PUBLIC

PROCEDURE

Market Manual 5: Settlements

Part 5.5: IESO-Administered Markets Settlement Amounts

Issue 86.4~~Issue 86.3~~

June 7, 2024~~January 29, 2024~~

This *market manual* is provided for stakeholder engagement purposes. Please note that additional changes to this document may be incorporated as part of future engagement in MRP or other *IESO* activities prior to this *market manual* taking effect.

This procedure describes the *settlement amounts* associated with the *IESO-administered markets*.

MDP_PRO_0033

Document Change History

<table>
<tr><th>Issue</th><th>Reason for Issue</th><th>Date</th></tr>
<tr><td colspan="3">This version of MM 5.5 contains new content to reflect the settlement process under the Market Renewal Program (MRP). The previous version of MM 5.5 will be obsolete post-MRP. For history prior to MRP, refer to version 86.0 and prior.</td></tr>
<tr><td>86.1</td><td>Updated and repurposed to reflect how settlement amounts associated with the IESO-administered markets are determined.</td><td>December 1, 2022</td></tr>
<tr><td>86.2</td><td>Updated for stakeholder engagement</td><td>April 24, 2023</td></tr>
<tr><td>86.3</td><td>Updated to:
incorporate operating reserve non-accessibility settlement amounts;
incorporate capacity obligation settlement amounts;
incorporate design changes presented to stakeholders at the September 21, 2023 Engagement Webinar: day-ahead market balancing credit;
incorporate design changes presented to stakeholders at the December 15, 2023 Engagement Webinar: settlement of non-dispatchable generation resources and intertie failure charges; and
address internal and external feedback</td><td>January 29, 2024</td></tr>
<tr><td>86.4</td><td>Updated for MRP – Final Alignment</td><td>June 7, 2024</td></tr>
</table>

Related Documents

Document ID	Document Title

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Reference	Description of Change
Throughout	Changes made to conform to the new MRP style and convention for *market manuals.* Updated to address internal and external feedback.
Section 1.2	Updated to include reference to *market rules* for *dispatch scheduling errors.*
Section 1.3	Table 1-1 updated language for reference to rounds of any *TR auction* to align with *market rules*.
Section 2.1	Under sub-heading 'Settlement statements' - removed reference to '*preliminary settlement statements* and *final*' as they are included in the definition of *settlement statements* per MR Ch.11.
Section 2.1.3	Under sub-heading 'HORSA charge types' – removed reference to *settlement amounts* to align with other sections of the *market manual.*
Section 2.2	Updated name of load forecast deviation charge and acronym LFDC to load forecast deviation adjustment and acronym LFDA. Under sub-heading 'HPTSA NDL and DAM failure/suspension' - added 'and the LFDA will be 0' to the *settlement* of *non-dispatchable loads* to align with *market rules*.
Section 2.6	Added new *charge type* 1852 – Day-Ahead Market Reliability Scheduling Uplift – Virtual Transactions to Sell as the portion of the DRSU that is allocated to virtual transactions to sell is not subject to GST/HST.
Section 2.13.2	Updated references from combustion turbine/steam turbine *generation unit* to combustion turbine/steam turbine *resource* as the *settlement process* is typically at the *resource* level.
Section 2.20	Added 'within Ontario' for further clarity that the ICLR is for *load resources* within Ontario.
Section 2.29.1.1	Included reference to *pseudo-units* in the steps to calculate the ORSCB as the same steps apply to both aggregated *dispatchable generation resources* not associated with a *pseudo-unit* and associated with a *pseudo-unit*.

Reference	Description of Change
Section 2.29.2.1	Removed *charge type* acronyms from Table 2-42 to align with other sections of the *market manual*.
Section 4.3.1	Added *resources* types to which the market power mitigation tests for *physical withholding* apply to.
Section 4.3.2	Updated *settlement amount* name and references to uncompetitive interties to align with defined term *intertie economic withholding*.
Section 4.3.3	Updated *settlement* resolution from monthly to daily.
Section 4.5	New section for the Independent Review Process.
Section 5	Added reference to MR Ch.7 s.7.6.
Appendix A	Removed Fuel Cost Compensation form from Table A-1 as this form has been automated and will be available in Online IESO.
Appendix C	Update to data set used to calculate the price bias adjustment factors.

Market Transition

A.1.1 This *market manual* is part of the *renewed market rules,* which pertain to:

A.1.1.1 the period prior to a *market transition* insofar as the provisions are relevant and applicable to the rights and obligations of the *IESO* and *market participants* relating to preparation for participation in the *IESO administered markets* following commencement of *market transition;* and

A.1.1.2 the period following commencement of *market transition* in respect of all the rights and obligations of the *IESO* and *market participants.*

A.1.2 All references herein to chapters or provisions of the *market rules* or *market manuals* will be interpreted as, and deemed to be references to chapters and provisions of the *renewed market rules.*

A.1.3 Upon commencement of the *market transition*, the *legacy market rules* will be immediately revoked and only the *renewed market rules* will remain in force.

A.1.4 For certainty, the revocation of the *legacy market rules* upon commencement of *market transition* does not:

A.1.4.1 affect the previous operation of any *market rule* or *market manual* in effect before the *market transition*;

A.1.4.2 affect any right, privilege, obligation or liability that came into existence under the *market rules* or *market manuals* in effect prior to the *market transition*;

A.1.4.3 affect any breach, non-compliance, offense or violation committed under or relating to the *market rules* or *market manuals* in effect prior to the *market transition*, or any sanction or penalty incurred in connection with such breach, non-compliance, offense or violation

A.1.4.4 affect an investigation, proceeding or remedy in respect of,

(a) a right, privilege, obligation or liability described in subsection A.1.4.2, or

(b) a sanction or penalty described in subsection A.1.4.3.

A.1.5. An investigation, proceeding or remedy described in subsection A.1.4.3 may be commenced, continued or enforced, and any sanction or penalty may be imposed, as if the *legacy market rules* had not been revoked.

Market Manual Conventions

The standard conventions followed for *market manuals* are as follows:

- The word 'shall' denotes a mandatory requirement;
- References to *market rule* sections and sub-sections may be abbreviated in accordance with the following representative format: '**MR Ch.1 ss.1.1-1.2'** (i.e. *market rules,* Ch.1, sections 1.1 to 1.2);
- References to *market manual* sections and sub-sections may be abbreviated in accordance with the following representative format: **'MM 1.5 ss.1.1-1.2'** (i.e. *market manual* 1.5, sections 1.1 to 1.2);
- Internal references to sections and sub-sections within this manual take the representative format: 'sections 1.1 – 1.2';
- Terms and acronyms used in this *market manual* in its appended documents that are italicized have the meanings ascribed thereto in **MR Ch.11**;
- All user interface labels and options that appear on the IESO gateway and tools are formatted with the bold font style;
- Data fields are identified in all capitals.

– End of Section –

1 Introduction

1.1 Purpose

This *market manual* provides administrative and procedural details to the *market rules* governing the *settlement process,* including supplementary information relevant to understanding the rights and obligations of the *IESO* and *market participants*.

Market manuals must be read in conjunction with the applicable *market rules*. Where there is a conflict between a *market manual* and the *market rules*, the *market rules* shall prevail.

1.2 Scope

This *market manual* supplements the following *market rules*:

- MR Ch.3 s.2.5: Notice of Dispute, Negotiation and Response
- MR Ch.7 s.7.5.8B
- MR Ch.7 s.7.6: Dispatch Scheduling Errors
- MR Ch.7 s.8.4A: Administrative Pricing
- MR Ch.7 22.5.11
- MR Ch.8 s.3.18: TR Clearing Account
- MR Ch.8 s.3.19: Settlement
- MR Ch.9 s.1: Introductory Rules
- MR Ch.9 s.2: Settlement Data Collection and Management
- MR Ch.9 s.3: Hourly Settlement Amounts
- MR Ch.9 s.4: Non-Hourly Settlement Amounts
- MR Ch.9 s.5: Market Power Mitigation
- MR Ch.9 s.6: Settlement Statements

This *market manual* also includes a listing of each hourly and non-hourly *settlement amount* by *charge type* that will appear on a *market participant's settlement statement* and *invoice.*

For *settlement amounts* not associated with the *IESO-administered markets,* which include, but are not limited to those as directed by *applicable law*, refer to **MM 5.6**.

1.3 Overview

The following markets form the *IESO-administered markets*:

Table 1-1: IESO-Administered Markets

Market Type	Transactions
Physical Market	1. *Day-Ahead Market* a. *energy* transactions b. *operating reserve* transactions 2. *Real-Time Market* a. *energy* transactions b. *operating reserve* transactions 3. *Procurement Market* a. *contracted ancillary services*, including *regulation, voltage control* and *reactive support services, black-start capability*, and for *reliability must-run contracts* 4. Payments to *TR holders*[1] 5. *Virtual Transactions*[2]
Financial Market	1. *Transmission Rights Market (TR Market*) a. transactions ~~in~~ for all rounds of any *TR auction*[3]

For the tax treatment of the *settlement amounts* in this *market manual*, refer to **IESO Charge Types and Equations**.

The general principles of financial neutrality for the *physical market* are set out in **MR Ch.9 s.6.18**. The *physical market* will be financially balanced (net neutral) each month.

The financial *TR market* is self-funding and cannot be financially balanced each month. Refer to **MR Ch.8 ss.3.18-3.19** for further details.

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[1] Excludes *settlement amounts* relating to transactions in all rounds of any *TR auction* which will appear on the financial market *settlement statement* and *invoice*.

[2] *Virtual transactions*, although part of the financial market, will be *settled* as part of the *physical market* and will appear on the *physical market settlement statements* and *invoices*.

[3] For more information on the *TR auction* process, refer to **MM 4.4**. Only those *settlement amounts* relating to transactions for all ~~in any~~ rounds of any *TR auction* will appear on the financial market *settlement statement*.

1.4 Contact Information

Changes to this *market manual* are managed via the *IESO* Change Management process. Stakeholders are encouraged to participate in the evolution of this *market manual* via this process.

As part of the authorization and registration process[4], *market participants* are required to identify a Settlements Contact. If a *market participant* has not identified a specific contact, the *IESO* will seek to contact the Primary Contact for activities within this procedure, unless alternative arrangements have been established between the *IESO* and the *market participant*.

To contact the *IESO*, *market participants* can email *IESO* Customer Relations at customer.relations@ieso.ca or use telephone or mail. Telephone numbers and the mailing address can be found on the *IESO* website. *IESO* Customer Relations staff will respond as soon as possible.

If *market participants* have a specific inquiry regarding a *settlement amount* on any of its *settlement statements*, they can refer to **MM 5.10** for further details.

– End of Section –

[4] Refer to **MM 1.5** for adding and updating contact roles with the *IESO*.

2 Day-Ahead Market and Real-Time Market Settlement Charges, Credits and Uplifts

2.1 Two-Settlement System

(MR Ch.9 s.3.1)

Overview of two-settlement - The *settlement* of the *day-ahead market* and *real-time market* for *energy* and *operating reserve* will be accomplished through the two-*settlement* system for *dispatchable resources.*

The two-*settlement* system, as described in **MR Ch.9 s.3.1**, includes a *day-ahead market settlement* and a real-time balancing *settlement*. *Settlement amounts* from each include the following:

- ***Day-ahead market settlement*** includes *settlement amounts* for *energy* and *operating reserve* that can be completely calculated on the basis of *settlement*-ready data from the *day-ahead market calculation engine*. The *IESO* pays or charges *market participants* the *day-ahead scheduled* quantity for *energy* and *operating reserve* at the applicable *day-ahead market locational marginal price*.
- **Real-time balancing *settlement*** includes *settlement amounts* that can be calculated on the basis of *settlement*-ready data from the *day-ahead market calculation engine*, reconciled with the *real-time market* results. It balances any deviations between the *day-ahead market* and the *real-time market*. The *IESO* pays or charges *market participants* at the applicable *real-time market locational marginal price* if the actual *energy* consumed or produced, or *operating reserve offered*, differs from the quantity in its *day-ahead schedule*.

Settlement statements - The *settlement amounts* calculated under both the *day-ahead market settlement* and the real-time balancing *settlement* for *virtual transactions* and *physical transactions* will be provided to *market participants* via ~~*preliminary settlement statements* and *final*~~ *settlement statements.*

2.1.1 Hourly Physical Transaction Settlement Amount (HPTSA)

(MR Ch.9 ss.3.1.2-3.1.7)

Overview of HPTSA - As described in **MR Ch.9 ss.3.1.2-3.1.7**, the *settlement* of the *day-ahead market* and *real-time market* for *energy* for:

- *dispatchable loads*, *dispatchable generation resources, non-dispatchble generation resources, self-scheduling electricity storage resources* that are registered to inject, *dispatchable electricity storage resources*, and *energy* *traders* participating with *boundary entity resources* will be accomplished through the Hourly Physical Transaction Settlement Amount (HPTSA)

- *price responsive loads* and *self-scheduling electricity storage resources* that are registered to withdraw will be accomplished through the HPTSA_PRL,

where:

- the *day-ahead market settlement* (HPTSA{1}/HPTSA{1}_PRL) establishes a *market participant's* position for *energy* in the *day-ahead market*; and
- the real-time balancing *settlement* (HPTSA{2}/HPTSA{2}_PRL) reconciles the difference between a *market participant's* position for *energy* in the *day-ahead market* and their actual *real-time market* activity.

The sum of the *day-ahead market settlement* (HPTSA{1}/HPTSA{1}_PRL) and the real-time balancing *settlement* (HPTSA{2}/HPTSA{2}_PRL) will establish a *market participant's* net *energy* position.

HPTSA and PBCs - Where applicable, the following *settlement amounts* will be included in the *market participant's* net *energy* position as captured in each of the *energy charge types* below:

- *day-ahead market settlement* of *physical bilateral contracts* (PBCs) (HPTSA_PBC{1}); and
- real-time balancing *settlement* of *physical bilateral contracts* (HPTSA_PBC{2}).

Refer to **MM 5.3** for further information on *physical bilateral contracts*.

HPTSA charge types - The following table lists the HPTSAs on the basis of the *dispatchable resource* type.

Table 2-1: Hourly Physical Transaction Settlement Amounts

Dispatchable Resource Type	DAM Settlement Charge Type	Real-Time Balancing Settlement Charge Type
• *Dispatchable generation resources* • *Non-dispatchable generation resources* • *Self-scheduling electricity storage resources* that are registered to inject • *Dispatchable electricity storage resources* that are registered to inject	*Charge type* 1100 Day-Ahead Market Energy Settlement Amount for Generators	*Charge type* 1101 Real-Time Energy Settlement Amount for Generators
• Dispatchable loads • *Dispatchable electricity storage resources* that are registered to withdraw	*Charge type* 1102 Day-Ahead Market Energy Settlement Amount for Dispatchable Loads	*Charge type* 1103 Real-Time Energy Settlement Amount for Dispatchable Loads
• *Price responsive load*[5] • *Self-scheduling electricity storage resources* that are registered to withdraw	*Charge type* 1104 Day-Ahead Market Energy Settlement Amount for Price Responsive Loads	*Charge type* 1105 Real-Time Energy Settlement Amount for Price Responsive Loads
• *Energy traders* participating with *boundary entity resources* – import	*Charge type* 1110 Day-Ahead Market Energy Settlement Amount for Imports	*Charge type* 1111 Real-Time Energy Settlement Amount for Imports
• *Energy traders* participating with *boundary entity resources* – export	*Charge type* 1112 Day-Ahead Market Energy Settlement Amount for Exports	*Charge type* 1113 Real-Time Energy Settlement Amount for Exports

[5] *Price responsive loads* can be inclusive of physical *hourly demand response resources* (HDRs). The *settlement* of both will be combined and will appear under the *price responsive load*. Both the PRL and the physical HDR must have the same *metered market participant*.

2.1.2 Hourly Virtual Transaction Settlement Amount (HVTSA)

(MR Ch.9 ss.3.1.8-3.1.9)

Overview of HVTSA - As described in **MR Ch.9 ss.3.1.8-3.1.9**, the *settlement* of *energy* for *virtual transactions* in both the *day-ahead market* and *real-time market* will be accomplished through the Hourly Virtual Transaction Settlement Amount (HVTSA), where:

- the HVTSA is applicable to all *virtual zonal resources* that have a *day-ahead schedule*;
- the *day-ahead market settlement* (HVTSA{1}) establishes a *virtual trader's virtual transaction* for *energy* position in the *day-ahead market*; and
- the real-time balancing *settlement* (HVTSA{2}) reflects any price differences between the *day-ahead market settlement* and the real-time balancing *settlement*.

The sum of the *day-ahead market settlement* (HVTSA{1}) and the real-time balancing *settlement* (HVTSA{2}), will establish a *virtual traders* net *energy* position. Specifically, the *settlement* of the *virtual transaction* will be based on the *energy* price difference between the *day-ahead market* and the *real-time market*.

HVTSA charge types - The following table lists the HVTSAs on the basis of the *virtual transaction* type involved.

Table 2-2: Hourly Virtual Transaction Settlement Amounts

Virtual Transaction Type	DAM Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Virtual transaction to sell *energy* (i.e. *day-ahead schedule* to inject)	*Charge type* 1106 Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Sell	*Charge type* 1107 Real-Time Energy Settlement Amount for Virtual Transactions to Sell
Virtual transaction to buy *energy* (i.e. *day-ahead schedule* to withdraw)	*Charge type* 1108 Day-Ahead Market Energy Settlement Amount for Virtual Transactions to Buy	*Charge type* 1109 Real-Time Energy Settlement Amount for Virtual Transactions to Buy

2.1.3 Hourly Operating Reserve Settlement Amount (HORSA)

(MR Ch.9 ss.3.1.10-3.1.11)

Overview of HORSA - As described in **MR Ch.9 ss.3.1.10-3.1.11**, the *settlement* of the *day-ahead market* and *real-time market* for *operating reserve* for *dispatchable resources* will be accomplished through the Hourly Operating Reserve Settlement Amount (HORSA), where:

- the *day-ahead market settlement* (HORSA{1}) establishes a *market participant's* position for *operating reserve* in the *day-ahead market*; and
- the real-time balancing *settlement* (HORSA{2}) reconciles the difference between a *market participant's* position for *operating reserve* in the *day-ahead market* and their actual *real-time market* activity.

The sum of the *day-ahead market settlement* (HORSA{1}) and the real-time balancing *settlement* (HORSA{2}) will establish a *market participant's* net *operating reserve* position.

HORSA charge types - The following table lists the HORSAs ~~*settlement amounts*~~ on the basis of the type of *class r reserve*.

