.6 Where a *market participant* that initiates an *electronic funds transfer* to which section 6.14.4 applies fails to provide the information contained in or accompanying an *electronic funds transfer* referred to in section 6.14.4, the *IESO* shall allocate:

6.14.6.1 the aggregate amount of the *electronic funds transfer;* and

6.14.6.2 the entire amount of any associated overpayment or underpayment,

to that *market participant*.

6.15 Confirmation Notices

6.15.1 At the end of each calendar month, the *IESO* shall issue a *monthly confirmation notice* to each *market participant* which shall contain statements of the amounts received from or paid out to the *market participant* on each *market participant payment date* and *IESO payment date* in that month and any payments outstanding.

6.16 Payment Default

6.16.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in accordance with section 6.3.9 and 6.3.20 or, where applicable, determined in accordance with any of sections 6.3.27, 6.3.31, and 6.3.33*,* the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account*.

6.16.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.

6.16.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.13.2**,** the provisions of section 6.3 of Chapter 3 shall apply and *default interest* shall accrue on all amounts outstanding.

6.16.4 If the *market participant's invoice* includes a *settlement amount* owing for the smart metering charge under section 6.13.5 and the *market participant*

a. fails to remit the full *invoice* amount due by the *market participant payment date*; and

b. does not direct the *IESO* how to apportion the payment between the smart metering charge and all other *settlement amounts* on the *invoice* prior to the *IESO payment date*, the *IESO* shall allocate the payment made by the *market participant* first to satisfying any *settlement amounts* due under the *market rules* before being applied to the smart metering charge.

6.16.5 The *IESO* shall be authorized to borrow short-term funds to clear the credits in any settlement cycle only if the following conditions are met:

6.16.5.1 there are insufficient funds remitted into the *IESO settlement clearing account* or *TR clearing account* to pay all applicable *market creditors* due for payment from the funds in the *IESO settlement clearing account* or *TR clearing account,* and clear the *IESO settlement clearing account* or *TR clearing account* on a given *IESO payment date*, due to:

a. payment default by one or more *market participants* in the *real-time markets*; or

b. the circumstances referred to in section 4.19.2 or 4.19.6 of Chapter 8;

6.16.6 If the *IESO* borrows short-term funds pursuant to section 6.16.5, it shall recover this borrowing:

6.16.6.1 where the insufficient funds were due to a payment default referred to in section 6.16.5.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules,* including, if necessary, by imposing the *default levy* in accordance with section 8 of Chapter 2; or

6.16.6.2 where the insufficient funds were due to the circumstances referred to in section 6.16.5.1 (b), in the manner referred to in sections 4.19.3 and 4.19.5 of Chapter 8 and then, if necessary, by recovering from *market participants* proportionately based on *transmission service charges* paid during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.16.6.2.1 Where a *market participant* has paid provincial *transmission service charges*, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *RWMs* excluding *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.2.2 Where a *market participant* has paid export *transmission service* charges, recovery pursuant to section 6.16.6.2 shall be recovered individually, proportionate to the quantities of *energy* withdrawn at all *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*, in accordance with section 6.16.6.3

6.16.6.3 The portion of any short-term funds borrowed by the *IESO* to be recovered from *market participant* ‘k’ in the current *energy market billing period* shall be calculated as follows:

For market participants that have paid provincial transmission service charges in the current energy market billing period:

$$TRCAC_k = TRCAD_L \times \sum_H{}^{M,T} [(AQEW_{k,h}{}^{m,t}) / \sum_{K,H}{}^{M,T} (AQEW_{k,h}{}^{m,t})$$

For market participants that have paid export *transmission service charges* in the current energy market billing period**:**

$$TRCAC_k = TRCAD_E \times \sum_H{}^{I,T} [(SQEW_{k,h}{}^{i,t}) / \sum_{K,H}{}^{I,T} (SQEW_{k,h}{}^{i,t})]$$

Where:

$$TRCAD_L =(\sum_K TD_C / \sum_K TD_{C,C1}) \times TRCAR$$

$$TRCAD_E = (\sum_K TD_{C1} / \sum_K TD_{C,C1}) \times TRCAR$$

TRCAR = the total dollar value of TR shortfall recovery from the *TR clearing account* authorized by the *IESO Board* in the current *energy market billing period*

6.16.7 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participant*s or to the circumstances referred to in section 6.16.5.1 (b), the *IESO* shall borrow funds in accordance with section 6.16.5 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date*.

6.16.8 If the *IESO* has exhausted credit availability contemplated by section 6.16.5, then the *IESO* shall pay *real-time market creditors* on a pro rata basis in proportion to the amounts owed to each *market creditor*. Any amounts that remain owing to *real-time market creditors* shall bear interest at the *default interest rate* until paid.

6.16.9 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default levy*, the *IESO* shall first repay all existing lines of credit and other banking facilities, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *market creditors* owed amounts pursuant to section 6.16.8.

6.17 Payment Errors, Adjustments, and Interest

6.17.1 If a *market participant* receives an overpayment on any *IESO payment date:*

6.17.1.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* of the overpayment or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.1.2 if the *IESO* determines or becomes aware of the overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* of the overpayment;

6.17.1.3 the *market participant* receiving the overpayment shall, until it has refunded the overpayment to the *IESO*, be deemed to be holding the amount of such overpayment in trust for any other *market participant*s that may have been underpaid in consequence of such overpayment, pro rata to the amount of the underpayment;

6.17.1.4 the *IESO* shall be entitled to treat the overpayment and any interest accruing thereon as an unpaid amount to which section 6.16 applies; and

6.17.1.5 if not repaid fully within 2 *business days* of receiving the overpayment, the unpaid amount of any overpayment shall bear interest at the *default interest rate* from the date of overpayment until the date on which repayment is credited to the *IESO's* relevant *settlement account*.

6.17.2 The *IESO* shall be responsible for identifying any *market participant*s who have been underpaid as a result of an overpayment to another *market participant*.

6.17.3 The *IESO* shall pay any underpaid *market participant* for the amounts of their underpayment, including interest calculated from the date the *market participant* should have been paid, as soon as practicable following repayment by the overpaid *market participant*.

6.17.4 If a *market participant* has overpaid the *IESO* on any *market participant* payment date:

6.17.4.1 the *market participant* shall notify the *IESO* of such overpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.4.2 if the *IESO* determines or becomes aware of such overpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly;

6.17.4.3 the *market participant* may request that the overpaid amount be either refunded or treated as a prepayment pursuant with section 6.13.2; and

6.17.4.4 any related administration and transaction costs incurred by the *IESO* in managing and resolving the over-payment shall be charged to the account of the *market participant* involved.

6.17.5 If the *IESO* underpays any *market participant* on any *IESO payment date*:

6.17.5.1 the *market participant* shall notify the *IESO* of such underpayment within two *business days* or immediately as soon as the *market participant* thereafter becomes aware of the situation;

6.17.5.2 if the *IESO* determines or becomes aware of the underpayment prior to being notified by the *market participant*, the *IESO* shall notify the *market participant* accordingly; and

6.17.5.3 the *IESO* shall use all reasonable endeavours to promptly correct any underpayments, including interest thereon at the *default interest rate*.

6.17.6 If the *IESO* is underpaid by a *market participant* on any *market participant payment date,* the provisions of section 6.16 or of section 4.20 of Chapter 8 shall apply.

6.17.7 If the *IESO* borrows funds in accordance with section 6.16.5 because a payment due from a *market participant* was received too late to be credited to the *IESO settlement clearing account* by *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* when such payment was due, then such remittance when it does arrive shall be used to repay the borrowed funds. Any such late payments shall be charged the *Canadian prime interest rate* plus 2%.

6.17.8 If the *IESO* holds or has under its control after five *business days* from receipt in the *IESO settlement clearing account* amounts which it ought properly to have paid to *market participant*s, such *market participant*s shall be entitled to interest on such amounts at the *default interest rate* from the date on which the *IESO* commenced to improperly hold or have such amounts under its control to the date on which such amounts are paid to the relevant *market participants.*

6.17.9 Monies in the *IESO settlement account*s at the end of each year which have been earned from interest on funds in the *IESO settlement account*s and which are not attributable to any incomplete *settlement process* or outstanding *settlement* dispute shall be used to off-set the *IESO administration charge* in the following year.

6.17.10 Where an amount is payable to a former *market participant* as a result of a *settlement* adjustment, the *IESO* shall endeavor to distribute the amount as specified in the applicable *market manual*. If the *IESO* cannot distribute the amount to the former *market participant* as specified in the applicable *market manual*, such amount shall be used to offset the *IESO administration charge*.

6.18 Settlement Financial Balance/Maximum Amount Payable by IESO

6.18.1 The *IESO* shall provide and operate a *settlement* control process to monitor the financial balance of the calculated charges and payments so as to ensure that, subject to section 6.18.3:

6.18.1.1 for *hourly market* transactions, other than transactions in the *TR market,* the sum of all payments for all *market creditors* involved in such *hourly market* transactions exactly equal the sum of all charges for *market debtors* involved in such *hourly market* transactions for each *trading day* of a *billing period*; and

6.18.1.2 for all other transactions, other than transactions in the *TR market* including monthly charges, adjustment charges and payments, the sum of all payments to *market creditors* of those transactions exactly equals the sum of all charges to *market debtors* of those transactions for each *billing period*.

6.18.2 Subject to the provisions of section 6.16, the *IESO* shall not be liable to make payments in excess of the amount it receives for transactions in the *real-time markets*.

6.18.3 If there is an aggregate imbalance for all transactions for a given *trading day* or *billing period,* the *IESO* shall, in accordance with section 6.18.4 or by such other means as the *IESO* determines appropriate, recover that portion of the imbalance that arises by virtue of the rounding of *settlement amounts* or of an adjustment to the *settlement statement* of one *market participant* that is too small to be reflected in corresponding *settlement statement* of other *market participants* provided that:

6.18.3.1 the manner of calculation of that portion of the imbalance can be evidenced in a manner satisfactory for purposes of the audit referred to in section 6.19; and

6.18.3.2 that portion of the imbalance has accumulated to an amount which is sufficient to permit recovery.

6.18.4 The *IESO* may recover the portion of an aggregate imbalance referred to in section 6.18.3 by means of an adjustment to a *settlement statement* applied:

6.18.4.1 to *market participants* to whom *hourly uplift* may be allocated pursuant to these *market rules*;

6.18.4.2 in the same manner as *hourly uplift;* and

6.18.4.3 in respect of all *settlement hours* of the last day of the *billing period* in which the portion of such aggregate imbalance is determined to arise and be recoverable pursuant to section 6.18.3.

6.19 Audit

6.19.1 The audit of *settlement* functions referred to in this section 6.19 shall serve to examine and evaluate compliance with management control objectives and operational effectiveness of *settlement process*es and procedures.

6.19.2 The audits referred to in section 6.19.3 shall be performed by an external, independent auditing firm.

6.19.3 Unless otherwise directed by the *IESO Board*, the *IESO* shall every two years, on the anniversary of the *market commencement date*, direct a comprehensive external audit on the *settlement process*es and procedures. The audit shall include the following tasks:

6.19.3.1 gauge the performance of the *settlement process* in meeting the objectives of these *market rules;*

6.19.3.2 review the accuracy and timeliness of the production of *settlement statements*, including *settlement* calculations and financial allocations;

6.19.3.3 review the accuracy and timeliness of the production of *invoice*s and supporting market and system information;

6.19.3.4 review the *reliability* and integrity of the market and system operational data used in the *settlement process*es and procedures;

6.19.3.5 review the *reliability* and security of the information technology system infrastructure used to measure, validate, classify, compute and report *settlement* information;

6.19.3.6 review the adequacy of *settlement processes* and procedures to safeguard *confidential information*; and

6.19.3.7 review the adequacy and effectiveness of risk management controls of the *settlement process*es and tools, including the effectiveness of the *disaster recovery plan.*

6.19.4 *Settlement statements*, financial *settlement* records and any documentation pertaining to the *IESO's settlement* activities shall, subject to sections 2.11.1 to 2.11.3, be kept in secure storage for a period of at least seven years and made available for auditing purposes.

6.19.5 An audit report shall be prepared by the auditors in respect of each audit conducted pursuant to this section 6.19 and shall be commissioned on the basis that the audit report must be provided to the *IESO* within one month after completion of the audit activities.

6.19.6 Each audit report prepared pursuant to this section 6.19 shall be made available to a *market participant* upon request, subject to such measures as may be required to be taken to safeguard any *confidential information* contained in such audit report.

6.20 Settlement Accounts

6.20.1 The *IESO* shall establish and maintain the *settlement accounts* described in this section 6.20 for the operation of its *settlement* and billing systems.

6.20.2 The *IESO* shall obtain lines of credit and other banking facilities it deems necessary for the operation of the *settlement accounts* described in this section 6.20, which lines of credit and other banking facilities shall not exceed an aggregate amount approved by the *IESO Board*.

6.20.3 The *IESO* may establish *settlement accounts* in addition to those referred to in this section 6.20 as may be necessary to implement the *settlement* and billing processes outlined in this Chapter. *Market participant*s shall be notified 60 *business days* prior to any such additional *settlement accounts* becoming *operational*.

6.20.4 The *IESO* shall open and maintain the *IESO settlement clearing account* as a single bank account to and from which all *settlement* payments shall be made in accordance with the provisions of this Chapter and the details of which shall appear in the *invoice*s sent by the *IESO* to *market participant*s as provided in section 6.12.2.4**.**

6.20.5 The *IESO* shall open and maintain the *IESO adjustment account*, which *account* shall operate as follows:

6.20.5.1 the *IESO adjustment account* shall be a single bank account established to receive and disburse payments related to penalties, damages, fines and payment adjustments arising from resolved *settlement* disputes, and to reimburse the *IESO* for any associated costs or expenses;

6.20.5.2 any amounts paid into the *IESO adjustment account* by *market participant*s shall first be applied to reimburse the *IESO* in respect of any costs or expenses described in section 6.20.5.1 which it has or will incur. Any remaining amount shall be credited to the *IESO adjustment account;* and

6.20.5.3 the *IESO Board* shall review, at least annually, the allocation of any credit balance of the *IESO adjustment account*, and may:

a. establish an amount to be retained in the *IESO adjustment account*;
b. direct that some or all of the credit balance be applied to special education projects or initiatives; and/or
c. direct that some or all of the balance be distributed to *market participants* on a basis to be determined by the *IESO board*.

6.20.6 The *IESO* shall open and maintain the *IESO prepayment account,* which *account* shall operate as follows:

6.20.6.1 the *IESO prepayment account* shall be a bank account established for *market participants* to deposit prepayments at an earlier date than the specified *market participant payment date*; and

6.20.6.2 the arrangements for making the prepayment and transferring funds from the *IESO prepayment account* to the *IESO settlement clearing account* shall be in accordance with the provisions of section 6.13.2.

6.20.7 The *IESO* shall open and maintain the *TR clearing account*, which *account* shall operate in the manner described in sections 4.18 and 4.19 of Chapter 8.

6.20.8 Unless otherwise specified, the *IESO* shall recover all banking costs reasonably incurred in opening and operating the *IESO's settlement accounts* through the *IESO administration charge.*

6.20.9 The *IESO* shall maintain its *settlement accounts* at a bank or financial institution in the Province of Ontario approved by the *IESO Board*.

6.20.10 Each *transmitter* shall be required to open and maintain a *transmission services settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.11 Each *transmitter* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *transmitter's transmission services settlement account*.

6.20.12 Each *market participant* shall be required to open and maintain a *market participant settlement account* at a bank named in a Schedule to the *Bank Act*, S.C. 1991, c. 46, located in the Province of Ontario, and capable of performing electronic funds transfers.

6.20.13 Each *market participant* shall inform the *IESO* of all applicable information required for the *IESO* to make payment into the *market participant's market participant settlement account*.

6.20.14 The *settlement accounts* referred to in this section 6.20 may be changed or closed as follows:

6.20.14.1 the *IESO* may change the bank or the details of any of its *settlement accounts*, on the condition that the bank or financial institution is reasonably acceptable to the *IESO Board* and that all *market participant*s are notified by the *IESO* in writing at least 60 *business days* before the change takes effect; and

6.20.14.2 any *transmitter* or *market participant* may change its bank or the details of its *settlement account*, on the condition that the *IESO* is notified in writing at least 60 *business days* before the change takes effect.

Market Rules

Chapter 9

Settlements and Billing - Appendices

Power to Ontario.
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Appendix 9.1 – VEE Process

1.1 Introduction and Interpretation

1.1.1 This Appendix sets forth the obligations of the *IESO* and of *metered market participants* with respect to the validation, estimation and editing of *metering data*.

1.1.2 [Intentionally left blank – section deleted]

1.1.3 For the purposes of this Appendix, a reference to an interval means:

1.1.3.1 in the case of a *metering installation* that collates *metering data* by *metering intervals*, a *metering interval*; and

1.1.3.2 in all other cases, such multiple of *metering intervals* for which the *metering installation* collates *metering data.*

1.2 Manner of Data Collection by the IESO

1.2.1 The *IESO* shall collect or receive *metering data* for *settlement* purposes using, in respect of a given *RWM*, one or more of the following methods as may be applicable:

1.2.1.1 electronic access to the *RWM* as described in Chapter 6;

1.2.1.2 a wide area network; or

1.2.1.3 such manual collection method as may be required to resolve a trouble call in respect of the *RWM.*

1.3 Obligation of the Metered Market Participant to Provide Data

1.3.1 Each *metered market participant* shall, for each *RWM* in respect of which it is the *metered market participant* and that is a *main/alternate metering installation*, provide to the *IESO*, for validation purposes, *metering data* from each of the main *meter* and the alternate *meter* in accordance with the provisions of Chapter 6 and the *VEE standard*.

