Section 201.1 Pool Participant Registration

External Consultation Draft
November 20, 2018

Applicability

1 Section 201.1 applies to:

(a) an **electricity market participant**; and

(b) the **ISO**.

Requirements

Mandatory Registration as a Pool Participant

2 In order to exchange electric energy through the **power pool** or provide **ancillary services**, an **electricity market participant** must be registered with the **ISO** as a **pool participant**.

Application by an Electricity Market Participant

3 An **electricity market participant** seeking to register as a **pool participant** must provide the **ISO** with the following:

(a) a completed **pool participant** application form, available on the AESO website; and

(b) at the time of submitting the application, the non-refundable pool participation fee as set out in the *Schedule of ISO Fees.*

Registration Eligibility Criteria

4 The **ISO** must process a **pool participant** application from an **electricity market participant** who has submitted the application form and fee referred to in subsection 3 and satisfied the following eligibility criteria:

(a) has provided any **financial information** and **financial security**, and has the ability to meet any **financial obligations** under the **ISO rules** as applicable to a **pool participant**;

(b) has an agreement with a **meter data manager**, **load settlement agent** or any other such **agent** or **person** the **ISO** otherwise approves to provide **metered energy** data to the **ISO** or, if the **electricity market participant** intends to act as an importer, an exporter or both, has a valid **system access service** agreement with the **ISO**;

(c) has satisfied any outstanding **financial obligations** attributable to any previous **pool participant** registration; and

(d) in the case of an application to facilitate the provision of **ancillary services**, has entered into a contract to trade such products, either with the **ISO** or with an approved **agent** of trading services or both, and has met the technical requirements the **ISO** has set for the provision of **ancillary services**.

Receipt and Approval or Rejection of an Application

5(1) The **ISO** must acknowledge in writing the receipt of a **pool participant** application, including any supporting documents and the non-refundable pool participation fee within 5 **business days** of the **ISO** receiving them.

(2) The **ISO** must review the **pool participant** application and any supporting documents to ensure completeness, and may request additional clarification or information from the **electricity market participant**.

(3) Within 20 **business days** of receiving the application, the **ISO** must process it and provide written notification to the **electricity market participant** of approval or rejection of the application, or of any requested clarification or information deficiencies in the application, including any deficiencies regarding **financial information**, **financial security** or supporting documents.

(4) The 20 **business day** review deadline date will be extended while the **ISO** is waiting for the **electricity market participant** to provide any further information or clarification, or to remedy any deficiencies referenced in subsection 5(3), if applicable.

(5) If, in the **ISO's** opinion, the application is complete and the **electricity market participant** has satisfied the eligibility requirements, then the **ISO** must approve the application.

(6) If the application is deficient, then the **ISO's** remedy is to reject it.

(7) If the **ISO** approves the application, then on the condition that the **pool participant** continues to meet the eligibility criteria set out in subsection 4, the registration remains in force and effect until December 31 of that same calendar year.

ISO Requirement to Maintain Lists

6 The **ISO** must maintain one or more lists containing current **pool participant** information including all **pool assets**, the status of such **pool assets**, the names of the **pool participant** associated with **pool assets** and any **agents**, and must make the lists available on the AESO website.

Pool Participant Registration Updates

7(1) A **pool participant** must provide updated information regarding its **pool participant** registration, its **agents** and its **pool assets** by following the procedures set out on the AESO website.

(2) The **ISO** must process updates to registration information:

(a) within 20 **business days** of receiving such information, if the update is one that requires the **pool participant** to meet additional technical requirements; or

(b) within 10 **business days** of receiving such information if the update is not one that requires the **pool participant** to meet additional technical requirements.

Failure of a Pool Participant to Continue to Meet Registration Requirements

8(1) At any point in time after initial registration, if the **ISO** has reason to believe that a **pool participant** has ceased to meet any eligibility criteria set out in subsection 4, then the **ISO** must notify the **pool participant** in writing of the matter and provide the **pool participant** an opportunity to explain the circumstances in writing.

(2) After reviewing the explanation, if the **ISO** continues to have reason to believe that the **pool participant** has ceased to meet the requirements of subsection 4, then the **ISO** may suspend or terminate the **pool participant's** registration, and may realize on any **financial security** to the extent of any **ISO** outstanding financial exposure which results from the suspension or termination of the registration.

(3) A **pool participant** who has had its registration suspended or terminated under this subsection 8 may dispute the **ISO's** decision under the dispute resolution provisions of Section 103.2 of the **ISO rules**, *Dispute Resolution,* with ultimate recourse to the **Commission** or the **Market Surveillance Administrator** as provided for in Section 103.2 of the **ISO rules**, *Dispute Resolution*.

(4) Notwithstanding Section 103.2 of the **ISO rules**, *Dispute Resolution*, the initiation of a dispute resolution process will stay the suspension or termination of the **pool participant's** registration pending the outcome of such dispute resolution process unless the **pool participant** is in default under

Section 103.7 of the **ISO rules**, *Financial Default and Remedies*.

Voluntary Termination of Registration by a Pool Participant

9 A **pool participant** who wishes to terminate its registration may do so by completing all of the following:

(a) notifying the **ISO** in writing that it wishes to terminate its registration;

(b) requesting in writing that the **ISO** retire any of its **pool assets** identified on the **ISO** list of **pool assets***;*

(c) specifying in the notice a date upon which it will cease to be a **pool participant**; and

(d) satisfying any outstanding **financial obligations** to the **ISO**.

Effect of Termination

10(1) A **pool participant** that is or may become liable under these **ISO rules** in connection with its activities as a **pool participant** remains liable after the date of termination of its registration and despite ceasing to be a **pool participant**.

(2) After the **ISO** has terminated a **pool participant** registration, it must release any related **financial security** to the **pool participant** no later than 30 **days** after the date the last **financial obligations** of such **pool participant** are satisfied and to the extent there is no additional outstanding **financial obligation** exposure for or to the **ISO**.

Reinstatement of Registration

11 If the **ISO** terminates a **pool participant** registration or if an **electricity market participant** previously has voluntarily terminated its registration under subsection 9, then the **electricity market participant** must submit a new application for registration under this section 201.1 in order to once again become a **pool participant**.

Renewal of Registration

12 The **ISO** must renew a **pool participant's** registration effective each January 1st but, in addition to the provisions of subsection 8(2), may suspend or terminate it if the **pool participant** fails to pay the applicable non-refundable pool participation fee as invoiced on its December **power pool** statement issued in January.

Revision History

Date	Description
XXXX-XX-XX	Revised to clarify "market participant" as "electricity market participant" Administrative amendments
2015-12-07	Update to add non-refundable to subsections 3, 5 and 12
2011-09-30	Supersedes September 16, 2010 version

ISO Rules
Part 200 Markets
Division 201 General
Section 201.4 Energy Market Submission Methods and Coordination of Submissions

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Applicability

1 Section 201.4 applies to:

(a) a **pool participant**; and

(b) the **ISO**.

Requirements

Submission Method

2(1) Unless otherwise set out in the **ISO rules**, a **pool participant** must submit any information required under sections 201 through 206 of the **ISO rules**, including **offers**, **bids**, operating constraints, **net settlement instructions**, **acceptable operational reasons** and reasons for restatements, through the Energy Trading System in accordance with the *Pool Participant Manuals* published on the AESO website.

(2) The **ISO** must make submission procedures available and give reasonable notice regarding any changes to the Energy Trading System.

Unable to Submit through the Energy Trading System

3(1) A **pool participant** must, if the **pool participant** is unable to submit information through the Energy Trading System in accordance with subsection 2 because the **pool participant**'s computer systems are unavailable, submit mandatory restatements to the **ISO** by telephone.

(2) If a **pool participant** submits information by telephone in accordance with subsection 3(1), the following conditions apply:

(a) the **ISO** will not enter the information into the Energy Trading System on behalf of the **pool participant**; and

(b) the **pool participant** must resubmit all restatements for current and future **settlement intervals** submitted under subsection 3(1) as soon as it is possible to do so.

(3) The **ISO** must:

(a) not use information received by telephone to determine the energy market **merit order**; but

(b) use such information to satisfy the requirements that a **pool participant** advise the **ISO** as soon as practicable that a **dispatch** or **directive** will not be complied with and to provide operational information to the **ISO**.

Extension of Time

4(1) The **ISO** may extend the time set for submitting an **offer** or **bid** if there is a system-wide unavailability of the Energy Trading System and the **ISO** determines the length of the unavailability warrants such extension.

(2) The **ISO** may not extend the time for submitting **offers** or **bids** longer than 1 **settlement interval** following the **settlement interval** the Energy Trading System is back in service.

(3) The **ISO** must notify **pool participants** of any extension of time and its duration.

Coordination of Submissions

5 A **pool participant** must coordinate its submissions in a manner that ensures the **pool participant** is able to comply with all **dispatches** related to those submissions

Revision History

Date	Description
xxxx-xx-xx	Revised title of ISO rule and other administrative changes
2014-07-02	Replaced the word “outage” with “unavailability” in subsection 4(1).
2013-01-08	Initial Release

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November 20, 2018

Applicability

1 Section 201.7 applies to:

(a) a **pool participant**; and

(b) the **ISO**.

Requirements

Issuing Dispatches

2(1) The **ISO** may issue a **dispatch** to a **pool participant**.

(2) The **ISO** may issue a **dispatch** verbally or electronically.

Requirement to Comply

3(1) A **pool participant** must comply with a **dispatch** it receives subject to any other **ISO rule** or **reliability standard** and the exceptions in subsections 3(2).

(2) A **pool participant** that is a **legal owner** of a generating **source asset** or an **operator** of a generating **source asset**, must comply with a **dispatch** it receives subject to the following exceptions:

(a) it considers that a real and substantial risk of damage to its generating **source asset** could result if it complied with the **dispatch**;

(b) it considers that a real and substantial risk to the safety of its employees or the public could result if it complied with the **dispatch**;

(c) it considers that a real and substantial risk of undue injury to the environment could result if it complied with the **dispatch**;

(d) it has received verbal authorization from the **ISO** to vary the requirements of the **dispatch** during **commissioning** and testing in accordance with any one or all of Section 504.3 of the **ISO rules**, *Coordinating Energization, Commissioning and Ancillary Services Testing*, Section 504.4 of the **ISO rules**, *Coordinating Operational* Testing, Section 505.3 of the **ISO rules**, *Coordinating Synchronization, Commissioning, WECC Testing and Ancillary Services Testing*, and Section 505.4 of the **ISO rules**, *Coordinating Operational Testing*; or

(e) those exceptions set out in subsections 5 and 6 of Section 203.4 of the **ISO rules**, *Delivery Requirements for Energy*.

Report Inability to Acknowledge a Dispatch

4(1) If a **pool participant** is unable to acknowledge a **dispatch** electronically due to an unavailability at its facilities of the Automated Dispatch and Messaging System or other electronic or communication systems, then the **pool participant** must verbally notify the **ISO** of the unavailability immediately after becoming aware of the unavailability and as soon as practicable, must also:

(a) provide the reasons for the unavailability;

(b) provide an estimate of the duration of the unavailability;

(c) provide the details of an action plan to resolve the unavailability; and

(d) notify the **ISO** when the unavailability is over.

(2) A **pool participant** must, if the unavailability is longer than expected, keep the **ISO** updated with current information regarding the expected duration of the unavailability.

Acknowledging Dispatches

5 A **pool participant** must acknowledge receipt of a **dispatch**:

(a) in the case of an automated message and unless the **pool participant** has notified the **ISO** of an unavailability in accordance with subsection 4(1)(a) by responding via the Automated Dispatch and Messaging System:

(i) within two (2) minutes for an intra-Alberta transaction; and

(ii) within five (5) minutes for an **interchange transaction**;

(b) in the case of a voice **dispatch**, by repeating the **dispatch** to the **ISO**.

Revision History

Date	Description
xxxx-xx-xx	Removed the requirement to acknowledge a dispatch for load shed service for imports within the time frame set out in the contract.
2014-07-02	Updated the references in subsection 3(2)(d) to the energization, commissioning and testing sections of the ISO rules; deleted the word “outages” in subsections 4 and 5 and replaced it with “unavailability”.
2013-01-08	Initial Release

ISO Rules
Part 200 Markets
Division 202 Dispatching the Markets
Section 202.3 Issuing Dispatches for Equal Prices

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Applicability

1 Section 202.3 applies to:

(a) the **ISO**

when operating the energy market and managing **dispatch down service**.

Requirements

Equally-Priced Operating Blocks

2(1) The **ISO** must, if the price of an **operating block** in an **offer** or **bid** for a **pool asset** is identical to the price of 1 or more **operating blocks** in an **offer** or **bid** in respect of another **pool asset** for the same **settlement interval** issue **dispatches** on a pro rata basis amongst the **flexible blocks** within the **settlement interval**.

(2) The **ISO** must, if 1 or more of the equally-priced **operating blocks** is an **inflexible block**, attempt to accommodate the **inflexible blocks** and minimize the issuing of **dispatches** for **operating blocks** higher in the energy market **merit order**.

(3) Notwithstanding subsection 2(1), the **ISO** must:

(a) determine **dispatch** volumes for a **pool asset** that is an import asset or an export asset in accordance with the procedures set out in Section 303.3 of the **ISO rules**, Intertie Path Operations; and

(b) issue **dispatches** for equally priced $0.00 **offers** in accordance with Section 202.5 of the **ISO rules**, *Supply Surplus*.

Revision History

Date	Description
xxxx-xx-xx	Revised reference in subsection 2(3)(a).
2013-01-08	Initial release

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November 20, 2018

Applicability

1 Section 202.5 applies to:

(a) a **pool participant**; and

(b) the **ISO**.

Requirements

State of Supply Surplus and Multiple Zero Dollar ($0) Offers

2(1) If during a current hour the **ISO** forecasts that the **interconnected electric system** will experience a state of supply surplus in the next hour, as evidenced by the in merit electricity supply consisting of only multiple $0 **offers** and the supply of electricity available from these **offers** exceeds the **system load**, then the **ISO** may curtail next hour import **interchange transactions** to balance system supply and **system load**.

(2) Subject to subsection 2(3), if during a current hour the **ISO** determines that a state of supply surplus is imminent in the current hour or already exists, then the **ISO** must comply with the following procedures as may be required, in the following sequence, to balance system supply and **system load**:

(a) initiate curtailment of import **interchange transactions**;

(b) allow **pool participants** to submit **bids** to increase export **interchange transactions** within 2 hours of the start of a **settlement interval**;

(c) allow **pool participants** to submit **offers** to decrease import **interchange transactions** within 2 hours of the start of a **settlement interval**;

(d) allow **pool participants** to submit restatements reducing generating **source asset** output within 2 hours of the start of a **settlement interval**;

(e) issue **dispatches** in accordance with Section 202.3 of the **ISO rules**, *Issuing Dispatches for Equal Prices*;

(f) notwithstanding subsection 2(2)(e), if there are generating **source assets** with $0.00 **offers** for **inflexible blocks** stating volumes greater than their declared **minimum stable generation**, then issue **directives** to curtail those generating **source assets** to their declared **minimum stable generation**, starting with the generating **source assets** having the greatest difference in MW between the then current dispatch level and **minimum stable generation** and continuing in descending order until all those generating **source assets** have received **directives**; and

(g) issue **directives** for any other necessary actions, including shutting down generating **source assets**, to ensure system **reliability**.

(3) If the **ISO** determines that a generating **source asset** is running at a generation level higher than its **minimum stable generation** in order to provide **regulating reserve**, then the **ISO** may, as part of the effective execution of the procedures set out in subsection 2(2), issue a **dispatch** to curtail delivery of **regulating reserve** from that generating **source asset** and issue a **dispatch** for **regulating reserve** to another generating **source asset** which can provide **regulating reserve** while operating at a lower generation level at or above **minimum stable generation**.

(4) If during a current hour the present, real time operating conditions change such that the **ISO**

determines that following the procedural sequence set out in subsections 2(2) and 2(3) would put the **ISO** in contravention of any **reliability standard** requirement by failing to achieve compliance within the operating limits or required response time specified in that **reliability standard**, then the **ISO** may alter the procedural sequence.

(5) If the **ISO** alters the procedural sequence as set out in subsection 2(4), then once the **ISO** is assured that the **interconnected electric system** is operating in a safe and reliable mode, the **ISO** must recommence the procedural sequence set out in subsections 2(2) and 2(3).

Transitioning Out of a State of Supply Surplus

3 When the **ISO** determines that the **interconnected electric system** is transitioning out of a state of supply surplus, the **ISO** must reverse any actions taken under subsection 2(2), in reverse order, to balance system supply and **system load**.

Revision History

Date	Description
xxxx-xx-xx	Added reference to section 202.3, and administrative revisions.
2018-09-01	Revised “source asset” to “generating unit or aggregated generating facility”; clarified subsections 2 and 3; and administrative revisions.
2012-03-28	Initial release

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Applicability

1 Section 202.6 applies to:

(a) the **ISO**.

Requirements

Adequacy Assessments

2 The **ISO** must, in order to assist in determining whether to cancel a **planned outage, delayed forced outage**, or **automatic forced outage** under Section 306.5 of the **ISO rules,** *Generation Outage and Reporting*, assess the **adequacy** of supply by, at a minimum, completing a supply and load forecast using the peak demand hour of every **day** for a minimum 2 year period, calculated as the sum of the following:

(a) the **maximum capability** from all **generating units** and **aggregated generating facilities**, excluding wind and solar **aggregated generating facilities** with a **maximum capability** equal to or greater than 5 MW;

plus

(b) on-site generation that supplies behind-the-fence load and submits **available capability** as a net-to-grid value;

plus

(c) an estimate of the output from wind or solar **aggregated generating facilities**;

plus

(d) import **available transfer capability** on **interconnections** with a program that increases **available transfer capability**;

minus

(e) declared **maximum capability** derates from a **generating unit** or **aggregated generating facility**;

minus

(f) any capacity of **generating units** and **aggregated generating facilities** which are affected by **transmission constraints**;

minus

(g) anticipated **maximum capability** derates from a **generating unit** or **aggregated generating facility**;

minus

(h) the daily forecast **Alberta internal load**;

minus

(i) **operating reserves** requirements;

plus

(j) price responsive load

plus

(k) aggregate **planned outage** records for load;

plus

(l) load for **demand opportunity service**.

Short Term Adequacy Assessments

3 The **ISO** must, every hour, assess the short term **adequacy** of supply by, at a minimum, completing a real time **adequacy** assessment for each **settlement interval** of the current **day** and for the 6 remaining **days** of the **forecast scheduling period** on the **day** preceding that current **day**, calculated as the sum of the following:

(a) **available capability** from all **generating units** and **aggregated generating facilities** with a **maximum capability** equal to or greater than 5 MW, excluding wind and solar **aggregated generating facilities** with a start-up time less than or equal to 1 hour or with a submitted start time at or before the period being assessed;

plus

(b) estimated output from wind or solar **aggregated generating facilities**;

plus

(c) estimated amount of price responsive load;

plus

(d) estimated amount of **demand opportunity service** load that is to be curtailed;

plus

(e) on-site generation that supplies behind-the-fence load and submits **available capability** as a net-to-grid value;

plus

(f) import **available transfer capability** on the **interties**;

minus

(g) the peak forecast load from the day-ahead forecast of **Alberta internal load**;

minus

(h) the **ISO**'s **spinning reserve** requirement;

minus

(i) constrained down generation, with the exception of constrained down wind or solar **aggregated generating facilities**.

Long Term Adequacy Metrics and Reporting

4(1) The **ISO** must establish, maintain and report on **long term adequacy** metrics on a quarterly basis in accordance with this section 202.6.

(2) The **ISO** must make publicly available the following **long term adequacy** metrics:

(a) an Alberta electrical generation projects and retirements metric which is a non-confidential project list indicating such relevant information as the project name, the project proponents, the MW size of the project and the estimated year of project completion;

(b) a forecast reserve margin metric, including a reserve margin metric which must have a minimum five (5) year forecast period and be calculated using a methodology that:

(i) is a measure, expressed in percentage terms, representing the amount of generation capacity at the time of system peak that is in excess of the annual peak demand;

(ii) utilizes **ISO** load forecasts;

(iii) utilizes existing **generating unit** capacity information such as **maximum capability** and the generation metric forecast capacity published as part of the Alberta electrical generation projects and retirements metric;

(iv) accounts for behind-the-fence load and generation capacity;

(v) excludes wind and solar generation and adjusts for hydro generation available at the time of system peak;

(vi) incorporates **interconnection** capacity; and

(vii) may reflect more than a single supply and load scenario for the system;

(c) a supply cushion metric which provides a two (2) year forecast of available daily generation capacity and peak demand both measured in MW which must be calculated using a methodology that:

(i) incorporates **generating unit** capacity information such as the **maximum capability** of **generating units**;

(ii) utilizes **ISO** load forecasts;

(iii) incorporates daily average **planned outages** and derates as reported by **pool participants** in their **planned outage** scheduling submissions as well as a nominal average **unplanned outage** and **forced outage** rate;

(iv) accounts for behind-the-fence load and generation capacity;

(v) excludes wind and solar generation and adjusts for hydro generation available at the time of daily system peak;

(vi) excludes **interconnection** capacity; and

(vii) excludes existing generation that is contractually available but that does not participate in the energy market;

(d) a two (2) year probability of supply **adequacy** shortfall metric which provides a probabilistic assessment of a state of **supply shortfall** over the next two (2) years and which must be calculated using a methodology that:

(i) utilizes **ISO** load forecasts;

(ii) utilizes existing **generating unit** capacity information such as **maximum capability** and the generation metric capacity published as part of the Alberta electrical generation and retirements metric;

(iii) incorporates hourly **planned outages** and derates as reported by **pool participants** in their **planned outage** scheduling submissions;

(iv) incorporates **interconnection** capacity estimates; and

(v) utilizes a distribution of outcomes for the following inputs:

(A) intermittent or energy limited resources; and

(B) **unplanned outages** and **forced outages**.