Table 2-3: Hourly Operating Reserve Settlement Amounts

Class r Reserve Type	Day-Ahead Market Settlement Charge Type	Real-Time Balancing Settlement Charge Type
Spinning *ten-minute operating reserve*	*Charge type* 212 Day-Ahead Market 10-Minute Spinning Reserve Settlement Credit	*Charge type* 213 Real-Time 10-Minute Spinning Reserve Settlement Credit
Non-spinning *ten-minute operating reserve*	*Charge type* 214 Day-Ahead Market 10-Minute Non-Spinning Reserve Settlement Credit	*Charge type* 215 Real-Time 10-Minute Non-Spinning Reserve Settlement Credit
Thirty-minute operating reserve	*Charge type* 216 Day-Ahead Market 30-Minute Operating Reserve Settlement Credit	*Charge type* 217 Real-Time 30-Minute Operating Reserve Settlement Credit

2.1.3.1 Hourly Uplift of HORSA and ORSCB

(MR Ch.9 s.3.11)

Overview of HORSA and ORSCB Uplift - The cumulative amount of all HORSA incurred in the *day-ahead market* and the *real-time market*, in addition to all *operating reserve* standby payment clawback (ORSCB) *settlement amounts*, as defined in section 2.29.1, will be allocated as part of the *hourly uplift.*

HORSA uplift charge types - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-4: Hourly Uplift of HORSA

Charge Type Number	Charge Type Name
250	10-Minute Spinning Reserve Hourly Uplift
252	10-Minute Non-Spinning Reserve Hourly Uplift
254	30 Minute Operating Reserve Hourly Uplift

2.2 Non-Dispatchable Load Settlement (HPTSA_NDL)

(MR Ch.9 s.3.2)

Overview HPTSA_NDL - As described in **MR Ch.9 ss.3.2.1-3.2.3**, the *settlement* of *energy* for *non-dispatchable loads* will be accomplished through the Hourly Physical Transaction Settlement Amount for *non-dispatchable loads* (HPTSA_NDL)*.* As *non-dispatchable loads* do not have a *day-ahead market* position, the *settlement* of *energy* is based on the *day-ahead market Ontario zonal price* adjusted by the load forecast deviation adjustment~~charge~~(LFDA), and the actual quantity of *energy* withdrawn at the *delivery point* in real-time by the *non-dispatchable load.*

HPTSA_NDL and DAM failure/suspension - When there is a *day-ahead market* failure or a suspension of the *day-ahead market*, *settlement* of *non-dispatchable loads* will be based on the *real-time market Ontario zonal price* and the LFDA will be 0*,* as described in **MR Ch.9 s.2.14.2**.

HPTSA_NDL charge types - The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 2-5: Non-Dispatchable Load Energy Settlement Amount

Charge Type Number	Charge Type Name
1115	Non-Dispatchable Load Energy Settlement Amount

2.2.1.1 Load Forecast Deviation Adjustment~~Charge~~ (LFD~~C~~A)

(MR Ch.9 s.3.2.3)

Overview of load forecast deviation ~~charge~~ adjustment (LFD~~C~~A) - The purpose of the load forecast deviation ~~charge~~ adjustment is to account for the cost impacts of difference in forecasted demand and actual quantity of *energy* consumed in real-time of *non-dispatchable loads.* In accordance with **MR App.7.5 s.6.3.1**, the *IESO* will forecast load *demand* for *non-dispatchable loads* in the *day-ahead market*. Load forecast deviations occur when the *IESO* forecast *demand* for *non-dispatchable loads* in the *day-ahead market* differs from the actual quantity of *energy* consumed in real-time. This results in a cost impact arising from the change in quantity of *energy* over which *energy* costs are recovered in real-time versus the quantity of *energy* that were scheduled by the *day-ahead market calculation engine* for *non-dispatchable loads* and all virtual and physical *hourly demand response resource*s[6] that are not registered as a *price responsive load*. This cost impact is accounted for by the load forecast deviation adjustment~~charge~~.

The price paid by *non-dispatchable loads* for the real-time allocated quantity of *energy* withdrawn will be the sum of the *day-ahead market Ontario zonal price* and the hourly load forecast deviation adjustment~~charge~~. Effectively, the price adjustment to the *day-ahead market Ontario zonal price* reflects a two-*settlement* balancing, the cost of which is allocated to all *non-dispatchable loads*.

Components of load forecast deviation adjustment~~charge~~ - As described in **MR Ch.9 s.3.2.3**, the load forecast deviation adjustment~~charge~~, expressed in $/MWh, is an hourly rate that is the sum of two components:

- Real-Time Purchase Cost/Benefit; and
- DAM Volume Factor Cost/Benefit.

The following table provides a description of each load forecast deviation adjustment~~charge~~ component.

Table 2-6: Load Forecast Deviation ~~Charge~~ Adjustment Components

Component	Description
Real-Time Purchase Cost/Benefit	• represents the total hourly cost or benefit to all *non-dispatchable loads,* arising from *day-ahead market* load forecast deviations for *non-dispatchable loads* as assessed in the *real-time market.* • calculated as the difference between the actual *energy* consumed by *non-dispatchable loads* in real-time and the *day-ahead market load* forecast for *non-dispatchable loads* prepared by the *IESO*, multiplied by the applicable *real-time market locational marginal price.*

[6] The inclusion of *hourly demand response resources* in the calculation of the load forecast deviation adjustment~~charge~~ accounts for the HDR *metered quantity* as *non-dispatchable load* in real-time, and ensures that the load forecast deviation adjustment~~charge~~ is not over- or under- estimated.

Component	Description
DAM Volume Factor Cost/Benefit	• represents the total hourly cost or benefit to all *non-dispatchable loads,* arising from *day-ahead market load* forecast deviations for *non-dispatchable loads* as assessed in the *day-ahead market.* • calculated as the difference between the *day-ahead market load* forecast prepared by the *IESO* and the actual *energy* consumed by *non-dispatchable loads*, multiplied by the *day-ahead market Ontario zonal price.*

Possible ~~V~~values of load forecast deviation ~~charge~~ adjustment - The load forecast deviation ~~charge~~ adjustment can be a positive or negative value and will be *published* on the *IESO* website.

2.3 Day-Ahead Market Make-Whole Payment (DAM_MWP)

(MR Ch.9 s.3.4)

Overview of DAM_MWP - The purpose of the *day-ahead market* make-whole payment *settlement amount* (DAM_MWP) is to provide compensation to *dispatchable loads, price responsive loads, energy traders* participating with *boundary entity resources, dispatchable electricity storage resources*, *self-scheduling electricity storage resources* that are registered to withdraw, and *dispatchable generation resources* that receive a *day-ahead schedule* for *energy* or *operating reserve* that deviates from their economic operating point.

When this occurs, the *market participant* might incur a lost cost where the economic operating point is less than the *market participant's day-ahead schedule*. DAM_MWP will allow the *market participant* to recover losses associated with its *day-ahead schedule* being greater than its economic operating point.

As described in **MR Ch.9 s.3.4**, the DAM_MWP will be determined based on the difference in operating profit between the *resource's* economic operating point and *day-ahead schedule*, and will ensure that the *market participant* is compensated for those losses.

DAM_MWP bid price adjustment - A *dispatchable load, price responsive load, dispatchable electricity storage resource* that is registered to withdraw or an *energy trader* participating with a *boundary entity resource* – exports, may have their *bid* price adjusted in accordance with **MR Ch.9 s.3.4.3.2**. The relevant price used in this adjustment process is -$125/MWh for exporters and -$15/MWh for the other types of *resources.*

DAM_MWP uplift - All costs associated with DAM_MWP will be recovered through the *day-ahead market* uplift (DAM_UPL).

DAM_MWP and mitigation - DAM_MWP will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.4.

DAM_MWP charge types - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-7: Day-Ahead Market Make-Whole Payment Settlement Amounts

Component	Charge Type Number	Charge Type Name
Component 1 – Energy	1800	Day-Ahead Market Make-Whole Payment – Energy
Component 2 – Operating Reserve	1801	Day-Ahead Market Make-Whole Payment – 10-Minute Spinning Reserve
	1802	Day-Ahead Market Make-Whole Payment – 10-Minute Non-Spinning Reserve
	1803	Day-Ahead Market Make-Whole Payment – 30-Minute Operating Reserve

DAM_MWP is payment only - As described in **MR Ch.9 s.3.4**, the calculation of each component, for a given *settlement hour*, may result in either a charge or credit *settlement amount*. However, DAM_MWP will only be paid when the sum of all components, as may be applicable, for the *settlement hour* is positive (greater than zero).

2.3.1 Hydroelectric Generation Resource

(MR Ch.9 s.3.4.13)

Background information - *Market participants* with hydroelectric *generation resources* may have the option to participate in the *physical market* as either a single hydroelectric *generation resource* or as part of a *cascade group* and will indicate so on a daily basis through their submitted daily *dispatch data*. Further, *market participants* can indicate if the hydroelectric *generation resource* is start-limited or not with the submission of the *maximum number of starts per day* daily *dispatch data* parameter.

Types of calculations for hydroelectric *generation resources* - If the hydroelectric *generation resource*:

- is start-limited,
- has attained max starts, and

- has a *settlement hour* that is part of a start event,

then the DAM_MWP will be calculated on a *per-start* basis for each hydroelectric *generation resource,* in accordance with **MR Ch.9 s.3.4.13.4**. Otherwise, the DAM_MWP will be calculated on an hourly basis in accordance with **MR Ch.9 s.3.4.13.3**. *Settlement hours* with a *reliability* constraint will be calculated using the hourly equation. Appendix B provides an illustration of how the *IESO* determines a start and start event.

2.3.1.1 Determining a Start and Start Event

2.3.1.1.1 Determining a Start

The *IESO* will determine the number of starts of a hydroelectric *generation resource* for the purposes of **MR Ch.9 s.3.4.13.1** in accordance with the following.

A start is triggered between *dispatch hour* (h) and (h+1) if the hydroelectric *generation resource's day-ahead schedule* increases above any *start indication value*, as registered by the *market participant*.

The number of starts will increase by one each time the *day-ahead schedule* increases above a registered *start indication value*. A hydroelectric *generation resource* can have multiple starts within a *dispatch hour.*

2.3.1.1.2 Determining a Start Event

The *IESO* will determine start events of a hydroelectric *generation resource* for the purposes of **MR Ch.9 ss. 3.4.13.3 and 3.4.13.5.2** in accordance with the following.

A start event is defined as consisting of a set of *settlement hours* beginning with the first *settlement hour* of a start and ending with the first instance of either of the following:

- the *settlement hour* in which the *resource's day-ahead schedule* is less than the *resource's* lowest registered start indication value; or
- the *settlement hour* in which another start is triggered.

2.3.1.2 Cascade Group

This section provides further context in regards to the DAM_MWP *settlement* for hydroelectric *generation resources* that form part of a *cascade group* as described in **MR Ch.9 s.3.4.13***.*

Background for *cascade groups* - Hydroelectric *generation resources* participating as a *cascade group* may have their associated *forebays* linked for the purposes of receiving a *day-ahead schedule.* The *energy* that is scheduled for an upstream hydroelectric *generation resource* will also be scheduled on the downstream hydroelectric *generation resource*, subject to the *time lag* and *MWh ratio* submitted as *dispatch data.*

Each trading day is independent - The DAM_MWP is determined based on the *day-ahead schedules* of a particular *trading day*. Hydroelectric *generation resources* in a *cascade group*, due to their *time lag*, may be scheduled into the next *trading day.* However, each *trading day* is assessed independently.

Types of calculations for *cascade group resources* - Hydroelectric *generation resources* in the *cascade group* that are not associated with *linked forebays* will be *settled* either on an hourly basis in accordance with **MR Ch.9 s.3.4.13.3** or on a per-start basis in accordance with **MR Ch.9 s.3.4.13.4**.

Overview of steps for cascade group resources with *linked forebays* - Where the hydroelectric *generation resources* in a *cascade group* are associated with *linked forebays*, the DAM_MWP will first need to be assessed across all the hydroelectric *generation resources*. This assessment is necessary to offset profits and losses across all hydroelectric *generation resources* in the *cascade group* with *linked forebays*.

The *IESO* performs the following steps for a *cascade group* with *linked forebays*:

1. Assess DAM_MWP across all hydroelectric *generation resources* in the *cascade group* associated with *linked forebays* on an hourly basis in accordance with **MR Ch.9 s.3.4.13.5.3** to determine the net DAM_MWP. This assessment is done irrespective if any of the hydroelectric *generation resources* have attained max starts or not.
2. After the net DAM_MWP has been determined, *settle* each hydroelectric *generation resource* on a per-*resource* basis as follows:
    a. where the net DAM_MWP assessment is greater than 0, and the hydroelectric *generation resources* have attained max starts, use the *per-start* equation in accordance with **MR Ch.9 s.3.4.13.4**. Otherwise, the hourly equation is used if the hydroelectric *generation resources* are subject to the provisions of **MR Ch.9 s.3.4.13.5.2**;
    b. where the net DAM_MWP assessment is less than or equal to 0, and the hydroelectric *generation resources* have attained max starts, use the *per-start* equation in accordance with **MR Ch.9 s.3.4.13.4**. Otherwise, the hydroelectric *generation resources* are ineligible for DAM_MWP.

2.4 Day-Ahead Market Generator Offer Guarantee (DAM_GOG)

(MR Ch.9 s.4.4)

Overview of DAM_GOG - The purpose of the *day-ahead market generator offer* guarantee *settlement amount* (DAM_GOG) is to provide compensation to *market participants* with *GOG-eligible resources* that have a *day-ahead operational commitment* and are unable to recover their as-*offered* costs based on the revenue earned during the *day-ahead commitment period* for *energy* and *operating reserve*. As described in **MR Ch.9 s.4.4**, as-*offered* costs are based on the *GOG-eligible resources*:

start-up offer, *speed no-load offer* and incremental *offers* for *energy* and *operating reserve.*

Each trading day is independent - As described in **MR Ch.9 s.4.4**, the DAM_GOG *settlement amount* will be assessed for each *day-ahead commitment period* and where a *GOG-eligible resource* has multiple *day-ahead commitment periods* within a *day-ahead market dispatch day*, each *day-ahead commitment period* will be assessed separately. When a *GOG-eligible resource* is scheduled over midnight, DAM_GOG will be assessed separately for each *trading day*.

DAM_GOG and mitigation - DAM_GOG will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.4.

DAM_GOG charge types - The *IESO* will determine a *settlement amount* for each of the five components under the following *charge types.*

Table 2-8: Day-Ahead Market Generator Offer Guarantee Settlement Amounts

Charge Type Number	Charge Type Name	Component
1804	Day-Ahead Market Generator Offer Guarantee – Energy	Component 1
1805	Day-Ahead Market Generator Offer Guarantee – Operating Reserve	Component 2
1806	Day-Ahead Market Generator Offer Guarantee – Over Midnight	Component 3
1807	Day-Ahead Market Generator Offer Guarantee – Start-up	Component 4
1808	Day-Ahead Market Generator Offer Guarantee – DAM Make-Whole Payment Offset	Component 5

2.4.1 De-Synchronization of a GOG-Eligible Resource

The *IESO* may de-synchronize a *GOG-eligible resource* after it receives a *day-ahead operational commitment*. This could occur, for example, for *reliability* reasons.

As described in **MR Ch.9 s.4.4**, the timing of the de-synchronized event and its impact to the DAM_GOG assessment is set out in the following table.

Table 2-9: DAM_GOG Assessment for De-Synchronization of a GOG-Eligible Resource

GOG-Eligible Resource was De-synchronized	DAM_GOG Interaction with Other Settlement Amounts
After the start of its *day-ahead operational commitment*	DAM_GOG assessment will include: • *start-up offer*, and • *speed no-load offer* incurred for the *settlement hours* that the *GOG-eligible resource* was online.
Prior to the start of its *day-ahead operational commitment*	No assessment of DAM_GOG for *start-up offer* and *speed no-load offer.* *Market participants* may be able to submit claims for reimbursement of financial loss that is associated with the de-synchronized *GOG-eligible resource*. (Refer to section 2.25)

The *GOG-eligible resource* may be eligible to receive a *DAM* balancing credit *settlement amount* for those *settlement hours* where it is de-synchronized for *reliability.*

2.5 Day-Ahead Market Uplift (DAM_UPL)

(MR Ch.9 s.4.14.3)

Overview of DAM_UPL - As described in **MR Ch.9 s.4.14.3**, the *day-ahead market* uplift *settlement amount* (DAM_UPL) will recover the cost of the DAM_MWP and DAM_GOG*.* The calculation of the DAM_UPL will exclude the portion of the DAM_MWP and DAM_GOG that are *settled* under the *day-ahead market reliability* scheduling uplift (DRSU).

The *IESO* will allocate the DAM_UPL on a daily basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

DAM_UPL charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-10: Day-Ahead Market Uplift Settlement Amount

Charge Type Number	Charge Type Name
1850	Day-Ahead Market Uplift

2.6 Day-Ahead Market Reliability Scheduling Uplift (DRSU)

(MR Ch.9 s.4.14.4)

Overview of DRSU - This section provides context for the role of the *day-ahead market reliability* scheduling uplift (DRSU) *settlement amount.* During Pass 2[7]: Reliability Scheduling and Commitment of the *day-ahead market calculation engine*, the following additional *resources* may be committed:

- *GOG-eligible resources*; or
- newly scheduled or incrementally scheduled import transactions for *boundary entity resources.*

When this occurs, the *IESO* will need to recover any additional cost associated with scheduling these *resources*. These additional costs will be recovered through the DRSU*.*

As described in **MR Ch.9 s.4.14.4**, the DRSU will be distributed on a daily basis and will be allocated:

- first to *virtual zonal resources* with *day-ahead market schedules* to inject *energy.* The allocation will be based on their proportion of the total *energy* scheduled for all *virtual zonal resources* with *day-ahead market schedules* to inject *energy* and the quantity of *energy* that was over forecast in Pass 2 for *non-dispatchable loads* to meet actual real-time *energy demand*; and
- the remainder of the DRSU will be allocated to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

DRSU charge type - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-11: Day-Ahead Market Reliability Scheduling Uplift Settlement Amounts

Charge Type Number	Charge Type Name
1851	Day-Ahead Market Reliability Scheduling Uplift
1852	Day-Ahead Market Reliability Scheduling Uplift – Virtual Transactions to Sell

[7] Pass 2: Reliability Scheduling and Commitment, checks if the *resources* committed by Pass 1: Market Commitment and Market Power Mitigation Pass, are sufficient to satisfy the peak forecast *demand*. Pass 2 then commits additional *resources* if required. Refer to **MR Ch.7 App.7.5** for further information on all the passes of the day-ahead market calculation engine.