1.3.2 [Intentionally left blank – section deleted]

1.3.3 [Intentionally left blank – section deleted]

1.3.4 Each *metered market participant* shall, for each *RWM* in respect of which it is the *metered market participant* and that is a *single metering installation*, provide to the *IESO*, for validation purposes:

1.3.4.1 *metering data* from the *meter* in accordance with the provisions of Chapter 6 and the *VEE standard*; and

1.3.4.2 the validation criteria for *single metering installations* set forth in section 2.4 of the *VEE standard*.

1.4 Automated Processes and Trouble Calls

1.4.1 The validation and estimation procedures described in this Appendix 9.1 shall be effected by means of automated processes following the collection or receipt of *metering data* by the *IESO's* automated systems.

1.4.2 Where the *metering data* from any *meter* in an *RWM* is unavailable or fails to successfully pass the validation procedures referred to in:

1.4.2.1 sections 1.5.1 and, where applicable, 1.5.2; or

1.4.2.2 sections 1.6.1 and, where applicable, 1.6.2,

as the case may be, the *IESO* shall:

1.4.2.3 issue a trouble call to the *metering service provider* for the *metering installation* to which the *metering data* relates; and

1.4.2.4 notify the *metered market participant* for the *metering installation* of the issuance of the trouble call.

1.4.3 A *metering service provider* to whom a trouble call has been issued pursuant to section 1.4.2.3 shall respond to and resolve the trouble call in accordance with the requirements of sections 11.1.2.1 and 11.1.2.2 of Chapter 6.

1.4.4 A *metering service provider* that has resolved a trouble call issued pursuant to section 1.4.2.3 shall:

1.4.4.1 so notify the *IESO*;

1.4.4.2 provide the *IESO* with a written description of the cause of and the actions taken to resolve the trouble call; and

1.4.4.3 where applicable, provide to the *IESO* a request for an adjustment to the *metering data* that was the subject of the trouble call, together with auditable documentary justification for the adjustment,

in accordance with the requirements of the *VEE standard* and in such form and manner as may be required by the *IESO*.

1.5 Validation, Estimation and Editing: Main/Alternate Metering Installation

1.5.1 The following validation procedures shall be conducted, in accordance with the *VEE standard*, by the *IESO's* automated validation process in respect of each *RWM* that is a *main/alternate metering installation* to the extent permitted by the configuration of such *metering installation*:

1.5.1.1 determine whether any *metering data* has failed to be delivered to or received by the *IESO* from each of:

a. the main *meter*; and

b. the alternate *meter*,

in the manner and at the time required by these *market rules* and the intervals for which such *metering data* is missing;

1.5.1.2 test current and voltage data, if it has been provided;

1.5.1.3 conduct the data transmission/multiplier verification;

1.5.1.4 test for synchronization of the clock in each of:

a. the main *meter*; and

b. the alternate *meter*,

against the standard of accuracy described in section 11.2.2 of Chapter 6;

1.5.1.5 test for replacement of the *data logger* in each of the main *meter* and the alternate *meter*;

1.5.1.6 monitor error messages, flags and alarms received from each of:

a. the main *meter*; and

b. the alternate *meter*; and

1.5.1.7 compare the *metering data* collected or received from the main *meter* with the *metering data* collected or received from the alternate *meter*.

1.5.2 The *IESO* may, in addition to the validation procedures referred to in section 1.5.1, carry out such additional automated validation procedures in respect of *RWMs* that are *main/alternate metering installations* as it determines appropriate.

1.5.3 Where the *metering data* from each of:

1.5.3.1 the main *meter*; and

1.5.3.2 the alternate *meter,*

in an *RWM* that is a *main/alternate metering installation* has successfully passed the validation procedures referred to in sections 1.5.1 and, where applicable, 1.5.2, such *metering data* shall be deemed validated *metering data* and the *metering data* from the main *meter* shall, subject to any adjustment and totalization that may be required pursuant to Chapter 6, be used by the *IESO* for *settlement* purposes.

1.5.4 Where the *metering data* from the main *meter* in an *RWM* that is a *main/alternate metering installation* has successfully passed the validation procedures described in sections 1.5.1 and, where applicable, 1.5.2, such *metering data* shall, subject to:

1.5.4.1 any adjustment and totalization that may be required pursuant to Chapter 6; and

1.5.4.2 any subsequent adjustment made pursuant to section 1.5.10.2,

be used for *settlement* purposes notwithstanding that the *metering data* from the alternate *meter* is unavailable or has not successfully passed such validation procedures.

1.5.5 Where the *metering data* from the main *meter* in an *RWM* that is a *main/alternate metering installation* is unavailable or has not successfully passed the validation procedures referred to in section 1.5.1 and, where applicable, 1.5.2, the *metering data* from the alternate *meter* shall, subject to:

1.5.5.1 any adjustment and totalization that may be required pursuant to Chapter 6; and

1.5.5.2 [Intentionally left blank – section deleted]

1.5.5.3 any subsequent adjustment made pursuant to section 1.5.11.2,

be used for *settlement* purposes provided that the *metering data* from the alternate *meter* has successfully passed the validation procedures referred to in sections 1.5.1 and, where applicable, 1.5.2. The substitution of the *metering data* from the alternate *meter* for the *metering data* from the main *meter* shall be flagged in the *metering database*.

1.5.6 Where the *metering data* from both *meters* in an *RWM* that is a *main/alternate metering installation* is unavailable or has not successfully passed the validation procedures referred to in sections 1.5.1 and, where applicable, 1.5.2, an estimate of the *metering data* shall be prepared by automated process in accordance with section 1.5.7 and the *VEE standard*. Such estimate shall, subject to:

1.5.6.1 any adjustment and totalization that may be required pursuant to Chapter 6; and

1.5.6.2 any subsequent adjustment made pursuant to section 1.5.12.2,

be used for *settlement* purposes. Such estimation shall be flagged in the *metering database*.

1.5.7 An estimate of *metering data* referred to in section 1.5.6, 1.6.4 or 1.7.1.2 shall be based:

1.5.7.1 where the period for which the *metering data* is unavailable or has not successfully passed the validation procedures described in:

a. section 1.5.1 and, where applicable, 1.5.2; or

b. section 1.6.1 and, where applicable, 1.6.2,

is less than one hour, on a straight line joining the demand observed in the *metering data* in the interval immediately preceding such period and the interval immediately following such period; or

1.5.7.2 where such period is one hour or more, on validated *metering data* collected or received from the *metering installation* in the three most recent comparable *trading days* selected in accordance with section 1.5.8.

1.5.8 For the purposes of section 1.5.7.2, where the *metering data*:

1.5.8.1 relates to a *generation facility*, the *metering data* for the interval recording the lowest quantity shall be used for estimation;

1.5.8.2 relates to a *load facility*, the *metering data* for the interval recording the highest quantity shall be used for estimation;

1.5.8.3 relates to the injections for an *electricity storage facility*; the *metering data* for the interval recording the lowest quantity shall be used for estimation; and

1.5.8.4 relates to the withdrawals for an *electricity storage facility*, the *metering data* for the interval recording the highest quantity shall be used for estimation.

1.5.9 For the purposes of section 1.5.7.2, validated *metering data* shall include, where applicable, *metering data* that has been:

1.5.9.1 used in accordance with section 1.5.4 or 1.6.3;

1.5.9.2 substituted in accordance with section 1.5.5; or

1.5.9.3 estimated in accordance with section 1.5.6, 1.6.4 or 1.7.1.2,

subject to such adjustments as may have been made to such *metering data* in accordance with those sections at the time that the estimate is prepared pursuant to section 1.5.7.2.

1.5.10 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where the *metering data* from the main *meter* is being used in accordance with section 1.5.4:

1.5.10.1 use such *metering data* for *settlement* purposes provided that the *IESO* is satisfied that such *metering data* is correct and any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly; or

1.5.10.2 adjust such *metering data* in accordance with section 1.7.1 if the *IESO* is satisfied that such *metering data* has been affected by the failure of the alternate *meter*.

1.5.11 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where the *metering data* from the alternate *meter* is being used in accordance with section 1.5.5:

1.5.11.1 use such *metering data* for *settlement* purposes provided that the *IESO* is satisfied that such *metering data* is correct and any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly; or

1.5.11.2 adjust such *metering data* in accordance with section 1.7.1 if the *IESO* is satisfied that such *metering data* has been affected by the failure of the main *meter.*

1.5.12 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where an estimate has been prepared pursuant to section 1.5.6:

1.5.12.1 adjust such estimate in accordance with section 1.7.1 if the *IESO* is satisfied that resolution of the trouble call has identified a source of *metering data* that is more accurate that such estimate; or

1.5.12.2 in all other cases, use such estimate for *settlement* purposes.

1.6 Validation, Estimation and Editing: Single Metering Installations

1.6.1 The following validation procedures shall be conducted, in accordance with the *VEE standard*, by the *IESO's* automated validation process in respect of each *RWM* that is a *single metering installation*:

1.6.1.1 determine whether any *metering data* has failed to be delivered to or received by the *IESO* from the *meter* in the manner and at the time required by these *market rules* and the intervals for which such *metering data* is missing;

1.6.1.2 test current and voltage data, if it has been provided;

1.6.1.3 conduct the data transmission/multiplier verification;

1.6.1.4 test for synchronization of the *meter* clock against the standard of accuracy described in section 11.2.2 of Chapter 6;

1.6.1.5 test for replacement of the *data logger* in the *meter*; and

1.6.1.6 monitor error messages, flags and alarms received from the *meter*.

1.6.2 The *IESO* may, in addition to the validation procedures referred to in section 1.6.1, carry out such additional automated validation procedures in respect of *RWMs* that are *single metering installations* as it determines appropriate.

1.6.3 Where the *metering data* from the *meter* in a *single metering installation* has not successfully passed the validation procedures referred to in section 1.6.1 and, where applicable, 1.6.2, such *metering data* shall, subject to:

1.6.3.1 any adjustment and totalization that may be required pursuant to Chapter 6; and

1.6.3.2 any adjustment made pursuant to section 1.6.5.2,

nonetheless be used for *settlement* purposes by the *IESO*. Such failure of validation shall be flagged in the *metering database*.

1.6.4 Where the *metering data* from the *meter* in a *single metering installation* is unavailable, an estimate of the *metering data* shall be prepared by automated process in accordance with section 1.5.7 and the *VEE standard*. Such estimate shall, subject to:

1.6.4.1 any adjustment and totalization that may be required pursuant to Chapter 6; and

1.6.4.2 any subsequent adjustment made pursuant to section 1.6.6.1,

be used for *settlement* purposes. Such estimation shall be flagged in the *metering database*.

1.6.5 Upon receipt of the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where the *metering data* from the *meter* is being used pursuant to section 1.6.3:

1.6.5.1 use such *metering data* for *settlement* purposes if the *IESO* is satisfied that such *metering data* is correct and any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly; or

1.6.5.2 adjust such *metering data* in accordance with section 1.7.1.

1.6.6 Upon the notification, the description and, where applicable, the request referred to in section 1.4.4, the *IESO* shall, where an estimate has been prepared pursuant to section 1.6.4:

1.6.6.1 adjust such estimate in accordance with section 1.7.1 if the *IESO* is satisfied that resolution of the trouble call has identified a source of *metering data* that is more accurate than such estimate; or

1.6.6.2 in all other cases, use such estimate for *settlement* purposes.

1.7 Adjustments and Failure to Resolve Trouble Call

1.7.1 An adjustment referred to in section 1.5.10.2, 1.5.11.2, 1.5.12.1, 1.6.5.2 or 1.6.6.1, as the case may be, shall be effected by the *IESO* by means of:

1.7.1.1 the application of a multiplier, an adder or subtractor or an absolute value for each applicable *metering interval*; or

1.7.1.2 the application of the estimation process referred to in section 1.5.7,

as the *IESO* determines appropriate in accordance with section 1.7.2, having regard to the written description and, where applicable, the request made by the *metering service provider* pursuant to section 1.4.4. Any flags in respect of the *metering data* previously entered into the *metering database* shall be modified accordingly.

1.7.2 The *IESO* shall, as between the adjustment methods referred to in section 1.7.1, select the method that in the *IESO's* opinion will result in the use of *metering data* for *settlement* purposes that most closely reflects the flow of *energy* through the *RWM* during the applicable intervals. Where both methods are determined by the *IESO* to be equivalent in this regard, the *IESO* shall select the method that is less likely to result in the *metered market participant* for the *RWM* to which the *metering data* relates obtaining a benefit from the adjustment relative to what the *metered market participant's* position would otherwise have been.

1.7.3 Where a trouble call has been issued pursuant to section 1.4.2.3 and:

1.7.3.1 the *IESO* does not receive the notification referred to in section 1.4.4.1;

1.7.3.2 the *IESO* does not receive the written description referred to in section 1.4.4.2; or

1.7.3.3 the trouble call is not resolved to the satisfaction of the *IESO*,

the *IESO* shall for *settlement* purposes use:

1.7.3.4 the *metering data*, substituted *metering data* or estimated *metering data* referred to in section 1.5.4, 1.5.5, 1.5.6, 1.6.3 or 1.6.4, as the case may be; and

1.7.3.5 where applicable, the estimates referred to in section 11.1.4A of Chapter 6, until such time as the trouble call is resolved to the satisfaction of the *IESO*.

Appendix 9.2 – [Intentionally left blank]

Market Rules

Chapter 10
Transmission Service and Planning

Connecting Today.
Powering Tomorrow.

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Table of Contents

1. Introduction

1.1 Objectives of this Chapter and Interpretation

1.1.1 This Chapter of the *market rules* sets forth the terms and conditions under which the *IESO* will administer the collection and distribution of *transmission services charges* for transactions that use the *IESO-controlled grid* for the transmission of *energy* and *ancillary services*.

1.1.2 The *market rules* in this Chapter and Chapter 7 are intended to satisfy the requirements of section 27 of the *Electricity Act, 1998* that the conveyance of electricity into, through or out of the *IESO-controlled grid* shall be pursuant to the *market rules*.

1.1.3 This Chapter sets forth procedures that the *IESO* and *market participants* will use to assess the *reliability* of the *IESO-controlled grid*.

1.1.4 For the purpose of giving effect to the collection and *settlement* of *transmission services charges* contemplated in this Chapter 10, all references in section 6, other than section 6.2 of Chapter 9 to a *market participant* shall be deemed to include a reference to a *transmission customer*.

1.1.5 For the purpose of giving effect to the collection and *settlement* of *transmission services charges* contemplated in this Chapter 10, all references in Chapter 6 to a *metered market participant* shall be deemed to include a reference to a *transmission customer*.

2. Transmission Services

2.1 Classes of Service

2.1.1 The *IESO* shall administer the collection and distribution of *transmission services charges* for the various classes of *transmission service* as required by this Chapter and in accordance with the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*.

2.1.1.1 [Intentionally left blank]

2.1.1.2 [Intentionally left blank]

2.1.1.3 [Intentionally left blank]

2.1.1.4 [Intentionally left blank]

2.2 Billing and Payment for Service

Billing Procedure

2.2.1 The *IESO* shall include a line item on each *invoice* issued in respect of an *energy market billing period* pursuant to Chapter 9 to each *transmission customer* that is required to pay for a *transmission service* with respect to which the *IESO* is required to collect charges in accordance with this Chapter, which shall cover the charges for *transmission services* during that *energy market billing period*. The charges for *transmission service* in such *invoice* shall be paid by the *transmission customer* on the *market participant payment date* associated with the *invoice* at the same time and in the same manner as required for the payment of *invoices* under Chapter 9.

Reimbursement of Transmitters

2.2.2 The *IESO* shall include a line item on each *invoice* issued in respect of an *energy market billing period* pursuant to Chapter 9 to each *transmitter* that is entitled to payment for a *transmission service* with respect to which the *IESO* is required to collect charges in accordance with this Chapter. Such line item shall, subject to section 2.2.2A, reflect and amount equal to that portion of the charges for *transmission services*, as invoiced to *transmission customers* pursuant to section 2.2.1, relating to that *transmitter's transmission system*. On each *IESO payment date* in respect of each applicable *energy market billing period*, the *IESO* shall remit any amount owing pursuant to such *invoice* to each applicable *transmitter* by *electronic funds transfer* in the manner provided in Chapter 9 and in accordance with the applicable rate order issued by the *OEB* to the *transmitter*.

2.2.2A Notwithstanding any other provision of these *market rules*, the *IESO* shall not be required to make payment to a *transmitter* in respect of charges for *transmission services* relating to that *transmitter's transmission system* that have been *invoiced* to a *transmission customer* that is not a *market participant* until such time as the *IESO* has received payment from such *transmission customer* for such charges.

Where such a *transmission customer* fails to pay such an *invoice*, the *IESO* shall not be required to take any action other than notifying the applicable *transmitter* of the default in payment.

Customer Default

2.2.3 Without limiting the generality of section 6.3.1.1 of Chapter 3, failure by a *market participant* to make payment to the *IESO* in respect of *transmission service* by the due date as described in section 2.2.1 constitutes an *event of default* in respect of that *market participant* pursuant to section 6 of Chapter 3 and shall be dealt with by the *IESO* accordingly.

Collection Obligation

2.2.3A The *IESO* shall not be required to collect charges for *transmission service* from any *transmission customer* in respect of the *transmission system* of a given *transmitter* unless the information or documentation referred to:

2.2.3A.1 in section 3.1.3, 5.1.3 or 6.1.3; or

2.2.3A.2 where section 6A.1.2 applies, in that section,

as may be applicable, relating to that *transmission customer* has been provided.

2.3 Arranging for Transmission Service and Dispatch

2.3.1 *Energy* and *ancillary service* transactions, including import and export transactions, using the *IESO-controlled grid* shall be arranged with the *IESO* using the *offer*, *bid*, *self-scheduling*, *contracted ancillary services* and other procedures set forth in Chapter 7.