Long Term Adequacy Threshold Determination and Use

5(1) The **ISO** must, for the two (2) year probability of supply **adequacy** shortfall metric model set out in subsection 4(2)(d), use a **long term adequacy** threshold which:

(a) represents the equivalent impact of the probability of having a system supply shortfall occur once every ten (10) years; and

(b) is calculated as the one (1) hour average **Alberta internal load** for a year divided by five (5);

(c) being the level which, if exceeded, would indicate a need for the **ISO** to consider taking preventative action.

(2) The **ISO** must, using the two (2) year probability of supply **adequacy** shortfall metric, estimate on a quarterly basis the expected total system MWh not served in a subsequent two (2) year period.

(3) The **ISO** must, if the estimated total system MWh not served exceeds the **long term adequacy** threshold established at the time, undertake further studies to verify the likely cause, magnitude and timing of the potential **adequacy** issue.

Long Term Adequacy Threshold Actions

6 The **ISO** may, if the **long term adequacy** threshold is exceeded and the **ISO** deems that a potential **adequacy** issue requires preventative action, procure any one (1) or more of the following services:

(a) load shed;

(b) self-supply and back-up generation that would not otherwise be available to participate in the energy market; and

(c) emergency portable generation;

being **long term adequacy** threshold actions.

Procurement of Long Term Adequacy Threshold Actions

7 The **ISO** must procure **long term adequacy** threshold actions using established **ISO** procurement procedures and, where possible and practical, in a manner that encourages competition.

Recovery of Long Term Adequacy Threshold Actions Costs

8(1) The **ISO** must, if it procures **long term adequacy** threshold actions, establish a methodology that results in the recovery of the costs of **long term adequacy** threshold actions.

(2) The **ISO** must institute a charge to load, primarily directed to the **pool participants** who consume energy during higher priced hours, which recovers the costs of **long term adequacy** threshold actions.

Revision History

Date	Description
xxxx-xx-xx	Revised subsections 2 and 3 to reflect current outage definitions, generation from aggregated generating facilities, and generation that supplies behind-the-fence load; administrative revisions.
2018-09-01	Revised references to “wind aggregated generating facilities” to “aggregated generating facilities”; replaced “wind” with “wind and solar generation”; administrative revisions.
2014-10-01	Amendment to the short term adequacy assessments calculation to include the **ISO**’s **spinning reserve** requirement.
2013-12-20	Initial release

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Applicability

1 Section 202.7 applies to:

(a) an **electricity market participant**; and

(b) the **ISO**.

Requirements

State of Limited Markets Operations

2 If, due to:

(a) the unavailability of **ISO** merit order related tools; or

(b) the **ISO** being required to completely evacuate **ISO** personnel from the **ISO**'s System Coordination Centre due to an emergency or disaster event, resulting in the **ISO** using its Back Up Coordination Centre;

the **ISO** cannot access the ordinary course energy market **merit order**, which lack of access materially impedes the **ISO**'s ability to accurately and substantially issue **dispatches** and operate any one or all of the **merit orders**, then the **ISO** may, by the issuance of a declaration in accordance with subsection 3:

(c) declare that a state of limited markets operations is in effect; and

(d) invoke the limited markets operations procedures set out in this section 202.7.

Declaration Invoking a State of Limited Markets Operations

3(1) The **ISO** must issue a declaration if it is invoking a state of limited markets operations.

(2) The declaration must include:

(a) the reasons that the **ISO** is invoking the state of limited markets operations; and

(b) the commencement date and time of the state of limited markets operations.

(3) The **ISO** must use all reasonable efforts to issue the declaration as simultaneously as is possible to **electricity market participants** who may reasonably be anticipated to be affected by the state of limited markets operations.

(4) The **ISO** from time to time may issue a subsequent declaration updating **electricity market participants** on limited markets operations developments as the circumstances warrant.

(5) The **ISO** may select one or more of the following methods to issue a declaration, depending on which is the most practical and effective method under the circumstances:

(a) the real time AIES Event Log or other message communications posted on the AESO website;

(b) Automated Dispatch and Messaging System communications; or

(c) pre-recorded telephone notifications, followed up by written confirmations.

Dispatches During a State of Limited Markets Operations

4 During a state of limited markets operations:

(a) the **ISO** must use the most current and reasonably accurate **merit orders** then available to the **ISO** under the circumstances, to continue to issue **dispatches** in a manner which is as close as possible to ordinary course operations;

(b) subject to subsection 4(c), the **ISO** must use all reasonable efforts to ensure that any **dispatches** the **ISO** has issued for **dispatch down services** and **ancillary services** at the commencement of the state of limited markets operations remain in effect until termination of the state of limited markets operations; and

(c) if the system marginal price exceeds the reference price during the state of limited markets operations, then the **ISO** may determine that any one or all of the **dispatch down services** must be terminated until the termination of the state of limited markets operations.

Energy Market Pricing During a State of Limited Markets Operations

5(1) During a state of limited markets operations and subject to subsection 5(2), the **ISO** must determine the energy market **pool price** as the system marginal price at each minute, which must be the highest eligible **pool asset** marginal price of all **pool assets** to meet **system load** in the energy market **merit order** referred to in subsection 4(a).

(2) The system marginal price during a state of limited markets operations must be $1,000 per MWh under the circumstances set out in section 201.6 of the **ISO rules**, *Pricing*.

Other Pricing During a State of Limited Markets Operations

6 During a state of limited markets operations:

(a) the **ISO** must make **dispatch down service** payments based on the system marginal price in each minute, in accordance with section 103.4 of the **ISO rules**, *Power Pool Financial Settlement*;

(b) the **ISO** must make **ancillary services** payments based on the **pool price**, which such price is determined in accordance with section 201.6 of the **ISO rules**, *Pricing*;

(c) the **ISO** may suspend uplift payments in accordance with section 103.4 of the **ISO rules**, *Power Pool Financial Settlement*; and

(d) the **ISO** may suspend payments for **transmission constraint rebalancing** in accordance with section 103.4 of the **ISO rules**, *Power Pool Financial Settlement*.

Termination of a State of Limited Markets Operations

7(1) The **ISO**, by issuing a declaration, must terminate a state of limited markets operations as soon as it restores ordinary course access to the merit orders.

(2) The **ISO** must use the most practical and effective communication method referenced in subsection 3(5) to issue a declaration to **electricity market participants** that the **ISO** has terminated a state of limited markets operations and ordinary course **merit order** operations are to recommence by the date and time specified in the declaration.

State of Markets Suspension

8(1) If:

(a) the **interconnected electric system** is experiencing a **blackout**;

(b) the **interconnected electric system** is breaking up into 2 or more **electrical islands** causing **transmission constraints** that significantly limit or prohibit markets operations; or

(c) the **ISO** is unable to continue in a state of limited markets operations under this section 202.7 because:

(i) the **ISO** no longer can use the most current and reasonably accurate energy market **merit order** due to material variances between that energy market **merit order** and the energy production capabilities of the **pool assets** associated with the energy market **merit order**; or

(ii) the **ISO** no longer can perform and operate **merit order** functions at the Back Up Coordination Centre as referenced in subsection 2(b);

then once an approval is granted under subsection 8(2), the **ISO** may issue a declaration in accordance with subsection 9 invoking a state of markets suspension for the energy market, the **ancillary services** market and the **dispatch down service** market, and implementing the markets suspension procedures set out in this section 202.7.

(2) The **ISO** may not issue a declaration invoking a state of markets suspension without the approval of the Chief Executive Officer of the **ISO** or a designee, but if the **interconnected electric system** is experiencing a **blackout** as referenced under subsection 8(1)(a), then the **ISO** may, by declaration in accordance with subsection 9, invoke a state of markets suspension without Chief Executive Officer approval.

Declaration Invoking a State of Markets Suspension

9(1) The **ISO** must issue a declaration if it is invoking a state of markets suspension.

(2) The declaration must include:

(a) the reasons that the **ISO** is invoking the state of markets suspension; and

(b) the commencement date and time of the state of markets suspension.

(3) The **ISO** must use all reasonable efforts to issue the declaration as simultaneously as is possible to **electricity market participants** who may reasonably be anticipated to be affected by the state of markets suspension.

(4) The **ISO** from time to time may issue a subsequent declaration updating **electricity market participants** on markets suspension developments as the circumstances warrant.

(5) The **ISO** may select one or more of the following methods to issue the declaration, depending on which is the most practical and effective method under the circumstances:

(a) the real time AIES Event Log or other message communications posted on the AESO website;

(b) Automated Dispatch and Messaging System communications; or

(c) pre-recorded telephone notifications, followed up by written confirmation.

Effect of a State of Markets Suspension

10 During the period of time a state of markets suspension is in effect, the **ISO**:

(a) is not required to follow the **merit orders**; and

(b) must determine the system marginal price in accordance with subsection 11.

System Marginal Pricing during a State of Markets Suspension

11(1) During a state of markets suspension and subject to subsection 11(2), the **ISO** must determine the system marginal price at each minute, which price must be either the prior 30 **day** average **on peak** price or **off peak** price, depending on the hour of **day** the state of markets suspension is in effect.

(2) The system marginal price during a state of markets suspension must be $1,000 per MWh under the circumstances set out in section 201.6 of the **ISO rules**, *Pricing*.

Operating Costs Recovery for Certain Electricity Market Participants

12(1) If for a state of markets suspension an **electricity market participant** does not recover from energy receipts revenue all operating costs, as specified in subsection 12(2) below, for any **pool asset** that operated during that state of market suspension, then the **ISO** must pay to the **electricity market participant** an additional amount up to, but not in excess of, those operating costs, net of the energy receipts revenue.

(2) Subject to subsection 12(3), the operating costs referred to in subsection 12(1) may include:

(a) variable **supply transmission service** charges which are the actual cost of all variable charges from *Rate Schedule STS* of the **ISO tariff**, including the applicable **loss factor** charge or credit;

(b) variable operating and maintenance charges;

(c) fuel cost to operate the **pool asset**; and

(d) other related reasonable costs the **ISO** approves.

(3) If during a state of markets suspension an **electricity market participant** incurs start-up costs for a **pool asset** as the result of receiving a **directive** to start-up the **pool asset**, and then subsequently the **electricity market participant**:

(a) receives a **directive** to shut down the same **pool asset**; or

(b) receives a **dispatch** to terminate energy delivery or consumption for the same **pool asset** upon the termination of the markets suspension and the return to ordinary course operations;

then the **electricity market participant** may include those start-up costs in the operating costs to be recovered in accordance with subsection 12(2).

(4) The **ISO** must include as a line item in a **power pool** statement any charge to a **pool participant** under section 103.6 of the **ISO** rules, *ISO Fees and Charges* for the **ISO** to recover any costs associated with the payment of operating costs net of energy receipts revenue due to a markets suspension under this section 202.7.

Termination of a State of Markets Suspension

13(1) The **ISO**, by issuing a declaration, must terminate a state of markets suspension as soon as it restores ordinary course markets operations.

(2) The **ISO** must use the most practical and effective communication methods referenced in subsection 9(5) to issue a declaration to **electricity market participants** that the **ISO** has terminated a state of markets suspension and ordinary course markets operations are to recommence by the date and time specified in the declaration.

(3) The **ISO** must publish a preliminary report on the AESO website, no later than 5 **business days** following the last **day** of a state of markets suspension, containing a summary of events and circumstances which led to the **ISO** invoking the state of markets suspension.

(4) The **ISO** must publish a final report on the AESO website, no later than 20 **business days** following the termination of a state of markets suspension, containing details on how the **ISO** managed the markets suspension situation and the **interconnected electric system** during the state of markets suspension**,** and the efforts the **ISO** undertook to return the markets to ordinary course markets operations.

Revision History

Effective	Description
20XX-XX-XX	Revision to clarify "**market participant**" as "**electricity market participant**" Administrative amendments
2015-11-26	Addition of subsection 6(d) to refer to new subsection 7 of section 103.4 of the ISO rules.
2013-01-08	Previously defined terms have been un-defined and so the words have been un-bolded. Updated to refer to section 201.6 *Pricing*.
2011-10-13	Initial release

External Consultation Draft

November 20, 2018

Applicability

1 Section 203.1 applies to:

(a) a **pool participant**; and

(b) the **ISO**,

when participating in the energy market.

Requirements

Submission Method and Timing

2(1) A **pool participant** may only submit an **offer** or a **bid** to the **power pool** in respect to an active **pool asset** listed opposite their name in the **ISO** list of **pool assets**.

(2) A **pool participant** submitting an **offer** or **bid** must submit such **offer** or **bid**:

(a) before 12:00 hours on the **day** before the **day** that the **offer** or **bid** is effective, subject to any extension of time granted pursuant to subsection 3 of section 201.4 of the **ISO rules**, *Submission Methods and Coordination of Submissions*; and

(b) no earlier than 00:00, seven (7) **days** prior to the **day** that the **offer** or **bid** is effective.

Obligation to Offer and Offer Content

3(1) A **pool participant** must, for each **settlement interval**, submit an **offer** for each of its **source assets** with a **maximum capability** of five (5) MW or greater.

(2) A **pool participant** must not, notwithstanding subsection 3(1), submit an **offer** for:

(a) any of its **source assets** with a **maximum capability** of less than five (5) MW; and

(b) capacity that is committed under a contract for **long term adequacy**.

(3) A **pool participant** must include in each **operating block** in an **offer**;

(a) a price in $/MWh to the nearest cent per MWh which:

(b) in the case of **source asset** that is not an import **asset**, is greater than or equal to zero dollars ($0) per MWh and less than one thousand dollars ($1000) per MWh; and

(i) in the case of an import, is zero dollars ($0);

(c) a quantity in MW; and

(d) an indication of whether the **operating block** is a **flexible block** or an **inflexible block**; and

must also include in the **offer** the **minimum stable generation** for **the source asset**.

(4) A **pool participant** that submits an **offer** must ensure that:

(a) the cumulative total MW, as entered for the highest priced **operating block** in the **offer** for the **settlement interval**, equals the **maximum capability** of the **source asset**; and

(b) the **minimum stable generation** submitted for the **source asset** does not exceed the MW of the **operating block** with the lowest **offer** price for the **source asset** and a quantity greater than zero (0), including when submitted as part of a restatement under subsection 5(2) of section 203.4, *Energy Restatements*.

(5) A **pool participant** may, for a generating **source asset** with **a maximum capability** of less than 5 MW that is not associated with **offers** into the energy market, flow energy onto the **interconnected electric system** without submitting an **offer** into the energy market and without receiving a **dispatch**.

Offers During Commissioning and Testing

4 Notwithstanding subsection 3(3)(a)(i), a **pool participant** that submits an **offer** for a generating **source asset** which is undergoing **commissioning** and testing under section 505.3 of the **ISO rules**, *Coordinating Synchronization, Commissioning, WECC Testing and Ancillary Services Testing* must, until the **ISO** otherwise authorizes in writing, submit a price for the **offer** of zero dollars ($0).

Available Capability

5 A **pool participant** that submits an **offer** must also submit the **available capability**, in MW, for each **source asset** which such **available capability** must equal the **maximum capability** of the **source asset** unless the **pool participant** has submitted an **acceptable operational reason** with the **offer**.

Operating Constraints for Offers

6(1) A **pool participant** that submits an **offer** must also submit the following operating constraints:
- (a) **ramp rate**;
- (b) for a generating **source asset** or a load **sink asset**, a ramp table in the manner the **ISO** specifies after a date specified by the **ISO** that is no later than November 1, 2021; and
- (c) the initial start-up time.

(2) A **pool participant** must submit to the **ISO** any changes to the operating constraints of a **source asset** as soon as reasonably practicable.

Option to Bid and Bid Content

8 A **pool participant** may, for a **settlement interval**, submit a **bid** for any of its **sink assets**.
(2) A **pool participant** must include in each **operating block** in a **bid**:
- (a) a price in $/MWh to the nearest cent per MWh which:
  - (i) in the case of a **sink asset** that is not an export asset, is greater than or equal to zero dollars ($0) per MWh and less than one thousand dollars ($1000) per MWh; and
  - (ii) in the case of export, is nine hundred and ninety-nine dollars and ninety-nine cents ($999.99); and
- (b) a quantity in MW.

(3) A **pool participant** that submits a **bid** must ensure that the total MW in the **bid** do not exceed the peak load of the **sink asset**.

Standing Submission

8(1) A **pool participant** may create a standing submission, being an **offer** or **bid** that remains in place until the **pool participant** changes it.
(2) The **ISO** must use the data contained in the standing submission for the **pool asset** for the **day** following the **forecast scheduling period**.

Validation

9 The **ISO** must, as soon as reasonably practicable following the receipt of an **offer** or **bid**, send to the **pool participant** who submitted the **offer** or **bid**:

(a) acknowledgment of receipt of the **offer** or **bid**;

(b) notification that the **offer** or **bid** is either valid or invalid with respect to this section 203.1 of the **ISO rules**; and

(c) if an **offer** or **bid** is invalid, an explanation as to why the **offer** or **bid** is not accepted.

Revision History

Effective	**Description**
xxxx-xx-xx	Addition of ramp table in subsection 6(1)(b) and subsection 3(5).
2013-12-20	Updated subsections 3(1) and 3(2) to clarify offers in the context of capacity that is committed under a contract for long term adequacy.
2013-01-08	Initial Release

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November 20 2018

Applicability

1 Section 301.2 applies to:

(a) An **electricity market participant**; and

(b) the **ISO**.

Requirements

Directives the ISO Issues

2(1) The **ISO** may issue a **directive** to an **electricity market participant**, including a **directive** to:

(a) increase or decrease the **real power** or **reactive power** output, or both of them, from a facility;

(b) shut down or start up a facility; and

(c) switch **transmission system** elements, alter **planned outage** or maintenance schedules, or load shed.

(2) The **ISO** may issue a **directive** verbally, electronically or in writing.

Requirement to Comply

3(1) An **electricity market participant** must comply with a **directive** it receives subject to any other **ISO rule** or **reliability standard** and the exceptions in subsections 3(2) and 3(3).

(2) An **electricity market participant** that is a **legal owner** of a **generating unit** or an **aggregated generating facility**, or an **operator** of a **generating unit** or an **aggregated generating facility**, must comply with a **directive** it receives subject to the following exceptions:

(a) it considers that a real and substantial risk of damage to its **generating unit** or **aggregated generating facility** could result if it complied with the **directive**;

(b) it considers that a real and substantial risk to the safety of its employees or the public could result if it complied with the **directive**; or

(c) it considers that a real and substantial risk of undue injury to the environment could result if it complied with the **directive**.

(3) An **electricity market participant** that is a **legal owner** of a **transmission facility** or an **operator** of a **transmission facility** must comply with a **directive** it receives, subject to subsection 39(4) of the **Act**.

(4) An **electricity market participant** that is a **pool participant** must, if the instructions contained in a **directive** it receives require an **operator** to take action, immediately communicate the **directive** to the **operator**.

Report Inability to Comply or Communicate

4(1) If an **electricity market participant** is unable to comply with a **directive** or is unable to communicate it to the **operator**, as applicable, then it must, unless otherwise stipulated in the **directive**, verbally notify the **ISO** of the inability and provide reasons.

(2) The **electricity market participant** must provide notice as soon as practical but, unless otherwise stipulated in the **directive**, not later than 5 minutes after determining it is unable to comply with a **directive** or is unable to communicate a **directive** to the **operator**, as applicable.

Revision History

Effective	**Description**
XXXX-XX-XX	Revision to clarify "**market participant**" as "**electricity market participant**"
2014-07-02	Bolded the word "planned" in subsection 2(1)(c).
2012-07-10	Initial release

External Consultation Draft

November 20 2018

Applicability

1 Section 302.1 applies to:

(a) a **electricity market participant**; and

(b) the **ISO**.

Requirements

Real Time Transmission Constraint Mitigation

2(1) Subject to subsection 3, the **ISO** must comply with the following procedures in the following sequence to mitigate a **transmission constraint** in the present, real time:

(a) taking into account the **constraint effective factors**, determine the **pool assets** that would be effective in mitigating the **transmission constraint** and apply the appropriate procedure set out in this subsection 2(1) to those effective **pool assets**;

(b) ensure that any **pool assets** effective in mitigating the **transmission constraint** are not generating MW above their **maximum capability**, by cancelling any related **directives**;

(c) curtail by **directives**, any **downstream constraint side** service under **ISO tariff** rate schedules *Rate XOS 1 Hour* and *Rate XOS 1 Month* and any **upstream constraint side** service under **ISO tariff** rate schedule *Rate IOS*, that are effective in mitigating the **transmission constraint**;

(d) curtail by **directives**, any **loads** receiving service under **ISO tariff** rate schedules *Rate DOS 7 Minutes, Rate DOS 1 Hour* and *Rate DOS Term* at the **downstream constraint side** of the **transmission constraint**, that are effective in mitigating the **transmission constraint**;

(e) issue a **dispatch** to any **pool asset** that is under contract with the **ISO** to provide **transmission must-run** and that is effective in mitigating the **transmission constraint** at the **downstream constraint side**;

(f) issue a **directive** for **transmission-must run** to any **pool asset** that is not under contract with the **ISO** to provide **transmission must-run** and that is effective in mitigating the **transmission constraint** at the **downstream constraint side**;

(g) issue **directives** to curtail any **pool assets** that are effective in mitigating the **transmission constraint** at the **upstream constraint side** using the following additional procedures:

(i) the **ISO** must curtail using the energy market **merit order** with the highest priced in merit **offer** from the **pool asset** effective in mitigating the **transmission constraint** being curtailed first, followed by the **pool asset** with the next highest priced in merit **offer**, if necessary, during the remainder of the then current **settlement interval** and the next two (2) **settlement intervals**;

(ii) if there is a need to curtail two (2) or more such **pool assets** having equally priced **offers**, then the **ISO** must issue **directives** to the **pool assets** to curtail using a pro-rata methodology;

(iii) if the **transmission constraint** persists on a continuous basis for longer than the remainder of the then current **settlement interval** and the next two (2) **settlement intervals**, then the **ISO** must reallocate the required curtailment, using a pro-rata

(iv) methodology, to all **pool assets** having in merit **offers** that are effective in mitigating the **transmission constraint**; and

(h) curtail by **directives** any **loads** receiving service under **ISO tariff** rate schedule *Rate DTS* at the **downstream constraint side** of the **transmission constraint**, if so required by the **reliability** criteria, using the following procedures:

(i) the **ISO** must allocate the **load** curtailment using the energy market **merit order** with the lowest priced effective **bid** being curtailed first, followed by the next lowest priced effective **bid**, if necessary;

(ii) if there is a need to curtail **loads** with equal price **bids**, or there are no **bids** remaining, then the **ISO** must curtail using a pro-rata methodology.