2.7 Real-Time Make-Whole Payment (RT_MWP)

(MR Ch.9 s.3.5)

Overview of RT_MWP - The purpose of the real-time make-whole payment *settlement amount* (RT_MWP) is to provide compensation to *dispatchable loads*, *energy traders* participating with *boundary entity resources, dispatchable electricity storage resources*, and *dispatchable generation resources*, and that receive a *real-time schedule* for *energy* or *operating reserve* that deviates from their economic operating point when following *IESO dispatch instructions*:

- for manual constraints; or
- when there are differences between the scheduling and pricing pass.

When this occurs, the *market participant* might incur a lost cost or lost opportunity cost, where:

- lost cost: the economic operating point is less than the *market participant's real-time schedule*. The RT_MWP will allow the *market participant* to recover losses associated with being scheduled above its economic operating point. The lost cost will not include quantities of *energy* that are included in the *day-ahead schedule*.
- lost opportunity cost: the economic operating point is greater than the *market participant's real-time schedule*. The RT_MWP will allow the *market participant* to recover lost profit associated with being scheduled below its economic operating point.

The RT_MWP will ensure that the *market participant* is compensated for such lost cost and lost opportunity cost losses when following such *IESO dispatch instructions*.

Ineligibility of export transactions - As described in **MR Ch.9 s.3.5**, for *energy traders* participating with a *boundary entity resource* with an export transaction, eligibility for RT_MWP will be determined according to the reason code assigned by the *IESO*. For more details on the applicable reason codes, refer to **MM 4.3**.

RT_MWP bid adjustment price - A *dispatchable load, dispatchable electricity storage resource* or *energy traders* participating with a *boundary entity resource* – exports, may have their *bid* price adjusted in accordance with **MR Ch.9 s.3.5.5.2**. The relevant price used in this adjustment process is -$125/MWh for exporters and -$15/MWh for the other types of *resources.*

Eligibility details for ELOC - MR Ch.9 s.3.5.4.9 sets out specific conditions related to a *resource's* eligibility for *energy* lost opportunity cost (ELOC). Both the nature of ramping up or down, as referred to in **MR Ch.9 s.3.5.4.9(a)**, and the nature of activation for *operating reserves*, as referred to in **MR Ch.9 s.3.5.4.9.1(b)**, are described in the following table.

Table 2-12: Dispatchable Load and Dispatchable Electricity Storage Resource Eligibility for ELOC

Circumstance	Conditions
Ramping (MR Ch.9. s.3.5.4.9(a))	The following conditions exist when the *resource* is ramping up: • the *real-time schedule* increases between *metering interval* 12 of the previous *settlement hour* and *metering interval* 3 of the current *settlement hour*; and • the RT_LOC_EOP in *metering interval* 12 of the previous *settlement hour* is less than the RT_LOC_EOP in *metering interval* 1 of the current *settlement hour*; and • there is a change in the *bid* lamination, or removal of the *bid*, between the previous *settlement hour* and the next *settlement hour*. The following conditions exist when the *resource* is ramping down: • the *real-time schedule* decreases between *metering interval* 9 and 12 of the current *settlement hour*; and • the RT_LOC_EOP in *metering interval* 12 of the current *settlement hour* is greater than the RT_LOC_EOP in *metering interval* 1 of the next *settlement hour*; and • there is a change in the *bid* lamination, or removal of the *bid*, between the current *settlement hour* and the next *settlement hour*.
Activation for *operating reserve* (MR Ch.9 s.3.5.4.9.1(b))	The *resource* is considered to be *dispatched* in a *metering interval* as part of an activation of *operating reserve* if any of the following conditions exist: • the *real-time schedule* has a reason code 'ORA'; or • the *metering interval* is within 1 to 3 *metering intervals* in advance of the *metering interval* with the 'ORA' code; or • the *metering interval* is within 1 to 3 intervals after the *metering interval* with the 'ORA' code.

RT_MWP and mitigation - RT_MWP will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.4.

RT_MWP charge types - The *IESO* will determine *settlement amounts* under the following *charge types.*

Table 2-13: Real-Time Make-Whole Payment Settlement Amounts

Charge Type Number	Charge Type Name
1900	Real-Time Make-Whole Payment – Lost Cost for Energy
1901	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve
1902	Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve
1903	Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve
1904	Real-Time Make-Whole Payment – Lost Opportunity Cost for Energy
1905	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve
1906	Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve
1907	Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve

2.8 Real-Time Make-Whole Payment Uplift (RT_MWPU)

(MR Ch.9 s.3.11)

Overview of RT_MWPU - The real-time make-whole payment uplift *settlement amount* (RT_MWPU) will recover the cost of the RT_MWP, in addition to the RT_MWP_RC, as defined in section 2.29.2.1, and will be allocated as part of the *hourly uplift*.

RT_MWPU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-14: Real-Time Make-Whole Payment Uplift Settlement Amount

Charge Type Number	Charge Type Name
1950	Real-Time Make-Whole Payment Uplift

2.9 Day-Ahead Market Balancing Credit (DAM_BC)

(MR Ch.9 s.3.3)

Overview of DAM_BC - The purpose of the *day-ahead market* balancing credit *settlement amount* (DAM_BC) for *market participants* with eligible *GOG-eligible resources* and *energy traders* participating with *boundary entity resources* is to compensate for financial losses incurred by the *market participant* in the circumstances specified by the *market rules.*

As described in **MR Ch.9 s.3.3**, for each applicable *settlement hour,* the DAM_BC will be the sum of the *energy* component (DAM_BCE) and the *operating reserve* component (DAM_BCOR) for each eligible *metering interval* within such *settlement hour*, and will be calculated in accordance with **MR Ch.9 ss.3.3.3-3.3.4.**

DAM_BC charge types - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-15: Day-Ahead Market Balancing Credit Settlement Amount

Charge Type Number	Charge Type Name
1815	Day-Ahead Market Balancing Credit – Energy
1816	Day-Ahead Market Balancing Credit – Operating Reserve

2.10 Day-Ahead Market Balancing Credit Uplift (DAM_BCU)

(MR Ch.9 s.3.11)

Overview of DAM_BCU - The *day-ahead market* balancing credit uplift *settlement amount* (DAM_BCU) will be allocated as part of the *hourly uplift.*

DAM_BCU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-16: Day-Ahead Market Balancing Credit Uplift Settlement Amount

Charge Type Number	Charge Type Name
1865	Day-Ahead Market Balancing Credit Uplift

2.11 Real-Time Generator Offer Guarantee (RT_GOG)

(MR Ch.9 s.4.5)

Overview of RT_GOG - The purpose of the real-time *generator offer* guarantee *settlement amount* (RT_GOG) is to provide compensation to *market participants* with *GOG-eligible resources* that are committed during the *pre-dispatch scheduling process* and are unable to recover their as-*offered* costs based on the revenue earned during the *real-time commitment period* or *real-time reliability commitment period*. As described in **MR Ch.9 s.4.5**, subject to mitigation, as-*offered* costs are based on the *GOG-eligible resources*: *start-up offer*, *speed no-load offer* and incremental *offers* for *energy* and *operating reserve.*

Independent assessment of RT_GOG - As described in **MR Ch.9 s.4.5**, the RT_GOG will be calculated over the *real-time commitment period* or *real-time reliability commitment period*. If a *GOG-eligible resource:*

- has multiple starts[8] within a *real-time dispatch day*, each start will be assessed separately as its own *real-time commitment period* or *real-time reliability commitment period*; or
- is scheduled over midnight, RT_GOG will be assessed separately for each *trading day*.

RT_GOG and mitigation - RT_GOG will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.4.

The *IESO* will determine a *settlement amount* for each of the five components under the following *charge types.*

Table 2-17: Real-Time Generator Offer Guarantee Settlement Amounts

Charge Type Number	Charge Type Name	Component
1910	Real-Time Generator Offer Guarantee – Energy	Component 1
1911	Real-Time Generator Offer Guarantee – Operating Reserve	Component 2
1912	Real-Time Generator Offer Guarantee – Over Midnight	Component 3
1913	Real-Time Generator Offer Guarantee – Start-up	Component 4
1914	Real-Time Generator Offer Guarantee – RT Make-Whole Payment Offset	Component 5

[8] ~~See~~ Refer to **MM 4.3**.

2.11.1 De-Synchronization of a GOG-Eligible Resource

The *IESO* may de-synchronize a *GOG-eligible resource* after it receives a *real-time operational commitment*. This could occur, for example, for *reliability* reasons.

The timing of the de-synchronized event and its impact to the RT_GOG assessment is set out in the following table.

Table 2-18: RT_GOG Assessment for De-Synchronization of GOG-Eligible Resource

GOG-Eligible Resource was De-Synchronized	RT_GOG Interaction with Other Settlement Amounts
After the start of its *pre-dispatch operational commitment*	For the *settlement hours* that the *GOG-eligible resource* was online, RT_GOG assessment will include: 1. *start-up offer,* and 2. *speed no-load offer*.
Prior to the start of its *pre-dispatch operational commitment*	No assessment of RT_GOG for *start-up offer* and *speed no-load offer.* *Market participants* may be able to submit claims for reimbursement of financial loss that is associated with the de-synchronized *GOG-eligible resource*. (Refer to section 2.25)

2.12 Real-Time Generator Offer Guarantee Uplift (RT_GOGU)

(MR Ch.9 s.4.14.2)

Overview of RT_GOGU - As described in **MR Ch.9 s.4.14.2**, the real-time *generator offer* guarantee uplift *settlement amount* (RT_GOGU) will recover the cost of the RT_GOG, in addition to the RT_GOG_CB, as defined in section 2.29.2.2, and will be allocated on a daily basis to all *real-time market* loads*, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

RT_GOGU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-19: Real-Time Generator Offer Guarantee Uplift Settlement Amount

Charge Type Number	Charge Type Name
1960	Real-Time Generator Offer Guarantee Uplift

2.13 Generator Failure Charge (GFC)

(MR Ch.9 s.4.10)

Overview of GFC - A *GOG-eligible resource* that experiences a *generator failure*, will incur a *generator failure* charge (GFC). The specific circumstances which may give rise to a *generator failure* are further described in Table 2-22.

Summary of GFC components - As described in **MR Ch.9 s.4.10**, there are two components to the GFC as described in the following table.

Table 2-20: Generator Failure Charge Components

Component	Description
Market Price Component	• Represents the impact of the increase to the *market price* for *energy* due to the *GOG-eligible resource's generator failure*. • Will be calculated for each *metering interval* for the failure event and will be *settled* on an hourly basis.
Guarantee Cost Component	• Represents an approximate cost of the impact to the market due to the *GOG-eligible resource's generator failure*. • Will be assessed and calculated for the failure event on a daily basis. • Where a *GOG-eligible resource* has a *generator failure* event that extends into the next *trading day*, the *generator failure* event will be considered as two separate events and the *generator failure* charge will be assessed separately for each *trading day.*

GFC charge types - The *IESO* will determine *settlement amounts* under the following *charge types.*

Table 2-21: Generator Failure Charge Settlement Amounts

Charge Type Number	Charge Type Name
1920	Generator Failure Charge – Market Price Component
1921	Generator Failure Charge – Guarantee Cost Component

2.13.1 Period Subject to the Generator Failure Charge for Non-Pseudo-Units

(MR Ch.9 s.4.10.4)

Definition of 'T1' for non-pseudo-units - When a *generator failure* occurs, the failure intervals within the failure event, defined as 'T1' in **MR Ch.9 s.4.10.1** must be determined. Table 2-22 defines the relevant failure intervals in regards to each type of failure event.

Table 2-22: Failure Event and Failure Intervals Subject to the Generator Failure Charge

Failure Event Number	Failure Event	Failure Intervals
1	Failing to inject into the *IESO-controlled grid* to meet a *pre-dispatch operational commitment*	All *metering intervals* of the *GOG-eligible resource's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.
2	Failing to reach *minimum loading point* by the first hour of the *pre-dispatch operational commitment*	From the first *metering interval* where a *GOG-eligible resource* has a *pre-dispatch operational commitment*, until the last *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point*.
3	Failing to complete its *minimum generation block run-time*	From the first *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point*, until the last *metering interval* where the *GOG-eligible resource* has a *binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.
4	Failing to complete its *extended pre-dispatch operational commitment*, where the extension period is still within the *binding pre-dispatch advisory schedule*	From the first *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point* until the earlier of: • the end of the *binding pre-dispatch advisory schedule* issued at the time of *start-up notice*; or

Failure Event Number	Failure Event	Failure Intervals
		• the end of the *binding pre-dispatch advisory schedule* at the time of extension.
5	Failing to complete its *extended pre-dispatch operational commitment*, where the extension period is outside the *binding pre-dispatch advisory schedule*	From the first *metering interval* where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point* until the end of its *extended pre-dispatch operational commitment*.

2.13.2 Period Subject to the Generator Failure Charge for Pseudo-Units

(MR Ch.9 s.4.10.7)

Definition of 'T1' for pseudo-units - When a *generator failure* occurs for a *pseudo-unit,* the failure intervals for both the combustion turbine ~~*generation unit*~~*resource* and steam turbine *resource*~~*generation unit*~~ within the failure event, defined as 'T1' in **MR Ch.9 s.4.10.1** must be determined. Table 2-23 defines the relevant failure intervals in regards to each type of failure event for both the combustion turbine *resource* ~~*generation unit*~~ and steam turbine *resource*~~*generation unit*~~*.*

Table 2-23: Failure Event and Failure Intervals Subject to the Generator Failure Charge for a Pseudo-Unit

Failure Event Number	Failure Event	Failure Intervals for the Combustion Turbine and associated Steam Turbine
1	The combustion turbine *resource*~~*generation unit*~~ fails to inject into the *IESO-controlled grid* to meet a *pre-dispatch operational commitment*	All *metering intervals* of the combustion turbine *resource*~~*generation unit*~~'s *pre-dispatch advisory schedule* issued at the time of *start up notice*.
2	The *pseudo-unit* operates in combined cycle mode and the combustion turbine *resource*~~*generation unit*~~ fails to reach its *minimum loading point* by the first hour of the *pre-dispatch operational commitment*	From the first *metering interval* where the combustion turbine *resource*~~*generation unit*~~ has a *pre-dispatch operational commitment*, until the last *metering interval* where the combustion turbine *resource*~~*generation unit*~~ has a *real-time schedule* less than its *minimum loading point.*

Failure Event Number	Failure Event	Failure Intervals for the Combustion Turbine and associated Steam Turbine
3	The *pseudo-unit* operates in combined cycle mode and the combustion turbine *resource*~~*generation unit*~~ fails to be scheduled at an amount that is greater than or equal to its *minimum loading point* for the duration of the *pseudo-unit's minimum generation block run-time*	From the first *metering interval* where the combustion turbine *resource*~~*generation unit*~~ has a *real-time schedule* less than its *minimum loading point,* until the last *metering interval* where the *pseudo-unit* has a *binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.
4	The *pseudo-unit* operates in combined cycle mode and the combustion turbine *resource*~~*generation unit*~~ fails to be scheduled at an amount that is greater than or equal to *minimum loading point* for the duration of its *extended pre-dispatch operational commitment*, where the extension period is still within the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*	From the first *metering interval* where the combustion turbine *resource*~~*generation unit*~~ has a *real-time schedule* less than its *minimum loading point*, until the earlier of: • the end of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*; or • the end of the *pseudo-unit's binding pre-dispatch advisory schedule* at the time of extension.
5	The *pseudo-unit* operates in combined cycle mode and the combustion turbine *resource*~~*generation unit*~~ fails to inject at an amount that is greater than or equal to its *minimum loading point* for the duration of its *extended pre-dispatch operational commitment*, where that extension period is outside of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*	From the first *metering interval* where the combustion turbine *resource*~~*generation unit*~~ has a *real-time schedule* less than its *minimum loading point*, until the end of the *pseudo-unit's extended pre-dispatch operational commitment*.
6	The *pseudo-unit* switches to *single cycle mode* after it is committed by the *pre-dispatch calculation engine* in combined cycle mode	Combustion Turbine *Resource*~~*Generation Unit*~~: • from the first *metering interval* where the *energy offer* has increased or the combustion turbine *resource*~~*generation unit*~~

Failure Event Number	Failure Event	Failure Intervals for the Combustion Turbine and associated Steam Turbine
		has a *real-time schedule* less than its *minimum loading point,* until the last *metering interval* of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice.* Steam Turbine *Resource~~Generation Unit~~*: • from the first *metering interval* where the *pseudo-unit* has switched to single cycle mode*,* until the last *metering interval* of the *pseudo-unit's binding pre-dispatch advisory schedule* issued at the time of *start-up notice*.

When a steam turbine *resource~~generation unit~~* experiences a *generator failure,* the steam turbine *resource~~generation unit~~* failure intervals will be determined as the set of contiguous failure *metering intervals* starting with earliest failed *metering interval* of the *pseudo-unit* that failed and ending with the latest *metering interval* of the *pseudo-unit* that failed.

2.14 Generator Failure Charge – Market Price Component Uplift (GFC_MPCU)

(MR Ch.9 s.3.11)

Overview of GFC_MPCU - The *generator failure* charge – *market price* component uplift *settlement amount* (GFC_MPCU) will be allocated as part of the *hourly uplift.*

GFC_MPCU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-24: Generator Failure Charge – Market Price Component Uplift Settlement Amount

Charge Type Number	Charge Type Name
1970	Generator Failure Charge – Market Price Component Uplift

2.15 Generator Failure Charge – Guarantee Cost Component Uplift (GFC_GCCU)

(MR Ch.9 s.4.14.1)

Overview of GFC_GCCU - As described in **MR Ch.9 s.4.14.1**, the *generator failure* charge – guarantee cost component uplift *settlement amount* (GFC_GCCU) will be allocated on a daily basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

GFC_GCCU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-25: Generator Failure Charge – Guarantee Cost Component Uplift Settlement Amount

Charge Type Number	Charge Type Name
1971	Generator Failure Charge – Guarantee Cost Component Uplift

2.16 Intertie Failure Charge (INFC)

(MR Ch.7 s.7.5.8B and Ch.9 s.3.7)

INFC and compliance - In addition to the *intertie* failure charge (INFC) for *intertie* transaction failures in the *day-ahead market* and *real-time market,* the *market rules* allow for compliance actions, which may include both imposing a financial penalty and/or adjusting any *settlement amounts* that were inappropriately gained or avoided by a *market participant*.