2.3.2 *Energy* and *ancillary service* transactions, including import and export transactions, using the *IESO-controlled grid* shall be subject to *dispatch* by the *IESO*:

2.3.2.1 in accordance with the procedures for dispatching generation facilities, electricity storage facilities, dispatchable loads and boundary entities, based on the offers, bids and self-schedules submitted by market participants pursuant to Chapter 7 or in accordance with the terms of applicable contracted ancillary services contracts; and

2.3.2.2 in circumstances where the *IESO* determines that *curtailment* is necessary to protect the *reliability* of the *IESO-controlled grid* or the *integrated power system* or to ensure the safety of any person, prevent the damage of equipment, or to prevent the violation of any *applicable law* pursuant to Chapter 5.

3. Network Service

3.1 Network Service

3.1.1 [Intentionally left blank]

3.1.1.1 [Intentionally left blank]

3.1.1.2 [Intentionally left blank]

3.1.1.3 [Intentionally left blank]

3.1.2 The *IESO* shall collect charges for *network service* from each *transmission customer*:

3.1.2.1 [Intentionally left blank]

3.1.2.2 [Intentionally left blank]

3.1.2.3 [Intentionally left blank]

3.1.2.4 that is identified by an applicable *transmitter* pursuant to section 3.1.3.1 as being required by the applicable rate order issued by the *OEB* to pay for *network service*; and

3.1.2.5 in respect of which the necessary *meter point* documentation has been provided by the *transmission customer's metering service provider* pursuant to section 1.3A of Appendix 6.5 of Chapter 6.

3.1.3 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and to whom the *OEB* has issued a rate order shall:

3.1.3.1 provide to the *IESO*, and update as required, a list of those *transmission customers* that, pursuant to the terms of the rate order issued to the *transmitter* by the *OEB*, are required to pay charges in respect of *network service* relating to such *transmission system*; and

3.1.3.2 for each *transmission customer* identified in the list referred to in section 3.1.3.1, provide to the *IESO*, as required under any agreement between the *IESO* and the *transmitter*, written confirmation of its approval of that portion of the *meter point* documentation specified in such agreement and of any updates thereto prepared in accordance with section 1.3 of Appendix 6.5 of Chapter 6 for each transmission delivery point, as described in the applicable transmission rate schedule approved by the *OEB*, for such *transmission customer*;

3.1.3.3 annually review the list of *transmission customers* provided to the *IESO* in accordance with section 3.1.3.1 and the information provided pursuant to section 3.1.3.2 and promptly notify the *IESO* of any errors within such list or information.

3.1.4 The *IESO* shall notify each *transmitter* providing the list referred to in section 3.1.3.1 as to the identity of those *transmission customers* who have:

3.1.4.1 not been registered with the *IESO* as a *market participant*; or

3.1.4.2 otherwise ceased to be a *market participant*.

3.2 Arranging for Network Service

3.2.1 [Intentionally left blank]

3.2.1.1 [Intentionally left blank]

3.2.1.2 [Intentionally left blank]

3.2.2 [Intentionally left blank]

3.2.3 No *transmission customer* shall commence to obtain *network service* until the relevant *transmitter* and the *transmission customer* have completed the installation of all equipment required to connect the *transmission customer* to, or otherwise provide access to, the *IESO-controlled grid*, as specified in Chapter 4, and the applicable *connection point*, other than an *interconnection*, or *embedded connection point* has, where required by these *market rules*, a *metering installation* that complies with the requirements of Chapter 6.

3.3 Maintaining Network Service

3.3.1 [Intentionally left blank]

3.3.2 To the extent that a *transmission customer* desires to add a new delivery point for *network service*, the *transmission customer* shall provide the *IESO* with as much advance notice as practicable of such addition. No *transmission customer* shall establish a new delivery point until *connection facilities* at the new delivery point have been completed and satisfy the requirements of Chapter 4.

3.4 Rates and Charges for Network Service

3.4.1 The rates and charges, if any, for *network service* to be applied to the *transmission customers* identified in a list provided to the *IESO* pursuant to section 3.1.3.1 shall be as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

3.4.2 [Intentionally left blank]

3.4.3 [Intentionally left blank]

3.5 [Intentionally left blank]

3.5.1 [Intentionally left blank]

3.5.2 [Intentionally left blank]

3.6 Responsibilities of Market Participants Utilising Network Service

3.6.1 Each *transmission customer* that is a *market participant* utilising *network service* shall plan, construct, operate and maintain its system, *facilities* and equipment in accordance with Chapters 4 and 5.

3.7 [Intentionally left blank]

3.7.1 [Intentionally left blank]

3.7.2 [Intentionally left blank]

3.7.2.1 [Intentionally left blank]

3.7.2.2 [Intentionally left blank]

3.7.2.3 [Intentionally left blank]

3.8 Import Transactions

3.8.1 The *IESO-controlled grid* shall be available for the transmission of *energy* and *ancillary services* into the *IESO control area* from a neighbouring *transmission system*. Charges for *network service* shall not be applicable to a *market participant* in respect of the use of the *IESO-controlled grid* for such transmission. The *IESO* shall determine the available transmission capability at each *interconnection* with a neighbouring *transmission system* for imports into the *IESO control area* and shall manage congestion over such *interconnections* in accordance with Chapter 7.

3.9 [Intentionally left blank]

3.9.1 [Intentionally left blank]

3.9.2 [Intentionally left blank]

3.9.3 [Intentionally left blank]

4. Export Transmission Service

4.1 Availability of Export Transmission Service

4.1.1 The *IESO-controlled grid* shall be available for the transmission of *energy* out of the *IESO control area* into a neighbouring *transmission system*. Charges for *network service* shall not be applicable to a *market participant* in respect of the use of the *IESO-controlled grid* for such transmission. The *IESO* shall determine the available transmission capability at each *interconnection* with a neighbouring *transmission system* for exports out of the *IESO control area* and shall manage congestion over such *interconnections* in accordance with Chapter 7.

4.1.2 The *IESO* shall collect charges for *export transmission service* from each *transmission customer* that uses the *IESO-controlled grid* for the transmission of *energy* out of the *IESO control area*.

4.2 [Intentionally left blank]

4.2.1 [Intentionally left blank]

4.2.2 [Intentionally left blank]

4.2.2.1 [Intentionally left blank]

4.2.2.2 [Intentionally left blank]

4.2.2.3 [Intentionally left blank]

4.2.3 [Intentionally left blank]

4.3 Arranging for Export Transmission Service

4.3.1 To arrange for *export transmission service*, a *transmission customer* desiring such *service* shall be a *market participant* and shall *register* a *boundary entity* to which the *export transmission service* will relate. A *transmission customer* that is a *market participant* may obtain *export transmission service* once the *boundary entity* has been registered by the *IESO* as a *registered facility*.

4.4 Responsibility for Third-Party Arrangements

4.4.1 Each *transmission customer* obtaining *export transmission service* shall be responsible for any arrangements with other *control areas* or third parties that are necessary to deliver *energy* from the *IESO-controlled grid* to the *transmission customer's* delivery point outside the *IESO-controlled grid*.

4.5 Rates and Charges for Export Transmission Service

4.5.1 The rates and charges, if any, for *export transmission service* to be applied to the *transmission customers* referred to in section 4.1.2 shall be as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*.

4.5.2 [Intentionally left blank]

4.5.3 [Intentionally left blank]

5. Line Connection Service

5.1.1 The *IESO* shall collect charges for *line connection service* from each *transmission customer*:

5.1.1.1 that is identified by an applicable *transmitter* pursuant to section 5.1.3.1 as being required by an applicable rate order issued by the *OEB* to pay for *line connection service*; and

5.1.1.2 in respect of which the necessary *meter point* documentation has been provided by the *transmission customer's metering service provider* pursuant to section 1.3A of Appendix 6.5 of Chapter 6.

The rates and charges, if any, for *line connection service* to be applied to such *transmission customer* shall be as established by the *OEB* from time to time under the *Ontario Energy Board Act, 1998*.

5.1.2 [Intentionally left blank]

5.1.3 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and to whom the *OEB* has issued a rate order shall:

5.1.3.1 provide to the *IESO*, and update as required, a list of those *transmission customers* that, pursuant to the terms of the rate order issued to the *transmitter* by the *OEB*, are required to pay charges in respect of *line connection service* relating to such *transmission system*; and

5.1.3.2 for each *transmission customer* identified in the list referred to in section 5.1.3.1, provide to the *IESO*, as required under any agreement between the *IESO* and the *transmitter*, written confirmation of its approval of that portion of the *meter point* documentation specified in such agreement and of any updates thereto prepared in accordance with section 1.3 of Appendix 6.5 of Chapter 6 for each transmission delivery point, as described in the applicable transmission rate schedule approved by the *OEB*, for such *transmission customer*; and

5.1.3.3 annually review the list of *transmission customers* provided to the *IESO* in accordance with section 5.1.3.1 and the information provided pursuant to section 5.1.3.2 and promptly notify the *IESO* of any errors within such list or information.

5.1.4 The *IESO* shall notify each *transmitter* providing the list referred to in section 5.1.3.1 as to the identity of those *transmission customers* who have:

5.1.4.1 not been registered with the *IESO* as a *market participant*; or

5.1.4.2 otherwise ceased to be a *market participant*.

6. Transformation Connection Service

6.1.1 The *IESO* shall collect charges for *transformation connection service* from each *transmission customer*:

6.1.1.1 that is identified by an applicable *transmitter* pursuant to section 6.1.3.1 as being required by an applicable rate order issued by the *OEB* to pay for *transformation connection service*; and

6.1.1.2 in respect of which the necessary *meter point* documentation has been provided by the *transmission customer's metering service provider* pursuant to section 1.3A of Appendix 6.5 of Chapter 6.

The rates and charges, if any, for *transformation connection service* to be applied to such *transmission customer* shall be as established by the *OEB* from time to time under the *Ontario Energy Board Act, 1998*.

6.1.2 [Intentionally left blank]

6.1.3 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and to whom the *OEB* has issued a rate order shall:

6.1.3.1 provide to the *IESO*, and update as required, a list of those *transmission customers* that, pursuant to the terms of the rate order issued by the *OEB*, are required to pay charges in respect of *transformation connection service* relating to such *transmission system*;

6.1.3.2 for each *transmission customer* identified in the list referred to in section 6.1.3.1, provide to the *IESO*, as required under any agreement between the *IESO* and the *transmitter*, written confirmation of its approval of that portion of the *meter point* documentation specified in such agreement and of any updates thereto prepared in accordance with section 1.3 of Appendix 6.5 of Chapter 6 for each transmission delivery point, as described in the applicable transmission rate schedule approved by the *OEB*, for such *transmission customer*; and

6.1.3.3 annually review the list of *transmission customers* provided to the *IESO* in accordance with section 6.1.3.1 and the information provided pursuant to section 6.1.3.2 and promptly notify the *IESO* of any errors within such list or information.

6.1.4 The *IESO* shall notify each *transmitter* providing the list referred to in section 6.1.3.1 as to the identity of those *transmission customers* who have:

6.1.4.1 not been registered with the *IESO* as a *market participant*; or

6.1.4.2 otherwise ceased to be a *market participant*.

6A. Other Transmission Service

6A.1.1 The *IESO* shall, where required by the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*, collect charges for any *transmission service* other than one referred to in sections 3, 4, 5 and 6 from each *transmission customer* that is required by such rate order to pay for such *transmission service* and, where section 6A.1.2 applies:

6A.1.1.1 that has been identified in the list referred to in section 6A.1.2.1; and

6A.1.1.2 in respect of which the information referred to in section 6A.1.2.2 has been provided.

The rates and charges for such *transmission service* shall be as established by the *OEB* from time to time under the <u>*Ontario Energy Board Act, 1998*</u>.

6A.1.2 At the request of the *IESO*, each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* shall provide to the *IESO*, and shall update as required:

6A.1.2.1 a list of those *transmission customers* that, pursuant to the terms of a rate order issued by the *OEB*, are required to pay charges in respect of any *transmission service* referred to in section 6A.1.1 relating to such *transmission system*; and

6A.1.2.2 such other information as the *IESO* may reasonably require in respect of such *transmission customer*, including but not limited to any confirmation that may be required from the *transmitter* under any agreement between it and the *IESO*, so as to enable the *IESO* to perform any necessary calculations for the charges referred to in section 6A.1.2.1 in a manner consistent with the rate order referred to in that section.

6A.1.3 The *IESO* shall notify each *transmitter* providing the list referred to in section 6A.1.2.1 as to the identity of those *transmission customers* who have:

6A.1.3.1 not been registered with the *IESO* as a *market participant*; or

6A.1.3.2 otherwise ceased to be a *market participant*.

6A.1.4 Each *transmitter* who has provided a list of *transmission customers* and/or other information as may be reasonably required by the *IESO* in accordance with section 6A.1.2 shall, annually review such list and information and promptly notify the *IESO* of any errors within such list or information.

6B. Liability

6B.1.1 The *IESO* shall be entitled to and shall rely on the list of *transmission customers* provided pursuant to section 3.1.3.1, 5.1.3.1, 6.1.3.1 or 6A.1.2.1 and on the *meter point* documentation or other information provided pursuant to section 3.1.2.2, 5.1.1.2, 6.1.1.2 or 6A.1.1.2, regardless of whether any portion of such *meter point* documentation has been confirmed by the applicable *transmitter*, for the purpose of the collection and distribution of charges for a *transmission service* and, notwithstanding section 13 of Chapter 1:

6B.1.1.1 the *IESO* shall not be liable to any person in respect of the collection from a *transmission customer* of, or the failure to collect from that *transmission customer*, charges in respect of a *transmission service* by reason of the erroneous identification, inclusion or exclusion of that person on or from such list or by reason of any inaccuracies in such *meter point* documentation or other information; and

6B.1.1.2 the applicable *transmitter* providing the *IESO* with such list or other information shall indemnify and hold harmless the *IESO* in respect of any and all claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the allocation or collection by the *IESO* of charges in respect of a *transmission service* by reason of the erroneous identification, inclusion or exclusion of a person on or from such list or by reason of any inaccuracies in such other information or *meter point* documentation pertaining to any of its *transmission customers*,

provided that nothing in this section 6B.1.1 shall be construed as affecting the liability of the *IESO* in respect of the manner of calculation of charges for a *transmission service* collected from a person that is properly identified or included on such list and in respect of which such *meter point* documentation or other information is accurate.

6B.1.2 Notwithstanding section 13.4.1 of Chapter 1, the liability and indemnification provisions of section 6B.1.1 shall apply to any agreement between the *IESO* and a *transmitter* pursuant to sections 3.1.3, 5.1.3, 6.1.3, or 6A.1.2.2.

6C. Correction of Errors in Lists

6C.1.1 The *IESO* shall promptly notify the applicable *transmitter* upon becoming aware that a *transmission customer* may be erroneously identified, included or excluded on or from a list of *transmission customers* provided by such *transmitter* pursuant to section 3.1.3.1, 5.1.3.1, 6.1.3.1 or 6A.1.2.1. Where applicable, the *transmitter* shall promptly update the list accordingly.

6C.1.2 Subject to section 6C.1.4, the *IESO* shall use reasonable endeavours to adjust the applicable *settlement statement* of a *transmission customer* that:

6C.1.2.1 has been charged or that has failed to be charged for a *transmission service* by reason of the erroneous identification, inclusion or exclusion of that *transmission customer* on or from a list of *transmission customers* provided by the applicable *transmitter* pursuant to section 3.1.3.1, 5.1.3.1, 6.1.3.1 or 6A.1.2.1; or

6C.1.2.2 has been incorrectly charged for a *transmission service* by reason of any inaccuracies in the *meter point* documentation or other information referred to in section 3.1.3.2, 5.1.3.2, 6.1.3.2 or 6A.1.2.2.

6C.1.3 Subject to section 6C.1.4, where the *IESO*:

6C.1.3.1 charges a *transmission customer* for *transmission service* pursuant to section 6C.1.2.1, the *IESO* shall include such charge on the applicable *invoice* issued to the *transmission customer* in accordance with section 2.2.1 and shall, subject to section 2.2.2A, include as a credit on the applicable *invoice* submitted to each applicable *transmitter* an amount equal to that portion of the charges for *transmission services*, as charged to *transmission customers*, relating to that *transmitter's transmission system* in accordance with section 2.2.2;

6C.1.3.2 credits a *transmission customer* for charges for *transmission service* for which it should not have been charged pursuant to section 6C.1.2.1 the *IESO* shall include such credit on the applicable *invoice* issued to the *transmission customer* in accordance with section 2.2.1 and shall include as a debit on the applicable *invoice* submitted to each applicable *transmitter* an amount equal to that portion of the charges for *transmission services*, as credited to *transmission customers*, relating to that *transmitter's transmission system* in accordance with section 2.2.2; or

6C.1.3.3 corrects the amount charged for a *transmission service* pursuant to section 6C.1.2.2, the *IESO* shall include an amount equal to such correction as a credit or debit, as the case may be, on the applicable *invoice* issued to the *transmission customer* in accordance with section 2.2.1 and shall include as a credit or debit, as the case may be, on the applicable *invoice* submitted to each applicable *transmitter* an amount equal to such correction, as credited or debited to *transmission customers*, relating to that *transmitter's transmission system* in accordance with section 2.2.2.

6C.1.4 The IESO shall not take any action or make any correction under section 6C in regards to any settlement amount if a limitation period applicable to such settlement amount prescribed in applicable law has lapsed. Additionally, where a transmitter fails to conduct a review, in accordance with sections 3.1.3.3, 5.1.3.3, 6.1.3.3, or 6A.1.4, as the case may be, the IESO shall not take any action or make any correction under section 6C in regards to any settlement amount pertaining to the information which the transmitter failed to review that arose prior to the date on which the transmitter failed to conduct the applicable review.

6C.1.5 If a market participant disagrees with the IESO's conclusion and action taken in accordance with section 6C.1.2, the market participant may pursue their disagreement through the dispute resolution process outlined in section 2 of Chapter 3.