(2) The **ISO** must comply with the following procedures in order to restore the energy balance to the **interconnected electric system**:

(a) where the procedures set out in subsection 2(1)(e) or (f) are used, issue **dispatches** for **dispatch down service** in accordance with section 204.2 of the **ISO rules**, *Issuing Dispatches for Dispatch Down Service*;

(b) except where the procedures set out in subsection 2(1)(e) and (f) are used:

(i) in circumstances where the **ISO** has notice of a **transmission constraint** that is anticipated to be of a significant duration and magnitude, as determined by the **ISO** acting reasonably, issue a **dispatch** to any **pool asset** that is effective in restoring the energy balance to the **interconnected electric system** and that is under contract with the **ISO** to provide **transmission must-run** in accordance with section 205.8 of the **ISO rules** – *Transmission Must-Run* and section 301.2 of the **ISO rules** – *ISO Directives,* and issue dispatches for **dispatch down service** in accordance with section 204.2 of the **ISO rules** – *Issuing Dispatches for Dispatch Down Service*;

(ii) in all other circumstances, or where necessary to supplement the volume **dispatched** for **transmission must-run** in subsection 2(2)(b)(i), issue **dispatches** for **transmission constraint rebalancing**, in accordance with the energy market **merit order**, and make payment to a **pool participant** with a **source asset** that has provided energy for **transmission constraint rebalancing** in accordance with subsection 7(1) of section 103.4 the **ISO rules**.

(3) With regard to any of the procedures set out in subsection 2(1) that involve **pool asset** or **load** curtailment, if the **pool asset** or **load** is supplying both **ancillary services** and energy production, then the **ISO** must first curtail **ancillary services** before energy production.

(4) When a **transmission constraint** has activated or is expected by the **ISO** to activate a **remedial action scheme,** then after the **ISO** has ensured that the **interconnected electric system** is operating in a safe and reliable mode, the **ISO** must recommence the procedural sequence set out in subsection 2(1) to manage the **transmission constraint**.

Additional Real Time Constraint Management Procedures

3 As the circumstances may warrant, the **ISO** may take into account the following alternative or complementary procedures to mitigate any present, real time **transmission constraint**:

(a) if the result of following the procedures set out in subsection 2(1)(g)(i) will be to curtail any **pool asset** below its **minimum stable generation** level but the **ISO** expects the **transmission constraint** to last only a short duration, then the **ISO** by **directive** may curtail the **pool asset** to above or at the **minimum stable generation** level of that **pool asset**;

(b) in circumstances where abnormal operating or market conditions exist, the **ISO** acting reasonably may, in implementing mitigation measures to address a **transmission constraint**, take procedural steps not listed in subsection 2(1) if those steps are substantially consistent with **good electric industry operating practice** and the duties of the **ISO** under the **Act** to direct the safe, reliable and economic operation of the **interconnected electric system**;

(c) the abnormal conditions referred to in subsection 3(b) include circumstances of unusual natural risks to the **interconnected electric system**, and issues raised by a unique real time system configuration or **reliability** concerns stemming from voltage or **reactive power** effects;

(d) in mitigating a **transmission constraint**, the **ISO** must follow the procedural sequence set out in subsection 2(1) and any more specific and complementary **ISO rules** applicable for a given regional area of the **interconnected electric system**, unless real time operating conditions change such that following the specified sequence would put the **ISO** in contravention of any **reliability standard** requirement by failing to achieve compliance within the operating limits or required response time specified in that **reliability standard**;

(e) if the **ISO** alters the procedural sequence as set out in subsection 2(1), or takes alternate mitigating actions because of the circumstances referred to in subsection 3(b) or 3(d) above, then once the **ISO** is assured that the **interconnected electric system** is operating in a safe and reliable mode, the **ISO** must recommence the procedural sequence set out in subsection 2(1).

Reporting

4(1) The **ISO** must use reasonable efforts to publish, as near to real time as possible, information on the location of **transmission constraints** and costs of resolving these constraints.

(2) The **ISO** must monitor and publicly report on the costs incurred as a result of mitigating **transmission constraints** on an annual basis.

Revision History

Effective	Description
xxxx-xx-xx	Revision to clarify "**market participant**" as "**electricity market participant**"
2015-11-26	Revisions to subsections 2(1) and 2(2). Amendment to numbering references in subsection 3(a). Addition of subsection 4 "Reporting".
2013-01-08	Previously defined terms have been un-defined and the words have been un-bolded.

	Reference to section 6.3.6.3 *Determining Dispatch Down Service Dispatch Quantity* has been replaced with section 204.2 *Issuing Dispatches for Dispatch Down Service*.
2012-03-26	Initial release

External Consultation Draft

November 20, 2018

Applicability

1 Section 303.1 applies to:

(a) an **electricity market participant** that contracts with the **ISO** to provide **load shed service**; and

(b) the **ISO**.

Requirements

Providing Data

2 The **electricity market participant** must provide the **ISO** with any information related to the provision of **load shed service** that the **ISO** requires in order to properly administer the service and must do so in real time via systems the **ISO** designates.

Determining Amount to Arm

3(1) The **ISO** must use current **Alberta internal load** levels and the net import schedule of the combined British Columbia and Montana transfer paths to determine the amount of **load shed service** that the **ISO** must arm.

(2) When arming the required amount of service, the **ISO** must prioritize the arming of available **load shed service** so as to minimize expected cost.

(3) The **ISO** must set the **load shed service** arming level at the beginning of the scheduling hour but may modify it if the requirement changes during the scheduling hour by more than fifteen (15) MW.

Restoring Service

4 After the operation of **load shed service**, while maintaining the **reliability** of the **interconnected electric system**, the **ISO** must restore the following in the following order:

(a) **contingency reserves**; then

(b) **load shed service**.

Arming and Disarming Service

5(1) The **ISO** will issue **dispatches** to arm and disarm **load shed service**.

(2) The **electricity market participant** must arm and disarm services in accordance with any **dispatches** the **ISO** issues unless the **electricity market participant** identifies a circumstance that, in the **ISO**'s opinion, amounts to an event of **force majeure** that would prevent the **electricity market participant** from complying with a **dispatch**.

Determining the Alberta Internal Load Range

6 If the estimated **Alberta internal load** falls right on, or very close to, the boundary of one of the ranges the **ISO** identifies, the **ISO** will use the lower **Alberta internal load** range to determine the amount of **load shed service** to arm during the hour that the **Alberta internal load** is expected to be at, or near, the boundary.

Curtailing Import during the Scheduling Hour

7 If there is insufficient **load shed service** due to the unavailability of this service, the **ISO** must adjust the import transfer level to the level corresponding to the required amount.

Restoring Service

8 The **electricity market participant** must not restore **load shed service** that has been tripped until the earlier of 1 hour after tripping or the **ISO** authorizing such restoration.

No Double-Counting

9 The **electricity market participant** must not use the MWs it uses to provide **load shed service** under this section of the **ISO rules** to also simultaneously provide **ancillary services** under any other section of the **ISO rules** or under any contract.

Revision History

Date	Description
20xx-xx-xx	Revised to change “market participant” as “electricity market participant”
2013-07-01	Amendments made to accommodate the energization of MATL
2011-04-01	Initial release

External Consultation Draft

November 20, 2018

Applicability

1 Section 304.2 applies to:

(a) the **operator** of an industrial complex that is:

(i) the Shell Limestone industrial complex; or

(ii) the Edson Gas Storage industrial complex;

(b) the **operator** of the **transmission facility** that operates **bulk transmission line** 854L from the 39S Bickerdike substation to the 397S Benbow substation;

(c) the **operator** of the **transmission facility** that operates 348S Marlboro substation; and

(d) the **ISO**.

Requirements

ISO Approval Prior to Starting an Electric Motor

2(1) The **operator** of an industrial complex must have the prior verbal approval of the **ISO** by means of direct access telephone to start an electric motor at the industrial complex, in accordance with the specific requirements set out in subsections 3 and 4, as applicable.

(2) The **operator** of an industrial complex must report to the **ISO** by means of direct access telephone when an attempt to start the electric motor has been completed, whether successful or not.

(3) The **ISO** must notify the **operator** of the **transmission facility** in the regional area of the industrial complex that there has been a request to start up the electric motor, and confirm that the **operator** of the **transmission facility** is not aware of any **reliability** reason to not start the electric motor.

(4) The **ISO** must grant approval to start the electric motor unless the **ISO** has **reliability** concerns that would prevent the electric motor start.

Shell Limestone Electric Motor Start

3(1) If the **ISO** receives a request from the **operator** of an industrial complex that is the Shell Limestone industrial complex to start the eighteen thousand (18 000) horsepower electric motor located at that industrial complex, then the **operator** must provide the anticipated date and time of the start of the electric motor and make the verbal request to the **ISO** at least one (1) hour prior to that start.

(2) In addition, the **operator** must provide all affected direct connect **electricity market participants**, served from the 581S Amoco Ricinus substation and which the **ISO** indicates, with at least one (1) hour notice by telephone prior to the starting of the electric motor, indicating the expected time of start and that there may be a short dip in their utility voltage due to the electric motor start.

Edson Gas Storage Electric Motor Start

4(1) If the 348S Marlboro substation located in the Hinton/Edson Area experiences an outage or derate resulting in any of the five thousand (5 000) horsepower electric motor-driven compressors at the Edson Gas Storage industrial complex shutting down, then the **operator** of that industrial complex must request approval from the **ISO** before restarting any of the compressor electric motors.

(2) If an outage or derate is in the nature of a permanent fault, then depending on the location of the permanent fault, the **operator** of the **transmission facility** must sectionalize the appropriate section of **bulk transmission line** 854L to allow radial supply to the 348S Marlboro substation from either the 39S Bickerdike substation or the 397S Benbow substation.

Revision History

Effective	Description
2018-xx-xx	Revised “market participant” to “electricity market participant”; Removed requirements for Empress Area; Removed examples of reliability conditions from Appendix 1.
2014-07-02	Amended subsections 4(1), 4(2) and 5(1) of Appendix 1 by unbolding the references to “outages” and adding the words “or derate” after the word “outages”
2012-05-31	Initial release

External Consultation Draft

November 20, 2018

Applicability

1 Section 304.8 applies to:

(a) the **operator** of a **transmission facility**;

(b) the **operator** of an **electric distribution system**;

(c) the **operator** of a facility that provides **ancillary services**;

(d) the **operator** of a **generating unit** that:

(i) is not part of an **aggregated generating facility**;

(ii) has a **maximum authorized real power** rating greater than 4.5 MW; and

(iii) is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat, including a **generating unit** situated within an industrial complex that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(e) the **operator** of an **aggregated generating facility** that:

(i) has a **maximum authorized real power** rating greater than 4.5 MW; and

(ii) is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat, including an **aggregated generating facility** situated within an industrial complex that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(f) the **legal owner** of a **transmission facility**;

(g) the **legal owner** of an **electric distribution system**;

(h) the **legal owner** of a facility that provides **ancillary services**;

(i) the **legal owner** of a **generating unit** that:

(i) is not part of an **aggregated generating facility**;

(ii) has a **maximum authorized real power** rating greater than 4.5 MW; and

(iii) is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat, including a **generating unit** situated within an industrial complex that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(j) the **legal owner** of an **aggregated generating facility** that:

(i) has a **maximum authorized real power** rating greater than 4.5 MW

(ii) is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat, including an **aggregated generating facility** situated within an industrial complex that is directly connected to the **transmission system** or to **transmission facilities** within the City of Medicine Hat;

(collectively referred to as the “Responsible Entities”)

and

(k) the **ISO**.

Requirements

Requirements to Perform Event Analysis

2(1) The **ISO** may conduct an event analysis of an event listed in Appendix 1.

(2) The **ISO** may conduct an event analysis for an event that is not listed in Appendix 1 where:

(a) the **ISO** determines that an analysis is necessary to evaluate the impact of an event on the reliable operation of the **interconnected electric system**; or

(b) an event analysis report is requested by the **NERC** or the **WECC**.

(3) The **ISO** may categorize the event using the highest applicable category in Appendix 1 where Category 1 is the lowest and Category 5 is the highest.

Event Analysis Requests

3 The **ISO** may request a brief report or an event analysis report or both from a Responsible Entity while conducting an event analysis.

Responsible Entity Reporting

4(1) A Responsible Entity must provide the **ISO** with a report requested in accordance with subsection 3:

(a) in a manner specified by the **ISO**;

(b) within 10 **business days** if the **ISO** requests a brief report; and

(c) within 30 **business days** if the **ISO** requests an event analysis report.

(2) Notwithstanding subsection 4(1), a Responsible Entity may request, in writing, including all relevant supporting documentation, that the **ISO** provide an extension to the time frames indicated in subsections 4(1)(b) and 4(1)(c):

(a) to allow for system restoration; or

(b) to allow the Responsible Entity to obtain accurate and complete information regarding the event.

(3) The **ISO** must respond, in writing, to an extension request made in accordance with subsection 4(2) within 3 **business days** of receiving the request.

Review

5(1) Upon reviewing a brief report or event analysis report provided in accordance with subsection 4, the **ISO** may request that the Responsible Entity provide additional information as required to complete the event analysis within a specified time frame.

(2) A Responsible Entity must, upon receiving a request from the **ISO** under subsection 5(1) and within the time frame specified in the request:

(a) provide the **ISO** with the requested information; or

(b) notify the **ISO**, in writing, of the reasons for which the requested information is not available or the specified time frame cannot be met.

ISO Reporting

6(1) The **ISO** may, after reviewing the reports provided in accordance with subsection 4 and subsection 5, decide to author additional reports.

Event Analysis Recommendations

7(1) The **ISO** may, after completing a report under subsection 6, identify:

(a) the Responsible Entity required to implement each recommendation in the report; and

(b) an implementation date for each recommendation in the report.

(2) The **ISO** may:

(a) provide a copy of a report issued under subsection 6 to each Responsible Entity identified under subsection 7(1); and

(b) advise each Responsible Entity identified under subsection 7(1), in writing, of the implementation date for each recommendation applicable to that Responsible Entity.

(3) Subject to subsection 7(2), the **ISO** and each Responsible Entity identified under subsection 7(1) must treat a report provided under subsection 7(2)(a) as confidential.

(4) Each Responsible Entity identified under subsection 7(1) must implement each applicable recommendation by resolving the outstanding issues associated with each recommendation on or before the implementation date.

(5) Each Responsible Entity identified in subsection 7(1) must provide the **ISO** with:

(a) notification that the recommendation has been implemented in accordance with subsection 7(4) within 5 **business days** following such implementation, or

(b) a revised implementation date at least 5 **business days** before the implementation date identified by the **ISO** in subsection 7(2)(b), if the recommendation cannot be implemented in accordance with subsection 7(4).

Lessons Learned

8(1) The **ISO** may complete a *Lessons Learned* document which includes the following information:

(a) high level details of the event;

(b) corrective actions for possible future events; and

(c) a list of lessons learned from the event.

(2) A *Lessons Learned* document must not contain any of the following information:

(a) names of **electricity market participants**;

(b) names of facilities;

(c) the date on which the event occurred; and

(d) to the extent practicable, any other information that would otherwise permit the identification of an **electricity market participant** or facilities.

(3) The **ISO** may publish the *Lessons Learned* document on the AESO website.

Requirement to Report to the NERC and the WECC

9 The **ISO** may forward the reports and documents described in this section 304.8 to the **NERC** and the **WECC**.

Appendices

Appendix 1 – Event Categories

Revision History

Date	Description
XXXX-XX-XX	Revision to clarify "**market participant**" as "**electricity market participant**"; Addition of subsections 1(i)(ii) and 1(j)(i).
2018-04-30	Initial release

Appendix 1

Event Categories

Category 1: An event that results in one or more of the following:

(a) An unexpected sustained outage caused by a common disturbance and contrary to design of any combination of three (3) or more **transmission facilities**, **aggregated generating facilities** or **generating units** with an aggregate generation of 500 MW to 1,999 MW at the time of the outage.

(b) Failure or misoperation of a **remedial action scheme**.

(c) A system wide voltage reduction of 3% or more that lasts more than fifteen (15) continuous minutes due to an emergency on the **interconnected electric system**.

(d) Unintended separation within the **interconnected electric system** that results in an island of 100 MW to 999 MW. Excludes **transmission system** radial connections, and **electric distribution system** level islanding.

(e) The loss of monitoring or control that significantly affects a Responsible Entity's ability to make operating decisions for thirty (30) continuous minutes or more, including:

(i) loss of **operator** ability to remotely monitor or control elements of the **bulk electric system**, **aggregated generating facilities** or **generating units** connected to the **bulk electric system**;

(ii) loss of communications from supervisory and data acquisition remote terminal units for a substation rated 69 kV and above;

(iii) unavailability of inter **control centre** protocol links reducing **bulk electric system** visibility

(iv) loss of the ability to remotely monitor and control **generating units** providing **regulating reserves**; or

(v) state estimator or contingency analysis failing to solve at a **control centre** for:

(A) the **ISO**; or

(B) the **operator** of a **transmission facility**.

Category 2: An event that results in one or more of the following:

(a) Complete loss, for thirty (30) minutes or more, of all voice communication systems for a **control centre** including a **control centre** for:

(i) the **ISO**;

(ii) the **operator** of a **transmission facility** (that controls **transmission facilities** at two (2) or more locations); or

(iii) the **operator** of a **generating unit** (that controls **generating units** at two (2) or more locations).

(b) Operating voltage excursions at the **point of connection** equal to or greater than 10% lasting more than fifteen (15) continuous minutes.

(c) Unintended separation within the **interconnected electric system** that results in an island of 1,000 MW to 4,999 MW.

(d) Unintended loss of 300 MW or more of firm load for more than fifteen (15) minutes.

(e) **Interconnection reliability operating limit Tv** violation.

Category 3: An event that results in one or more of the following:

(a) Unintended loss of load or generation within the **interconnected electric system** of 2,000 MW to 5,000 MW.

(b) Unintended separation within the **interconnected electric system** that results in an island of 5,000 to 10,000 MW. Excludes the loss of **interconnections**.

Category 4: An event that results in one or more of the following:

(a) Unintended loss of load or generation within the **interconnected electric system** of 5,001 MW to 9,999 MW.

(b) Unintended separation within the **interconnected electric system** that results in an island of more than 10,000 MW. Excludes the loss of **interconnections**.

Category 5: An event that results in one or more of the following:

(a) Unintended loss of load within the **interconnected electric system** of 10,000 MW or more.

(b) Unintended loss of generation within the **interconnected electric system** of 10,000 MW or more.

Section 305.3 Blackstart Restoration

External Consultation Draft

November 20, 2018

Applicability

1 Section 305.3 applies to:

(a) a **legal owner** of a **transmission facility**;

(b) a **legal owner** of a **generating unit**;

(c) a **legal owner** of an **aggregated generating facility**; and

(d) the **ISO**.

Requirements

Contracting for Blackstart

2 The **ISO** must establish contracts with **electricity market participants** for the provision of blackstart services.

Blackstart Procedures

3(1) The **ISO** must develop and maintain procedures to facilitate the restoration of the **interconnected electric system** in the event of a partial or complete blackout of the **interconnected electric system**.

(2) The **legal owner** of a **transmission facility** must develop and maintain procedures to facilitate restoration of its facilities in the event of a partial or complete black out of the **interconnected electric system**.

(3) The **legal owner** of a **transmission facility** must, with respect to the procedures required under subsection 3(2):

(a) ensure that they are aligned with the **ISO**'s procedures; and

(b) provide them to the **ISO** on an annual basis and no later than December 31 of each year.

(4) The **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility** must develop and maintain procedures to facilitate restoration of its facilities in the event of a partial or complete black out of the **interconnected electric system**.

(5) The **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility** must ensure that its procedures are aligned with the procedures of the **legal owner** of a **transmission facility** with whose facilities the **generating unit** or **aggregated generating facility** is connected.

Training of Blackstart Procedures

4(1) The **ISO** must train its staff on its blackstart procedures.

(2) The **ISO** must, on an annual basis, conduct a blackstart exercise to test its blackstart procedures.

(3) The **legal owner** of a **transmission facility** must train its staff on its blackstart procedures.

(4) The **legal owner** of a **generating unit** and the **legal owner** of an **aggregated generating facility** must train its staff on its blackstart procedures.

Coordination of Blackstart Restoration Plan

5(1) The **legal owner** of a **transmission facility**, **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must only execute blackstart procedures under the **ISO**'s direction.

(2) The **legal owner** of a **transmission facility** must coordinate blackstart restoration with the **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility,** connected to its facility.

(3) The **legal owner** of a **generating unit** and **legal owner** of an **aggregated generating facility** must coordinate any blackstart restoration with the **legal owner** of a **transmission facility** with whose facilities the **generating unit** or **aggregated generating facility** is connected.

Revision History

Effective	**Description**
XXXX-XX-XX	Revision to clarify "**market participant**" as "**electricity market participant**".
2012-11-30	Initial release

External Consultation Draft

November 20, 2018

Applicability

1 Section 305.4 applies to:

(a) an **electricity market participant**; and

(b) the **ISO**.

Requirements

ISO Responsibilities

2(1) The **ISO** must schedule to prevent a threat to **system security**.

(2) The **ISO** may schedule out of the **merit order** to prevent a threat to **system security**.

(3) The **ISO** must issue **dispatches** in a manner to prevent a threat to **system security**.

(4) The **ISO** may issue **dispatches** out of the **merit order** to prevent a threat to **system security** or to return the **interconnected electric system** to a safe and reliable state.

(5) The **ISO** must issue **directives** to prevent a threat to **system security** or to return the **interconnected electric system** to a safe and reliable state.

(6) The **ISO** must, when there is a system emergency, use reasonable efforts to promptly advise:

(a) affected **legal owners** of a **transmission facility**; and

(b) all **pool participants**.

Electricity Market Participant Responsibilities

3 An **electricity market participant** must use reasonable efforts to promptly advise the **ISO** upon becoming aware of any circumstance with respect to its facilities that could be expected to adversely affect **system security** or the **interconnected electric system**'s ability to deliver energy.