Overview of INFC - As described in **MR Ch.9 ss.3.7 and 3.7A**, *intertie* failure charges will apply to an *intertie* transaction that fails to flow in real-time for reasons within the *market participant's* control that are not considered 'bona fide and legitimate'. An *intertie* failure charge will apply:

- *day-ahead market* (DAM_INFC): for the portion of the *day-ahead market* quantity of *energy* scheduled in the *pre-dispatch schedule* and is not scheduled in the *real-time market*;

- *real-time market* (RT_INFC): for the portion of the quantity of *energy* in the *pre-dispatch schedule* that is greater than the quantity of *energy* in the *day-ahead schedule* and is not *scheduled* in the *real-time market*.

Where the conditions set out in **MR Ch.9 s.3.7A.1**, for the *day-ahead market,* or **MR Ch.9 ss.3.7.3 and 3.7.5**, for the *real-time market*, are satisfied, an *intertie* failure charge (INFC) *settlement amount* will be triggered and:

- calculated in accordance with **MR Ch.9 ss.3.7A.2 and 3.7A.3** for the *day-ahead market* import failure charge (DAM_IMFC) and *day-ahead market* export failure charge (DAM_EXFC), respectively; or
- calculated in accordance with **MR Ch.9 ss.3.7.4 and 3.7.6** for the *real-time* import failure charge (RT_IMFC) and *real-time* export failure charge (RT_EXFC), respectively.

Price b~~B~~ias a~~A~~djustment f~~F~~actor - An hourly applicable price bias adjustment factor, determined by the *IESO* in accordance with **MR Ch.9 s.3.7.2**, will be calculated and included in the calculation of the real-time *intertie* failure charge. The purpose of the price bias adjustment factor is to compensate for systematic differences between the pre-dispatch *intertie border price* and the *real-time market intertie border price*. Refer to Appendix C for the methodology used to calculate the price bias adjustment factor.

2.16.1 Intertie Transaction Reason Codes and Resultant Settlement Treatment

Bona fide and legitimate reasons – As per **MR Ch.9 s.3.7.3.3**, the INFC does not apply in circumstances where there are bona fide and legitimate reasons for the failed transaction. The *IESO* will apply one of several reason codes to import and export schedules to determine the appropriate *settlement* treatment. These reason codes, and whether they comprise bona fide and legitimate reasons, are defined in detail in **MM 4.3**.

INFC charge types - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 2-26: Intertie Failure Charge Settlement Amounts

Charge Type Number	Charge Type Name
1828	Day-Ahead Market Import Failure Charge
1829	Day-Ahead Market Export Failure Charge
1928	Real-Time Import Failure Charge
1929	Real-Time Export Failure Charge

2.17 Intertie Failure Charge Uplift (IFCU)

(MR Ch.9 s.3.11)

Overview of IFCU - The *intertie* failure charge uplift *settlement amount* (IFCU) will be allocated as part of the *hourly uplift*.

IFCU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-27: Intertie Failure Charge Uplift Settlement Amount

Charge Type Number	Charge Type Name
186	Intertie Failure Charge Uplift

2.18 Real-Time Intertie Offer Guarantee (RT_IOG)

(MR Ch.9 s.3.6)

Overview of RT_IOG - *Boundary entity resources* are scheduled during the hour-ahead *pre-dispatch process*, which presents a price risk as *energy traders* are compensated based on *real-time market locational marginal prices*, possibly resulting in the *energy traders* operating at a loss. To reduce this price risk and ensure an adequate supply of *energy* into Ontario, *energy traders* participating with a *boundary entity resource* may be eligible to receive a single real-time *intertie offer* guarantee payment (RT_IOG), net of any IOG offsets, for an *energy* import transaction scheduled in the *real-time market*.

Day-ahead schedules are financially binding. Therefore, *energy* import transactions scheduled in the *day-ahead market* that are subsequently scheduled for the same quantity of *energy* in the *real-time market* will not be impacted by any price changes and will not be compensated for RT_IOG.

As described in **MR Ch.9 s.3.6**, the *settlement* of *energy traders* participating with a *boundary entity resource* under the *day-ahead market*, as well as other *energy* import transactions and *energy* export transactions scheduled in the *real-time market,* will need to be taken into account when determining the appropriate RT_IOG. *Energy* import transactions and *energy* export transactions for the same *market participant*, and flowing in the same *settlement hour*, are considered to be implied *linked wheeling through transactions*[9]. The *IESO* will take these *day-ahead schedules* and implied *linked wheeling through transactions* into account through the IOG offset process described below in order to determine the RT_IOG for each *settlement hour*. The

[9] An implied *linked wheeling through transaction* is a transaction where the import transaction and export transaction are not formally linked, in the same hour.

market participant is only compensated for *real-time market energy* import transaction quantities of *energy* that do not form part of a linked *wheeling through transaction.*

Real-time market energy import transactions that are part of a *linked wheeling through transaction* are not eligible for a RT_IOG payment.

RT_IOG charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-28: Real-Time Intertie Offer Guarantee Settlement Amount

Charge Type Number	Charge Type Name
1927	Real-Time Intertie Offer Guarantee

2.18.1 IOG Offset Process

(MR Ch.9 ss.3.6.3-3.6.5)

As described in **MR Ch.9 ss.3.6.3-3.6.5**, the IOG offset process involves calculating the potential RT_IOG and then subtracting the IOG_Offset amount. The IOG offset amount is determined by calculating an RT_IOG rate and multiplying it by the IOG_Offset MWs. If the total IOG_Offset MWs equals the quantity of *energy* scheduled for the eligible *real-time market energy* import transaction, the *energy trader* participating with a *boundary entity resource* will not receive a RT_IOG *settlement amount* for such an *energy* import transaction.

The *IESO* implements the process described below to determine the IOG_Offset MWs. Appendix D provides an illustration of the IOG offset process.

For each *market participant* and for each *settlement hour*:

Step 1: Identify all *energy traders* participating with *boundary entity resource energy* transactions for the *settlement hour*, including all *real-time market* import transactions, *day-ahead market* import transactions, *real-time market* export transactions and *day-ahead market* export transactions.

Step 2: Identify and remove all *day-ahead market* and *real-time market linked wheeling through transactions*.

Step 3: Calculate the Potential_IOG for each *energy* import transaction scheduled in the *real-time market* in accordance with **MR Ch.9 s.3.6.3**.

- The Potential_IOG is the maximum possible RT_IOG *settlement amount* for such *real-time market energy* import transaction and is reduced by the application of the IOG offsets.

Step 4: Calculate the RT_IOG rate ($/MW) for each *energy* import transaction scheduled in the *real-time market*, in accordance with **MR Ch.9 s.3.6.4**.

Step 5: Remove all *energy* import transactions scheduled in the *real-time market* with a RT_IOG rate of $0/MW.

Step 6: Sort *energy* import transactions scheduled in the *real-time market* in ascending order of the RT_IOG rate.

Step 7: Determine the incremental *real-time market energy* export transactions by subtracting the quantity of *energy* for *day-ahead market* export transactions from the quantity of *energy* for *real-time market* export transactions for the same *energy traders* participating with a *boundary entity resource* for the same *settlement hour*.

- Any incremental *real-time market energy* export transactions will be carried forward and any incremental *day-ahead market energy* export transactions will automatically be set to 0.

After Steps 1 through 7 have been completed*,* the IOG_Offset MWs will be determined in three stages: (1) *intertie* level, (2) *neighbouring electricity system* level and (3) *IESO-control area* (Ontario) level.

Step 8: Perform the following IOG offset at the *intertie* level:

1. On the same *intertie,* identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market,* but for which the *day-ahead energy* import transaction was not scheduled in the *real-time market.*
    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of import transactions scheduled in the *day-ahead market* but not in the *real-time market.*
    b. Repeat Step 8:1a for each *intertie*, in ascending order of RT_IOG rate*.*
    c. The remaining quantity of *energy* for any import transaction scheduled in the *day-ahead market* or in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.
2. On the same *intertie,* identify *energy* import transactions and *energy* export transactions scheduled in the *real-time market.*
    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of export transactions scheduled in the *real-time market.*
    b. Repeat Step 8:2a for each *intertie*, in ascending order of RT_IOG rate*.*
    c. The remaining quantity of *energy* for any import transaction or export transaction scheduled in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.

Step 9: Perform the following IOG offset at the *neighbouring electricity system* level:

For the same *neighbouring electricity system,* identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market,* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market.*

a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of import transactions scheduled in the *day-ahead market* but not in the *real- time market.*

b. Repeat Step 9:1a for each *neighbouring electricity system*, in ascending order of RT_IOG rate.

c. The remaining quantity of *energy* for any import transaction scheduled in the *day-ahead market* or in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.

For the same *neighbouring electricity system,* identify *energy* import transactions and *energy* export transactions scheduled in the *real-time market.*

a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset the quantities of *energy* of export transactions scheduled in the *real-time market.*

b. Repeat Step 9:2a for each *neighbouring electricity system*, in ascending order of RT_IOG rate.

c. The remaining quantity of *energy* for any import transaction or export transaction scheduled in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next steps.

Step 10: Perform the following IOG offset at the *IESO-control area* (Ontario) level:

1. Identify remaining *energy* import transactions scheduled in the *real-time market* and remaining *energy* import transactions scheduled in the *day-ahead market,* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset with the quantities of *energy* of import transactions scheduled in the *day-ahead market* but not in the *real-time market.*

    b. Repeat Step 10:1a in ascending order of RT_IOG rate.

    c. The remaining quantity of *energy* for any import transaction scheduled in the *real-time market* that was not fully offset, or was not subject to offset at this step, will be carried forward to the next step.

2. Identify *energy* import transactions and *energy* export transactions scheduled in the *real-time market.*
    a. For the *energy* import transaction scheduled in the *real-time market* with the lowest RT_IOG rate, offset with the quantities of *energy* of export transactions scheduled in the *real-time market.*
    b. Repeat Step 10:2a in ascending order of RT_IOG rate*.*
    c. The remaining quantity of *energy* for any import transaction scheduled in the *real-time market* that was not fully offset, will be included in determining the IOG_Offset MWs.

Step 11: Determine the IOG_Offset MWs for each eligible *energy* import transaction scheduled in the *real-time market*.

Step 12: Determine the IOG_Offset ($) for each eligible *energy* import transaction scheduled in the *real-time market,* calculated in accordance with **MR Ch.9 s.3.6.4***.*

Step 13: Determine the RT_IOG *settlement amount* for each eligible *energy* import transaction scheduled in the *real-time market,* calculated in accordance with **MR Ch.9 s.3.6.3**.

2.19 Real-Time Intertie Offer Guarantee Uplift (RT_IOGU)

(MR Ch.9 s.3.11)

Overview of RT_IOGU - The real-time *intertie offer* guarantee uplift *settlement amount* (RT_IOGU) will be allocated as part of the *hourly uplift.*

RT_IOGU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-29: Real-Time Intertie Offer Guarantee Uplift Settlement Amount

Charge Type Number	Charge Type Name
1977	Real-Time Intertie Offer Guarantee Uplift

2.20 Internal Congestion and Loss Residuals (ICLR)

(MR Ch.9 s.4.7)

Overview of ICLR - Locational pricing and the physical realities of the *IESO-controlled grid* (for e.g. congestion and line losses), mean the amount paid for *energy* by consumers does not always equal the amount paid to suppliers. This differential is known as residuals.

These residuals can arise in both the *day-ahead market* and the *real-time market* as part of the *energy settlement* from all *market participants* that consume or supply *energy.*

As described in **MR Ch.9 s.4.7**, the internal congestion and loss residual *settlement amount* (ICLR) will be calculated for each *energy market billing period* and disbursed to or collected from *load resources* within Ontario, at each *delivery point* during the same *energy market billing period* based on their proportionate share of *energy* withdrawn (AQEW).

ICLR charge type -The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-30: Internal Congestion and Loss Residual Settlement Amount

Charge Type Number	Charge Type Name
1116	Internal Congestion and Loss Residual

2.21 External Congestion and Net Interchange Scheduling Limit Residuals

(MR Ch.9 s.4.8)

Overview of external congestion and NISL residuals - Residuals are created at the *interties* in the *day-ahead market* and *real-time market* as part of the *energy settlement* from all *boundary entity resources* that consume or supply *energy.*

Four types of residuals can arise at the *interties*:

- *Day-ahead market* external congestion residual;
- *Real-time market* external congestion residual;
- *Day-ahead market* net interchange scheduling limit (NISL) residual; and
- *Real-time market* NISL residual.

External congestion and NISL residual charge types - The following table identifies the *settlement amounts* associated with each type of residual.

Table 2-31: External Congestion and NISL Residual Settlement Amounts

Residual Type	Charge Type Number and Name	Settlement
Day-Ahead Market External Congestion	*Charge type* 1117	Refer to section 2.22 for details.

Residual Type	Charge Type Number and Name	Settlement
Residual (DAM_ECR)	Day-Ahead Market Net External Congestion Residual	
Real-Time External Congestion Residual (RT_ECR)	*Charge type* 1118 Real-Time External Congestion Residual Uplift	The Real-Time External Congestion Residual Uplift (RT_ECRU) *settlement amount* will be calculated for each *energy market billing period* and disbursed to or collected from all *real-time market load resources* and exports in accordance with **MR Ch.9 ss.4.8.1-4.8.4***.*
Day-Ahead Market Net Interchange Scheduling Limit Residual (DAM_NISLR)	*Charge type* 1119 Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift	The Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift (DAM_NISLRU) *settlement amount* will be allocated on a daily basis to all *real-time market load resources* and exports in accordance with **MR Ch.9 ss.4.8.5-4.8.7**.
Real-Time Net Interchange Scheduling Limit Residual (RT_NISLR)	*Charge type* 1120 Real-Time Net Interchange Scheduling Limit Residual Uplift	The Real-Time Net Interchange Scheduling Limit Residual Uplift (RT_NISLRU) *settlement amount* will disburse the Real-Time Net Interchange Scheduling Limit Residual (RT_NISLR), calculated in accordance with **MR Ch.9 s.4.8.8**, on an hourly basis as part of the hourly uplift described in **MR Ch.9 s.3.11**.

2.22 Transmission Rights

(MR Ch.9 s.3.8.2 and s.4.9)

Overview of transmission rights settlement - After payments are made to *TR holders* under *charge type* 104, the net *day-ahead market* external congestion residual (DAM_NECR), calculated in accordance with **MR Ch.9 s.3.8.2**, will be allocated to the *TR clearing account* for future disbursement in accordance with **MR Ch.9 s.4.9***.*

The following two tables identify the *settlement amounts* applicable to *transmission rights* and under which market they are *settled*. For further information on the *TR market*, refer to **MM 4.4**.

Transmission rights auction charge type - The following *settlement amounts* will appear on the financial market *settlement statements* and *invoices.*

Table 2-32: Transmission Rights Settlement Amounts – Financial Market

Charge Type	Settlement Amount
Charge type 52 Transmission Rights Auction Settlement Debit	*Settlement amounts* relating to transactions in all rounds of any *TR auction.*

Transmission rights charge types - The following *settlement amounts* will appear on the *physical market settlement statements* and *invoices.*

Table 2-33: Transmission Rights Settlement Amounts – Physical Market

Charge Type	Settlement Amount
Charge type 102 TR Clearing Account Credit	Disbursement of surplus funds from the *TR clearing account* by the *IESO* to *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).
Charge type 104 Transmission Rights Settlement Credit	Payment from the *IESO* to *TR holders.*
Charge type 1117 Day-Ahead Market Net External Congestion Residual	*Day-ahead market external congestion rent* collected by the *IESO*, net of payments to *TR holders* under *charge type* 104.
Charge type 168 TR Market Shortfall Debit	Payment from *market participants* to the *IESO* when payments to *TR holders* exceeds *day-ahead market external congestion rent* collected and there are insufficient funds in the *TR clearing account* to fund these payments to *TR holders.*

2.22.1 Transmission Rights Clearing Account Disbursement

(MR Ch.9 s.4.9, MR Ch.8 ss.3.18.2-3.18.3)

Overview of the transmission rights clearing account disbursement - The *IESO* will review the *TR clearing account* balance on a semi-annual basis and disburse the surplus funds in excess of the Reserve Threshold of $5M, or as directed by the *IESO Board*.

As described in **MR Ch.9 s.4.9**, the surplus funds are divided into two classes, respectively, based on the proportion of total provincial *transmission service charges* (*charge type* 650, 651 and 652) and total export *transmission service charges* (*charge type* 653) collected from *transmission customers* during the six (6) month period immediately preceding the month-end on which it will be disbursed, or as otherwise directed by the *IESO Board* (“TRCA balance period”).

Each class of funds will then be settled as a single payout based on the total allocated quantity of *energy* withdrawn over a six (6) month prior period, or as otherwise directed by the *IESO Board* ("TRCA look-back period")

The following representative diagram illustrates an example of a "TRCA balance period" and a "TRCA look-back period".

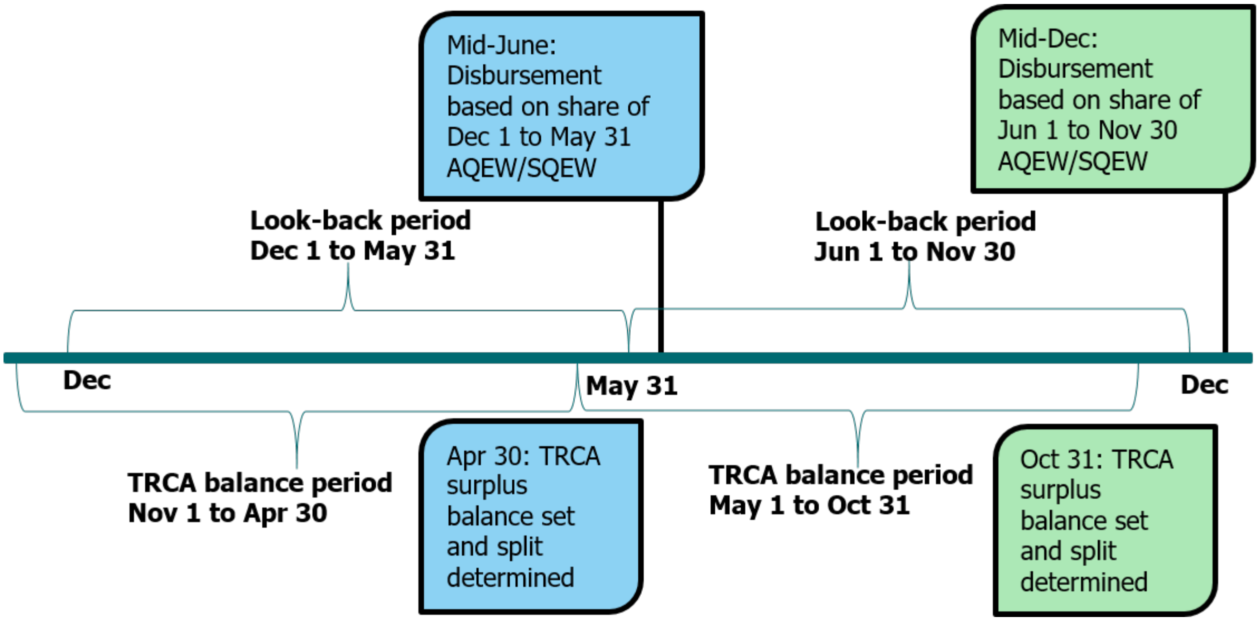

Figure 2-1: Example of TRCA balance period and TRCA look-back period

The surplus funds allocated to *load resources* are distributed based on their proportionate share of *energy* withdrawn at all *delivery points*. The surplus funds allocated to exporters are distributed based on their proportionate share of *energy* withdrawn at all *intertie metering points*.