7. [Intentionally left blank – section deleted]

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7.2.4 [Intentionally left blank – section deleted]

8. Information Requirements

8.1 [Intentionally left blank – section deleted]

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8.7 Retirements

8.7.1 [Intentionally left blank – section deleted]

8.7.2 Each *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* shall provide to the *IESO* not less than six months' advance notice of the commencement of planned retirements of transmission *facilities*, including notification of any plans the *transmitter* may have to construct replacement *facilities* for those being retired. If the *IESO* believes that a planned retirement of transmission *facilities* may have an adverse effect on the *reliability* of the *IESO-controlled grid*, or on the efficient operation of the *IESO-administered markets*, the *IESO* may request that the *transmitter* not retire the *facility*. If the *IESO* and a *transmitter* disagree regarding the retirement of a transmission *facility*, or with respect to the *transmitter's* plans to replace such a *facility*, the matter may, subject to *licence* of the *IESO* or of the *transmitter* or to the provisions of the applicable *operating agreement,* be submitted for resolution using the dispute resolution procedures set forth in section 2 of Chapter 3.

8.7.3 [Intentionally left blank – section deleted]

8.7.4 [Intentionally left blank – section deleted]

8.8 Transmitter Data Access

8.8.1 Each *transmitter* for which the *IESO* administers the collection and distribution of *transmission services charges* for the various classes of *transmission service* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998* and whose *transmission system* forms part of the *IESO-controlled grid* shall, where applicable, have access to the following *confidential information* related to each type of *transmission services charge* in a manner and form specified by the *IESO*:

8.8.1.1 *energy* readings that reside in the *metering database* pursuant to section 10.1.5.3 of Chapter 6 which have been loss adjusted and totalized to their respective *delivery points* defined for the purposes of *transmission services charges* as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*;

8.8.1.2 *interchange schedule data* used in the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*;

8.8.1.3 the coincident or non-coincident peak demand quantity for each transmission delivery point to the extent that such quantities are relevant to the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*;

8.8.1.4 the peak demand quantity applicable to the *transmitter's transmission system* or the *IESO-controlled grid* as the case may be, to the extent that such quantities are relevant to the calculation of *transmission services charges* as required by this Chapter and as established by the *OEB* from time to time pursuant to the *Ontario Energy Board Act, 1998*; and

8.8.1.5 the transmission services charges payable by each transmission customer to the transmitter at each delivery point defined for the purposes of transmission services charges or intertie metering point to the extent that such data is relevant to the calculation of transmission services charges as required by this Chapter and as established by the OEB from time to time pursuant to the Ontario Energy Board Act, 1998.

8.8.2 The *transmitter* to whom the disclosure of information described in section 8.8.1 is made shall use the *confidential information* so disclosed solely for the purposes of collecting and administering those *transmission services charges* and shall use all reasonable endeavours to protect the confidentiality of such *confidential information*, including but not confined to adherence of any code, licence condition, order by the *OEB* or applicable law regarding the separation of the *transmitter's* commercial activities and information with respect to any other affiliated entities as may be defined in said code, licence condition, order, or applicable law.

8.8.3 Notwithstanding section 13 of Chapter 1, the applicable *transmitter* receiving the *confidential information* referred to in section 8.8.1 shall indemnify and hold harmless the *IESO* in respect of any and all claims, losses, costs, liabilities, obligations, actions, judgements, suits, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the *IESO* arising from the subsequent use of such information by, the *transmitter*.

9. [Intentionally left blank – section deleted]

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Market Rules

Chapter 11
Definitions

Connecting Today.
Powering Tomorrow.

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Distribution List

Name	**Organization**

Table of Contents

1. Definitions

Rule Notes:

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In the market rules:

actual exposure means, in respect of a given *market participant*, the amount calculated at any given time by the *IESO* for that *market participant* pursuant to section 5.5 of Chapter 2;

adequacy means the ability of the *electricity system* to supply electrical demand and *energy* requirements at all times, taking into account scheduled and unscheduled *outages* of equipment or components;

adjustment period allocation refers to a means of allocating post-final adjustments to *settlement amounts.* This allocation is based on *market participant* activity in the *energy market* during the event that is the subject of the originating *settlement* adjustment;

administrative price means a price established by the *IESO* in the circumstances referred to and in accordance with section 8.4A of Chapter 7;

advance approval means *IESO* approval of a *planned outage* before the scheduled start date of the *planned outage*. *Advance approval* includes *quarterly advance approval, weekly advance approval, three-day advance approval* and *one-day advance approval*;

affiliate, with respect to a corporation, has the meaning ascribed thereto in the *Business Corporations Act* (Ontario);

amend, in relation to the *market rules*, means any change to the *market rules*, whether by amendment, alteration, addition or deletion;

amendment submission has the meaning ascribed thereto in section 4.2.4 of Chapter 3;

ancillary service provider means a person who provides an *ancillary service*;

ancillary service means services necessary to maintain the *reliability* of the *IESO-controlled grid*, including, but not limited to, *regulation*, *black start capability*, *voltage control*, reactive power, *operating reserve* and any other such services established by the *market rules*;

applicable law means all laws, regulations, other statutory instruments and rules and other documents of a legislative nature which apply to the *IESO* or to *market participants*, and all orders of a government, governmental body, authority or agency having jurisdiction over the *IESO* or a *market participant* including, but not limited to, any *licence* issued to the *IESO* or a *market participant*;

applicant has the meaning ascribed thereto in section 2.5.1 of Chapter 3;

application for authorization to participate means the form *published* by the *IESO* and by which a person may apply for authorization to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

<u>Arbitration Act, 1991</u> means the Arbitration Act, 1991, S.O. 1991, c. 17;

arbitrator means a qualified person appointed pursuant to section 2.7 of Chapter 3 to arbitrate a dispute;

area control error or *ACE* means the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias;

attended means regularly staffed on a twenty-four hours a day, seven days a week basis;

auction capacity means an amount in megawatts of electricity available to be provided to the *IESO-controlled grid*, by *capacity market participants* in association with a *capacity auction*;

auction period means, with respect to a *capacity auction,* the length of time commencing with the opening of the window during which the IESO receives *capacity auction offers*, and finishing at the time at which the *IESO publishes* auction results;

authority center means, in respect of a *facility*, an *attended* location at which indirect operational control of the *facility* is effected;

automatic generation control or *AGC* means the process that automatically adjusts the output from a *generation facility* or an *electricity storage facility* that is providing *regulation;*

automatic voltage regulation or *AVR* means the process that automatically adjusts the reactive output of a *generation unit, electricity storage unit,* or synchronous condenser to maintain the *unit* terminal voltage within a pre-determined range;

availability de-rating factor means, in respect of an *obligation period*, a value which is assigned to a *capacity auction resource,* as determined in accordance with the applicable *market manual.*

availability window means the hours in an *obligation period* during which *capacity auction resources* are required to be available to provide *auction capacity*;

basecase means a model of electrical components of the *IESO-controlled grid* and *neighbouring electricity systems.* Such components may include but are not limited to transformers, *generation facilities, electricity storage facilities,* and transmission lines, and includes the steady-state, dynamic and short circuit attributes of each component where applicable.

BES exception applicant means (i) a *market participant* who owns *IESO controlled-grid* elements or *facilities* who applies to the *IESO* for a *BES exception*; or (ii) a *connection applicant* who applies to the *IESO* for a *BES exception*;

BES exception request means an application for the approval, amendment, termination, or transfer of a *BES exception* pursuant to section 3.2B of Chapter 5;

bid means a statement of the quantities of a commodity that a buyer will purchase at different *market price* levels for that commodity in the *real-time market* or the *procurement market*;

bidding limit means, in respect of a given *TR participant*, the amount calculated by the *IESO* for that *TR participant* in accordance with section 4.14.1 of Chapter 8;

billing period means, in respect of the purchase or sale of *TRs* in a round of a *TR auction,* a period of a *trading week,* in respect of the *real-time markets* and the *settlement* of amounts owing to *TR holders* under section 4.4.1 of Chapter 8, a period of a calendar month;

black start capability means the capability of a *generation facility* to start without an outside electrical supply so as to be used to energize a defined portion of the *IESO-controlled grid*;

boundary entity means an entity designated and maintained by the *IESO* for the purpose of energy trading, and which represents the capacity of one or more resources, including but not limited to *generation facilities* or *load facilities*, located at a point or points external to the *IESO control area* which a *market participant* is entitled to inject into or withdraw from the *IESO-controlled grid* and which shall be deemed to be located in an *intertie zone* in accordance with section 2.2.7.2 of Chapter 7;

bulk electric system exception or *BES exception* is an exception from compliance with the requirements of *NERC reliability standards* relating to elements or *facilities* connected to the *IESO controlled-grid* in accordance with the Ontario-adapted *NERC* procedure for processing *BES exceptions;*

business day means any day other than a Saturday, a Sunday or a holiday as defined in section 88 of the *Legislation Act* and, where expressed by reference to the jurisdiction of a *market participant* other that the Province of Ontario, means any day other than a Saturday, a Sunday or a day on which banks are authorized or required to be closed in the jurisdiction of that *market participant*;

buying market participant means a *market participant* that is purchasing *energy* under a *physical bilateral contract*;

called capacity export means an *energy* export from the *IESO control area* that is supported by the capacity of a *generation unit* or the capacity for injection of an *electricity storage unit* within the *IESO control area* that has committed its capacity, or a portion thereof, to an external *control area* and that capacity has been called by the external *control area operator* in accordance with section 20.3 of Chapter 7;

Canadian prime interest rate means the base lending rate that the bank where the *IESO settlement clearing account* is maintained charges for commercial loans to its best and most creditworthy commercial customers;

capability factor means the ratio of the *energy* which could have been delivered by a generating station with *generation unit* limitations in effect, to the *energy*, over the same period of time, that could have been delivered if the generating station had operated at its *maximum continuous rating*;

capacity auction means an auction operated by the *IESO* to acquire *auction capacity*, and includes a *demand response auction;*

capacity auction capacity test means a test which is used to evaluate a *capacity auction resource* on their ability to provide *capacity*, as specified in the applicable *market manual*;

capacity auction clearing price means the price at which *a capacity auction* clears for an *obligation period* and is expressed in $/MW-day;

capacity auction deposit means the deposit required to be made by a *capacity auction participant* in accordance with section 18 of Chapter 7, as a condition of participating in a *capacity auction;*

capacity auction dispatch test means a test conducted by the *IESO* in which *capacity auction resources* are evaluated on their ability to successfully respond to *dispatch* instructions as specified in the applicable *market manual*;

capacity auction eligible generation resource means a *non-committed resource* that is associated with a *generation facility,* which is also a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as dispatchable with the *IESO* prior to the *obligation period* in accordance with the timelines specified in the applicable *market manual*;

capacity auction eligible storage resource means a *non-committed resource* associated with an *electricity storage facility*, which is also a *connected facility* at the commencement of the capacity qualification process for a given *capacity auction*, and which is registered as dispatchable with the *IESO* prior to the *obligation period* in accordance with the timelines specified in the applicable *market manual*;

capacity auction offer means an *offer(s)* from a *capacity auction participant*, in the form of a *price-quantity pair(s)*, to provide *auction capacity* through a *capacity auction resource* for an applicable *obligation period*, reflecting the amount of *auction capacity* that the *capacity auction participant* can reliably and responsibly provide if received as a *capacity obligation*, and which *offer* amount is no greater than the *capacity auction participant's unforced capacity;*

capacity auction participant means a person that is authorized to participate in a *capacity auction* and submit *capacity auction offers*;

capacity auction reference price represents the price at which resources would be incentivized to enter the market and recover the necessary costs to make their capacity available, recognizing their revenue opportunities and avoided costs in the *energy market*. The reference price is directly associated with the *target capacity* as another key reference point in the demand curve;

capacity auction resource means a resource type specified in section 19.1.2 of Chapter 7 and is utilized by a *capacity auction participant* to satisfy a *capacity obligation*;

capacity auction zonal constraints means the minimum or maximum amount of *auction capacity*, or virtual *demand response capacity* that a *capacity auction* seeks to secure for a specific electrical zone or group of electrical zones as detailed by the *IESO* in each pre-auction report;

capacity dispatchable load resource means the *capacity auction resource* associated with a *dispatchable load* that has received a *capacity obligation* in a given *capacity auction* in accordance with the applicable *market manual*;

capacity export agreement means an agreement between the *IESO* and a *control area operator* regarding the management of *called capacity exports*, and which may include but is not limited to *interconnection agreements*;

capacity export request means a request submitted to the *IESO* by a *market participant* for approval to commit the Ontario-based capacity of a *generation unit* or the injection capacity of an *electricity storage unit* to an external *control area* in accordance with section 20.1 of Chapter 7*;*

capacity generation resource means a *capacity auction eligible generation resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual*;

capacity import call means an *energy* import from an external *control area* that is supported by the capacity of a *generation unit* or the capacity for injection of an *electricity storage unit* within the external *control area* that has committed its capacity, or a portion thereof, to the *IESO control area* and that capacity has been called by the *IESO* in accordance with section 19.9 or 19.9B of Chapter 7;

capacity market participant means a *capacity auction participant* that has registered with the *IESO* as a *capacity market participant,* and who satisfies requirements contemplated in Chapter 7, section 18;

capacity obligation means the amount of *cleared UCAP* that a *capacity market participant* is required to provide from a particular *capacity auction resource* during each hour of the *availability window* of an *obligation period*;

capacity prudential support means the collateral provided by a *market participant* with a *capacity obligation in* accordance with the requirements contemplated in Chapter 2, section 5B;

capacity prudential support obligation means the dollar amount of collateral required as specified by the *IESO* as a condition of satisfying a *capacity obligation*;

capacity qualification request means a request submitted to the *IESO* by a *capacity auction participant* which includes the *installed capacity* and all other applicable information, using the forms specified by the *IESO,* for the determination of the *unforced capacity* of a *capacity auction resource* in the capacity qualification process specified in the applicable *market manual*;

capacity storage resource means a *capacity auction eligible storage resource* with a *capacity obligation* received in a given *capacity auction,* in accordance with the applicable *market manual;*

capacity transferee means a *capacity auction participant* who is willing to accept all or a portion of a *capacity obligation* from a *capacity transferor.* A *capacity transferee* may be the same *capacity auction participant* as the *capacity transferor;*

capacity transferor means a *capacity auction participant* who intends to transfer all or a portion of its *capacity obligation* received through a *capacity auction* to a *capacity transferee.* A *capacity transferor* may be the same *capacity auction participant* as the *capacity transferee;*

Certified black start facility means a *registered facility* that, to the satisfaction of the *IESO* acting reasonably, has complied with and continues to comply with equipment and staffing configurations, training and maintenance programs and inspection and testing regime as set out in the *market rules* or the *Ontario power system restoration plan*, and from which the *IESO* may direct the delivery of power without assistance from the electrical system.

charge type means the identifier designating an item on an *invoice* or a *settlement statement*;

class r reserve means operating reserve of class r, where r = 1 denotes *ten-minute operating reserve* and r = 2 denotes *thirty minute operating reserve*;

cleared ICAP means, in respect of a *capacity auction resource*, an amount in megawatts of electricity, as determined in accordance with section 18.8.2 of Chapter 7 and adjusted for any applicable *capacity obligation* buy-outs or *capacity obligation* transfers;

cleared UCAP means an amount in megawatts of electricity that a *capacity auction resource* cleared in a given *capacity auction* and adjusted for any applicable *capacity obligation* buy-outs, *capacity obligation* transfers, or in-period *cleared UCAP* adjustments;

close of banking business means 3:00 p.m. on the day the relevant bank is open for business;

cogeneration facility means a *generation facility* that produces both electric *energy* and either steam or other forms of useful energy (such as heat), which are used for industrial, commercial, heating, or cooling purposes, and qualifies for treatment as a Class 43.1 facility or has qualified as a Class 34 facility under the Income Tax Act, R.S.C. 1985, c.1.;

combined guaranteed costs means all eligible costs incurred by a *generation facility* from either the point of ignition or synchronization to the *IESO-controlled grid* as applicable, until the earlier of the end of the *minimum generation block run-time* and the end of the *minimum run-time* for the *generation facility;*

commissioning electricity storage facility means an *electricity storage facility* located within the *IESO control area* that is either (i) newly constructed or (ii) significantly redesigned or rebuilt and is designated by the *IESO* as a *commissioning electricity storage facility* and, in either case, that has not yet completed the commissioning tests referred to in section 2.2D.4.2 of Chapter 7;

commissioning generation facility means a *generation facility* located within the *IESO control area* that is either (i) newly constructed or (ii) significantly redesigned or rebuilt and is designated by the *IESO* as a *commissioning generation facility* and, in either case, that has not yet completed the commissioning tests referred to in section 2.2A.4.2 of Chapter 7;

commitment period means the period of time for each *capacity auction* over which it secures *capacity*. It consists of two *obligation periods;*

confidential information means (i) information which has been supplied by the disclosing person in confidence implicitly or explicitly, where disclosure could reasonably be expected to: (a) prejudice significantly the competitive position of the disclosing person; (b) interfere significantly with the contractual or other negotiations of the disclosing person or another person; (c) result in undue loss or gain to the disclosing person or another person; (d) compromise the efficiency of the *IESO-administered markets*; (e) result in the disclosing person being in breach of a bona fide confidentiality agreement to which the information is subject; or (f) in the opinion of the *IESO*, pose a potential security threat to the *integrated power system*, the *IESO-administered markets*, or those of neighbouring jurisdictions; and (ii) information that, pursuant to the *market rules* or *applicable law*, the *IESO* or a *market participant* cannot disclose or make available to one or more persons;

confidentiality classification means a classification referred to in section 5.4.1 of Chapter 3;

connect means to form a physical link to or with the *IESO-controlled grid* through a *connection facility*;

connected facility means a *facility* connected to the *IESO-controlled grid*;

connected wholesale customer means a wholesale customer, other than a *distributor*, that is directly connected to the *IESO-controlled grid*;

connection agreement means an agreement entered into between a *transmitter* and a *market participant* governing the terms and conditions pursuant to which the *market participant* is *connected* to the *transmitter's transmission system*;

connection applicant means any of:
(i) a *market participant* or person that applies to the *IESO* for approval of a new *connection* to the *IESO-controlled grid* or for approval of the modification of an existing *connection* to the *IESO-controlled grid*, or
(ii) a *distributor* in whose *distribution system* a *market participant* or person is or intends to be connected as an *embedded generator* or *embedded electricity storage participant* whose *facility* is or will be rated greater than 10 MW, that seeks to establish a new or modify an existing connection pursuant to section 6.1.6 of Chapter 4;

connection assessment means a study conducted by the *IESO* pursuant to section 6.1.5 of Chapter 4 to assess the impact of a new *connection* to the *IESO-controlled grid* or of the modification of an existing *connection* to the *IESO-controlled grid* on the *reliability* of the *integrated power system*;

connection charge means a charge for recovering costs associated with connection to a *transmission system*;

connection facility means a *facility* and equipment that allow a person to become *connected* to the *IESO-controlled grid* and includes, in the case of a *distributor*, distribution assets owned by a person other than the *distributor* that have been deemed by the *OEB* to be transmission assets;

connection-related reliability information means any information provided or requested pursuant to section 2.2.5 of Chapter 7 and/or section 6.1.6.2 of Chapter 4.