Revision History

Date	Description
yyyy-mm-dd	Revision to clarify "**market participant**" as "**electricity market participant**" Unbold system emergency
2012-10-31	Initial release

External Consultation Draft
November 20, 2018

Applicability

1 Section 306.3 applies to:

(a) an **electricity market participant** with a load **sink asset**; and

(b) the **ISO**.

Requirements

Load Planned Outage Reporting

2(1) Subject to subsection 2(2), an **electricity market participant** who has a planned decrease in its capability to consume load at a facility of 40 MW or greater, must comply with the **planned outage** reporting requirements of this section 306.3.

(2) Subsection 2(1) does not apply if the **market participant** has documented the decrease in a restated **available capability** for the facility, in accordance with section 203.3 of the **ISO rules**, *Restatements for Energy*.

(2) The **electricity market participant** referred to in subsection 2(1) must submit to the **ISO** the following **planned outage** information, in a form the **ISO** approves and publishes on the AESO website:

(a) the commencement date and time of the **planned outage**, but not where such date and time is historical;

(b) the end date and time of the **planned outage**; and

(c) the actual decrease, in MW, in the load capability.

(3) The **electricity market participant** must submit the information to the **ISO** as soon as reasonably practicable after the **electricity market participant** is aware of the **planned outage** information.

(4) Subsequent to the **ISO** receiving from **electricity market participants** the submissions referred to in subsection 2(2), on each **business day** the **ISO** must aggregate all **planned outage** records for loads as submitted, and determine the aggregate daily **planned outages** in MW which the **ISO** will calculate as:

the sum of MWh of all submitted **planned outages** by time period;

divided by

the number of hours in the time period.

(5) Once the **ISO** has determined the aggregate daily **planned outages** under subsection 2(4), the **ISO** also must prepare a daily **planned outage** report and publish it each **business day** on the AESO website, which report must include:

(a) the time and date the report was prepared; and

(b) the daily average **planned outage** amount in MW, rounded to the nearest MW, for each **business day** of the then current **month** and the next 3 successive **months**.

(6) Subject to subsection 2(7), the **ISO** must keep confidential all **planned outage** information for loads submitted to it under this section 306.3, except as otherwise required to be made public under the provisions of section 103.1 of the **ISO rules**, *Confidentiality.*

(7) The **ISO** must publish on the AESO website the aggregate daily **planned outage** report in a manner that, in accordance with section 103.1 of the **ISO rules**, *Confidentiality*, seeks to preserve the confidential nature of any **planned outage** information as submitted by any one **electricity market participant**, and precludes the identification of any one **electricity market participant**, or other directly affected **pool participant**.

Revision History

Effective	Description
XXXX-XX-XX	Revision to clarify "**market participant**" as "**electricity market participant**". Removal of subsection 2(2)
2014-07-02	Renumbered from section 208.1 of the ISO rules to section 306.3 of the ISO rules; unbolded all references to "load" and "loads"; and replaced references to "outage" with "planned outage".
2013-01-08	Removed reference to section 3.5 *Offers and Bids*, and replaced with section 203.3 *Restatements for Energy*.
2011-09-30	Initial Release

ISO Rules
Part 300 System Reliability and Operations
Division 306 Outages and Disturbances
Section 306.4 Transmission Planned Outage Reporting and Coordination

External Consultation Draft
November 20, 2018

Applicability

1 Section 306.4 applies to:

(a) the **legal owner** of a **transmission facility**;

(b) the **legal owner** of **generating unit** connected to a **transmission facility**;

(c) the **legal owner** of an **aggregated generating facility**;

(d) the **legal owner** of an **electric distribution facility**;

(e) the **legal owner** of an **intertie**;

(f) the **legal owner** of load directly connected to the **transmission system**; and

(g) the **ISO**;

when managing the reporting and coordination of **planned outages**, including live line work and recloser block situations, for **transmission facilities**.

Requirements

General

2 The **legal owner** of a **transmission facility** must, prior to the occurrence of a **planned outage**, submit to the **ISO** a **planned outage** request for approval by submitting the information specified in this section 306.4 and according to the timelines set out below.

Planned Outage Schedule and Requests

3(1) The **legal owner** of a **transmission facility** must submit to the **ISO**, by the first **day** of every **month**, a schedule of significant **planned outages** that are planned to occur within the next 24 **months**.

(2) The **legal owner** of a **transmission facility** must submit to the **ISO** a significant **planned outage** request as soon as possible, and not less than 30 **days** before the start of the **operating week** in which the significant **planned outage** is intended to occur.

(3) The **legal owner** of a **transmission facility** must, in its schedule of significant **planned outages** and in its significant **planned outage** requests, include a **planned outage** that meets any 1 or more of the following criteria:

(a) it affects a **transmission facility** operating at 240 kV or greater;

(b) it affects an **intertie**;

(c) it affects a **system element** connecting facilities owned by 2 or more different **legal owners** of **transmission facilities**;

(d) it affects a **system element** that connects a **generating unit** or an **aggregated generating facility** to the **interconnected electric system**;

(e) it requires the **ISO** to issue a **dispatch** or **directive** for generation in order to facilitate the **planned outage**;

(f) it affects a cutplane limit;

(g) it limits or reduces the operability of a synchronous condenser, static VAr compensator, static compensator or other similar dynamic device; or

(h) it affects high voltage direct current facilities.

(4) The **legal owner** of a **transmission facility** must submit to the **ISO** a non-significant **planned outage** request no later than 12:00 noon on Tuesday in the week before the **operating week** in which the non-significant **planned outage** is intended to occur.

(5) The **legal owner** of a **transmission facility** must, on the Tuesday before each **operating week** and prior to 12:00 noon, resubmit to the **ISO** all **planned outage** requests that the **legal owner** intends to conduct in the following **operating week**.

Changes to Requests and Cancellations

4(1) The **legal owner** of a **transmission facility** must submit to the **ISO** any changes to a previously submitted **planned outage** request, including cancellations, as soon as possible, and no later than 10:00 am on the **business day** before the first **day** impacted by the intended change to the previously submitted **planned outage** request.

(2) The **legal owner** of a **transmission facility** must, if it is unable to comply with subsection 4(1), submit to the **ISO** a cancellation of a **planned outage** request as soon as possible after the deadline set out in subsection 4(1), and provide a reason as to why it was unable to submit the cancellation by that deadline.

Outage Pre-Work and Information

5(1) The **legal owner** of a **transmission facility** must, prior to submitting to the **ISO** any **planned outage** request or a change to a previously submitted **planned outage** request:

(a) coordinate the **planned outage** with other affected **legal owners**;

(b) perform a **contingency** assessment of the **planned outage**, considering conditions throughout the duration of the **planned outage,** and develop plans to mitigate any concerns identified; and

(c) determine the **planned outage** does not conflict with any other **planned outage**.

(2) The **legal owner** of a **transmission facility** must, as part of any **planned outage** request, provide **planned outage** information to the **ISO** in the form the **ISO** specifies, including the following:

(a) the **transmission facility** being taken out of service;

(b) dates and times, indicating the start of switching to isolate a facility and the end of switching to return the facility to service;

(c) nature of work and any related **system elements** that will be affected;

(d) details of the **contingency** assessment and any mitigation plans;

(e) confirmation of coordination with all affected **legal owners**;

(f) isolation points energized at greater than 25 kV; and

(g) time to restore the **transmission facility** in an emergency.

ISO Assessments

6(1) The **ISO** must, no later than the start of the **operating week** in which the **planned outage** is to occur, assess:

(a) in the case of a significant **planned outage**:

(i) a **planned outage** request submitted prior to 90 **days** before the start of the **operating week** in which the **planned outage** is to occur; and

(ii) a change to a **planned outage** request, previously submitted pursuant to subsection 6(1)(a)(i), that is submitted prior to 30 days before the start of the **operating week** in which the change is to occur; and

(b) in the case of a non-significant **planned outage**, a **planned outage** request, and any change to such request, that is submitted prior to 12:00 noon on Tuesday in the week before the **operating week** in which the **planned outage** or the change, as applicable, is to occur.

(2) The **ISO** may assess a change to a **planned outage** request that is submitted in accordance with subsection 4, but that is submitted later than the timelines specified in subsection 6(1).

(3) The **ISO** must, if it assesses a **planned outage** request or any change to such request, do so by taking into account:

(a) the **reliability** of the **interconnected electric system**;

(b) potential impacts to **electricity market participants**;

(c) coordination of the **planned outage** with other affected **legal owners**; and

(d) coordination of the **planned outage** with other anticipated conditions on the **interconnected electric system**.

ISO Approvals

7(1) The **ISO** must approve a **planned outage** request or any changes to such request, excluding cancellations, if the **ISO**:

(a) assesses the **planned outage** request, or any change to such request, as set out in subsection 6; and

(b) determines that the **planned outage** can be conducted without adversely affecting the **reliability** of the system or the fair, efficient and openly competitive operation of the market.

(2) The **ISO** must, if it approves a **planned outage** request or any change to such request, communicate such approval via an approved outage report posted on the AESO website.

(3) The **ISO** must approve a **planned outage** request and any change to such request in order for the **planned outage** to proceed.

(4) The **ISO** may, based on real time **reliability** requirements of the **interconnected electric system** and necessary **ISO** operational flexibility, cancel any **planned outage** it has already approved under subsection 7(1) by providing written or verbal notice to the **legal owner** of the **transmission facility**.

Real-Time ISO Approval

8(1) The **legal owner** of a **transmission facility** must, in relation to any **planned outage**, obtain real-time approval from the **ISO** prior to switching transmission equipment out of service.

(2) The **legal owner** of a **transmission facility** must, in relation to any **planned outage**, obtain real-time approval from the **ISO** prior to energization of equipment after completion of an outage.

Coordination

9 The **legal owner** of a **generating unit**, the **legal owner** of an **aggregated generating facility**, the **legal owner** of an **electric distribution system** and the **legal owner** of load must, on a reasonable efforts basis, coordinate with the affected **legal owners** regarding any **planned outages**.

Provision of Outage Information by the ISO

10(1) The **ISO** must publish on the AESO website a list of significant **planned outages** that are to occur in the period beginning in the **operating week** after the upcoming **operating week** and ending 24 **months** later.

(2) The **ISO** must publish on the AESO website a list of all **planned outages** it has approved to occur during the remaining **days** of the current **operating week** and all **days** of the following **operating week**, and must use reasonable efforts to do so by 18:00 (6:00 pm) each Wednesday.

(3) The **ISO** must document details of its assessments of the approved **planned outages** noted on the list referred to in subsection 10(2) in a report commonly known as the coordination plan.

(4) The **ISO** must not include details of generation **dispatches**, generation **directives** or generation outage schedules in the coordination plan.

(5) The **ISO** must email the coordination plan to each **legal owner** of a **transmission facility** and must use reasonable efforts to do so by 18:00 (6:00 pm) each Thursday.

Revision History

Date	Description
XXXX-XX-XX	Revision to clarify "**market participant**" as "**electricity market participant**".
2016-08-30	Inclusion of the defined term **system element**.
2014-07-02	Initial release

Section 306.5 Generation Outage Reporting and Coordination

External Consultation Draft
November 20, 2018

Applicability

1 Section 306.5 applies to:

(a) a **pool participant** with a generating **source asset** with a **maximum capability** of five (5) MW or higher, excluding a wind facility;

(b) a **legal owner** of a **source asset** described in subsection 1(a); and

(c) the **ISO**.

Requirements

General

2(1) A **pool participant** must, for any outage that results or will result in a change in **available capability** of five (5) MW or greater, comply with the notification requirements set forth in subsections 3, 4 or 5, as applicable.

(2) A **pool participant** must provide to the **ISO**, in writing and in conjunction with its first **planned outage** notification, a list of contact **persons** who must be involved in the planning of outages and be in a position of authority to resolve with the **ISO** any issues or concerns regarding outages.

(3) A **pool participant** must submit information required to be provided to the **ISO** pursuant to this section 306.5 via the Energy Trading System.

Planned Outage Notification Requirements

3(1) A **pool participant** must, in respect of any **planned outage**, submit to the **ISO**:

(a) the dates, times, durations and impact to MW capability for the **planned outage**;

(b) the specific nature of the **planned outage** work to be done; and

(c) a designation of the **planned outage** as “Derate-Planned” or **“**Outage-Planned”.

(2) A **pool participant** must, by the first (1st) **day** of every **month** after the date of **energization**, submit the information set out in subsection 3(1) to the **ISO** related to **planned outages** that, as of the time of the submission, are planned to occur at any time within the next twenty-four (24) **months.**

(3) A **pool participant** must, with respect to:

(a) any revisions to the information submitted to the **ISO** under subsection 3(1); or

(a) a **planned outage** that is not included in the submission set out in subsection 3(2);

submit such information or **planned outage** as soon as reasonably practical.

(4) A **pool participant** must, if information submitted under subsection 3(3) is submitted later than three (3) **months** prior to the **day** the **planned outage** is to start, include a statement in its submission setting out the reasons that the information varies from the original subsection 3(1) submission or was not included in the submission set out in subsection 3(2).

Delayed Forced Outage Notification Requirements

4(1) A **pool participant** must, as soon as reasonably practicable, in respect of a **delayed forced outage**, submit to the **ISO**:

(a) the dates, times, durations and impact to MW capability for the **delayed forced outage**;

(b) the specific nature of the **delayed forced outage** work to be done; and

(c) a designation of the **delayed forced outage** as “Derate-Forced” or “Outage-Forced”.

(2) A **pool participant** must also, as soon as reasonably practicable, in respect of a **delayed forced outage** for which the **pool participant** has less than 24 hours between the time of discovering the circumstances requiring the **delayed forced outage** and the time of commencing the **delayed forced outage**, contact the **ISO** by telephone, on a telephone number that the **ISO** designates, which must contain a voice recording system.

Automatic Forced Outage Notification Requirements

5 A **pool participant** must, as soon as reasonably practicable, submit **automatic forced outage** information as follows:

(a) through contacting the **ISO** by telephone, on a telephone number that the **ISO** designates, which must contain a voice recording system; and

(b) submit a designation of the **automatic forced outage** as "Derate-Forced" or "Outage-Forced".

Authority to Issue an Outage Cancellation Directive

6(1) The **ISO** may, if after:

(a) completing the assessments and procedures set out in subsections 7(2) through 7(6) the **ISO** determines that there remains:

(i) an immediate need on a short term basis for services provided by certain **source assets** to maintain the necessary level of **reliability** or **adequacy**, as the case may be; and

(ii) a high probability that the situation will not be alleviated in a voluntary manner:

(A) by any **pool participants** amending or revising outage plans; or

(B) through the ordinary course operation of the market; and

(b) taking into account the factors set out in subsection 7(7) below,

issue a **directive** to cancel any one (1) or more of a **planned outage** or a **delayed forced outage**.

(2) The **ISO** must not issue a **directive** canceling an outage without the authorization of the Chief Executive Officer of the **ISO** or his designee.

Outage Cancellation Procedure

7(1) The **ISO** must, prior to issuing a **directive** canceling an outage, comply with the procedures set out in subsection 7(2) through 7(8) in sequence.

(2) The **ISO** must consider and analyze the results of the **adequacy** assessments undertaken in accordance with subsection 2 of section 202.6 of the **ISO rules**, *Adequacy of Supply*, and perform a further assessment of the status of all **source assets** based on all **planned outage** plans **pool participants** submit under subsection 3.

(3) The **ISO** must:

(a) after completing the assessments and taking into account the total amount of all generating **source assets** which are planned for outages; and

(b) if the **ISO** anticipates a high probability of a supply **adequacy** shortfall or **reliability** concern

notify **market participants** on the AESO website of its determination.

(4) The **ISO** must continue to conduct further situational analysis to seek to alleviate the potential supply **adequacy** shortfall or **reliability** concern and avoid the cancellation of any outages.

(5) The **ISO** must post the determination referred to in subsection 7(3) above for a minimum period of one (1) calendar week, and in anticipation that certain **pool participants** may have flexibility to voluntarily amend plans for outages to assist in the alleviation of the supply **adequacy** shortfall or **reliability** situation.

(6) The **ISO** must, if the **ISO** posting referred to in subsection 7(5) and any resulting voluntary actions do not result in a reduction in the total amount of generating **source asset** capacity planned for outages such that the forecast supply **adequacy** shortfall or **reliability** remains unresolved, contact the individual

pool participants to request that they further review outage plans.

(7) The **ISO** must consider all of the following factors in its determination as to whether or not to issue a **directive** canceling an outage as contemplated in this subsection 7:

(a) the economic and operational consequences for the **legal owner** of the **source asset** and for any designated **pool participant**, if a different **person**;
(b) the operational and functional impact on the **source asset** if the outage is cancelled;
(c) the effectiveness of canceling the outage in alleviating the supply **adequacy** shortfall or **reliability** concern;
(d) the historical frequency that a given **source asset** has been the subject of outage cancellations relative to other **source assets**;
(e) the length of time of, and reasons for, any outage the **pool participant** has previously submitted to the **ISO** under the reporting requirements set out in this section 505.6;
(f) the extent to which the outage will begin or end during the period of the forecast supply **adequacy** shortfall or **reliability** concern;
(g) any requirements or material implications under or related to any applicable municipal, provincial or federal legislation or regulations if the **ISO** proceeds to issue a **directive** to cancel an outage; and
(h) the practicality and effectiveness of market-based solutions to alleviate the supply **adequacy** shortfall or **reliability** concern, including a consideration of load curtailment options.

(8) The **ISO** must not issue a **directive** canceling an outage more than ninety (90) **days** in advance of the first **day** of the period which has been determined to be the commencement of the **reliability** or **adequacy** shortfall.

Outage Planned Costs and Work Submission

8(1) A **pool participant** who has received a **directive** for the cancellation of an outage must use all reasonable efforts to submit to the **ISO** in advance of the period when the outage would have occurred:

(a) a detailed description and estimation of the work, which was to have been carried out during the outage, including an itemization of the specific plant, machinery and equipment which are the subject of the work during the that period; and
(b) an estimate of any known or anticipated **incremental generation costs** that may be the basis for a claim for compensation under these **ISO rules**.

(2) The submissions set out in subsection 8(1) do not limit compensation claims for other reasonable demonstrable costs.

Time Constrained Outage Cancellation

9 The **ISO** may, notwithstanding subsection 7, dispense with any or all of the procedures set out in that subsection 7 and proceed to issue a **directive** to cancel an outage, if in the **ISO**’s opinion, it is evident that immediate **reliability** or **adequacy** circumstances do not allow sufficient time to permit the **ISO** to comply with such procedures.

Outage Cancellation Report

10 The **ISO** must, if it issues a **directive** under subsection 6 to cancel an outage, prepare a report and post it on the AESO website, which report must contain:

(a) an explanation of the circumstances, background and chronological events that caused and are related to the issuance of the **directive** cancelling the outage;
(b) the particulars of the outage that was cancelled, including date of cancellation, duration and MW affected;
(c) any material market impacts known to the **ISO**;

(d) whether the cancellation was a time and procedurally constrained one under subsection 9, and if so, the reasons for a decision to depart from any prescribed procedures set out in subsection 7; and
(e) any other matters that, in the **ISO**'s opinion, are necessary in order to provide a full and complete explanation to **market participants** of the decision.

Payment Eligibility for Incremental Generation Costs and Claim Limitations

11(1) Subject to this subsection 11, subsection 5.1 of section 103.4 of the **ISO rules**, *Power Pool Financial Settlement* and the definition of **incremental generation costs**, a **pool participant** or **legal owner** of a generating **source asset**, or both of them if different **persons**, that has complied with a **directive** to cancel an outage issued pursuant to subsection 6, is eligible to receive payment for **incremental generation costs** from the **ISO**.

(2) A **pool participant** or a **legal owner** who is a claimant under this subsection 11 must, within forty (40) **days** after the end of the **settlement period** related to the period during which the **directive** was effective, provide the **ISO** with a written statement which contains:
(a) the detailed information of the claim and calculation of **incremental generation costs** as incurred and caused by the cancellation, to the extent those details and calculations are known or estimable as of the date of delivery of the statement to the **ISO**; or
(b) if any detailed information or calculations are not known or estimable as of the date of delivery of the statement, an estimate of the date by which any of the outstanding information or calculations required under subsection 11(2)(a) will be finally determined and delivered to the **ISO**.

(3) A **pool participant** or a **legal owner** who is a claimant under this subsection 11 must provide the **ISO** with a supplementary written statement setting out all outstanding information or calculations as soon as reasonably practicable after the delivery of the original statement, but in any event no later than one (1) year after the end of the **settlement period** related to the period during which the cancellation **directive** was effective.

(4) A **pool participant** or a **legal owner** who is a claimant under this subsection 11 must provide to the **ISO**:
(a) any and all of its own and third party supporting data, records, invoices, formulas, calculations, third party contract claims and related terms and conditions;
(b) any other information or materials used to calculate or determine the amounts claimed in the statement or any supplementary statement; and
(c) any other detail and information the **ISO** may reasonably request

in order to verify the **incremental generation costs**, claims, calculations and particulars.

(5) The **ISO** must approve the compensation and settlement in respect of any **incremental generation costs** on or before the fortieth (40^{th}) **day** following the **day** of the receipt by the **ISO** of the last of the initial statement, supplementary statement or deficiency materials.

(6) The **ISO** must reject the portion of a claim for **incremental generation costs** related to any of the following:
(a) costs or claims related to a cancellation for which the claimant is eligible for compensation pursuant to the provisions of a **transmission must-run** contract with the **ISO**;
(b) costs or claims associated with or related to the claimant’s market or hedging portfolio, other than those allowed under subsection (iv)(d)(B) of the definition of **incremental generation costs** which limits such costs and claims to the **source asset** which is the subject of the **directive**;
(c) lost opportunity costs, or other form of loss of profits, revenue, earnings or revenue not

specifically provided for in the definition of **incremental generation costs**;

(d) raw material, fuel, processing, production, manufacturing or industrial costs of any nature which are not directly related to the **source asset**'s participation in the energy market;

(e) fixed costs; or

(f) costs or claims that the claimant could otherwise have mitigated through all reasonable efforts.