The following diagram illustrates the disbursement of the TRCA surplus balance.

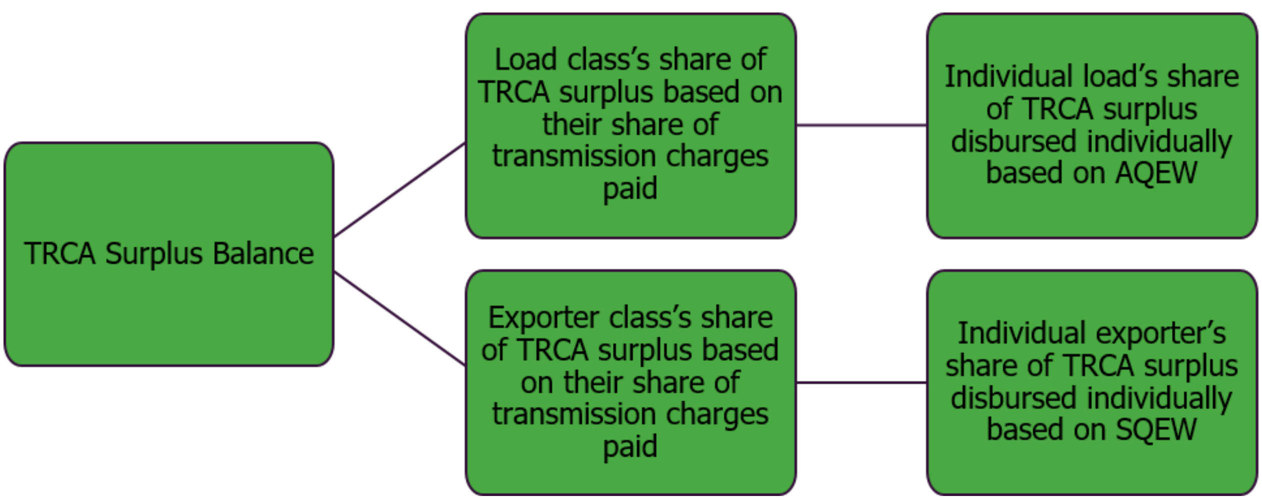

Figure 2-2: TRCA Surplus Balance Disbursement

Transmission rights clearing account disbursement charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-34: Transmission Rights Clearing Account Disbursement Settlement Amount

Charge Type Number	Charge Type Name
102	TR Clearing Account Credit

2.23 Real-Time Ramp-Down Settlement Amount (RT_RDSA)

(MR Ch.9 s.4.6)

Overview of RT_RDSA - The purpose of the real-time ramp-down *settlement amount* (RT_RDSA) is to compensate *GOG-eligible resources* for ramp-down costs and, as described in **MR Ch.9 s.4.6**, will be calculated for *settlement hours* where the *GOG-eligible resource's real-time schedule* is less than its *minimum loading point,* indicating the *GOG-eligible resource's* intent to de-synchronize from the *IESO-controlled grid.*

As described in **MR Ch.9 s.4.6**, the calculation of RT_RDSA will:

- include an adjusted *energy offer* price as described below;
- use the ramp-down factor as described below;
- be limited to the ramp-down *metering intervals* for the *trading day* in which the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point*; and
- be adjusted where the *GOG-eligible resource* has a *real-time schedule* less than its *minimum loading point* and has a *day-ahead schedule.*

RT_RDSA and mitigation - RT_RDSA will incorporate any required adjustment and mitigation test results into the calculation as described in section 4.4.

RT_RDSA charge type - The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 2-35: Real-Time Ramp-Down Settlement Amount

Charge Type Number	Charge Type Name
1917	Real-Time Ramp-Down Settlement Amount

2.23.1 Determining the Energy Offer for the Real-Time Ramp-Down Settlement Amount Calculation

As described in **MR Ch.9 s.4.6.2.2**, the relevant *energy offer* to be used for the RT_RDSA calculation will be determined as follows.

The *IESO* will assess each *metering interval* that the *GOG-eligible resource* is ramping down, starting from the *metering interval* with a zero MWh *dispatch instruction* until all of the following criteria no longer exist:

- ramp-down rate limited (RDRL);
- *dispatch instruction* is less than the registered *minimum loading point*; or
- revised *dispatch instruction* is sent due to *dispatch* deviation.

The *energy offer* that will be used in the RT_RDSA calculation will be the *energy offer* from the *settlement hour* immediately preceding the last *metering interval* that was assessed.

The ramp-down factor described in **MR Ch.9 s.4.6.2.2** is 1.3.

2.24 Real-Time Ramp-Down Settlement Amount Uplift (RT_RDSAU)

(MR Ch.9 s.4.14.11)

Overview of RT_RDSAU - As described in **MR Ch.9 s.4.14.11**, the real-time ramp-down *settlement amount* uplift (RT_RDSAU) will be allocated on a daily basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

RT_RDSAU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-36: Real-Time Ramp-Down Settlement Amount Uplift

Charge Type Number	Charge Type Name
1967	Real-Time Ramp-Down Settlement Amount Uplift

2.25 Fuel Cost Compensation Credit (FCC)

(MR Ch.9 s.4.11)

Overview of FCC - As described in **MR Ch.9 s.4.11**, the *IESO* may compensate *market participants* for the cost incurred in securing unused fuel as a result of specified *IESO* actions described in the *market rules*.

The purpose of the fuel cost compensation credit (FCC) is to allow *GOG-eligible resources* to recover the cost of fuel incurred to meet the *day-ahead operational commitment* or *pre-dispatch operational commitment* that it may not otherwise be able to recover from the *IESO-administered market*. The fuel cost compensation credit is only applicable to the procurement of fuel required to achieve and maintain *minimum loading point* for the duration of the relevant operational commitment.

Submitting an FCC claim - In order to receive a fuel cost compensation credit and as per **MR Ch.9 s.4.11.1.3**, a *market participant* must submit a claim to the *IESO* for such fuel costs using the "Fuel Cost Compensation" form available within Online IESO no later than one month after the *trading day* to which the claim applies to, with supporting documentation. In determining the direct fuel costs to be compensated, the *IESO* will use the most appropriate comparator price for the relevant fuel, as determined by the *IESO*.

FCC charge type - If the *IESO* determines that the claim is valid, it will determine a *settlement amount* under the following *charge type.*

Table 2-37: Fuel Cost Compensation Credit Settlement Amount

Charge Type Number	Charge Type Name
1138	Fuel Cost Compensation Credit

2.26 Fuel Cost Compensation Credit Uplift (FCCU)

(MR Ch.9 s.4.14.8)

Overview of FCCU - As described in **MR Ch.9 s.4.14.8**, the fuel cost compensation credit uplift *settlement amount* (FCCU) will be allocated on a monthly basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

FCCU charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-38: Fuel Cost Compensation Credit Uplift Settlement Amount

Charge Type Number	Charge Type Name
1188	Fuel Cost Compensation Credit Uplift

2.27 Station Service Rebate

(MR Ch.9 ss.2.2.12-2.2.16)

Overview of station service rebate - Some *facilities* in the *IESO-administered markets* consume *energy* as *station service*. As described in **MR Ch.9 ss.2.2.12-2.2.16**, *metered market participants* for certain *facilities* are eligible for a reimbursement of the *hourly uplift* and non-*hourly uplift settlement amounts* related to AQEW consumed as *station service*. The *station service* rebate is applicable to:

- *generation facilities* that consume *energy* as *generation station service*; and
- *electricity storage facilities* that consume *energy* as *electricity storage station service*.

Application for station service rebate - If the *metered market participant* believes that their *facility* is eligible for a *station service* rebate, the *metered market participant* should:

- download IMO_FORM_1419 "Application for Designation of a Facility for Generation Station Service Rebate" from the *IESO* website;
- complete all applicable sections; and
- submit the form to the *IESO*.

The *IESO* will:

- review the *market participant's* application;
- request additional information in order to assess the application, if necessary;
- determine if the *generation facility* meets the requirements for the rebate designation; and
- notify the *market participant* in writing of the *IESO's* determination.

Application of station service rebate - If the requirements are met for the rebate designation, the *IESO* will adjust, on the last *trading day* of the month, the *hourly uplift* and non-*hourly uplift settlement amounts* that may have accumulated at the *station service delivery point* during the periods where the eligible *facility* was a net injector of *energy* into the *IESO-controlled grid*.

Station service rebate charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-39: Station Service Reimbursement Credit

Charge Type Number	Charge Type Name
119	Station Service Reimbursement Credit

2.28 Station Service Debit

(MR Ch.9 s.2.2.17)

Overview of station service debit - As described in **MR Ch.9 s.4.14.12**, the *station service* debit *settlement amount* will be allocated on a monthly basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

Station service debit charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 2-40: Station Service Reimbursement Debit

Charge Type Number	Charge Type Name
169	Station Service Reimbursement Debit

2.29 Operating Reserve Non-Accessibility Charge and Associated Reversal Charges

(MR Ch.9 s.3.10)

Overview - A reliable *operating reserve* (OR) product is critical to the effective operation of the *IESO-controlled grid*. When the full scheduled amount of *operating reserve* is not accessible, it can create challenges for the *IESO* to recover the supply-demand balance after a system event.

The purpose of the operating reserve standby payment clawback *settlement amount* (ORSCB) and associated reversal charges is to clawback *operating reserve* payments and other *settlement amounts,* made to *market participants* of *dispatchable loads*, *dispatchable electricity storage resources*, or *dispatchable generation resources*, individually or as aggregated in accordance with **MR Ch.7 s.2.3**, as applicable, when the *IESO* has determined that the *market participant* was unable to meet the *operating reserve* requirements for that particular *class r reserve*.

The *operating reserve* non-accessibility charges and associated reversal charges will be triggered when there is a difference between the scheduled *operating reserve* and total accessible *operating reserve*, representing the total inaccessible *operating reserve* to the *IESO,* as determined in accordance with **MR Ch.9 ss.3.10.7, 3.10.11** and **3.10.13**, as applicable. *Market participants* may still be subject to compliance assessment for failure to provide the activated *operating reserve*.

2.29.1 Operating Reserve Non-Accessibility Charge (ORSCB)

(MR Ch.9 s.3.10.1)

Overview of ORSCB - As described in **MR Ch.9 s.3.10.1**, the ORSCB will adjust *operating reserve* payments based on the *operating reserve* that cannot be accessed. Total inaccessible *operating reserve (TAOR)* will be calculated as the difference between total *operating reserve* scheduled for all classes and total accessible *operating reserve*, in accordance with **MR Ch.9 s.3.10.6,** and applying the total accessible *operating reserve* in the following order*:*

i. r1 or synchronized *ten-minute operating reserve* (10S);
ii. r2 or non-synchronized *ten-minute operating reserve* (10N); and
iii. r3 or *thirty-minute operating reserve* (30R).

2.29.1.1 Aggregated Dispatchable Generation Resources

Overview of *dispatchable generation resources* as part of a compliance aggregated model - A *dispatchable generation resource* can participate in the *IESO-administered market* as either a single *dispatchable generation resource* or as part of a compliance aggregation model. Where the *dispatchable generation resource* is part of a compliance aggregation model, the *operating reserve* non-accessibility charge (ORSCB) will be calculated over all *dispatchable generation resources* that are part of the compliance aggregation model. This assessment is necessary to offset profits and losses across all the *dispatchable generation resources.*

Non-*pseudo-units* - The ORSCB calculation for non-*pseudo-units* will only be applied to the aggregated *dispatchable generation resources* for the duration that the *resources* remain aggregated in accordance with **MR Ch.7 s.2.3.** Where a *dispatchable generation resource* no longer meets any of these requirements, the ORSCB calculation will be based on the remaining *dispatchable generation resources* that form part of the compliance aggregation model.

The *IESO* performs the following steps to calculate the ORSCB for both aggregated *dispatchable generation resources* not associated with a *pseudo-unit* and associated with a *pseudo-unit*:

1. Determine total accessible *operating reserve* (TAOR) for each *dispatchable generation resource,* in accordance with **MR Ch.9 s.3.10.6**;
2. Determine for each *dispatchable generation resource*, the inaccessible *operating reserve* (ORIA) for each class of *operating reserve* in order or *operating reserve* class: 10S, 10N and 30R, in accordance with **MR Ch.9 s.3.10.9**;
3. Determine for each *dispatchable generation resource*, the total *operating reserve* provided (TAOR – RT_QSOR), in accordance with **MR Ch.9 s.3.10.10**;
4. Determine the excess available headroom (EAH), in accordance with **MR Ch.9 s.3.10.10**;
5. Reallocate any excess headroom (REAH), in accordance with **MR Ch.9 s.3.10.10**;
6. Determine the net *operating reserve* deviation (NORD), in accordance with **MR Ch.9 s.3.10.10**; and
7. Determine the total ORSCB in accordance with **MR Ch.9 s.3.10.10** and then prorate the total ORSCB amount, in accordance with **MR Ch.9 s.3.10.9**, to all aggregated *dispatchable generation resources* based on the amount of their inaccessible *operating reserve* per *class r reserve*.

ORSCB charge types - The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 2-41: Operating Reserve Standby Payment Clawback Settlement Amounts

Charge Type Number	Charge Type Name	Clawback of Settlement Amounts
206	10-Minute Spinning Non-Accessibility Settlement Amount	Claws back a portion of *charge type* 212 and 213
208	10-Minute Non-Spinning Non-Accessibility Settlement Amount	Claws back a portion of *charge type* 214 and 215
210	30-Minute Non-Accessibility Settlement Amount	Claws back a portion of *charge type* 216 and 217

2.29.2 Associated Reversal Charges

(MR Ch.9 s.3.10)

Overview - The *IESO* will adjust any real-time make-whole payment *settlement amount* and real-time *generator offer* guarantee *settlement amount* for the amount of the *operating reserve* that was not accessible to the *IESO* to avoid overpayments to the *market participant*. Each respective *settlement amount* will be adjusted for the total accessible *operating reserve* in the following order of *operating reserve* class:

i. r1 or synchronized *ten-minute operating reserve* (10S);
ii. r2 or non- synchronized *ten-minute operating reserve* (10N); and

iii. r3 or *thirty-minute operating reserve* (30R).

Associated reversal charges and mitigation – As described in section **MR Ch.9 s.3.10.4**, if the relevant *resource* during the relevant time had their real-time make whole payment *settlement amount* or real-time *generator offer* guarantee *settlement amount* mitigated pursuant to **MR Ch.9 s.5**, the associated reversal charges will incorporate the same substitutions as provided for in **MR Ch.9 s.5.1.2.2**.

2.29.2.1 Real-Time Make-Whole Payment Reversal Charge (RT_MWP_RC)

(MR Ch.9 s.3.10.2)

Overview of RT_MWP_RC - The real-time make-whole payment *settlement amounts* for *operating reserve* lost cost (OLC) and *operating reserve* lost opportunity cost (OLOC) will be adjusted for the total accessible *operating reserve* from all *class r reserves.*

The methodology for determining the RT_MWP_RC for *pseudo-units* is the same for non-*pseudo-units.*

RT_MWP operating reserve non-accessibility reversal charge types - The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 2-42: Real-Time Make-Whole Payment – Operating Reserve Non-Accessibility Reversal Settlement Amounts

Charge Type Number	Charge Type Name	Reversal of Settlement Amounts
1908	Real-Time Make-Whole Payment – Operating Reserve Non-Accessibility Lost Cost Reversal ~~(RT_OLCR)~~	*Charge Types*: 1901 – Real-Time Make-Whole Payment – Lost Cost for 10-Minute Spinning Reserve 1902 – Real-Time Make-Whole Payment – Lost Cost for 10-Minute Non-Spinning Reserve 1903 – Real-Time Make-Whole Payment – Lost Cost for 30-Minute Operating Reserve

Charge Type Number	Charge Type Name	Reversal of Settlement Amounts
1909	Real-Time Make-Whole Payment – Operating Reserve Non-Accessibility Lost Opportunity Cost Reversal ~~(RT_OLOCRC)~~	*Charge Types*: 1905 – Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Spinning Reserve 1906 – Real-Time Make-Whole Payment – Lost Opportunity Cost for 10-Minute Non-Spinning Reserve 1907 – Real-Time Make-Whole Payment – Lost Opportunity Cost for 30-Minute Operating Reserve

2.29.2.2 Real-Time Generator Offer Guarantee Clawback (RT_GOG_CB)

(MR Ch.9 s.3.10.3)

Overview of RT_GOG_CB - The real-time *generator offer* guarantee *settlement amounts* for *operating reserve* (Component 2) and real-time make-whole payment offset (Component 5) will be adjusted for the total accessible *operating reserve* through the real-time *generator offer* guarantee clawback (RT_GOG_CB).

The RT_GOG_CB will comprise of four terms described in the following table.

Table 2-43: Real-Time Generator Offer Guarantee Clawback - Terms

Term	Description
Term 1	Reversal of ORSCB (*charge types* 206, 208 and 210).
Term 2	Operating profit or loss incurred on quantities between total accessible *operating reserve* (TAOR) and *operating reserve* schedule (COMP2_CB).
Term 3	Revenue earned on quantity that was scheduled but not accessible (ORIA_AMT).
Term 4	Reversal of real-time make-whole payment.

The methodology for determining the RT_GOG_CB for *pseudo-units* is the same for non-*pseudo-units.*

RT_GOG_CB charge types - The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 2-44: Real-Time Generator Offer Guarantee Clawback Settlement Amount

Charge Type Number	Charge Type Name	Reversal of Settlement Amounts
1915	Real-Time Generator Offer Guarantee – Operating Reserve Non-Accessibility Reversal	*Charge Type*: 1911 – Real-Time Generator Offer Guarantee – Operating Reserve

3 Other Market Charges, Credits and Uplifts

3.1 Forecasting Services

(MR Ch.9 s.4.12)

Overview of forecasting services - The *IESO* has established forecasting services as a procured service to accommodate *variable generation* from wind and solar *resources*. The forecasting service *settlement amount* will be paid to forecasting service providers.