connection point means a point of connection between the *IESO-controlled grid* and a *generation facility, electricity storage facility,* or *load facility*, or the point at which a neighbouring *transmission system* is connected to the *IESO-controlled grid*;

connection request means a request submitted by a *market participant* or a *connection applicant* to a *transmitter* for *connection* to the *IESO-controlled grid*;

connection station service is *station service* associated with transformers, capacitors, switchgear, protection systems and control systems that *connect generation facilities*, *electricity storage facilities, load facilities* or *distribution facilities* to the *IESO-controlled grid*;

conservative operating state means the state described in section 2.5 of Chapter 5;

constrained IESO-controlled grid model means the model capable of being used by the *dispatch algorithm* and described in section 4.5.1.2 of Chapter 7;

constrained off dispatchable load means a *dispatchable load, electricity storage unit* or *boundary entity dispatched* by the *IESO* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) less *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *dispatchable load, electricity storage unit* or *boundary entity* would, but for such constraint or *security limit*, otherwise be or have been *dispatched* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) more *energy*;

constrained off event means, in respect of a *generation unit,* an *electricity storage unit,* a *dispatchable load*, or a *boundary entity*, the event of being *dispatched* as a *constrained off facility*;

constrained off facility means a *constrained off generation unit,* a *constrained off dispatchable load* or both;

constrained off generation unit means a *generation unit, electricity storage unit,* or *boundary entity dispatched* by the *IESO* to supply (or to inject in the case of an *electricity storage unit* or *boundary entity*) less *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *generation unit, electricity storage unit,* or *boundary entity* would, but for such constraint or *security limit,* otherwise be or have been *dispatched* to supply (or to inject in the case of an *electricity storage unit* or *boundary entity*) more *energy*;

constrained on dispatchable load means a *dispatchable load, electricity storage unit* or *boundary entity dispatched* by the *IESO* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) more *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *dispatchable load, electricity storage unit* or *boundary entity* would, but for such constraint or *security limit*, otherwise be or have been *dispatched* to consume (or to withdraw in the case of an *electricity storage unit* or *boundary entity*) less *energy*;

constrained on event means, in respect of a *generation unit,* an *electricity storage unit,* a *dispatchable load* or a *boundary entity*, the event of being *dispatched* as a *constrained on facility*;

constrained on facility means a *constrained on generation unit,* a *constrained on dispatchable load* or both;

constrained on generation unit means a *generation unit, electricity storage unit,* or *boundary entity dispatched* by the *IESO* to supply (or to inject in the case of an *electricity storage unit* or a *boundary entity*) more *energy* in order to assist in addressing a transmission flow constraint on the *IESO-controlled grid* or a *security limit* in circumstances where such *generation unit, electricity storage unit,* or *boundary entity* would, but for such constraint or *security limit*, otherwise be or have been *dispatched* to supply (or to inject in the case of an *electricity storage unit, boundary entity*) less *energy*;

consumer means a person who uses, for the person's own consumption, electricity that the person did not generate;

contingency event means the unexpected failure of a single component or multiple components connected to the *electricity system*;

contracted ancillary services means *ancillary services*, other than *operating reserve,* procured by the *IESO* by contract rather than in the *real-time markets* in accordance with sections 9.2 to 9.5 of Chapter 7;

contributor outage means an *outage* of a *demand response contributor* where its energy consumption is less than 1% of its peak consumption measured in the prior three months, excluding any *outages* related to *generation units*;

control area means an area on an electricity system where supply and demand are kept in balance through *dispatch* by the *control area operator*;

control area operator means the person responsible for the *secure* operation of a *control area*, and includes independent system operators and regional transmission organizations in other jurisdictions;

control centre means, in respect of a *registered facility* or group of *facilities,* an *attended location* where signals and instructions for controlling the *facilities* are received from an *authority centre* or the *IESO*, and transferred directly to the *facilities* for implementation;

costs of the arbitration means the fees and expenses of an *arbitrator* and any other costs and expenses related to the arbitration of a dispute under section 2 of Chapter 3, other than the legal costs and expenses of the parties to the dispute and of any intervener;

costs of the mediation means the fees and expenses of a *mediator* and any other costs and expenses related to the mediation of a dispute under section 2 of Chapter 3, other than the legal costs and expenses of the parties to the dispute and of any person permitted by the *mediator* to attend a mediation session pursuant to section 2.6.6;

current period adjustment means an adjustment that is effected against amounts owing or payable in respect of transactions reflected in a *settlement statement* issued for the *billing period* or *trading day* during which the *current period adjustment* is effected regardless of the *billing period* or *trading day* during which the *preliminary settlement statement* to which the adjustment relates occurred;

curtailment means the involuntary curtailment of *non-dispatchable load* as a result of insufficient *generation capacity* or *electricity storage capacity*, of a limitation in the capacity of a *transmission system* or of actions taken by the *IESO* pursuant to Chapter 5 to maintain the *reliability* of the *IESO-controlled grid* or of the *electricity system*;

daily cascading hydroelectric dependency means there is a minimum hydraulic time lag of less than 24 hours from a hydroelectric *generation facility* to one or more adjacent upstream and/or downstream hydroelectric *generation facilities* operated by the same *registered market participant*;

data collection system means a means of extracting *metering data* from a *metering installation* and transferring such *metering data* into a remote *metering database*;

data logger means a device designed to be capable of reading and holding data until that data is collected;

default amount means a dollar amount by which a *market participant* has defaulted upon its obligations to *settle* with the *IESO* and shall, for purposes of the imposition of a *default levy,* be calculated in accordance with section 8.3.1 or 8.5.1 of Chapter 2;

default interest means interest at the *default interest rate*;

default interest rate means the interest rate calculated as the *Canadian prime interest rate* plus 2%;

default levy means a levy imposed by the *IESO* on *non-defaulting market participants* in accordance with section 8 of Chapter 2;

defaulting market participant means a *market participant* that is in default of payment in respect of monies owing to the *IESO* under the *market rules*;

default protection amount means, in respect of a given *market participant*, the dollar amount determined from time to time by the *IESO* for that *market participant* in accordance with section 5.3.8 of Chapter 2;

defined meter point means (a) in respect of a *facility connected* to the *IESO-controlled grid* by a *connection facility* that is a radial line designated by the *IESO* for such purpose, the point at a voltage above 50 kV at which the designated radial line is *connected* to (i) the high voltage bus of the *facility*, or (ii) the *facility*, if there is no such high voltage bus; (b) in respect of a *facility connected* to the *IESO-controlled grid* by a *connection facility* other than one referred to in (a), the point at a voltage above 50 kV at which the *connection facility* is *connected* to the *IESO-controlled grid*; and (c) in respect of an *embedded market participant*, the point at which the *embedded market participant's facility* is connected to the distribution system within which it is *embedded*;

delivery point means a uniquely identified reference point determined in accordance with section 2.4A.1 of Chapter 9 and used for *settlement* purposes in the *real-time markets*, other than in respect of transactions involving the transmission of *energy* or *ancillary services* into or out of the *IESO-controlled grid* from a neighbouring *transmission system*;

demand means the rate at which electric *energy* is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time;

demand response auction means an auction operated by the *IESO* prior to December 31, 2019, to acquire *demand response capacity,* in accordance with section 18 of Chapter 7;

demand response bid price threshold means the price at which a *demand response energy bid* shall exceed, in the day-ahead commitment process and the *real-time market,* to be considered a *demand response energy bid* in accordance with the applicable *market manual*;

demand response capacity means the quantity of load reduction provided by *dispatchable loads* and/or *hourly demand response resources*;

demand response contributor means a *load facility* that is associated with an *hourly demand response resource* and is used to satisfy in whole or a portion of a *capacity obligation.*

Demand response contributors are registered by *capacity market participants* as part of the contributor management process detailed in the applicable *market manual*;

demand response energy bid means a *bid* in the day-ahead commitment process and the *real-time market,* greater than the *demand response bid price threshold*, except during the *capacity auction capacity test* testing window, and less than the *MMCP,* by a *capacity market participant* entered for either a *capacity dispatchable load resource* or an *hourly demand response resource* to fulfill a *capacity obligation* availability requirement;

demand response resource means, in a *capacity auction,* either an *hourly demand response resource* or a *capacity dispatchable load resource*;

designated constrained off watch zone means an area within Ontario as set out in the applicable *market manual*, including connected *intertie zones*, that is monitored to determine if persistent and significant congestion management *settlement* credit payments for *constrained off events* are being made. These watch zones may be further designated for injections, withdrawals or both;

disaster recovery plan means the plan for maintaining *IESO* settlement functions in the event of a disaster;

disconnect means to separate *facilities* or equipment from the *IESO-controlled grid*, a *transmission system,* a *distribution system* or from a host *market participant*, as the case may be, and, in the case of a *distributor* that is *connected* to the *IESO-controlled grid* by distribution assets owned by a person other than the *distributor* that have been deemed by the *OEB* to be transmission assets, to separate the *distributor* from those assets;

disconnection order means an order issued by the *IESO* to any one of, or a combination of, a *transmitter,* a *distributor* or other *market participant*, directing such *transmitter, distributor* or other *market participant*, as applicable, to *disconnect facilities* or equipment specified within such order;

dispatch means the process by which the *IESO* directs the real-time operation of *registered facilities* to cause a specified amount of electric *energy* or *ancillary service* to be provided to or taken off the *electricity system*;

dispatch algorithm means the mathematical algorithm used by the *IESO* to determine various operating schedules and prices in accordance with Chapter 7;

dispatch centre means, in respect of a *registered facility* or group of *facilities,* an *attended location* at which employees have the authority and capability to *dispatch* the *facilities* based on the *dispatch instructions* received from the *IESO;*

dispatch data means the *offers*, *bids*, *self-schedules* and estimates of *intermittent generation* required to be submitted to the *IESO* in accordance with Chapter 7 and used by the *IESO* to determine physical operations and *physical market prices;*

dispatch day means a period from midnight EST to the following midnight EST;

dispatch hour means a one hour period within a *dispatch day*;

dispatch instructions means in respect of a *registered facility* other than a *boundary entity*, a physical operating instruction issued by the *IESO* either in the *real-time dispatch process* or in those *dispatch intervals* when *administrative prices* were applied pursuant to section 8.4A of Chapter 7 or the *IESO-administered markets* are suspended pursuant to section 13 of Chapter 7, and, in respect of a *registered facility* that is a *boundary entity*, the *interchange schedule* pertaining to that *registered facility*;

dispatch interval means a five-minute interval within a *dispatch hour*;

dispatch period means, in respect of a *pre-dispatch schedule*, a *dispatch hour* and, in respect of a *real-time schedule*, a *dispatch interval*;

dispatch scheduling error means an error made by the *IESO* in the *real-time dispatch process,* in circumstances where these *market rules, market manuals* or any standard, policy or procedure established by the *IESO* pursuant to these *market rules* do not admit of any deviation or departure from such *real-time dispatch process*;

dispatch workstation means the communication equipment that is required to be installed and maintained in accordance with Appendix 2.2 for the purposes referred to in section 1.3.1 of Appendix 2.2 of Chapter 2;

dispatchable load means a *load facility* which is subject to *dispatch* by the *IESO* and whose level is selected or set based on the price of *energy* in the *real-time market,* and excludes *hourly demand response resources*;

dispute outcome means the outcome of a dispute resolution process that requires adjustments to one or more *settlement statements*, whether arising from good faith negotiations, mediations, or an *arbitrator*'s order;

dispute resolution panel means the panel of the same name established by the *IESO* pursuant to the *Governance and Structure By-law*;

distribute, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

distribution system means a system for *distributing* electricity, and includes any structures, equipment or other things used for that purpose;

distributor means a person who owns or operates a *distribution system*;

elapsed time to dispatch is the minimum amount of time, in minutes, between the time at which a startup sequence is initiated for a *generation unit* and the time at which it becomes dispatchable by reaching its *minimum loading point*;

Electricity Act, 1998 means the *Electricity Act*, *1998*, S.O. 1998, c. 15, Schedule A;

Electricity and Gas Inspection Act means the Electricity and Gas Inspection Act, R.S.C. 1985, c. E-4;

electricity storage capacity means the maximum power that an *electricity storage unit* or *electricity storage facility* can supply, usually expressed in megawatts (MWs);

electricity storage energy rating means the maximum amount of stored energy of an *electricity storage unit* or *electricity storage facility*, usually expressed in megawatt hours (MWhs);

elec*tricity storage facility* means a *facility* that is comprised of one or more *electricity storage units* and includes any structures, equipment or other things to support the functioning of its *electricity storage units;*

electricity storage facility size means the greater of the absolute values of the maximum injection and maximum withdrawal capabilities of the *electricity storage facility* expressed in either megawatts (MWs) or megavolt amperes (MVAs);

electricity storage participant means a person who owns or operates an *electricity storage facility*;

electricity storage station service means *station service* associated with an *electricity storage facility* comprising one or more *electricity storage units* each of which is a *registered facility* or which together have been aggregated as a *registered facility* in accordance with section 2.3 of Chapter 7;

electricity storage unit means the equipment used for the sole purpose of withdrawing electricity from the *electricity system*, storing that electricity, and re-injecting it, or a portion thereof, into the *electricity system*;

electricity storage unit size means the greater of the absolute values of the maximum injection and maximum withdrawal capabilities of the *electricity storage unit* expressed in either megawatts (MWs) or megavolt amperes (MVAs);

electricity system means the *integrated power system* and all *registered facilities* connected to that system;

electronic funds transfer means the transfer of funds between bank accounts by electronic means;

electronic information system means the internet or the real-time communication network that is used for the exchange of information referred to in section 1.4.1 of Appendix 2.2 of Chapter 2 via the *participation workstation*;

embedded connection point means the point of connection between a *facility* and a *distribution system*;

embedded generator means a *generator* within the *IESO control area* whose *generation facility* is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system* and *embedded generation facility* shall be interpreted accordingly;

embedded electricity storage facility means an *electricity storage facility* within the *IESO control area,* not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded electricity storage participant means an *electricity storage participant* within the *IESO control area* whose *electricity storage facility* is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system;*

embedded load consumer means a person that owns or operates an *embedded load facility*;

embedded load facility means a *dispatchable load* or a *non-dispatchable load* within the *IESO control area* that is not directly *connected* to the *IESO-controlled grid* but is instead embedded within a *distribution system*;

embedded market participant means a *market participant* within the *IESO control area* whose *facility* is not directly connected to the *IESO-controlled grid* but is instead connected to a *distribution system*;

embedded RWM means an *RWM* that is not a *primary RWM* and that measures flows that are also part of the flows measured by a *primary RWM*;

emergency means any abnormal system condition that requires remedial action to prevent or limit loss of a *transmission system* or generation supply that could adversely affect the *reliability* of the *electricity system*;

emergency energy means *energy* acquired by the *IESO* from another *control area* or provided by the *IESO* to another *control area* in order to maintain the *reliability* of the *IESO-controlled grid* or of a *transmission system* within such other *control area*;

emergency operating state means the state described in section 2.3 of Chapter 5;

emergency preparedness plan means a plan prepared by the *IESO* or required to be prepared by a *market participant* and submitted to the *IESO* in accordance with section 11.2.1 of Chapter 5;

energy means, in respect of the *market rules* other than Chapter 5 or 6, real *energy* only and may, in respect of Chapter 5 or 6, mean both real *energy* and reactive *energy* if the context so requires;

energy market means the *real-time market* for *energy* administered by the *IESO* pursuant to Chapter 7 in which *energy offers* and *energy bids* are cleared and a *market price* for *energy* is determined;

enhanced combined cycle facility means a combined cycle facility in which the steam utilized to generate electricity in one or more of the steam turbines is supplemented by recovery of waste heat from an independent industrial process/processes such as waste heat from the gas turbine exhaust of a natural gas compressor station, and qualifies for treatment as a Class 43.1 facility or has qualified as a Class 34 facility under the Income Tax Act, R.S.C. 1985, c.1. Combined cycle facilities are *generation facilities* in which electricity is generated by one or more combustion turbines or engines, and by one or more steam turbines for which steam is supplied by recovery of waste heat from one or more of the combustion turbines or engines;

estimated market prices means the price forecasts developed by the *IESO* for the purposes of determining *market participant maximum net exposures* and *prudential support obligations*;

exemption means an exclusion from one or more specific obligations or standards which are or may be imposed on the *exemption applicant* or in respect of the *exemption applicant's facilities* or equipment pursuant to the *market rules*, *market manuals* or from any standard, policy or procedure established by the *IESO* pursuant to the *market rules*;