Cost Recovery

12 The **ISO** must treat the **incremental generation costs** paid to a claimant for an approved claim under subsection 11(6) as an **ancillary services** cost.

Timely Information from Legal Owner

13 A **legal owner** of a **source asset** must, if it is not the **pool participant** for that **source asset**, provide such timely and complete information to the **pool participant** for such **source asset** to enable the **pool participant** to comply with its obligations under subsections 3, 4 and 5.

Revision History

Date	**Description**
XXXX-XX-XX	Addition of timing requirement for submission of delay forced outages in subsection 4; administrative changes.
2015-04-01	The words “excluding a wind facility” were deleted from subsection 1(a).
2014-07-02	Initial release

External Consultation Draft

November 20, 2018

Applicability

1 Section 501.10 applies to:

(a) the **ISO**; and

(b) an **electricity market participant** who has requested or is receiving **system access service** under:

(i) Rate STS of the **ISO tariff**, *Supply Transmission Service*;

(ii) Rate XOS of the **ISO tariff**, *Export Opportunity Service*;

(iii) Rate IOS of the **ISO tariff**, *Import Opportunity Service*; or

(iv) Rate DOS of the **ISO tariff**, *Demand Opportunity Service*.

Requirements

Establish and Maintain Loss Factors

2(1) The **ISO** must establish and maintain a final **loss factor** for each calendar year, subject to subsection 2(4) below, for each **system access service** that an **electricity market participant** is receiving under a rate of the **ISO tariff** included in subsection 1(b) above.

(2) The **ISO** must determine the anticipated losses on the **transmission system** and the average **loss factor** for the **transmission system** for each calendar year, subject to subsection 2(4) below.

(3) The **ISO** must establish a final **loss factor** for a new **system access service** that an **electricity market participant** has requested under a rate of the **ISO tariff** included in subsection 1(b) above, as part of a **loss factor** study completed in accordance with section 4 of the **ISO tariff**, *System Access Service Requests*.

(4) The **ISO** may adjust one (1) or more final **loss factors** during a calendar year when a change has occurred to a generating, load, transmission, or other facility that is part of or is connected to the **interconnected electric system** and if as a result:

(a) the final **loss factor** for a **system access service** increases or decreases by zero point two five (0.25) or more percentage points, then the **ISO** may adjust the final **loss factor** for that **system access service**; or

(b) the average **loss factor** for the **transmission system** increases or decreases by zero point two five (0.25) or more percentage points, then the **ISO** may adjust the final **loss factors** for all **system access services** that **electricity market participants** are receiving under rates of the **ISO tariff** included in subsection 1(b) above.

Make Loss Factors Publicly Available

3(1) The **ISO** must make final **loss factors** publicly available on the AESO website no later than the fifth **business day** of November prior to the calendar year in which the **loss factors** will apply, including the dates when each **loss factor** becomes effective and ceases to be effective.

(2) The **ISO** must, when publishing final **loss factors** in accordance with subsection 3(1) above, also make publicly available on the AESO website the following information used to establish the **loss factors**:

(a) the hourly **merit order** data described in subsection 6(1) below, being the hourly **metered energy** and **operating blocks** for **source assets** and the **available transfer capability** that is not scheduled for imports over **interties**;

(b) a sample of the hourly load data described in subsection 6(2) below, being a sample of the hourly **metered energy** for **sink assets** that includes four (4) hours randomly selected from each of the following:

(i) hours in which **system load** is in its highest quartile in each **month**;

(ii) hours in which **system load** is in its lowest quartile in each **month**; and

(iii) all other hours in each **month**;

and

(c) the process for requesting access to the twelve (12) system topologies described in subsection 7 below;

(d) the *Procedure to Determine Transmission System Losses for Loss Factor Calculations* referred to in subsection 8(1) below;

(e) the software and scripts used to calculate hourly raw **loss factors** in accordance with subsection 8 below;

(f) a workbook showing the calculations from hourly raw **loss factors** to final **loss factors** in accordance with subsections 8(8), 9, 10, 11 and 12 below; and

(g) the anticipated losses on the **transmission system** and the average **loss factor** for the **transmission system** determined in subsection 2(2) above.

(3) The **ISO** must, when the final **loss factors** or other information changes in conjunction with an adjustment to a final **loss factor** in accordance with subsection 2(4) above, publish updated versions of the final **loss factors** made available in accordance with subsection 3(1) above and make publicly available updated versions of the other information described in subsection 3(2) above.

Recovery of Cost of Transmission System Losses

4(1) The **ISO** must reasonably recover the cost of losses on the **transmission system** by using the final **loss factor** for each **system access service** that an **electricity market participant** receives under a rate of the **ISO tariff** included in subsection 1(b) above, as specified in the applicable rate of the **ISO tariff**.

(2) The **ISO** must reasonably recover the cost of losses on the **transmission system**, excluding **interties**, by using the final **loss factors** applied under Rate STS, Rate IOS and Rate DOS of the **ISO tariff**.

(3) The **ISO** must reasonably recover the cost of losses on an **intertie** that is not a merchant **intertie** by using the final **loss factors** applied under Rate XOS and Rate IOS of the **ISO tariff** over that **intertie**.

(4) The **ISO** must adjust final **loss factors** to ensure that the actual cost of losses is reasonably recovered on an annual basis through the use of Rider E of the **ISO tariff**, *Losses Calibration Factor Rider*.

Location at Which Loss Factors Are Determined

5(1) The **ISO** must establish a final **loss factor** for each location that is:

(a) a **point of supply** for **system access service** provided under Rate STS;

(b) a point where an **intertie** connects to the remainder of the **interconnected electric system** for **system access service** provided under Rate XOS or Rate IOS over that **intertie**; or

(c) a **point of delivery** for **system access service** provided under Rate DOS.

(2) An **electricity market participant** must, subject to subsection 5(4) below, ensure that all **generating units** and **aggregated generating facilities** connected to the **transmission system** through a single location under subsection 5(1)(a) above:

(a) are owned or controlled, managed, and operated by the same entity;

(b) are part of a single economic enterprise or undertaking and not independent, standalone businesses; and

(c) have energy submitted in the energy market as part of the price-quantity **offers** for a single **source asset**, where that **source asset** does not include any other **generating unit** or **aggregated generating facility**.

(3) An **electricity market participant** must, when ensuring it meets the requirements of subsection 5(2) above, consider that:

(a) all **generating units** that are part of a single industrial system that has been designated as such by the **Commission** satisfy the single owner and single enterprise requirements of subsections 5(2)(a) and 5(2)(b) above;

(b) all **generating units** and **aggregated generating facilities** that are connected to part of an **electric distribution system** that receives **system access service** under subsection 5(1)(a) above satisfy the single owner, single enterprise, and single **source asset** requirements of subsection 5(2) above, including any of those **generating units** and **aggregated generating facilities** that have energy submitted in the energy market as a separate **source asset**;

(c) all **generating units** and **aggregated generating facilities** that are connected to the **electric distribution system** or **transmission facilities** owned by the City of Medicine Hat satisfy the single owner, single enterprise, and single **source asset** requirements of subsection 5(2) above, including any of those **generating units** and **aggregated generating facilities** that have energy submitted in the energy market as a separate **source asset**;

(d) all **generating units** that are subject to **power purchase arrangements** and are held by a single **power purchase arrangement** buyer satisfy the single owner and single enterprise requirements of subsection 5(2)(a) and 5(2)(b) above;

(e) a single **generating unit** that is subject to a **power purchase arrangement** and is held by more than one **power purchase arrangement** buyer satisfies the single owner and single enterprise requirements of subsection 5(2)(a) and 5(2)(b) above; and

(f) **generating units** that are subject to **power purchase arrangements** and are held by different **power purchase arrangement** buyers do not satisfy the single owner or single enterprise requirements of subsection 5(2)(a) and 5(2)(b) above, including any of those **generating units** that are subject to common **offer** control.

(4) An **electricity market participant** may, notwithstanding subsection 5(2) above, continue the connection of **generating units** to the **transmission system** in the following configurations that existed on December 31, 2016:

(a) for the connection of multiple hydro **generating units** owned by TransAlta Corporation on the Bow River system upstream of Calgary, Alberta, at eleven (11) locations that are **points of supply** for **system access service** provided under Rate STS and have energy submitted in the energy market in aggregate as a single **source asset**;

(b) for the connection of multiple **generating units** that are part of the Suncor Energy Inc. industrial system in the area of Fort McMurray, Alberta, at a single location that is a **point of supply** for **system access service** provided under Rate STS and have energy submitted in the energy market as three (3) **source assets**;

(c) for the connection of multiple **generating units** that are part of the Imperial Oil Resources Limited industrial system in the area of Cold Lake, Alberta, at a single location that is a **point of supply** for **system access service** provided under Rate STS and have energy submitted in the energy market as two (2) **source assets**; and

(d) for the connection of multiple **generating units** that are part of the Shell Canada Limited Scotford industrial system in the area of Fort Saskatchewan, Alberta, at a single location that is a **point of supply** for **system access service** provided under Rate STS and have energy submitted in the energy market as two (2) **source assets.**

(5) An **electricity market participant** may request, no more than once each calendar year, a change to the configuration of **generating units** or **aggregated generating facilities**:

(a) for:

(i) the aggregation of **generating units** and **aggregated generating facilities** that are currently connected to the **transmission system** through multiple locations; or

(ii) the disaggregation of **generating units** and **aggregated generating facilities** that are currently connected to the **transmission system** through a single location;

(b) while ensuring that the single owner, single enterprise, and single **source asset** requirements of subsections 5(2)(a), 5(2)(b), and 5(2)(c) above will continue to be satisfied; and

(c) by contacting the **ISO** no later than March 31 prior to the calendar year in which the **loss factors** will apply.

(6) The **ISO** must respond to a request under subsection 5(5) within sixty (60) calendar **days** by:

(a) approving the request in writing and proceeding to work with the **electricity market participant** to implement, on a best efforts basis, prior to the calendar year in which the **loss factors** will apply, any changes to **metering equipment**, **transmission facilities**, **system access service** agreements, or **source assets** required for the aggregation or disaggregation; or

(b) denying the request in writing, with reasons, which may include constraints on resources of the **ISO** or the **legal owner** of a **transmission facility** to implement changes to **metering equipment** or **transmission facilities** required for the aggregation or disaggregation.

(7) The **electricity market participant** must pay the following costs if incurred to implement an aggregation or disaggregation:

(a) any costs incurred by a **legal owner** of a **transmission facility** related to changes to **metering equipment** or **transmission facilities**;

(b) any costs required to comply with applicable provisions of the *AESO Measurement System Standard* or applicable **ISO rules**, for any measurement point associated with the aggregation or disaggregation;

(c) any costs required by applicable provisions of the **ISO tariff**, including provisions of sections 9 and 10 of the **ISO tariff**, *Changes to System Access Service After Energization* and *Generating Unit Owner's Contribution*; and

(d) any costs required to maintain compliance with any other applicable provisions of the **ISO rules**, **reliability standards**, or **ISO tariff.**

Data Used to Calculate Loss Factors

6(1) The **ISO** must calculate **loss factors** using hourly historical metered volume and **merit order** data for all **source assets** connected to the **transmission system**, for the calendar year for which **loss factors** are being determined, by:

(a) using hourly historical data for the calendar year two (2) years prior to the calendar year for which **loss factors** are being determined;

(b) including, in the following order, the following volumes for each **source asset**, including for the eleven (11) locations at which hydro **generating units** on the Bow River system are connected to the **transmission system**:

(i) all **metered energy** for **source assets** that do not submit price-quantity **offers** in the energy market;

(ii) all dispatched **operating blocks** for **source assets** that submit price-quantity **offers** in the energy market, in **merit order** first by price and then by size;

(iii) all undispatched **operating blocks** offered in the energy market for **source assets** that submit price-quantity **offers** in the energy market, in **merit order** first by price and then by size;

(iv) all volumes for **source assets** that the **ISO** accepts for **dispatch** for **contingency reserve**, in **merit order** first by price and then by size; and

(v) all **available transfer capability** which is not scheduled for imports over **interties**;

(c) incorporating any new **source asset** not included in the historical data but which has an expected in-service date by the end of the calendar year for which **loss factors** are being determined, by assigning such new **source asset** an hourly data profile after its expected in-service date reflecting the hourly data profile that is, for the same period:

(i) the average of all **source assets** of the same technology owned by the same **electricity market participant** in the historical data;

(ii) if no **source asset** of the same technology is owned by the same **electricity market participant** in the historical data, the average of all **source assets** of the same technology owned by any **electricity market participant** in the historical data; and

(iii) if no **source asset** of the same technology is owned by any **electricity market participant** in the historical data, determined by the **ISO** in conjunction with the **legal owner** of the new **source asset.**

and

(d) excluding any **source asset** during a **month** when, for the entirety of that **month** of the calendar year for which **loss factors** are being determined:

(i) the **electricity market participant** has notified the **ISO** that the **source asset** is planned to be subject to a **mothball outage** or a **planned outage**; or

(ii) the **system access service** for the **source asset** is planned to have been terminated.

(2) The **ISO** must calculate **loss factors** using hourly historical **metered energy** data for all **sink assets** connected to the **transmission system**, for the calendar year for which **loss factors** are being determined, by:

(a) using hourly historical data for the calendar year two (2) years prior to the calendar year for which **loss factors** are being determined;

(b) including all **metered energy** for each **sink asset**;

(c) incorporating any new **sink asset** not included in the historical data but which has an expected in-service date by the end of the calendar year for which **loss factors** are being determined, by assigning such new **sink asset** an hourly data profile reflecting the average hourly data profile of all **sink assets** included in the historical data after the expected in-service date of the new **sink asset**;

(d) excluding any **sink asset** during a **month** when, for the entirety of that **month** of the calendar year for which **loss factors** are being determined, the **system access service** for the **sink asset** is planned to have been terminated; and

(e) prorating all hourly **metered energy** for **sink assets** included in subsection 6(2)(b) above such that the total of the **metered energy** from the prorated **sink assets** plus the **metered energy** from the unprorated new **sink assets** included in subsection 6(2)(c) above is equal to the forecast **system load** annual volume for the calendar year for which **loss factors** are being determined.

System Topologies Used to Calculate Loss Factors

7(1) The **ISO** must create twelve (12) system topologies that represent the **transmission system** in each of the twelve (12) **months** of the calendar year for which **loss factors** are being determined.

(2) The **ISO** must, subject to subsections 7(3) and 7(4) below, include in each system topology all **transmission facilities** that the **ISO** reasonably expects to be in service before or on the last **day** of the **month** for which the system topology is created, based on the project queue most recently published by the **ISO** when the twelve (12) system topologies are created.

(3) The **ISO** must, subject to subsection 7(4) below, include in a system topology the **transmission facilities** that meet the in-service date criterion in subsection 7(2) above only when:

(a) for existing **transmission facilities**, the **transmission facilities**:

(i) are in service under normal operation when the system topologies are created; and

(ii) are not included in a plan approved by the **Commission** for decommissioning before the first **day** of the **month** for which the system topology is created;

(b) for proposed system **transmission facilities**, being **transmission facilities** that the **ISO** determines will benefit many **electricity market participants**, the **Commission** has issued a permit and licence for the **transmission facilities** before the system topologies are created;

(c) for a proposed connection project or **electricity market participant** choice project that requires construction of a new substation or transmission line:

(i) the **Commission** has issued a permit and licence for the **transmission facilities** before the system topologies are created; and

(ii) if required by the **ISO tariff**, the **electricity market participant** has paid a **generating unit** owner's contribution before the system topologies are created;

(d) for a proposed connection project that only requires construction at an existing substation:

(i) the **legal owner** of the **transmission facilities** has filed a facility application with the **Commission** before the system topologies are created; and

(ii) if required by the **ISO tariff**, the **electricity market participant** has paid a **generating unit** owner's contribution before the system topologies are created;

(e) for a proposed behind-the-fence project that does not require construction of **transmission facilities**:

(i) the **ISO** has, after completion of the functional specification stage of the connection process, issued an acknowledgement letter before the system topologies are created;

(ii) if required by the **ISO tariff**, the **electricity market participant** has paid a **generating unit** owner's contribution before the system topologies are created; and

(iii) if required by the *Hydro and Electric Energy Act*, the **electricity market participant** has filed a power plant application with the **Commission** before the system topologies are created;

and

(f) for a proposed **contract capacity** change project that does not require construction of **transmission facilities**, the **electricity market participant** has, after the **ISO** completes any required studies and calculations, acknowledged the **ISO**'s **construction contribution** decision before the system topologies are created.

(4) Notwithstanding subsections 7(2) and 7(3) above, the **ISO** may exclude or include a **transmission facility**, **source asset** or **sink asset** in a system topology if the **ISO** reasonably expects that the in-service date of the **transmission facility**, **source asset** or **sink asset** will differ from that provided in the project queue on which the system topologies are based.

(5) The **ISO** must replace this subsection 7 to be effective no later than the fifth business **day** of November in 2018, unless the replacement subsection 7 is then subject to a **Commission** proceeding.

Calculation of Hourly Loss Factors

8(1) The **ISO** must calculate hourly raw **loss factors** for each location included in subsection 5(1) above for **system access service** provided under Rate STS, Rate IOS or Rate DOS for the calendar year for which **loss factors** are being determined, using:

(a) an incremental **loss factor** methodology with **merit order** redispatch as described in this subsection 8 and which calculates, for a **pool asset** in an hour:

(i) first, **transmission system** losses using the historical volume for that **pool asset**, in subsection 8(4) below;

(ii) second, **transmission system** losses after removing the **pool asset**'s volume and replacing it by redispatching other assets, using the historical **merit order** for the hour, in subsection 8(5) below; and

(iii) third, the hourly raw **loss factor** as the difference between **transmission system** losses calculated in subsections 8(1)(a)(i) and 8(1)(a)(ii) above, divided by the **pool asset**'s historical volume in the hour, in subsection 8(6) below;

and

(b) the *Procedure to Determine Transmission System Losses for Loss Factor Calculations*, as published by the **ISO** on the AESO website and as amended from time to time by the **ISO** on notice to **electricity market participants**.

(2) The **ISO** must, when calculating a raw **loss factor** for an hour under this subsection 8, use:

(a) the historical metered volume and **merit order** data for all **source assets** for that hour as described in subsection 6(1) above;

(b) the historical **metered energy** data for all **sink assets** for that hour as described in subsection 6(2) above; and

(c) the system topology for the **month** in which that hour occurs as described in subsection 7 above.

(3) The **ISO** must, when calculating **transmission system** losses under this subsection 8, exclude any losses that occur on:

(a) a **transmission facility** that is owned and operated by an **electricity market participant** as part of its connection to the **transmission system** for **system access service**, including a **transmission facility** that is within an industrial system that has been designated as such by the **Commission**; or

(b) an **intertie**.

(4) The **ISO** must, unless it is not possible, calculate **transmission system** losses for an initial state for each hour of the calendar year for which **loss factors** are being determined, based on:

(a) the volumes for **metered energy** and dispatched **operating blocks** included in subsections 6(1)(b)(i), 6(1)(b)(ii), and 6(2)(b) above, as applicable, for that hour; and

(b) balancing total supply to total load plus **transmission system** losses in that hour by either:

(i) increasing the volume for undispatched **operating blocks**, **contingency reserve** and **available transfer capability** which is not scheduled from one (1) or more **source assets**, in the order described in subsection 6(1)(b) above; or

(ii) decreasing the volume for **metered energy** and dispatched **operating blocks** in the order described in subsection 6(1)(b) above.

(5) The **ISO** must, unless it is not possible, calculate **transmission system** losses for a redispatched state for each hour of the calendar year for which **loss factors** are being determined:

(a) for each location for **system access service** provided under Rate STS or Rate IOS, based on:

(i) reducing the volume for **metered energy** or dispatched **operating blocks** for the location such that net supply to the **transmission system** is zero (0) while the facilities of the **electricity market participant** remain connected for the applicable **system access service**; and

(ii) increasing the volume for undispatched **operating blocks**, **contingency reserve** and **available transfer capability** which is not scheduled from one (1) or more **source assets**, in the order described in subsection 6(1)(b) above, such that total supply balances the total load plus **transmission system** losses with the net supply to the **transmission system** set to zero (0) for the applicable **system access service**;

and

(b) for each location for **system access service** provided under Rate DOS, based on:

(i) reducing the volume for **metered energy** for the location such that net demand from the **transmission system** reflects the Rate DTS **contract capacity** for the applicable **system access service**; and

(ii) decreasing the volume for **metered energy** and dispatched **operating blocks** from one or more **source assets**, in the order described in subsection 6(1)(b) above, such that total supply balances the total load plus **transmission system** losses with the net demand from the **transmission system** reflecting the Rate DTS **contract capacity** for the applicable **system access service**.

(6) The **ISO** must, unless it is not possible, calculate the raw **loss factor**, in percent, for each location for **system access service** provided under Rate STS, Rate IOS or Rate DOS, for each hour of the calendar year for which **loss factors** are being determined, by dividing:

(a) the difference between:

(i) the **transmission system** losses for the initial state calculated in subsection 8(4) above; and

(ii) the **transmission system** losses for the redispatched state calculated in subsection 8(5) above;

by:

(b) the amount by which the volume for **metered energy** or dispatched **operating blocks** for the location was reduced or increased in the redispatched state in subsection 8(5) above.

(7) The **ISO** must exclude an hour from the calculations in subsections 8(8) through 11 below to determine final **loss factors** for all locations if, for any location in that hour, it is not possible to calculate **transmission system** losses for either the initial state in subsection 8(4) above or the redispatched state in subsection 8(5) above for any reason, including:

(a) missing or otherwise unavailable historical data for every **source asset** or every **sink asset** connected to the **transmission system** during that hour; or

(b) insufficient **source assets** to balance the **transmission system** in either the initial state in subsection 8(4) above or the redispatched state in subsection 8(5) above.

(8) The **ISO** must exclude an hour from the remaining calculations to determine a final **loss factor** for a single location if, for that location in that hour:

(a) for **system access service** provided under Rate STS or Rate IOS, the volume for **metered energy** or dispatched **operating blocks** for the location results in a net supply to the **transmission system** of less than 1.00 MW;

(b) for **system access service** provided under Rate DOS, the volume for **metered energy** for the location results in a net demand to the **transmission system** of less than 1.00 MW; or

(c) it is not possible to calculate, with reasonable effort, **transmission system** losses for either the initial state in subsection 8(4) above or the redispatched state in subsection 8(5) above.