Forecasting services charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 3-1: Forecasting Service Settlement Amount

Charge Type Number	Charge Type Name
1600	Forecasting Service Settlement Amount

3.2 Forecasting Service Uplift

(MR Ch.9 s.4.12.1)

Overview of forecasting services balancing - As described in **MR Ch.9 s.4.14.12**, the forecasting service balancing amount *settlement amount* will be allocated on a monthly basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW).

Forecasting services balancing charge type - The *IESO* will determine a *settlement amount* under the following *charge type.*

Table 3-2: Forecasting Service Uplift Settlement Amount

Charge Type Number	Charge Type Name
1650	Forecasting Service Balancing Amount

3.3 Adjustment Account Surplus Disbursement

(MR Ch.9 s.6.20.5.3)

Overview of adjustment account surplus disbursement - As described in **MR Ch.9 s.6.20.5.3**, the *IESO Board* will review, at least annually, the allocation of any credit balance in the *IESO adjustment account*. The *IESO Board* may direct the usage of such funds in accordance with **MR Ch.9 s.6.20.5.3**, which may include some or all of the credit balance (surplus) be distributed to *market participants*. The disbursement, if applicable, will be settled as a single payout on the basis determined by the *IESO Board*. Any such disbursement will be distributed to *market participants* as a non-hourly *settlement amount.*

Adjustment account surplus disbursement charge type - The *IESO* will determine a *settlement amount* under the following *charge type*.

Table 3-3: Adjustment Account Surplus Disbursement Settlement Amount

Charge Type Number	Charge Type Name
9920	Adjustment Account Credit

3.4 Capacity Obligations

(MR Ch.7 ss.18 and 19 and Ch.9 s.4.13)

General *capacity auction* - The *settlement* of *capacity obligations* and non-performance charges in this section apply only to *capacity market participants* with *capacity obligations*. For more information about the *capacity auction*, please refer to **MR Ch.7 ss.18 and 19** and **MM 12**.

Meaning of treatment and control group - In this *market manual* references to the *demand response contributors* of residential *hourly demand response resources* in the "treatment group" and in the "control group" refer to the treatment group and control group of *demand response contributors* established in accordance with **MM 12**.

Summary of the application of *capacity auction settlement amounts* - ~~Below is a table~~Table 3-4 identif~~y~~ies~~ing~~ the *settlement amounts* applicable to each type of resource that may have a *capacity obligation*:

Table 3-4: Application of Capacity Obligation Settlement Amounts

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resources*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
Payments	*capacity obligation* - availability payment *settlement amount* (*charge type* 1314)	Yes	Yes	Yes	Yes	Yes	Yes
Payments	*capacity obligation* test activation payment *settlement amount* & *capacity obligation* emergency operating state activation payment *settlement amount* (*charge type* 1320)	No	Yes	No	No	No	No
Non-Performance Charges	*capacity obligation* - availability charge *settlement amount* (*charge type* 1315)	Yes	Yes	Yes	Yes	Yes	Yes

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resources*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
	capacity obligation - administration charge *settlement amount* (*charge type* 1316)	No	Yes (only for virtual *HDR resources*)	No	No	No	Yes
	capacity obligation - dispatch charge *settlement amount* (*charge type* 1317)	No	Yes (only for C&I *HDR resources*)	No	No	No	No
	capacity obligation - capacity charge *settlement amount* (*charge type* 1318)	Yes	Yes	Yes	Yes	Yes	Yes
	capacity obligation - capacity import call failure *settlement amount* (*charge type* 1321)	No	No	No	No	No	Yes
	capacity obligation - capacity deficiency *settlement amount*	No	No	No	No	No	Yes

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resources*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
True-Ups	(*charge type* 1322)						
	capacity obligation - in-period *cleared UCAP* adjustment charge *settlement amount* (*charge type* 1323)	No	Yes	No	No	No	No
	capacity obligation - availability charge true-up payment *settlement amount* (*charge type* 1324)	Yes	Yes	Yes	Yes	Yes	Yes
	capacity obligation – capacity auction charges true-up payment *settlement amount* (*charge type* 1325)	Yes	Yes	Yes	Yes	Yes	Yes
Other	*capacity obligation* - buy-out charge *settlement amount*	Yes	Yes	Yes	Yes	Yes	Yes

		Resource Type					
		Capacity dispatchable load resources	*HDR resources*	*Capacity generation resources*	*Capacity storage resources*	*System-backed capacity import resources*	*Generator-backed capacity import resources*
	(*charge type* 1319)						

3.4.1 Settlement Timelines

Capacity market participants with *capacity obligations* will be settled for *capacity obligation settlement amounts* using the *physical markets settlement process*, and such *settlement amounts*, except those related to a buy-out process, will appear on the month-end *preliminary settlement statement* of the subsequent *energy market billing period*, resulting in a one-month lag. For clarity, those *settlement amounts* related to a buy-out process will appear on the next available *preliminary settlement statement* for the month end and will not be subject to a one-month lag.

3.4.2 Capacity Obligation - Availability Payment Settlement Amount (CAAP)

(MR Ch.9 s.4.13.1)

Overview of availability payment - *Capacity market participants* with a *capacity obligation* will be paid a *capacity obligation -* availability payment *settlement amount* for every *energy market billing period* of the *commitment period* to which the *capacity obligation* relates, based on its *capacity obligation*.

Availability payment charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month.

Table 3-5: Capacity Obligation - Availability Payment Settlement Amount

Charge Type Number	Charge Type Name
1314	Capacity Obligation – Availability Payment

3.4.2.1 Capacity Obligation - Dispatch Test Payment and Emergency Activation Payment Settlement Amounts (CATAP/CAEOP)

(MR Ch.9 s.4.13.11)

Overview of Dispatch Test and Emergency Activation Test Settlement Amounts - *Hourly demand response resources* will be compensated for each *settlement hour* of a *capacity auction dispatch test* or an activation that is in advance of or during an *emergency operating state*.

Calculation of Curtailed MW - In order to determine the applicable measured *demand response capacity* ($HDRDC^{m}_{k,h}$), as defined in **MR Ch.9 App.9.2 s.11**, the *IESO* will determine the applicable Curtailed $MW^{m}_{k,h}$ in accordance with the following:

Resource Type	Curtailed MWh Calculation
Commercial and industrial *hourly demand response resources*	Curtailed MWh = Max (0, ($C\&I\_HDR\_BL^{m}_{k,h}$ – $HDR\_AC^{m}_{k,h}$) Where: • "$C\&I\_HDR\_BL^{m}_{k,h}$" is the calculated baseline *energy* consumption (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *settlement hour* 'h', calculated in accordance with section 3.4.3.1; • "$HDR\_AC^{m}_{k,h}$" is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *settlement hour* 'h', as determined in accordance with the submitted measurement data and AQEW, as the case may be.
Residential *hourly demand response resources*	Curtailed MWh = Max (0, $TCTG^{m}_{k,h}$ x ($ACGL^{m}_{k,h}$ – $ATGL^{m}_{k,h}$)) Where: • "$TCTG^{m}_{k,h}$" is the absolute number of *demand response contributors* in the "Treatment group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h'; • "$ACGL^{m}_{k,h}$" is the average quantity of *energy* consumed (in MWh) by all of the *demand response contributors* in the "Control group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', calculated in accordance with section 3.4.3.1; and • "$ATGL^{m}_{k,h}$" is the average quantity of *energy* consumed (in MWh) by all of the *demand response contributors* in the "Treatment Group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* for *settlement hour* 'h', as determined in accordance with the submitted measurement data.

Value of HDRTAPR - For the purpose of determining the appropriate *capacity obligation dispatch test* payment *settlement amount*, HDRTAPR, as defined in **MR Ch.9 App.9.2 s.11**, shall equal $250/MWh.

Missing measurement data - For greater clarity, if measurement data for any *metering interval* is missing (i.e. measurement data was not submitted to the *IESO*), the *capacity obligation dispatch test* payment *settlement amount* or emergency activation payment *settlement amount* for that *settlement hour* will be $0.

Dispatch test and emergency activation test payment *settlement amounts* charge types - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month.

Table 3-6: Capacity Obligation – Dispatch Test and Payment Emergency Activation Payment Settlement Amount

Charge Type Number	Charge Type Name
1320	Capacity Obligation – Dispatch Test and Payment Emergency Activation Payment

3.4.3 Non-Performance Charges

3.4.3.1 Hourly Demand Response (HDR) Baselines

Overview of baselines - Due to how *hourly demand response resources* participate and deliver into the *energy market*, baselines are required to determine certain *settlement amounts* applicable to *hourly demand response resources*. A baseline is an approximation of an *hourly demand response resource's* consumption profile that is used to estimate what the *hourly demand response resource* would have been consuming had an activation not taken place.

The *IESO* calculates baselines for each *hourly demand response resource* for the *settlement hours* in which there were activations.

Missing measurement data - For greater clarity, if the measurement data for any *metering interval* is missing (i.e. measurement data was not submitted), the consumption for such *metering interval* is deemed to be zero (0) when calculating the baseline.

3.4.3.1.1 Baseline Methodology for Commercial & Industrial Hourly Demand Response Resources

The baseline in a *settlement hour* for a commercial and industrial *hourly demand response resource* shall be calculated as follows:

$$C\&I\_HDR\_BL_{k,h}^{m} = StdBL_{k,h}^{m} \times IDAF_{k,h}^{n}$$

Where:

- 'suitable *business days*' are any *business days* within the previous 35 *business day* period that meet the following criteria:
    i. For *business days* within the relevant *obligation period*, *business days* where the relevant commercial & industrial *hourly demand response resource*:

       a. placed at least one *demand response energy bid* for at least one *settlement hour* within the *availability window* for the *trading day*; and

       b. was not activated to provide *demand response capacity*; and

    ii. For *business days* prior to the relevant *obligation period*, any business day.
- "$StdBL^{m}_{k,h}$" is the calculated *energy* consumption (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h', and calculated as the average of the measured *energy* consumption of the *hourly demand response resource* for the same hour-ending period of the 15 suitable *business days* which have the highest measurement data for the same hour-ending period in the last 20 suitable *business days* prior to the relevant activation.
- "$IDAF^{m}_{k,h}$" is the In-Day Adjustment Factor for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' and calculated as: $IDAF^{m}_{k,h} = A \div B$

  Where:

    - "A" is the hourly average *energy* consumption of the *hourly demand response resource* during the adjustment window hours on the *trading day* in which the *hourly demand response resource* was activated, as determined in accordance with the submitted measurement data.
    - "B" is the hourly average *energy* consumption of the *hourly demand response resource* during the adjustment window hours in the 15 suitable *business days* which have the highest measurement data for the same adjustment window hours in the last 20 suitable *business days* prior to the relevant activation, as determined in accordance with the submitted measurement data.
    - 'adjustment window hours' are those *settlement hours* which form the 3-hour period ending one hour prior to the relevant *activation window*. For example, if the *activation window* starts on HE17, the adjustment window hours would be HE 13, 14 and 15.

- Notwithstanding the foregoing, the $IDAF^{m}_{k,h}$ shall not be less than 0.8 and shall not be greater than 1.2. For greater clarity, the $IDAF^{m}_{k,h}$ will be rounded either up or down if calculated as being less than 0.8 or greater than 1.2, respectively.
- Notwithstanding the foregoing, where the *IESO* is unable to identify 20 suitable *business days* within the relevant time period, the *IESO* shall utilize the following days in the calculation of the foregoing:

  i. If the *IESO* identifies more than 15 but less than 20 suitable *business days*, the *IESO* shall use the 15 suitable *business days* which have the highest measurement data in those suitable *business days* identified; and

  ii. If the *IESO* identifies 15 or fewer suitable *business days*, the *IESO* shall use all identified suitable *business days*.

3.4.3.1.2 Baseline Methodology for Residential Hourly Demand Response Resources

The baseline in *settlement hour* 'h' of an activation event for a residential *hourly demand response resource* shall be calculated as follows:

$$ACGL^{m}_{k,h} = CGL^{m}_{k,h}/TCCG^{m}_{k,h} \times SDAF^{n}_{k,h}$$

Where:

- "$CGL^{m}_{k,h}$" is the total quantity of *energy* consumed (in MWh) by all of the *demand response contributors* in the "Control Group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h', as determined in accordance with the submitted measurement data.
- "$TCCG^{m}_{k,h}$" is the absolute number of demand response contributors in the "Control Group" for capacity market participant 'k' at delivery point 'm' for an hourly demand response resource in settlement hour 'h'.
- "$SDAF^{m}_{k,h}$" is the Same-Day Adjustment Factor for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h' and calculated as $SDAF^{m}_{k,h} = C \div D$

  Where:

  - "C" is the hourly average *energy* consumption of all of the *demand response contributors* in the "Treatment Group" during the adjustment window hours on the relevant *trading day* divided by the absolute number of *demand response contributors* in the "Treatment Group".
  - "D" is the hourly average *energy* consumption of all of the *demand response contributors* in the "Control Group" during the adjustment window hours of the relevant *trading day* divided by the absolute number of *demand response contributors* in the "Control Group".

- “adjustment window hours” are those *settlement hours* which form the 3-hour period ending one hour prior to the relevant *activation window*. For example, if the *activation window* starts on HE17, the adjustment window hours would be HE 13, 14 and 15.

3.4.3.2 Capacity Obligation - Availability Charge Settlement Amount (CAAC)

(MR Ch.9. s.4.13.2)

Overview of availability charge *settlement amount* - The *capacity obligation* - availability charge *settlement amount* applies when *capacity market participants* with *capacity obligations* fail to submit and maintain their *demand response energy bids* or *energy offers*, as applicable in the *day-ahead market* and maintain such *energy bid/*offers as required in the *market rules* or below, as applicable for *auction capacity* at least equal to their *capacity obligation.* The charge is calculated for each *settlement hour* within the *availability window* of the *obligation period* for each *capacity auction resource.*

Non-performance factor - For the *settlement* of the availability charges, a non-performance factor (CNPF) multiplier is used based on the applicable month as per section 6.1 of **MM 12**.

Assessment for *capacity generation resources* – As described in **MR Ch.9 s.4.13.2.2**, the *IESO* will apply an availability charge to any *settlement hour* within the *availability window* where *capacity market participants* participating with a *capacity generation resource* fail to submit an *energy offer* for their *capacity generation resource* for an amount greater than or equal to their *capacity obligation* quantity in the following periods:

1. in the *day-ahead market*; and
2. in *pre-dispatch* for each *pre-dispatch* that occurs prior to the earliest of the commencement of the following:
    - the 2-hour mandatory window applicable to the relevant hour of the *availability window*;
    - a period of time equal to the *capacity generation resource’s* registered *elapsed time to dispatch* that is prior to the relevant hour of the *availability window*; and
    - a period of time equal to the *capacity generation resource’s minimum generation block down-time* that is prior to the relevant hour of the *availability window.*

Availability charge charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first *recalculated settlement statement* for the *trading day.*

Table 3-7: Capacity Obligation – Availability Charge Settlement Amount

Charge Type Number	Charge Type Name
1315	Capacity Obligation – Availability Charge

3.4.3.3 Capacity Obligation - Administration Charge Settlement Amount (CAADM)

(MR Ch.9 ss.4.13.4 and 4.13.10)

Overview of administration charge - The *capacity obligation -* administration charge *settlement amount* applies when *capacity market participants* with *hourly demand response resources* that are not revenue-metered by the *IESO* or *capacity market participants* with *generator-backed capacity import resources* fail to provide timely, accurate and complete data, including measurement data, to the *IESO* in accordance with the timelines and requirements of section 5.3.3 and 5.3.4 of **MM 12**.

The administration charge will also be applicable to *capacity market participants* with a virtual *hourly demand response resource* if the submitted measurement data is determined to be inaccurate during an audit conducted by the *IESO*.

Administration charge charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month.

Table 3-8: Capacity Obligation – Administration Charge Settlement Amount

Charge Type Number	Charge Type Name
1316	Capacity Obligation – Administration Charge

3.4.3.4 Capacity Obligation - Dispatch Charge Settlement Amount (CADC)

(MR Ch.9 ss. 4.13.3 and 4.13.10)

Overview of dispatch charge - The *capacity obligation - dispatch* charge *settlement amount* is applicable only to commercial & industrial *hourly demand response resources* that are determined to have failed to follow their *dispatch instructions* during an activation, including *capacity auction dispatch tests* and *capacity auction capacity tests*, for any *dispatch interval* within the *settlement hour*, as determined in accordance with **MR Ch.9 s.4.13.3.1**.

Missing measurement data - For greater clarity, if measurement data for the interval required for "Actual Consumption" is missing (i.e. measurement data was not submitted), $C\&I\_HDR\_BL^{m,t}_{k,h} - HDR\_AC^{m,t}_{k,h}$, in the formula outlined in **MR Ch.9 s.4.13.3.1** is 0.

Dispatch charge charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first *recalculated settlement statement* for the *trading day.*

Table 3-9: Capacity Obligation – Dispatch Charge Settlement Amount

Charge Type Number	Charge Type Name
1317	Capacity Obligation – Dispatch Charge

3.4.3.5 Capacity Obligation - Capacity Charge Settlement Amount (CACC)

(MR Ch.9 ss. 4.13.5 and 4.13.10)

Overview of capacity charge - The *capacity obligation -* capacity charge is applicable to all participating *capacity auction resources* when they fail the *capacity auction capacity test*, as determined in accordance with this section and section 5.3.3 of **MM 12**. The capacity charge for a failed *capacity auction capacity test* is equal to one month's availability payment.

Assessment for C&I HDR resources - A C&I *HDR resource* will be determined to have failed to deliver its *cleared ICAP* within the applicable threshold, as described in **MR Ch.9 s.4.13.5**, if the following condition is true for any *settlement hour* of the *capacity auction capacity test*:

$$\Sigma^T(C\&I\_HDR\_BL^{m,t}_{k,h} - HDR\_AC^{m,t}_{k,h})/12 < 90\% \times CICAP^m_{k,h}$$

Where:

- "$C\&I\_HDR\_BL^{m,t}_{k,h}$" is the amount calculated pursuant to section 3.4.3.1;
- "$HDR\_AC^{m,t}_{k,h}$" is the total measured quantity of *energy* consumed (in MWh) for *capacity market participant* 'k' at *delivery point* 'm' for the *hourly demand response resource* in *metering interval* 't' of *settlement hour* 'h', as determined in accordance with the submitted measurement data and allocated quantity of *energy* withdrawn, as the case may be;
- 'T' is the set of all *metering intervals* 't' within the relevant *settlement hour* 'h'.