exemption applicant means the *IESO* or a person, including a *market participant*, who submits an application to be exempted from an obligation or standard under the *market rules*;

exemption application means the material submitted by the *exemption applicant* pursuant to the practice and procedure established by the *IESO Board* for the processing of an *exemption*;

event of default means an event referred to in section 6.3.1 of Chapter 3;

existing support has the meaning ascribed thereto in section 5.2.5 of Chapter 2;

export transmission service means the *transmission service* relating to the use of the *IESO-controlled grid* for the transmission of *energy* out of the *IESO control area* into a neighbouring *transmission system* and in respect of which charges are required to be collected by the *IESO* pursuant to section 4 of Chapter 10;

facility means a *generation facility*, a *load facility,* an *electricity storage facility,* a *connection facility,* a *transmission system*, or a *distribution system,* located within the *IESO control area*, or any other equipment that is a component or part of the *electricity system*;

federal metering requirements means all requirements relating to *meters* and to *metering installations* imposed by or under the authority of an Act of Parliament;

final recalculated settlement statement means the *recalculated settlement statement* issued by the *IESO* in accordance with either section 6.3.6(b) or section 6.3.17(g) of Chapter 9;

final settlement statement means the *IESO's* final statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase or of *transmission rights* in the *TR market*, the *IESO*'s final statement of the payments to be made by a *TR holder* with respect to a given *TR auction* or the final statement of the payments to be made by a *TR holder* with respect to a given *billing period*;

financial market participant means a person that participates only in the *TR market*;

flexible nuclear generation means the component of a nuclear *generation facility* that has flexibility for reductions due to the operation of condenser steam discharge valves, and is made available at the sole discretion of the *flexible nuclear generator* to manoeuvre without requiring a unit to shutdown under normal operations, while respecting safety, technical, equipment, environmental and regulatory restrictions;

flexible nuclear generator means a *generator* whose *generation facility* has a component classified as *flexible nuclear generation*;

forbidden region means a predefined operating range within which a hydroelectric *generation facility* cannot maintain steady operation without causing equipment damage. A hydroelectric *generation facility* may have more than one *forbidden region*;

force majeure event means, in relation to a person, any event or circumstance, or combination of events or circumstances, (i) that is beyond the reasonable control of the person; (ii) that adversely affects the performance by the person of its obligations under these *market rules*; and (iii) the adverse effects of which could not have been foreseen and prevented, overcome, remedied or mitigated in whole or in part by the person through the exercise of diligence and reasonable care, and includes, but is not limited to, acts of war (whether declared or undeclared), invasion, armed conflict or act of a foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or act of terrorism; strikes, lockouts, restrictive work practices or other labour disturbances; unlawful arrests or restraints by governments or governmental, administrative or regulatory agencies or authorities; orders, regulations or restrictions imposed by governments or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the person of a permit, licence or other authorization or of any *applicable law*; and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or accumulation of snow or ice or lack of water arising from weather or environmental problems; provided however, for greater certainty, that (i) the lack, insufficiency or non-availability of funds shall not constitute a *force majeure event*, (ii) an act of the *IESO* effected in accordance with the *market rules* or with the provisions of any form, policy, guideline or other document referred to in section 7.7 of Chapter 1 shall not constitute a *force majeure event* in respect of a *market participant*, and (iii) an act of a *market participant* effected in accordance with the *market rules* or with the provisions of any form, policy, guideline or other document referred to in section 7.7 of Chapter 1 shall not constitute a *force majeure event* in respect of the *IESO*;

forced outage means an unanticipated intentional or automatic removal from service of equipment or the temporary de-rating of, restriction of use or reduction in performance of equipment;

forecasting entity means the entity or entities contracted by the *IESO* to provide forecasting services relating to *variable generation*;

forward period means the period of time beginning three (3) *business days* following a *capacity auction*, to the commencement of an *obligation period*;

funds transfer process means the process by which funds are transferred between the respective bank accounts of the *IESO*, *market participants* and *transmitters*;

generation capacity means the maximum power that a *generation unit*, generation station or other electrical apparatus can supply, usually expressed in megawatts;

generation facility means a *facility* for generating electricity or providing *ancillary services*, other than *ancillary services* provided by a *transmitter* or *distributor* through the operation of a *transmission* or *distribution system*, and includes any structures, equipment or other things used for that purpose;

generation station service means *station service* associated with a *generating facility* comprising one or more *generation units* each of which is a *registered facility* or which together have been aggregated as a *registered facility* in accordance with section 2.3 of Chapter 7;

generation unit means the equipment that actually *generates* electricity, together with all related equipment essential to its functioning as a single entity;

generator means a person who owns or operates a *generation facility*;

generator-backed capacity auction eligible import resource means one or more *generator-backed import contributors.* No portion of the capacity that is being offered into the *IESO capacity auction* may be *over committed capacity;*

generator-backed capacity import resource means a *generator-backed capacity auction eligible import resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual;*

generator-backed import contributor means an existing in-service *generation facility* or *storage facility* associated with a *generator-backed capacity auction eligible import resource*, and which is located in a neighbouring *control area* that has an agreement with the *IESO* to allow for the trade of capacity, is able to qualify capacity in accordance with the applicable *market manual*, has been in operation for at least one year prior to the *capacity auction*, is a resource type that is currently enabled to participate in the *IESO's capacity auction*, and is able to transmit energy from the *generation facility* or the *storage facility* to the Ontario border;

good utility practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, *reliability*, safety and expedition. *Good utility practice* is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

Governance and Structure By-law means the by-law of the *IESO* made pursuant to subsection 22(2) of the *Electricity Act, 1998*;

gross MW as related to active power output from an *electricity storage unit*, *generation unit*, or *facility*, is the total amount of active power produced by such unit or *facility* as measured at the unit's terminal or as measured as a sum of active power produced by the *facility*'s individual units;

gross MX as related to reactive power output from an *electricity storage unit*, *generation unit*, or *facility*, is the total amount of reactive power produced by such unit or *facility* as measured at the unit's terminal or as measured as a sum of reactive power produced by the *facility*'s individual units;

high priority path facility means a voice communication facility that meets the requirements of section 1.1.7 of Appendix 2.2 of Chapter 2;

high-risk operating state means the state described in section 2.4 of Chapter 5;

historical reference price means (i) in respect of an *investigated facility* which is not a hydroelectric *generation facility*, the unweighted average of the price contained in all *energy offers* or *energy bids* submitted by the *registered market participant* for that *investigated facility* and accepted by the *IESO*, as reflected in the most recent *market schedules* for that *investigated facility* for the *dispatch intervals* to which such *energy offers* or *energy bids* relate, during all relevant hours in the ninety days preceding the date for which an *investigated price* is submitted by the *registered market participant* for that *investigated facility* and (ii) in respect of an *investigated facility* which is a hydroelectric *generation facility*, the average *market price* weighted by the *market schedule* quantity during all relevant intervals in the thirty days preceding the date on which an *investigated price* was submitted by the *registered market participant* for that *investigated facility*;

hourly demand response resource means the *capacity auction resource* type that is a registered facility that has received a *capacity obligation* in a given *capacity auction* and is used by a *capacity market participant* to satisfy a *capacity obligation* on an hourly basis and is activated by the *IESO* in accordance with section 19.4 of Chapter 7;

hourly markets means those markets in which quantities and prices are determined using five-minute quantity and price information to derive composite hourly quantities and prices;

hourly Ontario energy price or HOEP means the arithmetic average of the uniform Ontario *energy* prices determined for each *dispatch interval* pursuant to section 8.3 of Chapter 7;

hourly uplift means the uplift payments that are determined for each hour based on *real-time market* results in that hour;

IESO or the *Independent Electricity System Operator* means the Independent Electricity System Operator, which is the continuation of the Independent Electricity Market Operator established under Part II of the *Electricity Act, 1998*;

IESO adjustment account means the *settlement account* operated by the *IESO* which is used for adjustments in *settlement* payments after a preliminary market *settlement* has been made;

IESO-administered markets means the markets established by the *market rules*;

IESO administration charge means the charge imposed by the *IESO* on *market participants* for the purpose of recovery by the *IESO* of its administration costs;

IESO Board means the Board of Directors of the *IESO*;

IESO catalogue of reliability-related information means the catalogue described in section 14.1.3 of Chapter 5;

IESO control area means that area, including the *IESO-controlled grid*, with respect to which the *IESO* is the *control area operator*;

IESO-controlled grid means the *transmission systems* with respect to which, pursuant to *operating agreements*, the *IESO* has authority to direct operations;

IESO payment date means the date on which the *IESO* is to make *settlement* payments to *market participants*;

IESO prepayment account means the *settlement account* operated by the *IESO* to hold payments by *market participants* prior to the relevant *market participant payment date* to which such payments relate;

IESO settlement clearing account means the *settlement account* operated by the *IESO* for holding market settlement payments made to the *IESO*;

IESO Settlement Schedule & Payments Calendar or SSPC means the *IESO*'s calendar of dates for providing settlement information to *market participants* and of dates on which settlement payments must be made by and to the *IESO*;

information confidentiality catalogue means the applicable *market manual* listing information and its *confidentiality classification* determined pursuant to section 5 of Chapter 3;

installed capacity or *ICAP* means the amount, in MW, of electricity submitted by a *capacity auction participant,* in accordance with the applicable *market manual*, during the *IESO's* capacity qualification process that reflects a *capacity auction resource's* maximum seasonal generation capability, load reduction capability, or import capability;

instrument transformer means an iron cored device that isolates a *meter* from the primary voltage while passing a correct value of the primary measured quantity to the *meter*;

integrated power system means the *IESO-controlled grid* and the structures, equipment and other things that connect the *IESO-controlled grid* with *transmission systems* and *distribution systems* in Ontario and *transmission systems* outside Ontario;

interchange schedule data means data pertaining to *interchange schedules*;

interchange schedule means the scheduled *intertie* flow between the *IESO-controlled grid* and a neighbouring *control area*;

interconnected systems means two or more individual *transmission systems* that have one or more *interties*;

interconnected transmitter means a *transmitter* whose transmission facilities are outside the Ontario *control area* and has entered into an *interconnection agreement* with the *IESO;*

interconnection agreement means an agreement between the *IESO* and another *control area operator, security coordinator* or *interconnected transmitter* regarding the operation of an *interconnection* with the *IESO-controlled grid*;

interconnection means a connection between the *IESO-controlled grid* and a *transmission system* outside the *IESO control area* that have one or more interconnecting *interties*;

intermittent generator means a *generation facility* located within the *IESO control area* that generates on an intermittent basis as a result of factors beyond the control of the *generator* unless limited by *dispatch,* and excludes a *variable generator*;

intertie means a transmission line which forms part of an *interconnection*;

intertie congestion price (ICP) means, in respect of a given *dispatch hour*, a price equal to the projected *market price* for *energy or operating reserve* for a given *intertie zone* minus the projected uniform *market price* for *energy* or *operating reserve* respectively*,* in the *IESO control area,* determined in accordance with section 8.1.1A of Chapter 7;

intertie metering point means a point within an *intertie zone*, at which the *IESO* obtains *interchange schedule data* for the purposes of the *settlement process*;

intertie zone means a market region designated by the *IESO* which is connected to the *IESO-controlled grid* by an *intertie*;

investigated facility means, in respect of an *investigated price,* the *constrained on facility* or the *constrained off facility* whose *registered market participant* submitted the *energy offer* or *energy bid* that contains that *investigated price*;

investigated price means a price contained in an *energy offer* or an *energy bid* submitted by the *registered market participant* for a *constrained on facility* or a *constrained off facility* that is the subject of investigation or of an inquiry pursuant to Appendix 7.6 of Chapter 7 in respect of a given *constrained on event* or a given *constrained off event*;

invoice means an invoice from the *IESO* to a *market participant* which sets forth a *settlement amount*;

licence means a licence issued by the Ontario Energy Board pursuant to the *Ontario Energy Board Act, 1998*;

line connection service means the *transmission service* relating to the use of the line connection assets of a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and in respect of which charges are required to be collected by the *IESO* pursuant to section 5.1.1 of Chapter 10;

load facility means a *facility* that draws electrical *energy* from the *integrated power system*;

load serving breaker means a device, or sequence of devices, which provide a single path for *energy* to flow between a *connection facility* and a *load facility*;

local area has the meaning ascribed thereto in section 5.4.1 of Chapter 5;

long-term auction means a *TR auction* conducted by the *IESO* for the purchase of *long-term transmission rights* and that may also include the purchase of *short-term transmission rights*;

long-term transmission right means a *transmission right* that is valid for a period of one year;

lower energy limit means the lowest energy amount to which an *electricity storage unit* can be consistently discharged without damage beyond expected degradation from normal use;

main/alternate metering installation means a *metering installation* comprised of two *revenue meters* measuring the same electrical quantities;

major dispatchable load facility means a *dispatchable load facility* that includes a *dispatchable load* that is rated at 100 MVA or higher; that comprises *dispatchable loads* the ratings of which in the aggregate equals or exceeds 100 MVA; or that is re-classified as a *major dispatchable load facility* pursuant to section 1.5.1 of Appendix 2.2 of Chapter 2 or section 7.8.1 of Chapter 4;

major electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 100 MVA or higher; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 100 MVA; or that is re-classified as a *major electricity storage facility* pursuant to section 1.5.1A of Appendix 2.2 of Chapter 2 or section 7.8.2A of Chapter 4;

major generation facility means a *generation facility* that provides *regulation*; that includes a *generation unit* that is rated at 100 MVA or higher; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 100 MVA; or that is re-classified as a *major generation facility* pursuant to section 1.5.1 of Appendix 2.2 of Chapter 2 or section 7.8.1 of Chapter 4;

margin call means a notice given by the *IESO* to a *market participant* pursuant to section 5.4.2 of Chapter 2 when the *actual exposure* of that *market participant* equals or exceeds its *trading limit*;

market assessment unit means the entity established by the *IESO* pursuant to section 3.2.1 of Chapter 3;

market commencement date means the date on which the *real-time market* commences operation;

market creditor means a person, including a *market participant*, that is owed monies by the *IESO* as a result of sales made or contracts existing in the *IESO-administered markets*;

market debtor means a person, including a *market participant*, that owes monies to the *IESO* as a result of purchases made or contracts existing in the *IESO-administered markets*;

market manual means a *published* document that is entitled as such and that describes procedures, standards and other requirements to be followed, met or performed by *market participants,* the *IESO* and other persons in fulfilling their respective obligations under the *market rules*;

market monitoring unit means the entity that monitors the markets administered by a *control area operator* or *security coordinator;*

market participant means a person who is authorized by the *market rules* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid* and includes a person that has received conditional authorization under section 4 of Chapter 2;

market participant payment date means the date on which *market participants* are to make settlement payments to the *IESO*;

market participant settlement account means an account designated by the particular *market participant* as the account from and into which *settlement* payments are made;

market price means the price of *energy* or *operating reserve* determined in the *real-time market* or the price of *auction capacity* determined in the *capacity auction* in accordance with the provisions of Chapter 7;

market rules means rules made under section 32 of the *Electricity Act, 1998*;

market schedule means the *dispatch* schedule which would have resulted in the absence of transmission constraints on the *IESO-controlled grid*;

market surveillance panel means the panel of the same name continued as a panel of the *OEB* in accordance with subsection 4.3.1(1) of the Ontario Energy Board Act, 1998;

maximum continuous rating means the gross or net maximum electrical output (in megawatts) which a *generation unit* or generating station is currently capable of producing continuously. This may include seasonal effects or other “long-term” deratings;

maximum market clearing price or *MMCP* means the maximum price that a *market participant* may be charged or paid for *energy*;

maximum number of starts per day is the number of times that a unit can be started within a *dispatch day*;

maximum net exposure means, in respect of a given *market participant*, the amount calculated from time to time by the *IESO* for that *market participant* in accordance with section 5.3 of Chapter 2;

maximum operating reserve price or *MORP* means the maximum price that can be determined or paid to a *market participant* for *operating reserve*;

maximum regulation price or *MRP* means the maximum price that a *market participant* may be charged or paid for *regulation*;

mediator means a qualified person appointed pursuant to section 2.6 of Chapter 3 to mediate a dispute;

meter means a device that measures and records active *energy*, reactive *energy* or both and shall be deemed to include the *data logger* but to exclude the *instrument transformers*;

meter point means, in respect of a *load facility* and of a *generation facility* or *electricity storage facility* that is injecting, with respect to which the current transformers are located on the output side of the *generation facility* or *electricity storage facility*, the physical location of the current transformers used to measure power flow and, in respect of a *generation facility* or an *electricity storage facility* with respect to which the current transformers are located on the grounded side of the *generation facility*, or the *electricity storage facility* the physical location of the voltage transformers;

metered market participant means, in respect of a *facility*, the *market participant* designated as the *metered market participant* for that *registered facility* in accordance with Chapter 9;

metering data means electrical quantities measured and recorded by a *metering installation*;

metering database means an information system established and maintained by the *IESO* in accordance with Chapter 6 for the purpose of storing *metering data*;

metering installation means any apparatus, including but not limited to an *RWM*, used to measure electrical quantities and includes the communication system by which *metering data* is transferred to the relevant telecommunications network through which *metering data* is transferred to the communication interface of the *metering database*;

metering interval means the five-minute period over which *metering data* is collected;

metering registry means the information system established and maintained by the *IESO* in accordance with Chapter 6;

metering service provider means a person that provides, installs, commissions, registers, maintains, repairs, replaces, inspects and tests *metering installations*;

minimum generation block down time is the minimum time, in hours, between the time a *generation facility* was last at its *minimum loading point* before de-synchronization and the time the *generation facility* reaches its *minimum loading point* again after synchronization;

minimum generation block run-time means the number of hours, specified by the *market participant*, that a *generation facility* must be operating at *minimum loading point*; in accordance with the technical requirements of the *facility*;

minimum loading point means the minimum output of *energy* specified by the *market participant* that can be produced by a *generation facility* under stable conditions without ignition support;

minimum run-time means the number of hours required for the *generation facility* to ramp from a cold start to *minimum loading point* plus *minimum generation block run-time,* specified by the *market participant*, in accordance with the technical requirements of the *facility*;

minimum shut-down time means the minimum time in hours between shutdown and start-up of a *generation unit*. This is measured from the time of de-synchronization from the *IESO-controlled grid* to the time of re-synchronization on start-up;

minimum trading limit means, in respect of a given *market participant*, the dollar amount determined from time to time by the *IESO* for that *market participant* in accordance with section 5.3.4 of Chapter 2;