(9) The **ISO** must, for each hour of the calendar year for which **loss factors** are being determined and which has not been excluded under subsection 8(7) above, add to or subtract from the hourly raw **loss factor** for each location a single hourly shift factor, in percent, such that the hourly shifted **loss factors** recover the **transmission system** losses calculated for the initial state in that hour in subsection 8(4) above, excluding any losses that occur on an **intertie**.

Calculation of Annual Loss Factors

9(1) The **ISO** must, subject to subsection 9(2) below, calculate an annual average **loss factor**, in percent, for each location included in subsection 5(1) above for **system access service** provided under Rate STS, Rate IOS or Rate DOS for the calendar year for which **loss factors** are being determined as the average of the shifted hourly **loss factors** calculated in subsection 8(9) above, weighted by the amount by which the volume for **metered energy** or dispatched **operating blocks** for the location was reduced or increased in each hour in the redispatched state in subsection 8(5) above.

(2) The **ISO** must, where all hours of the calendar year for which **loss factors** are being determined for a location have been excluded under subsections 8(7) and 8(8) above, use the following as the annual average **loss factor** for that location:

(a) the annual average **loss factor** calculated for the location for the year prior to the calendar year for which **loss factors** are being determined; or

(b) if no annual average **loss factor** was calculated for the location for the prior year, the average annual **loss factor** for the **transmission system** determined in subsection 2(2) above for the calendar year for which **loss factors** are being determined.

(3) The **ISO** must add to or subtract from the annual average **loss factor** for each location a single annual shift factor, in percent, such that the annual shifted **loss factors** recover the total **transmission system** losses forecast for the calendar year for which **loss factors** are being determined, excluding any losses that occur on an **intertie**.

(4) The **ISO** must use the annual shifted **loss factor** calculated in subsection 9(3) above as the uncompressed annual **loss factor**, in percent, for each location for **system access service** provided under Rate STS or Rate DOS for the calendar year for which **loss factors** are being determined.

Loss Factors for Interties

10(1) The **ISO** must calculate an uncompressed annual **loss factor**, in percent, for each location for **system access service** provided under Rate XOS over an **intertie** that is not a merchant **intertie**, that represents the average level of losses incurred in exporting electric energy over that **intertie**.

(2) The **ISO** must calculate an uncompressed annual **loss factor**, in percent, for each location for **system access service** provided under Rate IOS for an **intertie** that is not a merchant **intertie** for the calendar year for which **loss factors** are being determined, that is the sum of:

(a) the annual shifted **loss factor** calculated under subsection 9(3) above for **system access service** provided under Rate IOS over that **intertie**; and

(b) an additional **loss factor** that represents the average level of losses incurred in importing electric energy over that **intertie**.

(3) The **ISO** must use the annual shifted **loss factor** calculated in subsection 9(3) above as the uncompressed annual **loss factor**, in percent, for each location for **system access service** provided under Rate IOS over a merchant **intertie** for the calendar year for which **loss factors** are being determined.

(4) The **ISO** must calculate **loss factors** under subsections 10(1) and 10(2)(b) above based on historical data for the calendar year two (2) years prior to the calendar year for which **loss factors** are being determined, for net flow over each **intertie** that is not a merchant **intertie**.

Compressed Loss Factors

11(1) The **ISO** must use the uncompressed annual **loss factors** calculated under subsections 9(4) and 10 above for all locations included in subsection 5(1) above, if no uncompressed annual **loss factor** is a charge that exceeds 12.00% or a credit that exceeds 12.00%.

(2) The **ISO** must, if any uncompressed annual **loss factor** calculated under subsections 9(3) or 10 above is a charge that exceeds 12.00% or a credit that exceeds 12.00%, compress the **loss factors** by:

(a) estimating the single compression shift factor, in percent, that would need to be added to or subtracted from each uncompressed annual **loss factor** to address any loss recovery imbalance that would result from clipping each uncompressed annual **loss factor** that is:

(i) a charge that exceeds 12.00% to a charge equal to 12.00%; and

(ii) a credit that exceeds 12.00% to a credit equal to 12.00%;

(b) adding to or subtracting from each uncompressed annual **loss factor** the single compression shift factor estimated in subsection 11(2)(a) above and clipping each resulting compressed annual **loss factor** that is:

(i) a charge that exceeds 12.00% to a charge equal to 12.00%; and

(ii) a credit that exceeds 12.00% to a credit equal to 12.00%;

and

(c) if the loss recovery imbalance in subsection 11(2)(a) is not fully addressed by the compressed and clipped **loss factors** resulting from subsection 11(2)(b) above, adjusting the single compression shift factor used in subsection 11(2)(b) above, through multiple iterations if necessary, until the compression shift factor addresses any remaining loss recovery imbalance.

Final Loss Factors

12 The **ISO** must establish the **loss factor** calculated under subsection 11(1) or 11(2) above as the final **loss factor**, in percent, for each location included in subsection 5(1) above for **system access service** provided under Rate STS, Rate XOS, Rate IOS or Rate DOS for the calendar year for which **loss factors** are being determined.

Revision History

Date	Description
XXXX-XX-XX	Revision to clarify “**market participant**” as “**electricity market participant**”.
2017-12-07	Revised subsection 7.
2017-01-01	Revised to reflect directions, findings and guidance in Commission Decision

	790-D03-2015.
2013-10-25	Updated to reflect new ISO tariff rate schedule Rate XOM which is related to the MATL energization and other incidental amendments.
2012-10-10	Initial release.

External Consultation Draft
November 20, 2018

Applicability

1 Subject to subsections 2 and 3 below, section 502.8 applies to:

(a) the **legal owner** of a **generating unit,** an **aggregated generating facility**, or an **energy storage facility** that has a **gross real power** capability equal to or greater than 5 MW and is:

(i) connected to the **interconnected electric system** or an electric system in the service area of the City of Medicine Hat, including by way of connection to an **electric distribution system**;

(ii) part of an industrial complex connected to the **transmission system**; or

(iii) providing, or part of a facility providing, **ancillary services**;

(b) the **legal owner** of a **transmission facility** connected to the **transmission system** or **transmission facilities** in the service area of the City of Medicine Hat;

(c) the **legal owner** of a load that is:

(i) connected to the **transmission system**;

(ii) connected to **transmission facilities** in the service area of the City of Medicine Hat;

(iii) part of an industrial complex; or

(iv) providing **ancillary services**; and

(e) the **ISO**.

2 The **legal owner** of a **generating unit**, **aggregated generating facility**, **transmission facility, energy storage facility**, or a load that is energized and commissioned on or after April 7, 2017 must ensure the facility meets the minimum supervisory control and data acquisition requirements of this section 502.8 and, where applicable, verify to the **ISO** that the facility meets those requirements during **commissioning** and energization.

3(1) Subject to subsection 3(3), the provisions of this section 502.8 do not apply to the **legal owner** of a **generating unit**, **aggregated generating facility**, **transmission facility**, **energy storage facility**, or a load that was energized and commissioned prior to April 7, 2017 in accordance with a previous technical requirement, technical standard, **ISO rule** or functional specification, but the **legal owner** of such an existing **generating unit**, **aggregated generating facility**, **transmission facility**, or a load must remain compliant with all the standards and requirements set out in that previous technical requirement, technical standard, **ISO rule** or functional specification.

(2) Notwithstanding subsection 3(1), the **ISO** may require the **legal owner** of a **generating unit**, **aggregated generating facility**, **transmission facility**, **energy storage facility,** or a load to comply with any specific provision or all of the provisions of this section 502.8, if the **ISO** determines that such compliance is necessary for the safe and reliable operation of the **interconnected electric system**.

(3) Notwithstanding subsection 3(1), the **legal owner** of a **generating unit**, **transmission facility**, **aggregated generating facility**, **energy storage facility**, or a load must comply with the provisions of this section 502.8 if:

(a) it modifies its facilities after April 7, 2017 to:

(i) increase its Rate DTS or Rate STS contract capacity; or

(ii) upgrade or alter the functionality of its supervisory control and data acquisition system; and

(b) the **ISO** determines that such compliance is necessary for safe and reliable operation of the **interconnected electric system**.

Functional Specification

4(1) The **ISO** may issue a written functional specification containing details, work requirements and specifications for the design, construction and operation of a supervisory control and data acquisition system for the facility.

(2) The functional specification referred to in subsection 4(1) must be generally consistent with the provisions of this section 502.8 but may contain material variances the **ISO** approves of based upon its discrete analysis of any one (1) or more of the technical, economic, safety, operational and **reliability** requirements related to the specific system or connection project.

Use of the Term Legal Owner

5(1) Unless specified otherwise, where the term "**legal owner**" is used below it includes the **legal owner** of a **generating unit**, an **aggregated generating facility**, a **transmission facility**, an **energy storage facility**, or a load.

Supervisory Control and Data Acquisition Requirements

6(1) The **legal owner** of a synchronous **generating unit** must meet the supervisory control and data acquisition requirements set out in Appendix 1, *SCADA Requirements for Synchronous Generating Units*.

(2) The **legal owner** of a wind or solar **aggregated generating facility** must meet the supervisory control and data acquisition requirements set out in Appendix 2, *SCADA Requirements for Wind or Solar Aggregated Generating Facilities*.

(3) The **legal owner** of a **energy storage facility** must meet the supervisory control and data acquisition requirements set out in Appendix 3, *SCADA Requirements for Energy Storage Facilities*.

(4) The **legal owner** of a **generating unit** that is part of an industrial complex and the **legal owner** of a load must meet the supervisory control and data acquisition requirements set out in Appendix 4, *SCADA Requirements for Industrial Complexes and Load*.

(5) The **legal owner** of a **transmission facility** must meet the supervisory control and data acquisition requirements set out in Appendix 5, *SCADA Requirements for Transmission Facilities*, if at least one (1) of the following criteria is met:

(a) the substation contains two (2) or more buses operated above 60 kV nominal voltage;

(b) the substation contains one (1) or more buses operated above 200 kV nominal voltage;

(c) the substation contains a capacitor bank, reactor, static VAr compensator or synchronous condenser rated 5 MVAr or greater;

(d) the substation connects three (3) or more transmission lines above 60 kV;

(e) the substation supplies local site load, with normally energized site load equipment rated at 5 MVA or greater that are offered for **ancillary services** or are included in **remedial action schemes**;

(f) the substation supplies local site load with normally energized site load equipment rated at 10 MVA or greater;

(g) the substation supplies **supplemental reserve** load of 5 MVA or greater; or

(h) the substation supplies system load that is part of a **remedial action scheme**.

(6) The **legal owner** of a **generating unit**, the **legal owner** of an **aggregated generating facility**, the **legal owner** of an **energy storage facility**, or the **legal owner** of a load must, if they provide **ancillary services**, meet the supervisory control and data acquisition requirements for **ancillary services** set out in Appendix 6, *SCADA Requirements for Ancillary Services*.

(7) The **ISO** must meet the supervisory control and data acquisition requirements set out in:

(i) Appendix 2, *SCADA Requirements for Wind or Solar Aggregated Generating Facilities*; and

(ii) Appendix 6, *SCADA Requirements for Ancillary Services*.

Separate Meters

7 A **legal owner** must gather supervisory control and data acquisition data using a device that is independent from a revenue meter.

Data Acquisition

8(1) The **ISO** must initiate all supervisory control and data acquisition communications with a **legal owner**'s equipment directly connected to the **ISO**'s equipment to acquire supervisory control and data acquisition data from a **legal owner** and must do so using the following means:

(a) periodic scans; or

(b) report-by-exception polls.

(2) The **ISO** must configure the **ISO**'s communications device to be the "master" device.

(3) A **legal owner** must configure its communication device to be the "slave" device using the appropriate addressing the **ISO** assigns.

(4) The **ISO** must, if it initiates communications with a **legal owner** using report-by-exception polls, configure and acquire the supervisory control and data acquisition data so that the data value falls within the allowable deadbands set out in Table 1 below:

Table 1

Value	Allowable Deadband
MW	0.5 MW from 0 to 200 MW, 1.0 MW above 200 MW
MVAr	0.5 MVAR from 0 to 200 MVAr, 1.0 MVAr above 200 MVAr
kV	0.1 kV from 0 to 20 kV, 0.5 kV above 20 kV

(5) A **legal owner** must, if it is providing analog values to the **ISO**, provide those values with at least one (1) decimal place accuracy unless otherwise specified in the attached appendices.

(6) A **legal owner** must ensure that the transducer is scaled such that the maximum, full scale, value returned is between 120% and 200% of the nominal equipment rating.

(7) The **legal owner** of a **generating unit** that uses a mode of operation of either a synchronous condenser or motor, must ensure that the minimum, full scale, values are between 120% and 200% of the lowest operating condition.

(8) A **legal owner** must report supervisory control and data acquisition data relating to power flows with the sign convention of positive power flow being out from a bus, except in situations where source measurements are positive polarity.

(9) Notwithstanding subsection 8(8), a **legal owner** must report:

(a) MVAr measurements from a reactor as negative polarity;

(b) MW and MVAr measurements from a **collector bus** as positive polarity; and

(c) MVAr measurements from a capacitor as positive polarity.

(10) A **legal owner** must, if installing a global positioning system clock as required in a functional specification, use the coordinated universal time as the base time where the base time is the universal time code minus seven (7) hours.

(11) A **legal owner** must ensure that its global positioning system clock functionality provides for one (1) millisecond time stamped event accuracy and can automatically adjust for seasonal changes to daylight savings time.

Supervisory Control and Data Acquisition Communications

9(1) A **legal owner** must implement one (1) of the following communication methods between its facility and the **ISO**:

(a) an internet connection, if the **legal owner** has a latency time requirement of thirty (30) seconds or greater; or

(b) a dedicated telecommunications link, if the **legal owner** has a latency time requirement of less than thirty (30) seconds.

(2) A **legal owner** must provide and maintain a connectivity point and data communication to both the **ISO**'s primary system coordination centre and the **ISO**'s backup system coordination centre.

(3) The **ISO** must provide and maintain a connectivity point to the **legal owner**'s facility at both the **ISO**'s primary system coordination centre and the **ISO**'s backup system coordination centre.

(4) The **legal owner** of a **generating unit**, an **aggregated generating facility**, an **energy storage facility**, or a load must, if it owns a facility with the capability of combined load and generation greater than 1000 MW, provide two (2) communication circuits to each of the **ISO**'s primary system coordination centre and the **ISO**'s backup system coordination centre and to each of the **legal owner**'s primary and backup communication centres.

(5) A **legal owner** of a **generating unit**, an **aggregated generating facility**, an **energy storage facility**, or a load must, when providing **ancillary services**, send supervisory control and data acquisition data to each of the **ISO**'s primary system coordination centre and the **ISO**'s backup system coordination centre.

(6) A **legal owner** must, based on the **ISO**'s generic communication block diagrams and prior to connecting facilities to the **interconnected electric system** or an electric system in the service area of the City of Medicine Hat, indicate to the **ISO** the generic communication block diagram that depicts the communication protocols between the **legal owner**'s facility and the **ISO**'s system coordination centre, with any variations as appropriate.

(7) A **legal owner** must, if it changes the communication protocols used between itself and the **ISO**, communicate these changes to the **ISO** in writing ninety (90) **business days** prior to changing the protocols.

Notification of Unplanned Availability

10(1) A **legal owner** must, if any component in the communication circuit becomes unavailable due to an unplanned event, notify the **ISO** as soon as practicable, in writing, after determining such unavailability due to equipment failure.

(2) The **ISO** may, following receipt of the notification in 10(1), require the **legal owner** to discontinue the provision of **ancillary services**.

(3) A **legal owner** must provide the **ISO** as soon as practicable, in writing:

(a) the cause of any unavailability reported pursuant to subsection 10(1);

(b) in the event of an equipment failure, a plan, acceptable to the **ISO**, to repair the failed equipment, including testing; and

(c) the expected date when the equipment will be repaired and the required measurements will be restored.

(4) The **legal owner** must, if the equipment is not repaired and required measurements are not restored by the expected date, notify the **ISO** as soon as practicable, in writing, with the revised date and the reason why the communication system was not repaired.

(5) The **legal owner** must notify the **ISO** once the equipment is repaired and the required measurements are restored.

Suspected Failure or Erroneous Data of a Remote Terminal Unit

11(1) A **legal owner** must, if it suspects that a remote terminal unit has failed or is providing erroneous data, notify the **ISO** as soon as practicable, in writing, after identifying the failure or data error.

(2) The **ISO** must, if it suspects that a remote terminal unit has failed or is providing erroneous data, notify the **legal owner** as soon as practicable, after identifying the failure or data error.

(3) The **legal owner** must provide the **ISO** as soon as practicable, in writing, with the date it expects to test the remote terminal unit.

(4) The **legal owner** must, if it is unable to test the remote terminal unit on the expected date provided under subsection 11(3), provide the **ISO** as soon as practicable, in writing, with the revised date.

(5) The **legal owner** must, after testing the remote terminal unit, confirm if there is a problem with the remote terminal unit or not and notify the **ISO** as soon as practicable, in writing, with the results of the test.

(6) The **legal owner** must, if the results of the test indicated that the remote terminal unit has actually failed, provide the **ISO** as soon as practicable, in writing, with a plan acceptable to the **ISO** to repair the failed remote terminal unit and the date by which that the **legal owner** expects to repair or replace the remote terminal unit.

(7) The **legal owner** must, if the remote terminal unit is not repaired or replaced by the date provided under subsection 11(6), notify the **ISO** as soon as practicable, in writing, with the revised date.

(8) The **legal owner** must notify the **ISO** as soon as practicable, in writing, once the remote terminal is repaired or replaced.

Exceptions

12 A **legal owner** is not required to comply with the specific supervisory control and data acquisition submission requirements of this section 502.8 applicable to a particular device:

(a) that is being repaired or replaced in accordance with a plan acceptable to the **ISO** under subsections 10 or 11; and

(b) the **legal owner** is using reasonable efforts to complete such repair or replacement in accordance with that plan.

Appendices

Appendix 1 – *SCADA Requirements for Generating Units*

Appendix 2 - *SCADA Requirements for Wind or Solar Aggregated Generating Facilities*

Appendix 3 - *SCADA Requirements for Energy Storage Facilities*

Appendix 4 - *SCADA Requirements for Industrial Complexes and Load*

Appendix 5 - *SCADA Requirements for Transmission Facilities*

Appendix 6 - *SCADA Requirements for Ancillary Services*

Revision History

Date	Description
xxxx-xx-xx	Revised to include requirements for an energy storage facility.Added Appendix 3. Addition of trip status indicator for LSSi in Appendix 6. Clarification of point descriptions in Appendices
2018-09-01	Revised applicability section; clarified which requirements are applicable to synchronous generating units; added requirements for a distribution connected aggregated generating facility; added additional SCADA requirements for wind aggregated generating facilities to Appendix 2; and added SCADA requirements for solar aggregated generating facilities to Appendix 2.
2015-03-27	Replaced “effective date” with the initial release date in sections 2 and 3; and replaced the word “Effective” in the Revision History to “Date”.
2014-12-23	Appendix 1 amended by combining the two lines concerning generating unit

	automatic voltage regulation into one line. Appendix 5 amended reflect that the regulating reserve set point signal is sent by ISO every 4 seconds, not every 2 seconds. Appendix 5 amended to include the measurement point for load when providing spinning reserve.
2013-02-28	Initial Release

Appendix 1 – SCADA Requirements for Synchronous Generating Units

Facility/ Service Description	Signal Type	Point Description	Parameter		Accuracy Level	Resolution	Latency and Availability Requirements Based on Maximum Authorized Real Power					
							Maximum authorized real power less than 50 MW		Maximum authorized real power equal to or greater than 50 MW and less than 300 MW		Maximum authorized real power equal to or greater than 300 MW	
							Latency	Availability (%)	Latency	Availability (%)	Latency	Availability (%)
For each power plant	Status	Communications failure alarm from remote terminal unit acting as a data concentrator for one or more **generating units** to a **transmission facility control centre** (if applicable)	0 = Normal	1= Alarm	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Communications failure indication between an intelligent electronic device and any remote terminal unit acting as a data concentrator	0 = Normal	1= Alarm								
For each synchronous **generating unit** directly connected to the **transmission system** or **transmission facilities** in the service area of Medicine Hat.	Analog	**Gross real power** as measured at the stator winding terminal	MW		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time repair is to 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Gross **reactive power** as measured at the stator winding terminal	MVAr									
		Generating unit voltage at the generator stator winding terminal or equivalent bus voltage	kV									
		Unit frequency as measured at the stator winding terminal or equivalent bus frequency	Hertz		+/- 0.01 Hz	0.01 Hz						
		Net **real power** as measured on the high side terminal of the **transmission system** step up transformer	MW		+/- 2% of full scale	0.5% of the point being monitored						
		Net **real power** of summated generation of a facility with multiple **generating units** offering as a single **market participant**	MW									
		Net **reactive power** as measured on the high side terminal of the **transmission system** step up transformer	MVAr									
		Net **reactive power** of summated generation of a facility with multiple **generating units** offering as a single **market participant**	MVAr									
		Unit service load measured on the high side of the unit service transformer if the capacity is greater than 0.5 MW	MW									
		Unit service load measured on the high side of the unit service transformer if the capacity is greater than 0.5 MW	MVAr									
		Station service load **real power** if the capacity is greater than 0.5 MW, or if the station service load is for multiple units then the combined load for those units, measured on the high side of the station service transformer	MW									
		Station service load **reactive power** if the capacity is greater than 0.5 MW, or if the station service load is for multiple units then the combined load for those units, measured on the high side of the station service transformer	MVAr									
		Excitation system **real power** if the capacity is greater than 0.5 MW, measured on the high side of the excitation system transformer	MW									
		Excitation system **reactive power** if the capacity is greater than 0.5 MW, measured on the high side of the excitation system transformer	MVAr									
		Voltage at the **point of connection** to the **transmission system**	kV									
		Automatic voltage regulation setpoint	kV									
		Transmission system step-up transformer tap position if the step up transformer has a load tap changer	Tap position		Integer Value	1						
		Ambient temperature if the **generating unit** is a gas turbine **generating unit** (range of minus 50 degrees to plus 50 degrees Celsius)	degrees Celsius		+/- 2% of full scale	1 degree						
	Status	Breaker, circuit switchers, motor operated switches and other devices that can remotely or automatically control the connection to the AIES; and does not include manually operated air breaks.	0 = Open	1= Closed	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Transmission system step up transformer voltage regulator if the **transmission system** step up transformer has a load tap changer	0 = Manual	1= Auto								
		Generating unit power system stabilizer (PSS) status	0 = Off	1 = On								
		Generating unit automatic voltage regulation (AVR) in service and controlling voltage	0 = Off	1 = On								