Missing measurement data - For greater clarity, if measurement data for the *metering interval* required for "Actual Consumption" is missing (i.e. measurement data was not submitted), ($C\&I\_HDR\_BL^{m,t}_{k,h} - HDR\_AC^{m,t}_{k,h}$) in the above formula is zero.

Assessment for residential HDR resources - A residential *hourly demand response resource* will be determined to have failed to deliver its *cleared ICAP* within the applicable threshold, as described in **MR Ch.9 s.4.13.5**, if the following condition is true for the *capacity auction capacity test*:

$$\Sigma^{H}\ [(ACGL^{m}_{k,h} - ATGL^{m}_{k,h}) \times TCTG^{m}_{k,h}]/4 < 90\% \times CICAP^{m}_{k,h}$$

Where:

- "$ACGL^{m}_{k,h}$" is the amount calculated pursuant to section 3.4.3.1;
- "$ATGL^{m}_{k,h}$" is the average quantity of *energy* consumed (in MWh) by *demand response contributors* in the "Treatment Group" for *capacity market participant* 'k' at *delivery point* 'm' for an *hourly demand response resource* in *settlement hour* 'h', calculated by dividing the quantity of *energy* consumed by all of the *demand response contributors* in the "Treatment Group", as determined in accordance with the submitted measurement data, by $TCTG^{m}_{k,h}$;
- "$TCTG^{m}_{k,h}$" is the absolute number of demand response contributors in the "Treatment Group" for capacity market participant 'k' at delivery point 'm' for an hourly demand response resource in settlement hour 'h';
- 'H' is the set of all settlement hour 'h' within the relevant capacity auction capacity test.

Missing measurement data - For greater clarity, if measurement data for the *settlement hour* required are missing (i.e. measurement data was not submitted), or monthly residential contributor information was not submitted, ($ACGL^{m}_{k,h} - ATGL^{m}_{k,h}$) in the above formula is zero.

Capacity charge charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month.

Table 3-10: Capacity Obligation – Capacity Charge Settlement Amount

Charge Type Number	Charge Type Name
1318	Capacity Obligation – Capacity Charge

3.4.3.6 Capacity Obligation - Capacity Import Call Failure Settlement Amount (CACIF)

(MR Ch.9 s.4.13.6)

Overview of capacity call import failure - The *capacity obligation - capacity import call failure settlement amount* applies to *generator-backed capacity import resources* that fail to deliver the called upon *auction capacity* in response to a *capacity import call* in accordance with the process outlined in section 4.7.1 of **MM 4.3.**

Capacity call import failure charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month.

Table 3-11: Capacity Obligation – Capacity Import Call Failure Charge Settlement Amount

Charge Type Number	Charge Type Name
1321	Capacity Obligation – Capacity Import Call Failure Charge

3.4.3.7 Capacity Obligation - Capacity Deficiency Settlement Amount (CACD)

(MR Ch.9 s.4.13.7)

Overview of capacity deficiency - The *capacity obligation -* capacity deficiency *settlement amount* will apply to *generator-backed capacity import resources* deemed to have *over committed capacity* in accordance with the process outlined in section 3.3 of **MM 12**.

Capacity deficiency charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month.

Table 3-12: Capacity Obligation – Capacity Deficiency Charge Settlement Amount

Charge Type Number	Charge Type Name
1322	Capacity Obligation – Capacity Deficiency Charge

3.4.3.8 Capacity Obligation - In-Period Cleared UCAP Adjustment Charge Settlement Amount (CAIPA)

(MR Ch.9 s.4.13.8)

Overview of in-period UCAP adjustment charge - The *capacity obligation -* in-period *cleared UCAP adjustment* charge *settlement amount* claws back availability payments for *auction capacity* which exceeds the *auction capacity* demonstrated in the *capacity auction capacity test.* Where the *capacity market participant* agrees with the findings of the *capacity auction test*, and does not submit a *notice of disagreement*, the in-period *cleared UCAP* adjustment charge *settlement amount* will apply starting from the first *business day* of the *obligation period* and ending on the day on which **MR Ch.7 s.19.4.18** applies to reduce the *capacity market participant's capacity obligation.* Where the *capacity market participant* disagrees with the findings of the *capacity auction capacity test*, by submitting a *notice of disagreement,* the in-period *cleared UCAP* adjustment charge *settlement amount* will apply for every *energy market billing period* of the *obligation period* and any adjustment resulting from the *notice of disagreement* process will be made as necessary.

No audit-driven reassessment - Any *in-period cleared UCAP adjustment* will not be reassessed as a result of a measurement data audit conducted pursuant to **MM 12**.

In-period UCAP adjustment charge charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the first month-end *recalculated settlement statement* for the commitment month*.*

Table 3-13: Capacity Obligation – In-Period Cleared UCAP Adjustment Charge Settlement Amount

Charge Type Number	Charge Type Name
1323	Capacity Obligation – In-Period Cleared UCAP Adjustment Charge

3.4.4 Non-Performance Charge Exceptions

In limited circumstances, a *capacity market participant* may request a reduction or reversal of a previously levied *capacity obligation* availability charge *settlement amount,* pursuant to **MR Ch.9 s.4.13.2**, and/or a *capacity obligation dispatch* charge *settlement amount* pursuant to **MR Ch.9 s.4.13.3***.*

In order to request such an adjustment, a *capacity market participant* must submit such request using the *notice of disagreement* process outlined in **MR Ch.9 s.6** in accordance with the timelines and requirements thereof and must include supporting documentation and evidence to substantiate the allowable exception.

The allowable exceptions are subject to *IESO* approval and are as follows:

a. inability of an otherwise available *resource* to submit *demand response energy bids* or *energy offers*, as applicable, for some or all of the *capacity obligation* due to the *outage* of a third party *market participant* (e.g. a transmission *outage*); and
b. inability for a *resource* associated with a *capacity obligation* to provide *auction capacity* due to a *force majeure event*.

Table 3-14: Scenarios and Adjustments for Exceptions

Scenarios	**Adjustments**		**Required Documentation of the *Notice of Disagreement***
	Availability Charges	**Dispatch Charges**	
Third-Party *Outage*	The affected *resource* is deemed to have submitted *demand response energy bid/energy offer* and the charge is re-assessed using the impacted quantity assessed by the *IESO.*	Not applicable for the portion impacted by the *outage* since no *bids* were submitted.	Required supporting documentation must include proof, originating from the third party *market participant*, to the *IESO,* that the failure to provide *auction capacity* was due to the *outage* of that third party *market participant*
Force Majeure Event	The charge is re-calculated using a non-performance factor of 1.0.	The charge will be reversed (applicable to HDRs only).	Required supporting documentation must demonstrate adherence to the force majeure requirements set out in **MR Ch.1 s.13.3**, including that the *capacity market participant* has met the notification requirements for a *force majeure event*, and that force majeure conditions have been met.

3.4.5 Capacity Obligation - Buy-Out Charge (CABOC)

(MR Ch.9 s.4.13.9)

Overview of buy-out charge - Upon *IESO's* acceptance of a *capacity market participant* or *capacity auction participant's* buy-out request, as outlined in the buy-out process set out in section 7 of **MM 12**, the *IESO* will calculate a *capacity obligation -* buy-out charge *settlement amount*.

Revised capacity obligation - If the buy-out capacity is not the *capacity market participant* or *capacity auction participant's* entire *capacity obligation* amount, then the *IESO* will settle the remainder of the *obligation period* with the revised *capacity obligation* amount, calculated as the original *capacity obligation* minus the buy-out capacity ($CCO^{m}_{k,h}$ - $CBOC^{m}_{k}$).

Buy-out charge charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the *preliminary settlement statement* for the last day of the *energy market billing period* in which the *IESO* accepted the buy-out request*.*

Table 3-15: Capacity Obligation – Buy-Out Charge Settlement Amount

Charge Type Number	Charge Type Name
1319	Capacity Obligation – Buy-Out Charge

3.4.6 Capacity Obligation - Availability Charge True-Up Payment (CAACT)

(MR Ch.9 s.4.13.12)

Overview of availability charge true-up payment - At the end of each *obligation period*, the *IESO* will determine a *capacity obligation -* availability charge true-up payment *settlement amount* for all *capacity market participants* who meet the conditions set out in **MR Ch.9 s.4.13.12**. The calculation of the capacity *obligation -* availability charge true-up payment *settlement amount* set out in **MR Ch.9 s.4.13.12** ensures that such *settlement amount* is capped at the total dollar value of the charges the *capacity auction resource* incurred pursuant to **MR Ch.9 ss.4.13.2 or 4.13.2.1**, as applicable, during the applicable *obligation period*.

Determining RAC - To determine the amount of excess capacity offered, the *capacity obligation* - availability charge true-up payment *settlement amount* considers the difference between the *capacity auction resource's capacity obligation* ($CCO^{m}_{k,h}$) and its available capacity (RAC^{m}_{k}) which is defined in **MR Ch.9 App.9.2 s.11** as the minimum of:

- lesser of the quantity in MW of the *capacity auction resource's energy bids* or *energy offers*, as applicable, submitted in the *day-ahead market*, *pre-dispatch process*, and *real-time market*, as applicable(i.e. $DREBQ^{m}_{k,h}$ and $CAEO^{m}_{h,k}$)
- *capacity auction resource's cleared ICAP* (i.e. $CICAP^{m}_{k}$)
- 115% of a *capacity auction resource's capacity obligation* (i.e. 1.15* $CCO^{m}_{k,h}$)

- *capacity auction resource's demand response contributors* total registered capability (applicable only to virtual *HDR resources*) (i.e. $CARC_k^m$)

Availability charge true-up payment charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the *recalculated settlement statement* of the last commitment month of the *obligation period.*

Table 3-16: Capacity Obligation – Availability Charge True-Up Payment Settlement Amount

Charge Type Number	Charge Type Name
1324	Capacity Obligation – Availability Charge True-Up Payment

3.4.7 Capacity Obligation - Capacity Auction Charges True-Up Payment (CACT)

(MR Ch.9 s.4.13.13)

Overview of capacity obligation charges true-up payment - At the end of each *obligation period*, the *IESO* will determine a *capacity obligation – capacity auction* charges true-up payment *settlement amount* for all *capacity market participants* with *capacity obligations* during such *obligation period* in accordance with **MR Ch.9 s.4.13.13**.

Capacity obligation charges true-up payment charge type - The *IESO* will determine a *settlement amount* under the following *charge type* which will be *settled* on the *recalculated settlement statement* of the last commitment month of the *obligation period.*

Table 3-17: Capacity Obligation – Capacity Auction Charges True-up Payment Settlement Amount

Charge Type Number	Charge Type Name
1325	Capacity Obligation – Capacity Auction Charges True-up Payment

3.4.8 Capacity Obligation Uplift Settlement Amount (CAU)

(MR Ch.9 s.4.13.14)

Overview of capacity auction uplift - At the end of each *energy market billing period*, the *IESO* will recover the cost, if any, of all *capacity obligation settlement* *amounts* by allocating such costs to *consumers* utilizing the same allocation methodology used for the Global Adjustment.

Details of class A and class B loads - Refer to section 4.5.2 of **MM 5.6** for details on the determination or allocation for Class A and Class B loads for the Global Adjustment.

Variable definitions - Please refer to the **IESO Charge Types and Equations** document to find the definitions of the following variables: Class B Load, EEQ, $EGEI_k$, $GA\_AQEW_{g,k,h,M}^{m,t}$, and $PGS_{h,M}$.

Capacity auction uplift charge types - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 3-18: Capacity Obligation Uplift Settlement Amounts

Charge Type Number	Charge Type Name
1350	Capacity Based Recovery Amount for Class A Loads
1351	Capacity Based Recovery Amount for Class B Loads

3.5 Dispute Resolution Settlement

(MR Ch.3 s.2.7 and MR Ch.9 s.6.10)

Dispute resolution charge type - After the successful resolution of a dispute between the *IESO* and a *market participant*, the *IESO* will determine a *settlement amount* under the following *charge type.*

Table 3-19: Dispute Resolution Settlement Amount

Charge Type Number	Charge Type Name
700	Dispute Resolution Settlement Amount

The *settlement amount* can be an amount due to or owed by the *market participant* and will be fully balanced by one of the following *settlement amounts*, depending on the nature of the dispute and the associated resolution.

Table 3-20: Dispute Resolution Balancing Settlement Amount

Charge Type Number	Charge Type Name	Allocation
750	Dispute Resolution Balancing Amount (IESO)	Due to or owed by the *IESO* Adjustment Account and will be allocated on a monthly basis.
1750	Dispute Resolution Balancing Amount (Market)	Due to or owed by *market participants* and will be allocated on a monthly basis to all *real-time market load resources* and exports based on their proportionate share of *energy* withdrawn AQEW and SQEW.

– End of Section –

4 Market Power Mitigation

(MR Ch.9 s.5)

Overview - This section describes the impacts to the *settlement process* when the *IESO* implements the market power mitigation process to assess the exercise of global market power and local market power. For detailed information on the market power mitigation framework and processes, refer to **MM 14.1** and **MM 14.2**. The following *settlement* charges and *settlement amounts* are described in this section:

- Reference Level Settlement Charges
- Ex-Post Mitigation Settlement Charges
- Settlement Mitigation of Settlement Amounts

4.1 Reference Level Settlement Charges (RLSC)

(MR Ch.9 ss.5.2-5.3)

Overview of reference level settlement charge - *Market participants* that have *dispatchable generation resources* or *dispatchable electricity storage resources* that are registered to inject, with multiple cost profiles can make a request to the *IESO* through the mitigation process to use its higher-cost profile *reference level value* as it applies to *energy*. This request must be accompanied by sufficient supporting documentation as further described in **MR Ch.7 s.22.5.11** and **MM 14.2**.

Where the conditions set out in **MR Ch.9 s.5.2.1.1**, for the *day-ahead market*, or **MR Ch.9 s.5.3.1.1**, for the *real-time market*, are satisfied, a *reference level settlement* charge (RLSC) *settlement amount* will be triggered and:

- calculated in accordance with **MR Ch.9 s.5.2** for the *day-ahead market* reference level *settlement* charge (DAM_RLSC); or
- calculated in accordance with **MR Ch.9 s.5.3** for the real-time *reference level settlement* charge (RT_RLSC).

Reference level settlement charge charge types -The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 4-1: Reference Level Settlement Charge

Charge Type Number	Charge Type Name
1930	Day-Ahead Market Reference Level Settlement Charge
1931	Real-Time Reference Level Settlement Charge

4.2 Reference Level Settlement Charge Uplifts (RLSCU)

(MR Ch.9 s.3.11)

Overview of reference level settlement charge uplift - The uplift *settlement amounts* associated with the respective *reference level settlement* charges will be allocated as follows:

- *day-ahead market reference level settlement* charge uplift (DAM_RLSCU): allocated as part of the *hourly uplift*;
- real-time *reference level settlement* charge uplift (RT_RLSCU): allocated as part of the *hourly uplift*.

Reference level settlement charge uplift charge types - The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 4-2: Reference Level Settlement Charge Uplifts

Charge Type Number	Charge Type Name
1980	Day-Ahead Market Reference Level Settlement Charge Uplift
1981	Real-Time Reference Level Settlement Charge Uplift

4.3 Ex-Post Mitigation Settlement Charges

(MR Ch.9 ss.5.4-5.5)

The *settlement process* will support the ex-post market power mitigation activities performed after the *IESO* issues the final *settlement statement* for any *trading day* as described in **MM 14.1**.

4.3.1 Ex-Post Mitigation for Physical Withholding Settlement Charges (EXP_PWSC)

(MR Ch.9 s.5.4)

Overview of ex-post mitigation for *physical withholding settlement* charge - As described in **MM 14.1**, the *IESO* will apply market power mitigation tests to determine whether any *market participants* of *dispatchable generation resources, dispatchable loads,* and *dispatchable electricity storage resources,* engaged in *physical withholding.* These mitigation processes will test for *physical withholding* in both the *day-ahead market* and *real-time market.*

As described in **MR Ch.9 s.5.4**, the ex-post mitigation for *physical withholding settlement* charge (EXP_PWSC) *settlement amounts* will be a charge to the *market participant* where the market power mitigation processes have determined that the *market participant* engaged in *physical withholding*.

Ex-post mitigation for *physical withholding settlement* charge charge types - The *IESO* will determine a *settlement amount* under the following *charge types.*

Table 4-3: Ex-Post Mitigation for Physical Withholding Settlement Charges

Charge Type Number	Charge Type Name
1932	Mitigation Amount for Physical Withholding – Energy
1933	Mitigation Amount for Physical Withholding – 10S Operating Reserve
1934	Mitigation Amount for Physical Withholding – 10N Operating Reserve
1935	Mitigation Amount for Physical Withholding – 30R Operating Reserve

4.3.2 Ex-Post Mitigation for Intertie Economic Withholding ~~on Uncompetitive Interties~~ Settlement Charges (EXP_EWSC)

(MR Ch.9 ss.5.5)

Overview of ex-post mitigation for intertie economic withholding ~~on uncompetitive *interties*~~ settlement charge - As described in **MM 14.1**, the *IESO* will apply market power mitigation tests to determine whether any *market participants* engaged in *intertie economic withholding.*

As described in **MR Ch.9 s.5.5**, the ex-post mitigation for intertie *economic withholding* ~~on uncompetitive *interties*~~ *settlement* charge (EXP_EWSC) *settlement amounts* will be a charge to the *market participant* where the market power mitigation processes have determined that the *market participant* engaged in *intertie economic withholding*.

Ex-post mitigation for intertie economic withholding ~~on uncompetitive *interties*~~ settlement charge charge types - The *IESO* will determine a *settlement amount* under the following *charge types*.

Table 4-4: Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charges

Charge Type Number	Charge Type Name
1936	Mitigation Amount for Intertie Economic Withholding – Energy
1937	Mitigation Amount for Intertie Economic Withholding – 10N Operating Reserve
1938	Mitigation Amount for Intertie Economic Withholding – 30R Operating Reserve
1939	Mitigation Amount for Intertie Economic Withholding – Make-Whole Payment

4.3.3 Ex-Post Mitigation Settlement Charge Uplift (EXP_MSCU)

(MR Ch.9 ss.4.14.9-4.14.10)

Overview of ex-post mitigation settlement charge uplift - As described in **MR Ch.9 ss.4.14.9-4.14.10**, the uplift *settlement amounts* associated with the respective ex-post mitigation *settlement* charges will be allocated as follows:

- mitigation amount for *physical withholding* uplift (EXP_PWSU): allocated on a ~~monthly~~ daily basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW), calculated in accordance with **MR Ch.9 s.4.14.9**.
- mitigation amount for *intertie economic withholding* uplift (EXP_EWSCU): allocated on a ~~monthly~~ daily basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW), calculated in accordance with **MR Ch.9 s.4.14.10**.