Minister means the Minister of Energy, Northern Development and Mines or such member of the Executive Council that may be assigned the administration of the *Electricity Act, 1998* under the *Executive Council Act, 1990*;

minor amendment, in respect of the *market rules*, means an *amendment* to the *market rules* to correct a typographical or grammatical error, or to effect a change of a non-material procedural nature;

minor dispatchable load facility means a *dispatchable load facility* that includes a *dispatchable load* that is rated at 1 MVA or higher but less than 20 MVA; that comprises *dispatchable loads* the ratings of which in the aggregate equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor dispatchable load facility* pursuant to section 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.2 of Chapter 4;

minor electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 1 MVA or higher but less than 20 MVA; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor electricity storage facility* pursuant to section 1.5.1A or 1.5.2A of Appendix 2.2 of Chapter 2 or section 7.8.2A or 7.8.2B of Chapter 4;

minor generation facility means a *generation facility* that includes a *generation unit* that is rated at 1 MVA or higher but less than 20 MVA; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 1 MVA but is less than 20 MVA; or that is re-classified as a *minor generation facility* pursuant to section 1.5.1 or 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.1 or 7.8.2 of Chapter 4;

monthly confirmation notice means the notice provided by the *IESO* to each *market participant* containing a summary of the *market participant's settlement* payments made during a calendar month and of the payments outstanding for that calendar month;

neighbouring electricity system means a system comprising generation, transmission and *load facilities* that is connected to the *electricity system* via one or more *interconnections*;

NERC means the North American Electric Reliability Corporation;

NERC confidentiality agreement means an agreement required to be executed between NERC and all *security coordinators* and, where applicable, *control area operators* and *interconnected transmitters* which ensures that required data is available and that the confidentiality of such data is protected and disclosed only to those responsible for maintaining the operational security of electricity supply in North America;

net MW as related to active power output from an *electricity storage unit*, *generation unit*, or *facility* is equal to the applicable unit or *facility*'s *gross MW* output less the applicable unit or *facility station service* MW load and MW losses to the *defined meter point* for that applicable unit or *facility*;

net MX as related to reactive power output from an *electricity storage unit*, *generation unit*, or *facility* is equal to the applicable unit or *facility*'s *gross MX* output less the applicable unit or *facility station service* MX load and MX losses to the *defined meter point* for that applicable unit or *facility;*

net transaction dollar amount means an amount calculated in accordance with section 8.6.1.1 of Chapter 2;

network service means the *transmission service* relating to the use of the *IESO-controlled grid* for the transmission of *energy* and *ancillary services*, other than in respect of transactions to which *export transmission service* relates, and in respect of which charges are required to be collected by the *IESO* pursuant to section 3 of Chapter 10;

no margin call option means the option wherein a *market participant* elects, pursuant to Chapter 2, Section 5.6.4, to not be subject to *margin calls*;

non-committed resource means a *registered facility* that is neither - in whole or in part - rate-regulated, contracted to the *IESO*, contracted to the *OEFC*, or obligated as a resource backed capacity export to another jurisdiction during the entire duration of a given *obligation period*;

non-defaulting market participant means, for purposes of the imposition of the *default levy*, every *market participant* other than the *defaulting market participant* whose default in payment has triggered the imposition of the *default levy*;

non-dispatchable load means a load, within the *IESO control area*, that is not subject to *dispatch* by the *IESO* and whose level is not selected or set based on the price of *energy* in the *real-time market*;

normal operating state means the state described in section 2.2 of Chapter 5;

normal priority path facility means a voice communication facility that meets the requirements of section 1.1.8 of Appendix 2.2 of Chapter 2;

notice of default levy means a notice issued by the *IESO* to a *non-defaulting market participant* in accordance with section 8.2.3 or 8.4.1 of Chapter 2;

notice of disagreement means a notice provided by a *market participant* to the *IESO* in regard to a disagreement over a *preliminary settlement statement*;

notice of dispute has the meaning ascribed thereto in section 2.5.1 of Chapter 3;

notice of intent to suspend means a notice issued by the *IESO* to a *market participant* under section 6.3.3.1 of Chapter 3;

notice of intention means a notice issued by the *IESO* to a *market participant* under section 6.2B.2 of Chapter 3;

notice to elect shall be in such form as may be established by the *IESO* and means a written notice provided by the *market participant* to the *IESO* under section 6.2B.6 of Chapter 3;

NPCC means the Northeast Power Coordinating Council;

OEB or *Ontario Energy Board* means the Ontario Energy Board continued pursuant to section 4 of the *Ontario Energy Board Act, 1998*;

OEFC means the Ontario Electricity Finance Corporation established under Part V of the *Electricity Act, 1998;*

obligation period means the period of time for which a *capacity market participant* is required to fulfill its *capacity obligation* through the day-ahead commitment process and *energy market;*

offer means a statement of the quantities of a commodity that a seller will provide at different *market prices* for that commodity in the *real-time market,* the *procurement market,* or the *capacity auction*;

one-day advance approval means *IESO* approval of a *planned outage* of equipment no later than 14:00 EST on the *business day* prior to the scheduled start date of the *planned outage*;

Ontario electricity emergency plan means the plan describing the responsibilities of, and coordinating the actions of, *market participants* and the *IESO* for the purpose of alleviating the effects of an *emergency* on the *integrated power system*;

Ontario Energy Board Act, 1998 means the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B;

OPA or *Ontario Power Authority* means the Ontario Power Authority established under Part II.1 of the *Electricity Act, 1998*;

Ontario power system restoration plan means the detailed plan indicating how to re-energize the *IESO-controlled grid* or part of it in case the *IESO-controlled grid* or part of it collapses;

operating agreement means an agreement between the *IESO* and a *transmitter* which gives the *IESO* the authority to direct operations of the *transmitter's transmission system*, as contemplated in subsection 6(1)(b) of the *Electricity Act, 1998* and in subsection 70(2)(k) of the *Ontario Energy Board Act, 1998*;

operating deviation means the deviation described in section 3.8 of Chapter 9 between the performance of a *registered facility* and the performance required of that *registered facility* for the provision of *operating reserve*;

operating reserve means *generation capacity, electricity storage capacity* or load reduction capacity which can be called upon on short notice by the *IESO* to replace scheduled *energy* supply which is unavailable as a result of an unexpected *outage* or to augment scheduled *energy* as a result of unexpected *demand* or other contingencies;

operating reserve market means a *real-time market* in which *offers* to supply each class of *operating reserve* are cleared consistent with the *energy offers* and *energy bids*;

operating result means the physical quantity or quantities measured or estimated by the *IESO* as delivered by a *registered facility* during the actual operation of the *electricity system*;

outage means the removal of equipment from service, unavailability for connection of equipment or temporary derating, restriction of use, or reduction in performance of equipment for any reason including, but not limited to, to permit the performance of inspections, tests or repairs on equipment, and shall include a *planned outage*, a *forced outage* and an automatic *outage*;

over committed capacity means capacity has been contracted to or otherwise obligated to be provided to the *IESO*, the OEFC, or another *control area operator* at any time during a given *obligation period* where the same capacity is included in a *cleared ICAP* held by a *capacity market participant* participating with a *generator-backed capacity import resource;*

participation agreement means the agreement required to be executed between the *IESO* and each *market* participant pursuant to section 3.1.2 of Chapter 2 and pursuant to which the *IESO* and the *market participant* agree, among other matters, to be bound by the *market rules*;

participant technical reference manual means the document entitled “Participant Technical Reference Manual” and *published* by the *IESO*;

participant workstation means the communication equipment that is required to be maintained by *market participants* in accordance with Appendix 2.2 for the purposes referred to in section 1.4.1 of Appendix 2.2 of Chapter 2;

payment date means the date upon which payment is due;

per-start means the act of achieving synchronization to the *IESO-controlled grid*, ramping to the *minimum loading point* and operating at the *minimum loading point* until the end of the *minimum generation block run-time*;

performance adjustment factor means a value assigned to a *capacity auction resource* based on its historical performance during a *capacity auction capacity test* activation in the relevant summer or winter *obligation period* and is calculated in accordance with the process set out in the applicable *market manual;*

period of steady operation means a predefined number of intervals (0, 1, or 2) for which a non *quick-start* generation *facility* must maintain steady operation before changing direction of its *energy* output (either increasing or decreasing). Such a *facility* is considered to be in steady operation if the magnitude of change between *dispatch instructions* for the last two intervals is less than 0.1 multiplied by its ramp rate capability between the two intervals;

physical bilateral contract means an agreement between two parties, neither of which is the *IESO*, to trade a specified quantity of electricity at prices determined by the parties to the agreement, and pursuant to which the parties provide for the use of the *IESO settlement process* to account for *physical bilateral contract data*;

physical bilateral contract data means the data concerning a *physical bilateral contract* that a selling *market participant* provides to the *IESO* for purposes of *settlement*;

physical bilateral contract quantity means a quantity of *energy*, in MWh, that a *selling market participant* is selling to a *buying market participant* at a specified location and in a specified hour;

physical market means a *real-time market* and/or a *procurement market* administered by the *IESO* pursuant to Chapter 7;

physical service means the service of providing *energy* or *ancillary services*;

PJM means the Pennsylvania, New Jersey, Maryland Interconnection;

planned capability factor means the ratio of the *energy* which could have been delivered by a generating station with planned *generation unit* limitations in effect, to the *energy*, over the same period of time, that could have been delivered if the generating station had operated at its *maximum continuous rating*;

planned outage means an outage which is planned and intentional;

pre-dispatch day means the day prior to a *dispatch day*;

pre-dispatch schedule means an hourly schedule for the remaining hours of a *dispatch day* as determined by the *dispatch algorithm*;

pre-existing facility or equipment means a *facility* or equipment (i) that was or was part of a *facility* that was in existence on, and in respect of which a *licence* has been issued prior to, or on, the date of coming into force of Chapter 4 of the market rules (April 17, 2000); or was in service on the date of coming into force of Chapter 4 of the *market rules* (April 17, 2000); and (ii) in respect of which an *exemption* has been applied for or granted relating to any of the following standards or obligations: (a) the technical requirements set out in Appendix 2.2 of Chapter 2 relating to voice communication, monitoring and control but not those relating to the *participant workstation* or *dispatch workstation*; (b) the technical requirements set out in Section 12 of Chapter 5 relating to communications; and (c) the grid *connection* and data monitoring requirements set out in Chapter 4 other than the requirements set forth in sections 6.1.5 to 6.1.21 of that Chapter.

preliminary settlement statement means the *IESO's* preliminary statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase of *transmission rights* in the *TR market*, the *IESO*'s preliminary statement of the payments to be made by a *TR holder* with respect to a given *TR auction* or the preliminary statement of the payments to be made to a *TR holder* with respect to a given *billing period*;

price-quantity pair means a price and an associated quantity that define a "step" in an *offer* or *bid* curve or an *EFM offer* or *EFM bid* curve;

primary RWM means an *RWM* that measures *meter data* regarding flows directly into or from the *IESO-controlled grid*;

procurement market means any one of the markets operated by the *IESO*, pursuant to Chapter 7, for contracted *ancillary services*, including *regulation, voltage control* and *reactive support services* and *black-start capability*, and for *reliability must-run contracts*;

prudential support means the obligations owed to the *IESO* by a third party and other forms of security or support for the financial obligations of a *market participant,* in the form set forth in section 5.7 of Chapter 2;

prudential support obligation means, in respect of a *market participant*, an amount equal to that *market participant's maximum net exposure* less any allowable reductions calculated in accordance with section 5.8 of Chapter 2;

pseudo-unit means a combined cycle *generation facility* that is modeled based on a gas-to-steam relationship between generation units, and which is comprised of one combustion turbine generation unit and a share of one steam turbine generation unit at the same combined cycle *generation facility*;

publish means, in respect of a document or information, to place that document or information on the *IESO's* web site, and publication shall be interpreted accordingly;

quarterly advance approval means *IESO* approval of a *planned outage* of equipment no later than the end of the month that is one month prior to the start of a six month period, starting with the next calendar quarter, in which the *planned outage* is scheduled to start;

quick start facility means a *generation facility* or an *electricity storage facility* whose electrical *energy* output can be provided to the *IESO-controlled grid* within 5 minutes of the *IESO's* request and is provided by equipment not synchronized to the *IESO-controlled grid* when the request to start providing *energy* is made;

radial intertie means a transmission line or lines which form part of the *IESO-controlled grid* and that: (a) connect an isolated portion of the *IESO control area* to an adjacent *control area;* or (b) connect the *IESO control area* to an isolated portion of an adjacent *control area,* in either case where the connected portion cannot, in accordance with an *operating agreement* or an *interconnection agreement,* be simultaneously connected to either another portion of one such *control area* or to a third *control area*;

reactive support service means a service provided by a *market participant* so as to allow the *IESO* to maintain the reactive power levels around the *IESO-controlled grid*;

real-time dispatch process is the process described in sections 7.1, 7.2, 7.3, and 7.4 of Chapter 7, when applied (i) while the *IESO-controlled grid* is in a *normal operating state;* and (ii) at a time other than when *market operations* have been suspended or *administrative prices* have been implemented;

real-time market means any one of the markets operated by the *IESO* for *energy*, *operating reserve* pursuant to Chapter 7;

real-time schedule means, in respect of a *registered facility* that is not a *boundary entity*, a *dispatch schedule* for a *dispatch interval* as determined by the *dispatch algorithm* and, in respect of a *registered facility* that is a *boundary entity*, the *interchange schedule* pertaining to that *registered facility*;

recalculated settlement statement means the *IESO*'s recalculated statement of the payments to be made by or to a *market participant* with respect to a given *billing period* and, in respect of the *settlement* of the purchase and sale of *transmission rights* in the *TR market*, the *IESO*'s recalculated statement of the payments to be made by or to a *TR holder* with respect to a given *TR auction* or the recalculated statement of the payments to be made by or to a *TR holder* with respect to a given *billing period*;

record of review means the document issued by the *IESO* to a *restoration participant* pursuant to section 11.4.1 of Chapter 5;

reference bus - the *RWM* on the basis of which the *IESO* determines, where applicable in accordance with section 3.6.2 of Chapter 9, the *energy market* price for the purpose of determining the losses used in calculating contributions to the *transmission charge reduction fund*;

reference price means one or more of (i) a *historical reference price;* (ii) a price equal to the *market price* for *energy* determined for the *dispatch interval* in respect of which an *investigated price* was submitted; and (iii) such other *reference price* as may be established by the *IESO Board* pursuant to section 1.3.4 of Appendix 7.6 of Chapter 7;

registered facility means, in respect of a *facility*, a *facility* which is capable of supplying or withdrawing *physical services,* and which is registered with the *IESO* and means, in respect of a *boundary entity*, a *boundary entity* which is comprised of resources capable of supplying or withdrawing *physical services,* and is registered with the *IESO*;

registered market participant means a *market participant* that is registered with the *IESO* to submit *dispatch data* with respect to a *registered facility*;

registered wholesale meter or *RWM* means a *meter* that meets the criteria specified in Chapter 6 and that is registered with the *IESO.* References to a *registered wholesale meter* or *RWM* within Chapter 9 also include *meters* in *metering installations* whose registration has expired but the *IESO* determines that the continued use of the *metering installation* is necessary for the efficient operation of the *IESO-administered markets*;

regulation means the service required to control power system frequency and maintain the balance between load and generation;

release notification means in respect of a *variable generator* that is a *registered market participant,* a notification issued by the *IESO* providing that *energy* may be supplied from the *variable generation facility* to the *IESO-controlled grid* as ambient fuel conditions allow until a *dispatch instruction* is sent;

reliability means, in respect of electricity service, the ability to deliver electricity within *reliability standards* and in the amount desired and means, in respect of the *electricity system*, the *IESO-controlled grid*, the *integrated power system* or a *transmission system,* the ability of the *electricity system*, the *IESO-controlled grid,* the *integrated power system* or that *transmission system* to operate within *reliability standards* in an *adequate* and secure manner;

reliability must-run contract means a contract between the *IESO* and a *registered market participant* or prospective *registered market participant* for a *registered facility* that is or will be a *generation facility*, an *electricity storage facility,* a *dispatchable load facility* or a *boundary entity*, which allows the *IESO* to call on that *registered market participant's* or prospective *registered market participant's registered facility* in order to maintain reliability of the *IESO-controlled grid*;

reliability must-run resources means the resources described in section 4.8.1 of Chapter 5; these may also be referred to as *must-run resources*;

reliability standards means the criteria and standards, including an amendment to a standard or criterion, relating to the *reliable* operation of the *integrated power system* established by a *standards authority*, and declared in force subject to Chapter 5, sections 1.2.6 and 1.2.7, together with those set forth in these *market rules* or otherwise established by the *IESO* in accordance with these *market rules* and which has not otherwise been stayed or revoked and referred back to the *IESO* for further consideration by the *Ontario Energy Board*;

remaining duration of service means the remaining time it is expected that an *electricity storage facility* can continue injecting, or withdrawing, until it reaches its *lower energy limit,* or *upper energy limit*, respectively, assuming the *electricity storage facility* continues operating at its quantity offered or bid;

remedial action schemes or *RAS* means an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system *reliability*. The term special protection system or SPS shall have the same meaning;

request for connection assessment means a request for the approval of a new *connection* to the *IESO-controlled grid* or of the modification of an existing *connection* to the *IESO-controlled grid* made pursuant to section 6.1.6 of Chapter 4;