		Remedial action scheme armed status, if applicable	0 = Disarmed	1= Armed			latency is 15 seconds availability is 98% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Remedial action scheme operated status on communications failure, if applicable	0 = Normal	1 = Alarm					
		Remedial action scheme operated status on runback, if applicable	0 = Normal	1 = Alarm					
		Remedial action scheme operated status on trip, if applicable	0 = Normal	1 = Alarm					
For each distribution connected, including distributed connected in the service area of the City of Medicine Hat, synchronous **generating unit**, or **aggregated generating facilities** consisting of synchronous **generating units**, where the total turbine nameplate rating is greater than or equal to 5 MW.	Analog	**Gross real power** as measured at the stator winding terminal	MW		+/- 2% of full scale	0.5% of the point being monitored	Latency is 30 seconds; Availability is 98%; Mean time to repair is 48 hours		
		Gross **reactive power** as measured at the stator winding terminal	MVAr						
		Generating unit voltage at the generator stator winding terminal or equivalent bus voltage	kV						
	Status	Breaker, circuit switchers, motor operated air brakes and other devices that can remotely control the connection to the AIES; and does not include manually operated air breaks.	0 = Open	1= Closed	N/A				

Appendix 2 – SCADA Requirements for Wind or Solar Aggregated Generating Facilities

Facility / Service Description	Signal Type	Point Description	Parameter	Accuracy Level	Resolution	Latency and Availability Requirements Based on Maximum Authorized Real Power					
						Maximum authorized real power less than 50 MW		Maximum authorized real power equal to or greater than 50 MW and less than 300 MW		Maximum authorized real power equal to or greater than 300 MW	
						Latency	Availability (%)	Latency	Availability (%)	Latency	Availability (%)
For each wind or solar **aggregated generating facility** directly connected to the **transmission system** or **transmission facilities** in the service area of the City of Medicine Hat, and where its nameplate rating is greater than or equal to 5 MW.	Analog	**Real power** of each collector system feeder	MW	+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Reactive power of each collector system feeder	MVAr								
		Voltage for each **collector bus**	kV								
		Real power of station service over 0.5 MW	MW								
		Reactive power of station service over 0.5 MW	MVAr								
		Reactive power of each **reactive power** resource (other than **generating units**)	MVAr								
		Real power at the low side of **transmission system** step up transformer	MW								
		Reactive power at the low side of **transmission system** step up transformer	MVAr								
		Transmission system step-up transformer tap position if the step up transformer has a load tap changer	Tap position	Integer Value	1						
		Net **real power** at the **point of connection**	MW	+/- 2% of full scale	0.5% of the point being monitored						
		Net **reactive power** at the **point of connection**	MVAr								
		Frequency at the **point of connection**	Hertz	+/- 0.01 Hz	0.01 Hz						
		Voltage at the **point of connection**	kV	+/- 2% of full scale	0.5% of the point being monitored						
		Voltage regulation system set point	kV								
		Potential **real power** capability, being the **real power** that would have been produced at the **point of connection** without **aggregated generating facilities** curtailment and based on **real time** meteorological conditions	MW	+/-10% of full scale							
		Real power limit used in the power limiting control system at the aggregated generating facilities	MW	+/- 2% of full scale							
		Feedback response for the facility limit reason code used in the power limiting control system at the aggregated generating facilities	1 = Transmission, 2= Ramp, 3 = No limit	Integer Value	1						
		Wind speed at hub height as collected at the meterological tower, (for wind facilities)	km/h	+/- 2% of anemometer maximum	0.5% of the point being monitored						
		Wind direction from the true north as collected at the meterological tower, (for wind facilities)	Degrees	+/- 5 degrees	1 degree						
		Barometric pressure with precision for instantaneous measurements to the nearest 6 HPA (for wind facilities)	HPa	Nearest 6 HPA	1HPA						
		Ambient temperature (for wind facilities)	^{o}C	+/- 1 degrees	1 deg c						
		Wind Speed at 2-10m above ground (for solar facilities)	km/h	+/- 2% of anemometer maximum	0.5% of the point being monitored						
		Wind direction from the true north at 2-10m above ground (for solar facilities)	Degrees	+/- 5 degrees	1 degree						
		Ambient Temperature (for solar facilities)	^{o}C	+/- 1 degrees	1 deg C						
		Global Horizontal Irradiance (for solar facilities)	W/m^2	± 25 W/m^2	1 W/m2						
		(FROM ISO) Facility limit	MW	N/A	0.1 MW	Signal sent by **ISO**					
		(FROM ISO) Reason for facility limit	1 = Transmission, 2= Ramp, 3 = No limit	N/A		Signal sent by **ISO**					

	Status	Communications failure alarm from remote terminal unit acting as a data concentrator for one or more **generating units** to a **transmission facility control centre** (if applicable)	0 = Normal	1= Alarm	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Communications failure indication between an intelligent electronic device and any remote terminal unit acting as a data concentrator	0 = Normal	1= Alarm								
		Each collector system feeder breaker	0 = Open	1 = Closed								
		Each reactive resource feeder breaker	0 = Open	1 = Closed								
		power limiting control system	0 = Off	1 = On								
		Voltage regulation system status	0 = Manual	1 = Automatic								
		Breaker, circuit switchers, motor operated switches and other devices that can remotely or automatically control the connection to the AIES; and does not include manually operated air breaks.	0 = Open	1 = Closed								
		Generating unit step up transformer voltage regulator if the **transmission system** step up transformer has a load tap changer	0 = Manual	1 = Automatic								
		Remedial action scheme armed status, if applicable	0 = Disarmed	1= Armed								
		Remedial action scheme operated status on communications failure, if applicable	0 = Normal	1 = Alarm								
		Remedial action scheme operated status on runback, if applicable	0 = Normal	1 = Alarm								
		Remedial action scheme operated status on trip, if applicable	0 = Normal	1 = Alarm								
For each wind or solar **aggregated generating facility**, where the total nameplate rating is greater than or equal to 5 MWand is connected to an **electric distribution system** including distribution facilities in the service area of the City of Medicine Hat**.**	Analog	**Gross real power** as measured at the **collector bus**	MW		+/- 2% of full scale	0.5% of the point being monitored	latency is 30 seconds availability is 98% mean time to repair is 48 hours					
		Gross **reactive power** as measured at the **collector bus**	MVAr									
		Generating unit voltage at the **collector bus**	kV									
		Net **real power** at the **point of connection**	MW		+/- 2% of full scale	0.5% of the point being monitored						
		Net **reactive power** at the **point of connection**	MVAr		+/- 2% of full scale	0.5% of the point being monitored						
		Frequency at the **point of connection**	Hertz		+/- 0.01 Hz	0.01 Hz						
		Potential **real power** capability, being the **real power** that would have been produced at the **point of connection** without **aggregated generating facilities** curtailment and based on **real time** meteorological conditions	MW		+/-10% of full scale	0.5% of the point being monitored						
		Real power limit used in the power limiting control system at the aggregated generating facilities	MW		+/- 2% of full scale	0.5% of the point being monitored						
		Feedback response for the facility limit reason code used in the power limiting control system at the aggregated generating facilities	1 = Transmission, 2= Ramp, 3 = No limit		Integer Value	1						
		Wind speed at hub height as collected at the meterological tower, (for wind facilities)	km/h		+/- 2% of anemometer maximum	0.5% of the point being monitored						
		Wind direction from the true north as collected at the meterological tower, (for wind facilities)	Degrees		+/- 5 degrees	1 degree						
		Barometric pressure with precision for instantaneous measurements to the nearest 6 HPA (for wind facilities)	HPa		Nearest 6 HPA	1HPA						
		Ambient temperature (for wind facilities)	°C		+/- 1 degrees	1 deg C						
		Wind Speed at 2-10m above ground (for solar facilities)	km/h			0.5% of the point being monitored						
		Wind direction from the true north at 2-10m above ground (for solar facilities)	Degrees		+/- 5 degrees	1 degree						
		Ambient Temperature (for solar facilities)	°C		+/- 1 degrees	1 deg C						
		Global Horizontal Irradiance (for solar facilities)	W/m²		± 25 W/m²	1 W/m2						
		(FROM ISO) Facility limit	MW		N/A	0.1 MW	Signal sent by **ISO**					
		(FROM ISO) Reason for facility limit	1 = Transmission, 2= Ramp, 3 = No limit		N/A		Signal sent by **ISO**					

	Status	Breaker, circuit switchers, motor operated switches and other devices that can remotely or automatically control the connection to the AIES; and does not include manually operated air breaks.	0 = Open	1= Closed	N/A	Latency is 30 seconds; Availability is 98%; Mean time to repair is 48 hours

Appendix 3 – SCADA Requirements for Energy Storage Facilities

Facility/ Service Description	Signal Type	Point Description	Parameter	Accuracy Level	Resolution	Latency and Availability Requirements Based on Maximum Authorized Real Power					
						Maximum authorized real power less than 50 MW		Maximum authorized real power equal to or greater than 50 MW and less than 300 MW		Maximum authorized real power equal to or greater than 300 MW	
						Latency	Availability (%)	Latency	Availability (%)	Latency	Availability (%)
For each **energy storage facility,** where the total nameplate rating is greater than or equal to 5 MW, or that submits **offers** in the energy market, and is directly connected to the **transmission system** or **transmission facilities** in the service area of Medicine Hat.	Analog	**Real power** produced as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MW	+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time repair is to 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		R**eactive power** produced as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MVAr								
		Real power consumed as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MW								
		R**eactive power** consumed as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MVAr								
		Voltage as measured at the alternating current terminal closest to each inverter based technology or the equivalent bus voltage (for battery facilities)	kV								
		Real power of station service over 0.5 MW	MW								
		Reactive power of station service over 0.5 MW	MVAr								
		Reactive power of each **reactive power** resource (other than energy storage devices)	MVAr								
		Real power at the low side of **transmission system** step up transformer	MW								
		Reactive power at the low side of **transmission system** step up transformer	MVAr								
		Transmission system step-up transformer tap position if the step up transformer has a load tap changer	Tap position	Integer Value	1						
		Net **real power** at the **point of connection**	MW	+/- 2% of full scale	0.5% of the point being monitored						
		Net **reactive power** at the **point of connection**	MVAr								
		Frequency at the **point of connection**	Hertz	+/- 0.01 Hz	0.01 Hz						
		Voltage at the **point of connection**	kV	+/- 2% of full scale	0.5% of the point being monitored						
		Voltage regulation system set point	kV								

		Energy storage device state of charge	%		+/- 2%	1%						
		Energy storage device state of charge	MWHr		+/- 2% of full scale	0.5% of the point being monitored						
	Status	Communications failure alarm from remote terminal unit acting as a data concentrator for one or more energy storage facilities to a **transmission facility control centre** (if applicable)	0 = Normal	1= Alarm	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Communications failure indication between an intelligent electronic device and any remote terminal unit acting as a data concentrator	0 = Normal	1= Alarm								
		Voltage regulation system status	0 = Manual	1= Automatic								
		Breaker, circuit switchers, motor operated switches and other devices that can remotely or automatically control the connection to the AIES; and does not include manually operated air breaks.	0 = Manual	1= Auto								
		Step up transformer voltage regulator if the **transmission system** step up transformer has a load tap changer	0 = Off	1 = On								
		Energy storage device power system stabilizer (PSS) status	0 = Off	1 = On								
		Remedial action scheme armed status, if applicable	0 = Disarmed	1= Armed			latency is 15 seconds availability is 98% mean time to repair is 48 hours				4 seconds	99.8% mean time to repair is 4 hours
		Remedial action scheme operated status on communications failure, if applicable	0 = Normal	1 = Alarm								
		Remedial action scheme operated status on runback, if applicable	0 = Normal	1 = Alarm								
		Remedial action scheme operated status on trip, if applicable	0 = Normal	1 = Alarm								
For each **energy storage facility**, where the total nameplate rating is greater than or equal to 5 MW, or that submits **offers** in the energy market, and is connected to an **electric distribution system** including distribution facilities in the service area of the City of Medicine Hat.	Analog	**Real power** produced as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MW		+/- 2% of full scale	0.5% of the point being monitored	Latency is 30 seconds; Availability is 98%; Mean time to repair is 48 hours					
		Reactive power produced as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MVAr									
		Real power consumed as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MW									
		Reactive power consumed as measured at the alternating current terminal closest to each inverter based technology (for battery facilities)	MVAr									
		Voltage as measured at the alternating current terminal closest to each inverter based technology or the equivalent bus voltage (for battery facilities)	kV									
		Net **real power** at the **point of connection**	MW									
		Net **reactive power** at the **point of connection**	MVAr									
		Frequency at the **point of connection**	Hertz		+/- 0.01 Hz	0.01 Hz						
		Energy storage device state of charge	%		+/- 2%	1%						
		Energy storage device state of charge	MWHr		+/- 2% of full scale	0.5% of the point being monitored						
	Status	Breaker, circuit switchers, motor operated air brakes and other devices that can remotely control the connection to the AIES; and does not include manually operated air breaks.	0 = Open	1= Closed	N/A							

Appendix 4 – SCADA Requirements for Industrial Complexes and Loads

Facility / Service Description	Signal Type	Point Description	Parameter		Accuracy Level	Resolution	Latency and Availability Requirements Based on Maximum Authorized Real Power					
							Maximum authorized real power less than 50 MW		Maximum authorized real power equal to or greater than 50 MW and less than 300 MW		Maximum authorized real power equal to or greater than 300 MW	
							Latency	Availability (%)	Latency	Availability (%)	Latency	Availability (%)
For each facility	Status	Communications failure alarm from remote terminal unit acting as a data concentrator for one or more **generating units** to a **transmission facility control centre** (if applicable)	0 = Normal	1= Alarm	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Communications failure indication between an intelligent electronic device and any remote terminal unit acting as a data concentrator	0 = Normal	1= Alarm								
For each load facility or industrial complex	Analog	**Real power** at the **point of connection**	MW		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8% mean time to repair is 4 hours
		Reactive power at the **point of connection**	MVAr									
		Voltage at the **point of connection**	kV									
	Status	Breaker, circuit switchers, motor operated switches and other devices that can remotely or automatically control the connection to the AIES; and does not include manually operated air breaks.	0 = Open	1 = Closed	N/A							
A **market participant** with a **Remedial action scheme** on its load facility or industrial complex	Analog	Total **Remedial action scheme** load available	MW		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	99.8% mean time to repair is 4 hours	15 seconds	99.8% mean time to repair is 4 hours	4 seconds	99.8% mean time to repair is 4 hours
		Amount of load armed	MW									
	Status	**Remedial action scheme** circuit breaker, circuit switcher or other controllable isolating devices	0 = Open	1 = Closed	N/A							
		Arming status of the **Remedial action scheme**	0 = Disarmed	1 = Armed								
		Remedial action scheme operated status on communications failure, if applicable	0 = Normal	1 = Alarm								
		Remedial action scheme operated status on runback, if applicable	0 = Normal	1 = Alarm								
		Remedial action scheme operated status on trip, if applicable	0 = Normal	1 = Alarm								

Appendix 5 – SCADA Requirements for Transmission Facilities

Facility / Service Description	Signal Type	Point Description	Parameter		Accuracy Level	Resolution	Latency and Availability Requirements Based on Transmission Voltage			
							Any one bus operated at 60 kV or above, but less than or equal to 200 kV		Any one bus operated above 200 kV	
							Latency	Availability (%)	Latency	Availability (%)
For each substation	Status	Communications failure alarm from remote terminal unit acting as a data concentrator for one or more **generating units** to a **transmission facility control centre** (if applicable)	0 = Normal	1= Alarm	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours
		Communications failure indication between an intelligent electronic device and each remote terminal unit acting as a data concentrator	0 = Normal	1= Alarm						
Bus	Analog	Bus voltage line-to-line. Ring or split busses require a minimum of two voltage sources	kV		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours
	Status	Breakers, circuit switchers, motor operated switches, or other remotely or automatically controllable isolating device status	0 = Open	1= Closed	N/A					
Transformer winding greater than 60 kV	Analog	**Real power** as measured on the high side terminal of the transformer	MW		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours
		Reactive power as measured on the high side terminal of the transformer	MVAr							
		Transformer voltage regulation setpoint if the transformer has a load tap changer	kV							
		Transformer tap position if the step up transformer has a load tap changer	Tap position		Integer Value	1				
	Status	Load tap changer	0 = Manual	1 = Automatic	N/A					
Reactive Resources	Analog	**Reactive power** of switchable **reactive power** resource - capacitor bank (positive polarity) or reactor (negative polarity)	MVAR		+/- 2% of full scale	0.5% of the point being monitored	latency is 30 seconds; availability is 98%; mean time to repair is 48 hours			
		Reactive power of dynamic **reactive power** resource - SVC, synchronous condenser, or other similar device					latency is 15 seconds; availability is 98%; mean time to repair is 48 hours			
		Voltage setpoint of dynamic **reactive power** resource - SVC, synchronous condenser, or other similar device	kV				latency is 15 seconds; availability is 98%; mean time to repair is 48 hours			
	Status	**Reactive power** resource control device - capacitor bank or reactor	0 = Off	1 = On	N/A		latency is 30 seconds; availability is 98%; mean time to repair is 48 hours			
		Reactive power resource control device - SVC, synchronous condenser, or other similar device	0 = Off	1 = On			latency is 15 seconds; availability is 98%; mean time to repair is 48 hours			
		Automatic voltage regulation status for dynamic **reactive power** resource - SVC, synchronous condenser, or other similar device	0 = Off	1 = On			latency is 15 seconds; availability is 98%; mean time to repair is 48 hours			
Remedial Action Scheme	Status	**Remedial action scheme** circuit breaker, circuit switcher or other controllable isolating devices	0 = Open	1 = Closed	N/A		30 Seconds	99.8% mean time to repair is 4 hours	latency is 15 seconds availability is 99.8% mean time to repair is 4 hours	
		Remedial action scheme armed status, if applicable	0 = Disarmed	1= Armed						
		Remedial action scheme operated status on communications failure, if applicable	0 = Normal	1 = Alarm						
		Remedial action scheme operated on equipment overload, if applicable	0 = Normal	1 = Alarm						
		Remedial action scheme operated status on trip, if applicable	0 = Normal	1 = Alarm						
Transmission line where the nominal voltage is greater than or equal to 60 kV and less than 200 kV	Analog	**Real power**	MW		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98% mean time to repair is 48 hours	N/A	
		Reactive power	MVAr							
	Status	Breakers, circuit switchers, motor operated switches, or other remotely or automatically controllable isolating device status	0 = Open	1= Closed	N/A					
Transmission line where the nominal voltage is equal to or greater than 200 kV	Analog	**Real power**	MW		+/- 2% of full scale	0.5% of the point being monitored	N/A		15 seconds	98% mean time to repair is 48 hours
		Reactive power	MVAr							
		Line side voltage	kV							
	Status	Breakers, circuit switchers, motor operated switches, or other remotely or automatically controllable isolating device status	0 = Open	1= Closed	N/A					

Appendix 6 – SCADA Requirements for Ancillary Services

Facility / Service Description	Signal Type	Point Description	Parameter		Accuracy Level	Resolution	Latency and Availability Requirements Based on Maximum Authorized Real Power					
							Maximum authorized real power less than 50 MW		Maximum authorized real power equal to or greater than 50 MW and less than 300 MW		Maximum authorized real power equal to or greater than 300 MW	
							Latency	Availability (%)	Latency	Availability (%)	Latency	Availabili
For each resource providing black start services	Analog	Bus frequency in hertz with a range of at least 57 to 63Hz	Hertz		+/- 0.01 Hz	0.01 Hz	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8 mean time t is 4 hou
For each **regulating reserve resource**	Analog	**Gross real power** as measured at: (a) the stator winding terminals of the generating unit; (b) the circuit breaker or disconnection device that is electrically closest to each load; (c) the alternating current terminal closest to each inverter based technology; or (d) the collector bus for aggregated generating facilities	MW		0.25% of full scale	0.25% of the point being monitored	latency is 2 seconds availability is 99.8% mean time to repair is 4 hours					
		Net **real power** as measured on the high side terminal of the step up transformer	MW									
		Gross real power set point from the **regulating reserve** resource control system	MW									
		High limit of the regulation range	MW				latency is 10 seconds availability is 99.8% mean time to repair is 4 hours					
		Low limit of the regulation range	MW									
		(FROM ISO) Set point. Note if multiple resources are used to provide the full resource commitment, the **ISO** will send a totalized expected MW output signal.	MW		N/A	0.1 MW	Signal sent by **ISO** every 4 seconds					
	Status	**Regulating reserve** resource circuit breaker status (required for all circuit breakers composing the resource)	0 = Open	1= Closed	N/A		latency is 2 seconds availability is 99.8% mean time to repair is 4 hours					
		Regulating reserveresource control status	0 = Disabled	1= Enabled								
		(FROM ISO) ISO has control of the **regulating reserve** resource	0 = Disarmed	1= Armed	N/A		Signal sent by **ISO** when **regulating reserves** are in effect (on or off)					
For each spinning reserve resource	Analog	**Gross real power** as measured at: (a) the stator winding terminals of the generating unit; (b) the circuit breaker or disconnection device that is electrically closest to each load; (c) the alternating current terminal closest to each inverter based technology; or (d) the collector bus for aggregated generating facilities a)	MW		+/- 2% of full scale	0.5% of the point being monitored	latency is 10 seconds availability is 99.8%, mean time to repair is 4 hours					
	Status	Spinning reserve resource circuit breaker status (required for all circuit breakers composing the resource)	0 = Open	1= Closed	N/A							
For each **supplemental reserve resource**	Analog	**Gross real power** as measured at: (a) the stator winding terminals of the generating unit; (b) the circuit breaker or disconnection device that is electrically closest to each load; (c) the alternating current terminal closest to each inverter based technology; or (d) the collector bus for aggregated generating facilities	MW		+/- 2% of full scale	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	4 seconds	99.8 mean time t is 4 hou
	Status	**Supplemental reserve** resource circuit breaker status (required for all circuit breakers composing the resource)	0 = Open	1= Closed	N/A							
For each resource providing **load shed service** for imports	Analog	Actual Volume, being the **real power** consumed at the **point of connection**	MW		+/- 2% of dispatched signal	0.5% of the point being monitored	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours	N/A	
		Offered Volume, being the participant's **real power** offer to the **ISO**	MW									
		Armed Volume, being the **real power** commitment of the LSSI resource	MW									
		(From **ISO**) dispatched volume	MW		N/A		Signal sent by **ISO** when LSSI **dispatched** on or off					
	Status	LSSI provider status indication	0 = Disarmed	1 = Armed	N/A		30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours		

		LSSI provider trip status indication	0 = Not tripped	1 = Tripped	N/A	30 seconds	98.0% mean time to repair is 48 hours	15 seconds	98.0% mean time to repair is 48 hours
		(From **ISO**) **load shed service** for imports **dispatch** status	0 = Disarmed	1 = Armed	N/A	Signal sent by **ISO** when the **load shed service** for imports is **dispatched** on or off			
		(From **ISO**) **load shed service** for imports trip status	0 = Not tripped	1 = Tripped	N/A	Signal sent by **ISO** when the armed **load shed service** for imports are tripped via SCADA			

Section 502.9 Synchrophasor Measurement Unit Technical Requirements

External Consultation Draft

November 20, 2018

Applicability

1 Section 502.9 applies to:

(a) a **legal owner** of a **generating unit** implementing a synchrophasor measurement unit;

(b) a **legal owner** of an **aggregated generating facility** implementing a synchrophasor measurement unit;

(c) a **legal owner** of a **transmission facility** implementing a synchrophasor measurement unit; and

(b) the **ISO**.

Requirements

Facility with Functional Specifications Issued On or After February 28, 2013

2 A **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** who is a **legal owner** of a **generating unit**, an **aggregated generating facility** or **transmission facility** for which the **ISO** issues a functional specification on or after February 28, 2013, must design and construct its facility in accordance with the minimum synchrophasor measurement unit requirements of this section 502.9, and verify to the **ISO** that the facility meets the requirements during **commissioning** and energization of the new facility.

Functional Specifications, Technical Requirements and Standards Issued Prior to February 28, 2013

3(1) Subject to subsection 3(2), the provisions of this section 502.9 do not apply to a facility:

(a) that was built in accordance with a technical requirement or technical standard; or

(b) with a functional specification;

the **ISO** issued prior to February 28, 2013, but such facility must remain in compliance with that technical requirement, technical standard or functional specification including all of the standards and requirements set out in that technical requirement, technical standard or functional specification.

(2) Notwithstanding subsection 3(1), the **ISO** may require a **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** that is the **legal owner** of an existing facility to comply with any specific or all of the provisions of this section 502.9, if the **ISO** determines that such compliance is necessary for the safe and reliable operation of the **interconnected electric system**.

Functional Specification

4(1) The **ISO** must, in accordance and generally consistent with this section 502.9 and any other applicable **ISO rules**, approve of a functional specification containing further details, work requirements and specifications for the implementation of a synchrophasor measurement unit for a facility.

(2) The functional specification referred to in subsection 4(1) must be generally consistent with the provisions of this section 502.9 but may contain material variances the **ISO** approves of based upon its discrete analysis of any 1 or more of the technical, economic, safety, operational and **reliability** requirements related to the specific connection project.

Synchrophasor Measurement Unit Functionality

5 Each of the **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** and **legal owner** of a **transmission facility** implementing a synchrophasor measurement unit, must meet the functionality requirements, data requirements, data format requirements and communication requirements set out in the Institute of Electrical and Electronics Engineers document *IEEE Standard C37.118 – 2005 Synchrophasors for Power Systems* specific to a synchrophasor measurement unit.

Synchrophasor Measurement Unit Signal Names

6 The **ISO** must provide each **legal owner** of **generating unit**, **legal owner** of an **aggregated generating facility** and **legal owner** of a **transmission facility** with *IEEE Standard C37.118 - 2005 Synchrophasors for Power Systems* compliant synchrophasor measurement unit signal names and the appropriate data format, including the company identifier, device identifier and the necessary formatting.

Data Storage and Streaming

7(1) Subject to subsection 7(2), each of the **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** and **legal owner** of a **transmission facility** must collect and continuously store the synchrophasor measurement unit data for 1 year from the date the synchrophasor measurement unit data was collected.

(2) A **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility**, required to implement a synchrophasor measurement unit, as determined by the **ISO**, must stream the data to the **ISO**.

(3) The **legal owner** of a **generating unit, legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** may, within 1 year of streaming the data to the **ISO**, obtain the data from the **ISO** upon written request.

(4) The **ISO** must, if it receives a request as set out in subsection 7(3), provide the data to the **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** within 10 **business days**.

(5) The **ISO** must store any data streamed pursuant to subsection 7(2) for 1 year.

Suspected Failure or Malfunction of a Synchrophasor Measurement Unit

8(1) A **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** must, if it identifies or suspects a failure or malfunction of a synchrophasor measurement unit or any of its components, notify the **ISO** as soon as practicable but not later than 1 **business day** after identifying the suspected malfunction or failure.

(2) The **ISO** must, if it identifies or suspects a failure or malfunction of a synchrophasor measurement unit or any of its components, notify the applicable **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** as soon as practicable, but not later than 1 **business day**, after identifying the suspected failure.

(3) Each of the **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** and **legal owner** of a **transmission facility** must provide the **ISO** with the date it expects to investigate the suspected failure or malfunction of the synchrophasor measurement unit or any of its components which, in the case of an investigation in response to a notification under subsection 8(2), must be within 2 **business days** of receiving the **ISO**'s notification.

(4) The **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** must, if it is unable to test the synchrophasor measurement unit or any of its components on the expected date provided under subsection 8(3), provide the **ISO** with the revised date.

(5) The **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** must, after testing the synchrophasor measurement unit or any of its components, confirm if there is a failure or malfunction with the synchrophasor measurement unit or not and notify the **ISO** with the results of the test.

(6) The **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** must, if the results of the test indicated that the synchrophasor measurement unit or any of its components have failed, provide the **ISO** with the date that the **electricity market participant** expects to repair or replace the synchrophasor measurement unit.

(7) The **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** must, if the synchrophasor measurement unit or any of its components are not repaired or replaced by the date provided under subsection 8(6), provide the **ISO** with a revised date.

(8) The **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** must notify the **ISO** when the synchrophasor measurement unit or any of its components have been repaired or replaced.

As-Built Drawing

9 A **legal owner** of a **generating unit**, **legal owner** of an **aggregated generating facility** or **legal owner** of a **transmission facility** implementing a synchrophasor measurement unit, or required by the **ISO** to implement a synchrophasor measurement unit, must provide the **ISO** with an as-built engineering stamped 3 line drawing or a record representing the as-built installation, indicating:

(a) the voltage transformer and current transformer connections through to the synchrophasor measurement unit; and

(b) the voltage transformer and current transformer accuracy class.

Revision History

Date	Description
xxxx-xx-xx	Update to revision to clarify "**market participant**" as "**electricity market participant**"
2015-03-27	Replaced "effective date" with the initial release date in sections 2 and 3(1); and replaced the word "Effective" in the Revision History to "Date".
2013-02-28	Initial release

ISO Rules
Part 500 Transmission
Division 505 Legal Owners of Generating Facilities
Section 505.2 Performance Criteria for Refund of Generating Unit Owner's Contribution

External Consultation Draft

November 20, 2018

Applicability

1 Section 505.2 applies to:

(a) the **ISO**.

Requirements

Performance Assessment

2(1) The **ISO** must use the performance criteria in this section 505.2, in accordance with section 29(5) of the *Transmission Regulation*, to assess the satisfactory performance of a **generating unit** or an **aggregated generating facility**, for which an **electricity market participant**:

(a) has paid to the **ISO** a **legal owner**'s contribution for the **generating unit** or **aggregated generating facility** in accordance with subsection 4 of section 10 of the **ISO tariff**; and

(b) may receive a refund of that contribution in accordance with subsection 5 of section 10 of the **ISO tariff**.

(2) The **ISO** must calculate the performance assessment for the 2015 calendar year and each subsequent calendar year as:

(a) the availability assessment calculated in accordance with subsection 3, 4 or 5 below, as applicable,

multiplied by

(b) the overcontract assessment calculated in accordance with subsection 6 below.

(3) The **ISO** must calculate refund for each calendar year during the refund period as:

$$\text{refund} = \text{annual amount} \times \text{performance assessment},$$

where the annual amount is as specified in subsection 5(3) of section 10 of the **ISO tariff**, and the performance assessment is calculated in accordance with subsection 2(2) of this section 505.2.

Availability Assessment for Generation Other Than Hydro, Wind, Solar, Less Than 5 MW and Behind-the-Fence

3(1) The **ISO** must calculate the availability assessment in accordance with this subsection 3 for a **generating unit** or an **aggregated generating facility** that:

(a) is not a hydro **generating unit**, or a wind or solar **aggregated generating facility**;

(b) has a **maximum capability** of 5 MW or greater; and

(c) is not a **generating unit** or an **aggregated generating facility** that is behind-the-fence and primarily intended to fully or partially serve onsite industrial load.

(2) The **ISO** must calculate the availability assessment individually for each **generating unit** or **aggregated generating facility** to which this subsection 3 applies.

(3) The **ISO** must calculate the average hourly availability for each **generating unit** or **aggregated generating facility**, where:

(a) hourly availability (time weighted) $= \frac{\textbf{available capability}}{\textbf{maximum capability}}$; and

(b) average hourly availability $= \frac{\sum \text{hourly availability for all hours of the year}}{\text{number of hours in the year}}$

(4) The **ISO** must calculate the availability assessment for each **generating unit** or **aggregated generating facility**, based on the average hourly availability as follows:

Average Hourly Availability	Availability Assessment
Less than 0.60	0%
0.60 to 0.80	$\frac{\text{average hourly availability} - 0.60}{0.20} \times 100\%$
Greater than 0.80	100%

Availability Assessment for Generation Using Hydro, Wind, Solar or Less Than 5 MW

4(1) The **ISO** must calculate the availability assessment in accordance with this subsection 4 for a **generating unit** or an **aggregated generating facility** that:

(a) is a hydro **generating unit**;

(b) is a wind or solar **aggregated generating facility**; or

(c) has a **maximum capability** of less than 5 MW.

(2) The **ISO** must:

(a) calculate the availability assessment in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement; and

(b) apply the aggregate availability assessment to each **generating unit** or **aggregated generating facility** to which this subsection 4 applies.

(3) The **ISO** must calculate the average hourly availability in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement, over all hours in the period during which performance is being assessed, where:

(a) for an hour during a month in which Rate STS **contract capacity** is greater than zero (0):

hourly availability (time weighted) $= \frac{\textbf{metered energy}+\textbf{dispatch}\text{ volume of }\textbf{operating reserves}}{\text{Rate STS }\textbf{contract capacity}}$;

(b) for an hour during a month in which Rate STS **contract capacity** is zero (0):

hourly availability = 1.00 ; and

(c) average hourly availability $= \frac{\sum \text{hourly availability for all hours of the year}}{\text{number of hours in the year}}$

(4) The **ISO** must calculate the availability assessment in aggregate for all **generating units** and **aggregated generating facilities**, excluding solar **aggregated generating facilities**, that are served under a single Rate STS **system access service** agreement, based on the average hourly availability as follows:

Average Hourly Availability	Availability Assessment
Less than 0.15	0%
0.15 to 0.25	$\frac{\text{average hourly availability} - 0.15}{0.10} \times 100\%$
Greater than 0.25	100%

(5) The **ISO** must calculate the availability assessment in aggregate for all solar **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement, based on the average hourly availability as follows:

Average Hourly Availability	Availability Assessment
Less than 0.05	0%
0.05 to 0.10	$\frac{\text{average hourly availability} - 0.05}{0.10} \times 100\%$
Greater than 0.10	100%

Availability Assessment for Behind-the-Fence Generation

5(1) The **ISO** must calculate the availability assessment in accordance with this subsection 5 for a **generating unit** or **aggregated generating facility** that is behind-the-fence and primarily intended to fully or partially serve onsite industrial load.

(2) The **ISO** must:

(a) calculate the availability assessment in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement; and

(b) apply the aggregate availability assessment to each **generating unit** or **aggregated generating facility** to which this subsection 5 applies.

(3) The **ISO** must calculate the average hourly availability in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement, over all hours in the period during which performance is being assessed, where:

(a) if the **generating unit** or **aggregated generating facility** submits **offers** on a net basis:

(i) for an hour during a month in which Rate STS **contract capacity** is greater than zero (0):

$$\text{hourly availability (time weighted)} = \frac{\text{total } \textbf{available capacity}}{\text{Rate STS } \textbf{contract capacity}}\text{; and}$$

(ii) for an hour during a month in which Rate STS **contract capacity** is zero (0):

hourly availability = 1.00 ;

(b) if the **generating unit** or **aggregated generating facility** submits **offers** on a gross basis:

$$\text{hourly availability (time weighted)} = \frac{\textbf{available capability}}{\textbf{maximum capability}}\text{; and}$$

(c) $\text{average hourly availability} = \dfrac{\sum \text{hourly availability for all hours of the year}}{\text{number of hours in the year}}$

(4) The **ISO** must calculate the availability assessment in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement, based on the average hourly availability as follows:

Average Hourly Availability	Availability Assessment
Less than 0.60	0%
0.60 to 0.80	$\dfrac{\text{average hourly availability} - 0.60}{0.20} \times 100\%$
Greater than 0.80	100%

Overcontract Assessment

6(1) The **ISO** must, for a **generating unit** or an **aggregated generating facility** to which this section 505.2 applies:

(a) calculate the overcontract assessment in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement; and

(b) apply the aggregate overcontract assessment to each **generating unit** or **aggregated generating facility** that is served under that Rate STS **system access service** agreement.

(2) The **ISO** must calculate the overcontract factor in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement, based on the **metered energy** supplied above Rate STS **contract capacity**, over all hours in the period during which performance is being assessed, as follows:

$$\text{overcontract factor} = \frac{\sum_{\text{hours when } \textbf{metered energy} > \text{Rate STS } \textbf{contract capacity}} (\textbf{metered energy} - \text{Rate STS } \textbf{contractcapacity}}{\sum_{\text{all hours}} \text{Rate STS } \textbf{contract capacity}}$$

(3) The **ISO** must, in any month in which Rate STS **contract capacity** is less than 5 MW, deem Rate STS **contract capacity** to be 5 MW during that month for the calculation of the overcontract factor in subsection 6(2) above.

(4) The **ISO** must exclude from the calculation of the overcontract factor in subsection 6(2) above any hours in which the **ISO** issues a **directive** to the **legal owner** of a **generating unit** or **aggregated generating facility** to temporarily exceed the Rate STS **contract capacity** during an **emergency**.

(5) The **ISO** must calculate the overcontract assessment in aggregate for all **generating units** and **aggregated generating facilities** that are served under a single Rate STS **system access service** agreement, based on the overcontract factor calculated in subsection 6(2) above as follows:

Overcontract Factor	Overcontract Assessment
Less than 0.01	100%
0.01 to 0.05	$\frac{0.05 - \text{overcontract factor}}{0.04} \times 100\%$
Greater than 0.05	0%

Adjustments

7 The **ISO** may make adjustments to the hourly availability and/or the overcontract factor where the hourly availability and/or the overcontract factor are affected by events outside the control of the **owner** of a **generating unit** or **aggregated generating facility**, including but not limited to a transmission and/or distribution facility outage, congestion, a **directive** issued by the **ISO** or a circumstance arising under the **ISO tariff** or an **ISO rule**.

Communication

8 The **ISO** must provide a preliminary performance assessment, along with all related input data, to the **legal owner** of a **generating unit** or an **aggregated generating facility** by January 31 of the year following the calendar year to which the refund relates.

Revision History

Date	Description
XXXX-XX-XX	Revisions to clarify "**market participant**" as "**electricity market participant**"; "generating facility" as "generating unit or aggregated generating facility"; and applicability to a solar aggregated generating facility.
2016-01-29	Initial release.

External Consultation Draft

November 20, 2018

Applicability

1 Section 507.1 applies to:

(a) a **person** proposing an **intertie** be:

(i) constructed; or

(ii) upgraded or enhanced in a manner that would result in an increase to the path rating of the **intertie**.

Requirements

Open and Non-Discriminatory Manner

2(1) A **person** proposing an **intertie** must provide open access to **electricity market participants** and provide that the intertie be available in an open and non-discriminatory manner, similar to the access available to other **transmission facilities**.

(2) A **person** proposing an **intertie** must, as part of the open and non-discriminatory manner required in subsection 2(1):

(a) provide public notice which must, at a minimum:

(i) indicate the **person**'s intention to provide access to the **intertie** by way of an open and non-discriminatory process;

(ii) be inserted in major newspapers in Alberta and in jurisdictions outside Alberta in which the **intertie** is planned to be located, in the section of each such newspaper where such a notice would reasonably be expected to appear;

(b) include conducting public information sessions in Alberta and in jurisdictions outside Alberta in which the **intertie** is planned to be located; and

(c) make its terms and conditions of access publicly available.

Sale of Intertie Capacity

3(1) A **person** proposing an **intertie** may only sell, or otherwise make available, **intertie** capacity in accordance with an open and non-discriminatory process, including **intertie** capacity that was not sold in the initial process.

(2) The **person** proposing an **intertie** must make publicly available:

(a) the names of **persons** who have acquired **intertie** capacity; and

(b) the amount of **intertie** capacity each has acquired; and

must do so within 1 month of such acquisition.

Affiliates

4 If an **affiliate** of a **person** proposing an **intertie** participates in the open and non-discriminatory process identified in subsection 3, the **person** proposing an **intertie** must:

(a) make public that participation;

(b) confirm that the **affiliate** was not provided any advantage in such process over other interested parties; and

must do so within 1 month of such participation.

Terms and Conditions

5 A **person** proposing an **intertie** must include in the terms and conditions it files pursuant to subsection 27(5)(a) of the *Transmission Regulation*, provisions to prevent capacity withholding and other anti-competitive behavior.

Records

6 A **person** proposing an **intertie** must maintain its books and records at least to the extent reasonably necessary to verify compliance with this section 507.1 and must make those records available to the **ISO** upon reasonable prior notice.

Revision History

Date	Description
XXXX-XX-XX	Revision to clarify “market participant” as “electricity market participant”.
2012-11-16	Initial Release

External Consultation Draft

November 20, 2018

Terms and definitions to be amended for use in the Energy Market ISO rules:

"**adequacy**" means the ability of the **interconnected electric system** to supply the aggregate electrical demand and energy requirements of **electricity market participants** receiving **system access service**, taking into account **planned outages** and reasonably expected **delayed forced outages** and **automatic forced outages** of **system elements**.

"**agent**" includes:

(i) a representative of a **pool participant** duly appointed and authorized by the **pool participant** under Section 201.2 of the **ISO rules**, *Appointment of Agent* to act on behalf of and bind the **pool participant** with regard to transactions and other activities on the Energy Trading System and the automated dispatch and messaging system; or

(ii) a representative of a **market participant** or a **pool participant**, as the case may be, duly appointed and authorized to act on behalf of and bind that person with regard to other **ISO** activities, procedures and requirements, which such appointment is made under and in accordance with the applicable **ISO rules**, authorizations and procedures.

"**Alberta internal load**" means a number in MW:

(i) that represents, in an hour, **system load** plus load served by an on-site **generating unit** or **aggregated generating facility**, including those within an industrial system and the City of Medicine Hat; and

(ii) which the **ISO**, using SCADA data, calculates as the sum of the output of each **generating unit** and **aggregated generating facility** in Alberta and the Fort Nelson area in British Columbia, plus import volumes and minus export volumes.

"**business day**" as defined in the **Act** means a **day** other than a Saturday or a holiday as defined in the *Interpretation Act*.

"**market participant**" as defined in the **Act** means

an **electricity market participant** or a **capacity market participant**.

"**point of delivery**" means the point at which electricity is transferred from **transmission facilities** to facilities owned by an **electricity market participant** receiving **system access service** under the **ISO tariff**, including an **electric distribution system**.

"**point of supply**" means the point at which electricity is transferred to **transmission facilities** from facilities owned by an **electricity market participant** receiving **system access service** under the **ISO tariff**, including a **generating unit**, **aggregated generating facility** or an **electric distribution system**.

"**pool participant**" means an **electricity market participant** who is registered to transact, listed in the **pool participant** list.

"**system access service**" means the service obtained by a **market participant** through a connection to the **transmission system**, and includes access to exchange electric energy and **ancillary services**.

<u>Terms and definitions to be added for use in the Energy Market ISO rules:</u>

"**electricity market participant**" means

(i) any **person** that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or **ancillary services**, or

(ii) any broker, brokerage or forward exchange that trades or facilitates the trading of electricity, electric energy, electricity services or **ancillary services**

<u>Terms and definitions to be removed for use in the Energy Market ISO rules:</u>

"LTA metrics" means all **adequacy** information related items, including historical data and forecasts that the **ISO** will regularly capture, calculate and report on.

"LTA threshold" means the magnitude measured with respect to one of the **LTA metrics** that, if exceeded, would indicate a need for the consideration of preventative action.

"LTA threshold actions" means out-of-market measures the **ISO** may choose to implement to remedy an actual or impending **LTA** issue, where for the purpose of this definition, out-of-market measures are actions that either create revenue or cost impacts outside the energy market for **market participants**. **LTA threshold actions** are intended to preserve LTA until new generation capacity is built or load decreases.