Request for Segregation means a request from a *registered market participant* for approval to operate its *registered facility* in a *segregated mode of operation*;

reserve target means the minimum required MWs of any class of reserve required to satisfy reserve requirements;

respondent means a person against whom a complaint is made in a *notice of dispute*, a *response* or a response to a cross-claim;

response has the meaning ascribed thereto in section 2.5.4 of Chapter 3;

response to the notice of intention shall be in such form as may be established by the *IESO* and means a notice provided by the *market participant* under section 6.2B.3 of Chapter 3;

restoration participant means a *market participant* who has been identified by the *IESO* as having equipment or *facilities* that: (i) are directly connected to the *IESO-controlled grid* and (ii) affect the restoration process as set out in the *Ontario power system restoration plan*;

restoration participant attachment means the attachment to the *Ontario power system restoration plan* required to be prepared by a *restoration participant* and submitted to the *IESO* in accordance with section 11.3.5 of Chapter 5;

retail, with respect to electricity, means (a) to sell or offer to sell electricity to a consumer; (b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity; or (c) to act or offer to act as an agent or broker for a *consumer* with respect to the sale or offering for sale of electricity;

retailer means a person who *retails* electricity;

revenue meter means a *meter* that is the designated source of *metering data* to be used by the *IESO* for *settlement* purposes in accordance with the *VEE process*;

review notice has the meaning ascribed thereto in section 4.4.2 of Chapter 3;

reviewable decision means a decision of the *IESO* referred to in section 2.1.2, 4.4.3, 5.1.12, 5.3.9 or 6.1.5 of Chapter 6 and sections 3.2A.1, 3.2A.5.3, 3.2A.10, 3.2B.5.3, 3.2B.7 or 3.2B.10 of Chapter 5;

RSS commencement date means the date on which market rule amendment MR-00475-R00 comes into effect;

schedule of record means the last valid set of results from the day-ahead commitment process used by the *IESO* for the application of constraints and the calculation of various day-ahead *settlement amounts*;

second contingency loss means an unexpected loss of a second component from the *electricity system* after the first component is already lost;

secretary means the secretary of the *dispute resolution panel* appointed pursuant to the *Governance and Structure By-law*;

security means the ability of the *electricity system,* the *IESO-controlled grid*, the *integrated power* system or a *transmission system* to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of equipment or components;

security coordinator, in respect of the *IESO-controlled grid*, means the *IESO* and, in respect of another *transmission system*, means the person responsible for coordinating the security of that *system* with that of other *transmission systems*;

security limits include operating *electricity system* stability limits and thermal ratings;

segregated mode of operation means an electrical configuration where a portion of the *IESO-controlled grid* is used to *connect* one or more *registered facilities* that are *generation* *facilities* to a neighbouring *control area* using a *radial intertie* for the purposes of delivering electricity or *physical services* to such *control area*;

self-assessed trading limit means, in respect of a given *market participant*, the dollar amount determined by the *market participant* in accordance with section 5.3.2 of Chapter 2;

self-schedule means an hourly schedule specified by a *self-scheduling generation facility* or a *self-scheduling electricity storage facility,* and *self-scheduling* has an analogous meaning;

self-scheduling electricity storage facility means an *electricity storage facility* located within the *IESO control area* that can operate independently of *dispatch instructions* from the *IESO,* except for the provision of *regulation* services in respect of which it shall follow *dispatch instructions*;

self-scheduling generation facility means a *generation facility* located within the *IESO control area* that can operate independently of *dispatch instructions* from the *IESO*;

selling market participant means a *market participant* who is *selling energy* under a *physical bilateral contract*;

settlement means the process of transferring payments from those who are required to make payment to those who are required to be paid under the *market rules*;

settlement account means a bank account held by the *IESO*, a *market participant* or a *transmitter* pursuant to the *settlement* rules set forth in Chapters 8 and 9;

settlement amount means any amount of money to be paid by or to a *market participant,* determined in accordance with Chapter 9;

settlement hour means a period of one hour which corresponds to a particular *dispatch hour* for which *metering data* determined in accordance with Chapter 6 and *physical market prices* for services calculated pursuant to Chapter 7 are to be used to calculate the *settlement* debits and credits of *market participants*;

settlement process means any process administered by the *IESO* to effect *settlement*;

settlement statement means a *preliminary settlement statement*, a *final settlement statement*, and/or a *recalculated settlement statement*;

settlement statement re-calculation means the re-calculation of a *final settlement statement* during the attempted resolution of a *settlement* dispute;

short-term auction means a *TR auction* conducted by the *IESO* for the purchase of *short-term transmission rights*;

short-term transmission right means a *transmission right* that is valid for a period of one month;

significant dispatchable load facility means a *dispatchable load facility* that includes a *dispatchable load* that is rated at 20 MVA or higher but less than 100 MVA; that comprises *dispatchable loads* the ratings of which in the aggregate equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant dispatchable load facility* pursuant to section 1.5.1 or 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.1 or 7.8.2 of Chapter 4;

significant electricity storage facility means an *electricity storage facility* that includes an *electricity storage unit* with an *electricity storage unit size* rated at 20 MVA or higher but less than 100 MVA; or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant electricity storage facility* pursuant to section 1.5.1A or 1.5.2A of Appendix 2.2 of Chapter 2 or section 7.8.2A or 7.8.2B of Chapter 4;

significant generation facility means a *generation facility* that includes a *generation unit* that is rated at 20 MVA or higher but less than 100 MVA; that comprises *generation units* the ratings of which in the aggregate equals or exceeds 20 MVA but is less than 100 MVA; or that is re-classified as a *significant generation facility* pursuant to section 1.5.1 or 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.1 or 7.8.2 of Chapter 4;

single metering installation means a *metering installation* comprised of one *revenue meter*;

small distributor means, a *distributo*r with a projected *energy* consumption less than or equal to 0.25% of projected total system *energy* on an annual basis as determined by the *IESO* in accordance with the applicable *market manual*;

small electricity storage facility means an *electricity storage facility* that is comprised solely of an *electricity storage unit* with an *electricity storage unit size* rated at less than 1 MVA or that comprises multiple *electricity storage units*, the aggregated *electricity storage unit size* ratings of which is less than 1 MVA or that is re-classified as a *small electricity storage facility* pursuant to section 1.5.2A of Appendix 2.2 of Chapter 2 or section 7.8.2B of Chapter 4;

small generation facility means a *generation facility* that is comprised solely of a *generation unit* rated at less than 1 MVA or of *generation units* the ratings of which in the aggregate is less than 1 MVA or that is re-classified as a *small generation facility* pursuant to section 1.5.2 of Appendix 2.2 of Chapter 2 or section 7.8.2 of Chapter 4;

speed no-load cost is the hourly-value offered by the *registered market participant* to maintain a *generation facility* synchronized with zero net *energy* injected into the *IESO-controlled grid*;

SSPC means the *IESO* Settlement Schedule & Payments Calendar;

standards authority means NERC, NPCC, any successors thereof, and any other agency or body that approves standards or criteria applicable both in and outside Ontario relating to the *reliability* of *transmission systems*;

start-up cost is the value offered by the *registered market participant* to bring an off-line resource to its *minimum loading point*;

start-up time means the time in hours required to bring a *generation unit* or *electricity storage unit* on line. This is measured from the time of receiving a request to start the *generation unit* or *electricity storage unit* to the time of synchronization;

start volume means the incremental volume of fuel consumed by a *generation facility,* on a per registered resource basis, for an eligible real-time generation cost guarantee submission from either: (i) the point of ignition to the *minimum loading point* of the submitting eligible *registered facility*, on a per registered resource basis; or (ii) the point of synchronization to the *minimum loading point* of the submitting eligible *registered facility*, on a per registered resource basis, if operating in a full speed no-load state for more than five minutes in advance of synchronization to the *IESO-controlled grid*;

state of charge means the percentage of which an *electricity storage unit* is charged relative to the maximum registered *electricity storage energy rating* of the *electricity storage unit;*

station service means *energy* withdrawn from the *IESO-controlled grid* to power the on-site maintenance and operation of transmission *facilities*, *generation facilities, electricity storage facilities* and *connection facilities* located within the *IESO control area* but excludes *energy* consumed in association with activities which could be ceased or moved to other locations without impeding the normal and safe operation of the *facility* in question;

<u>*Statutory Powers Procedure Act*</u> means the *Statutory Powers Procedure Act,* R.S.O. 1990, c.S.22;

suspended market participant means a market participant that is the subject of a suspension order;

suspension order means an order issued pursuant to section 6.3A of Chapter 3 suspending all or part of the rights of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

system-backed capacity auction eligible import resource means a *capacity auction resource* associated with a *boundary entity* that is available to qualify capacity that a neighbouring *control area operator* is willing to allocate to Ontario, if a *capacity obligation* is secured, for the duration of the applicable *obligation period*, which capacity would be deemed to be supplied from the entire system of the *neighbouring control area*. The allocated capacity must not otherwise be – in whole or in part – contracted to or otherwise obligated to be provided to the *IESO*, the *OEFC*, or another *control area operator* during the entire duration of a given *obligation period*;

system-backed capacity import resource means a *system-backed capacity auction eligible import resource* with a *capacity obligation* received in a given *capacity auction* in accordance with the applicable *market manual;*

target capacity means the amount of *auction capacity* which the *IESO* seeks to acquire through *a capacity auction*;

technical feasibility exception or *TFE* is a temporary exception from compliance with certain requirements of *NERC reliability standards* relating to critical infrastructure in accordance with Ontario-adapted *NERC* procedures for processing *TFEs*;

technical panel means the panel of the same name established pursuant to the *Governance and Structure By-law*;

ten-minute operating reserve means those *operating reserve*s required to respond fully within ten minutes of being called upon by the *IESO*;

terminated market participant means a market participant that is the subject of a termination order;

termination order means an order issued pursuant to section 6.4 of Chapter 3 terminating the rights of a *market participant* to participate in the *IESO-administered markets* or to cause or permit electricity to be conveyed into, through or out of the *IESO-controlled grid*;

TFE applicant means (i) a *market participant* who applies to the *IESO* for a *TFE*; or (ii) a person applying to become a *market participant* who applies to the *IESO* for a *TFE*; or (iii) the *IESO*, in the event the *IESO* requires a *TFE*;

TFE application means an application for the approval, amendment, termination, or transfer of a *TFE* pursuant to section 3.2A of Chapter 5;

thirty-minute operating reserve means those *operating reserve*s required to respond fully within thirty minutes of being called upon by the *IESO*;

three-day advance approval means *IESO* approval of a *planned outage* of equipment no later than 16:00 EST on the third *business day* prior to the scheduled start date of the *planned outage;*

tieline means a transmission line which forms part of an *interconnection;* see *intertie*;

TR auction means an auction conducted by the *IESO* for the purchase of *transmission rights*;

TR bid means a statement of the quantities and prices at which a buyer is willing to purchase *transmission rights* in a *TR auction*;

TR bidder means a person that submits a *TR bid* to purchase a *transmission right* in a *TR auction*;

TR clearing account means the *settlement account* or fund established by the *IESO* and described in section 4.18.1 of Chapter 8;

TR holder means, in respect of a given *transmission right*, the *TR participant* recognized by the *IESO,* in accordance with section 4.3.1 or 4.9.5 of Chapter 8, as the *TR participant* that has the right to receive all *settlement amounts* under the *transmission right* or, in the case of a *long-term transmission right*, the right to receive all *settlement amounts* relating to one or more periods of one month under the *long-term transmission right*;

TR lamination means a price and an associated quantity that define a "step" in a *TR bid*;

TR market means the market operated by the *IESO* for *transmission rights* pursuant to section 4 of Chapter 8;

TR market clearing price means, in respect of a given *transmission right*, the market clearing price for the *transmission right* established in accordance with section 4.15 of Chapter 8;

TR market deposit means the deposit required to be made by a *TR participant* pursuant to section 4.8.2 of Chapter 8 as a condition of being a *TR bidder* in a *TR auction*;

TR participant means a person that has been authorized by the *IESO* to participate in the *TR market* in accordance with section 4.8 of Chapter 8;

TR settlement price means, in respect of a *TR zone*, the *energy market* price for one MWh of *energy* in that *TR zone*, determined in accordance with section 3.1.3 of Chapter 9;

TR zone means the *IESO control area* or an *intertie zone* in respect of which the *IESO* calculates prices for *energy* for *settlement* purposes in the *real-time markets*;

trading day means a period from midnight EST to the following midnight EST within a *billing period*;

trading limit means, in respect of a given *market participant*, the dollar amount determined from time to time by the *IESO* for that *market participant* in accordance with sections 5.3.5 or 5.3.6 of Chapter 2;

trading week means seven consecutive *trading days* commencing on and including a Sunday;

transformation connection service means the *transmission service* relating to the use of the transformation connection assets of a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid* and in respect of which charges are required to be collected by the *IESO* pursuant to section 6.1.1 of Chapter 10;

transitional scheduling generator means a *generation facility* located within the *IESO control* area that is under contract with *OEFC* effective April 1, 1999 and surviving the *market commencement date,* and is registered as such in accordance with the applicable sections of Chapter 7;

transmission charge reduction fund means the fund whose net proceeds are used to offset the charges levied on *market participants* for the recovery of the sunk and other costs of operating the *transmission systems* that make up the *IESO-controlled grid*;

transmission customer means a person, including but not limited to a *market participant*, that is required to pay for one or more *transmission services* pursuant to the terms of a rate order issued by the *OEB* to a *transmitter* whose *transmission system* forms part of the *IESO-controlled grid*;

transmission right or *TR* means a contractual right to receive a *settlement amount* determined in the manner described in section 4.4 of Chapter 8;

transmission service means any one or more of *network service*, *export transmission service*, *line connection service*, *transformation connection service* and such other service as may be approved by the *OEB* and in respect of which charges are required to be collected by the *IESO* pursuant to section 6A.1.1 of Chapter 10;

transmission services charges means all charges administered by the *IESO* to recover the costs of *transmission services*;

transmission services settlement account means a *settlement account* operated by a *transmitter* for the purpose of receiving payment of *transmission services charges* from the *IESO*;

transmission station service means *station service* associated with transformers, capacitors, switchgear, protection systems and control systems that are part of a transmission *facility* and that do not *connect generation facilities*, *electricity storage facilities, load facilities* or *distribution facilities* to the *IESO-controlled grid*;

transmission system means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

transmission tariff means a tariff fixed or authorised by the OEB in a rate order issued pursuant to the *Ontario Energy Board Act, 1998* with respect to the provision of *transmission services*;

transmission transfer capabilities means the measure, in terms of electric power expressed in megawatts, of the ability of *interconnected* electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines or paths between those areas under specified system conditions.;

transmitter means a person who owns or operates a *transmission system*;

unattended means not *attended*;

unconstrained IESO-controlled grid model means the model capable of being used by the *dispatch algorithm* and described in section 4.5.1.1 of Chapter 7;

unforced capacity or *UCAP* means the maximum amount, in MW, that a *capacity auction participant* is able to *offer* for a *capacity auction resource* for an applicable *obligation period*, as calculated pursuant to section 18.2A.1 of Chapter 7*;*

upper energy limit means the highest energy amount to which an *electricity storage unit* can be consistently charged without damage beyond expected degradation from normal use;

urgent amendment, in relation to the market *rules*, means an *amendment* to the *market rules* made in accordance with section 34 of the *Electricity Act, 1998* on an urgent basis for any of the purposes noted in subsection 34(1) of the *Electricity Act, 1998*;

urgent rule amendment committee means the committee referred to in the *Governance and Structure By-law* and established by the Board of Directors of the *IESO* under the authority of the *Governance and Structure By-law* for the purpose of making *urgent amendments* to the *market rules*;

variable generation means all wind and solar photovoltaic resources with an installed capacity of 5MW or greater, or all wind and solar photovoltaic resources that are directly connected to the *IESO-controlled grid*;

variable generator means a *generator* whose *generation facility* is classified as *variable generation;*

VEE process means the process described in Chapter 9 and used to validate, estimate and edit raw *metering data* to produce final *metering data* or to replicate missing *metering data*;

VEE standard means that part of the *market manual* pertaining to *metering* entitled *Validating, Estimating, and Editing – Requirements for Validating, Estimating, and Editing Of Revenue Metering Data in the IESO-Administered Market*;

voltage control service means a service provided by a *market participant* so as to allow the *IESO* to maintain the voltage around the *IESO-controlled grid*;

Voltage reduction capability means the capability to reduce demand by lowering a customer's voltage. Within the *IESO-administered markets*, this capability is specifically defined as being able to reduce *distribution* or secondary voltages by 3% and 5%, and having the controlling authority to be able to effect that voltage reduction within five minutes of receipt of the direction from the *IESO* to do so;

wear and tear means, for the purposes of the Real-Time Generation Cost Guarantee Program, the useful life consumption of certain parts or equipment of a *generation facility* that would occur as a result of operation of the *generation facility* in accordance with prudent industry practices and original equipment manufacturer guidelines of the *generation facility*. The useful life consumption of certain parts or equipment of a *generation facility* manifests from applicable physical mechanisms (such as creep and fatigue) during different operating conditions (e.g. start-up, steady state operation, transients and shutdown);

weekly advance approval means *IESO* approval of a *planned outage* of equipment no later than 16:00 EST on the second Friday prior to the start of the week, starting Monday, in which the *planned outage* is scheduled to start;

wholesale consumer means a person who purchases electricity or *ancillary services* in the *IESO-administered markets* or directly from another person;

wholesale customer means a *market participant* who takes supply from the *IESO-controlled grid* for its own consumption or for sale;

wholesale seller means a person who sells electricity or *ancillary services* through the *IESO-administered markets* or directly to another person;