Ex-post mitigation *settlement* charge uplift charge type - The *IESO* will determine a *settlement amount* under the following *charge types*:

Table 4-5: Ex-Post Mitigation Settlement Charge Uplifts

Charge Type Number	Charge Type Name
1982	Mitigation Amount for Physical Withholding Uplift
1986	Mitigation Amount for Intertie Economic Withholding Uplift

4.4 Settlement Mitigation of Settlement Amounts

(MR Ch.9 s.5.1 and Appendix 9.4)

Overview of settlement mitigation settlement amounts - The *IESO* will perform conduct and impact tests to determine the appropriate *settlement amounts* to be paid to *market participants*. For details on the *reliability* codes, refer to **MM 4.3**.

The purpose of the conduct test, as set out in **MR Ch.9 App.9.4**, is to determine whether enhanced mitigated *dispatch data* is applicable and the values of such enhanced mitigated *dispatch data*.

Where that enhanced mitigated *dispatch data* is applicable, the impact test, as set out in **MR Ch.9 s.5.1**, determines whether that data should be used in the final calculation of the following *settlement amounts*:

- *day-ahead market* make-whole payment *settlement amount*;

- *day-ahead market generator offer* guarantee *settlement amount*;
- real-time make-whole payment *settlement amount*;
- real-time *generator offer* guarantee *settlement amount*; and
- real-time ramp-down *settlement amount*.

4.5 Independent Review Process Settlement Amounts

(MR Ch.7 s.22.8.11.2, s.22.8.14 and MR Ch.9 s.4.14.12)

Overview of independent review process - The Independent Review Process (IRP) provides an avenue for *market participants* to address concerns with the *reference levels* and *reference quantities* established as part of the Market Power Mitigation framework. Refer to **MM 14.2** for further details.

Where the process is conducted pursuant to **MR Ch.7 s.22.8.14**, the costs of such process will be allocated on a monthly basis directly to the *market participant* that made such request.

Where the process is conducted pursuant to **MR Ch.7 s.22.8.11.2,** the costs of such process will be allocated on a monthly basis to all *real-time market load resources, electricity storage resources* that are registered to withdraw, and exports based on their proportionate share of *energy* withdrawn (AQEW and SQEW), in accordance with **MR Ch.9 s.4.14.12.**

Independent review process settlement charge charge types - The *IESO* will determine a *settlement amount* under the following *charge types*:

Table 4-6: Independent Review Process Settlement Charges

Charge Type Number	Charge Type Name
1940	Reference Level and Reference Quantity Independent Review Process Settlement Amount
1941	Reference Level and Reference Quantity Independent Review Process Recovery Amount (Market)
1942	Reference Level and Reference Quantity Independent Review Process Balancing Amount (IESO)

5 Market Remediation

(MR Ch.7 ss.7.6 and 8.4A and Ch.9 s.2.14)

Overview of market remediation - Potential market tool failures and errors may impact the operability of the *IESO-administered markets.* The *IESO* will assess the impact to the *IESO-administered markets* and will resolve incorrect and/or missing data and take corrective, appropriate action, that is specific to the timeframe in which the market failure and/or error occurred.

The *IESO* may take any of the following actions, depending on the specific circumstances for the *day-ahead market* or *real-time market*:

- administrative pricing;
- declare a *dispatch scheduling error;*
- declare a market failure; and/or
- declare a market suspension.

Published results may also be deemed invalid due to a number of factors, and corrective actions may be required after-the-fact. Refer to **MM 4.5** and the following *market manuals* for market remediation in the ~~*day*~~ *day-ahead market,* in pre-dispatch, and in the *real-time market*:

- **MM 4.2**
- **MM 4.3**

For additional clarity, in the event that a pre-dispatch error or a *pre-dispatch calculation engine* failure occurs, no corrections to *pre-dispatch schedules* or prices will be made. Deviations from the last recorded and *published pre-dispatch calculation engine* run will be reflected in real-time inputs for *non-quick start resources* and *intertie* transactions through transaction codes.

The results of these corrective actions will be received by the *settlement process* and *settlement amounts* will be calculated using this data.

Appendix A: Forms

This appendix contains a list of forms associated with this *market manual*, which are available on the *IESO's* website ~~(http://www.ieso.ca/)~~. The forms included are as follows:

Table A-1: List of Forms

Form Name	Form Number
~~Fuel Cost Compensation~~	~~TBD~~
Application for Designation of a Facility for Generation Station Service Rebate	IMO_FORM_1419

– End of Section –

Appendix B: Hydroelectric Generation Resources – Determining a Start and Start Event

B.1. Determining a Start

The following figure depicts an example of the *day-ahead schedule* for a hydroelectric *generation resource* for the first six *settlement hours* of a *trading day*, including HE4 which was issued for *reliability* reasons. In this example, the hydroelectric *generation resource* has registered three *start indication values* (SIV).

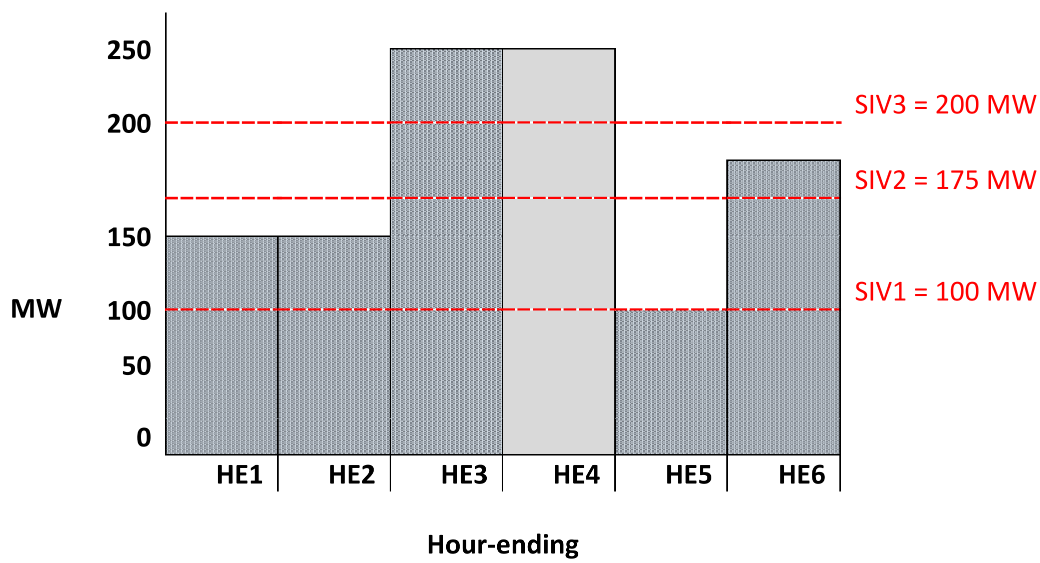

Figure B-1: Determining a Start

For the hydroelectric *generation resource*, the *maximum number of starts per day* submitted by the *market participant* is four.

The following table shows the *IESO*'s assessment of each *settlement hour* and how it would come to the conclusion that the hydroelectric *generation resource* has four starts (in HE1, HE3, HE3, and HE6). This equals the *maximum number of starts per day* submitted. Therefore, the hydroelectric *generation resource* has attained max starts.

Table B-1: IESO Assessment of Starts in Each Settlement Hour

Hour-ending	Day-Ahead Schedule	Assessment
HE1	150 MW	A start is counted in HE1 as the *day-ahead schedule* is 150 MW, which is above the first *start indication value* (SIV1).
HE2	150 MW	The *day-ahead schedule* is 150 MW and does not increase above another *start indication value*. Therefore, there is no start.
HE3	250 MW	The *day-ahead schedule* is 250 MW. In this *settlement hour*, two starts are counted as the hydroelectric *generation resource* increases above SIV2 (175 MW) and SIV3 (200 MW)
HE4	250 MW dispatched for *reliability*	The *day-ahead schedule* is 250 MW and does not increase over another *start indication value*. Therefore, no start is counted.
HE5	100 MW	The *day-ahead schedule* is 100 MW which is below SIV3 and SIV2. Therefore, no start is counted.
HE6	185 MW	The *day-ahead schedule* is 185 MW and increases from the *day-ahead schedule* in HE5 and increases above SIV2. Therefore a start is counted.

B.2. Determining a Start Event

Continuing with the above example, the following assessment will illustrate how the *IESO* determines which *settlement hours* are included in a start event.

Table B-2: IESO Determination of Settlement Hours in a Start Event

Hour-ending	Assessment
HE1	The first start is triggered and therefore is the beginning of start event 1.
HE2	Does not decrease below the lowest *start indication value* and no new start is triggered. Therefore, the *settlement hour* is also part of start event number 1.
HE3	Another start is triggered and therefore is the beginning of start event 2.
HE4	The hydroelectric *generation resource* was dispatched for *reliability*. Therefore, the hour will not be included in a start event. Start event 2 will continue to be assessed in the next *settlement hour*.

Hour-ending	Assessment
HE5	The *day-ahead schedule* does not decrease below the lowest *start indication value* and no new start is triggered. The *dispatch hour* will be included in start event 2.
HE6	Another start is triggered and is the beginning of start event 3.

Based on this assessment, the hydroelectric *generation resource* has three start events as described in the following table.

Table B-3: Start Events and DAM_MWP Calculations

Start Event	Hours	DAM_MWP Calculation
Start event 1	HE1 to HE2	DAM_MWP will be calculated on a *per-start* basis, in accordance with **MR Ch.9 s.3.4.13.4**.
Start event 2	HE3 to HE5, excluding HE4	DAM_MWP will be calculated on a *per-start* basis, in accordance with **MR Ch.9 s.3.4.13.4**, with the exception of HE4 which will be calculated on an hourly basis, in accordance with **MR Ch.9 s.3.4.13.5.2**.
Start event 3	HE6	DAM_MWP will be calculated on a *per-start* basis, in accordance with **MR Ch.9 s.3.4.13.4**.

– End of Section –

Appendix C: Price Bias Adjustment Factors Calculation Method for the Real-Time Import and Export Failure Charge

(MR Ch.9 s.3.7)

The real-time failure charge calculation for imports and exports includes the difference between the pre-dispatch ~~*energy market price*~~*intertie border price* and the *real-time market* ~~*energy market price*~~*intertie border price* during the *settlement hour* of the failure. Including transaction failures, there are many factors that contribute to these *market price* differences. The purpose of the price bias adjustment factors is to adjust this charge to take into account some of the systemic reasons for such differences in *market prices.*

The following calculation method produces 24 hourly factors that apply for a three-month period. These three-month periods are aligned with the seasons.

The periods are:

- the winter factors apply to December, January, and February;
- the spring factors apply to March, April, and May;
- the summer factors apply to June, July, and August; and
- the autumn factors apply to September, October, and November.

Effective time for each three-month block starts at the first hour of the first day of the month and ends at the 24th hour of the last day of the third month in the block.

The *IESO* will *publish* the price bias adjustment factors in advance of their effective *trading day*.

The *IESO* uses the following methodology to calculate the price bias adjustment factors.

Data Set

The total data set used to calculate the price bias adjustment factors includes ~~all~~the following historical differences in *energy market price* between pre-dispatch and the *real-time market*, including those differences which are zero, positive, and negative. ~~This total data set includes all differences from the start of the Ontario market (May 1, 2002) until the present calendar year.~~

For time periods prior to the commencement of *market transition*, the differences in *energy market price* between pre-dispatch and the *real-time market* will be the unconstrained prices. This total data set includes all differences from the thirty-six month period immediately prior to the relevant seasonal period to which the price bias adjustment factor relates.

For time periods following the commencement of *market transition*, the differences in *energy market price* between pre-dispatch and the *real-time market* will be determined as follows:

- Until the *IESO* determines that it has sufficient valid and consistent *locational marginal price* data for each of the relevant seasonal periods, the price bias adjustment factor will be determined using both the *real-time market hourly Ontario Energy Price* from the *legacy market rules* and the *real-time market Ontario zonal price* following the implementation of the *renewed market rules,* and their respective hourly pre-dispatch equivalents. The *IESO* will consider data going back 36 months and may weight the relevant *energy market prices* from the *legacy market rules* and the *renewed market rules* at its discretion. During this time, there will be a single price bias adjustment factor for every *intertie*.
- Once the *IESO* determines that it has sufficient valid and consistent *locational marginal price* data for each of the relevant seasonal periods, the price bias adjustment factor will be determined based exclusively on the *real-time market locational marginal price* and its hourly pre-dispatch equivalent. When the *IESO* has made such a determination, it will *publish* a notice to this effect. Following the *publication* of such notice, the *IESO* will determine a price bias adjustment factor for each *intertie*.

The *IESO* calculates each hourly price bias adjustment factor using a subset of the total data set. All the price differences are divided into those which occurred in each hour of the day during each seasonal block defined above. The price bias adjustment factors are calculated using the corresponding hours in the corresponding months. For example, the spring factor for hour 1 is calculated using all the price differences from hour 1 for the months of March, April, and May in the relevant time period~~of each year since market opening.~~ This results in data sets that are hourly, seasonal, and yearly.

The *IESO* then creates frequency distributions for these data sets and determines the median values of the frequency distributions.

Weighting Factors

Each yearly median value is assigned a weighting factor from 0 to 1. A year with a weighting factor of zero results in that year's median value not contributing to the determination of the price bias adjustment factor. Conversely, a year assigned a weighting factor of 1 will solely be considered at the exclusion of all other years. After taking into account the weighting factors, the *IESO* determines a price bias adjustment for each hour of the day for a three-month block.

The use of weighting factors allows the *IESO* to establish the best forecast by enabling the price bias adjustment factors to reflect short-term and long-term influences. The weighting factor assignments are at the *IESO's* discretion.

These calculations result in 24 hourly price bias adjustment factors for each season of the year. These factors are the same for the import and export *settlement* charge.

~~The *IESO* will *publish* the price bias adjustment factors in advance of their effective *trading day*.~~

– End of Section –

Appendix D: IOG Offset Process

The following is an example of the IOG offset process as described in section 2.18.

For *market participant* 123456 in *settlement hour* 4, the *energy trader* participating with a *boundary entity resource* received the following *energy* import transactions and *energy* export transactions in the *real-time market* and the *day-ahead market*.

Table D-1: Real-Time Market Energy Intertie Transactions

	Boundary Entity Resource	MW	Intertie	Neighbouring Electricity System	Potential_IOG	RT_IOG Rate ($/MW)
RT Import Transactions	Res1	100	PQQC	HQ	$1,000	$10
	Res4	400	PQBE	HQ	$8,000	$20
	Res5	100	MBSI		$3,000	$30
	Res9	100	MBSI		$0	$0
RT Export Transactions	Res6	100	MNSI			
	Res7	100	MBSI			
	Res8	100	PQXY	HQ		

Table D-2: Day-Ahead Market Energy Intertie Transactions

	Boundary Entity Resource	MW	Intertie	Neighbouring Electricity System
DAM Import Transactions	Res11	50	PQQC	HQ
	Res2	100	MBSI	
	Res3	100	MNSI	
	Res9	100	MBSI	
DAM export transactions	Res6	50	MNSI	

1. The real-time *energy* import transaction associated with Res9 is removed as it has a RT_IOG rate of $0/MW. The corresponding *DAM energy* import transaction is automatically removed as the *DAM schedule* of 100MW is equal to the *real-time schedule* of 100MW.

2. Determine the incremental *real-time market energy* export transactions for any *energy trader* participating with a *boundary entity resource* that was scheduled for an export transaction in the *day-ahead market* and the *real-time market*.

Table D-3: Incremental Real-Time Energy Export Transactions

Energy Transaction	Res6
	MNSI
RT Export MW	100
DAM Export MW	50
Offset MW	**50**
Remaining RT Export MW - Res6	**50**

3. Perform the IOG offset at the *intertie* level.
   a. On the same *intertie*, identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

Table D-4: IOG Offset at Intertie Level

Energy Transaction	PQQC
RT Import MW - Res1	100
DAM Import MW - Res11	50
Offset MW	**50**
Remaining RT Import MW - Res1	**50**

Energy Transaction	MBSI
RT Import MW - Res5	100
DAM Import MW - Res2	100
Offset MW	**100**
Remaining RT Import MW - Res5	**-**

   b. On the same *intertie*, offset *energy* import transactions and *energy* export transactions scheduled in the *real-time market*.
   c. There are no remaining offset of MWs at the *intertie* level. The remaining quantity of *energy* for any *intertie* transaction not offset will be carried forward to the next IOG offset level: *neighbouring electricity system* level.
4. Perform the IOG offset at the *neighbouring electricity system* level.
   a. In the same *neighbouring electricity system*, identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

Table D-5: IOG Offset at Neighbouring Electricity System Level

Energy Transaction	HQ
RT Import MW - Res1	50

Energy Transaction	HQ
RT Import MW - Res4	400
DAM Import MW	-
Offset MW	**-**
Remaining RT Import MW - Res1	**50**
Remaining RT Import MW - Res4	**400**

- There is no offset of MWs at this step.

b. In the same *neighbouring electricity system*, offset *energy* import transactions and *energy* export transactions scheduled in the *real-time market*.

Table D-6: IOG Offset at Neighbouring Electricity System Level

Energy Transaction	HQ
RT Import MW - Res1	50
RT Import MW - Res4	400
RT Export MW - Res8	100
Offset MW	**100**
Remaining RT Import MW - Res1	**-**
Remaining RT Import MW - Res4	**350**

c. The remaining quantity of *energy* for any *intertie* transaction not offset will be carried forward to the next IOG offset level: *IESO-control area* (Ontario) level.

5. Perform the IOG offset at the *IESO-control area* (Ontario) level.

The following *energy* import and export transactions are available for offset.

Table D-7: IOG Offset at IESO-Control Area (Ontario) Level

Energy Transaction	Res4 PQBE	Res6 MNSI	Res3 MNSI	Res7 MBSI
RT Import MW	350	-	-	-
DAM Import MW	-	-	100	-
RT Export MW	-	50	-	100

a. Identify *energy* import transactions scheduled in the *real-time market* and *energy* import transactions scheduled in the *day-ahead market* but for which the *day-ahead market energy* import transaction was not scheduled in the *real-time market*.

Table D-8: IOG Offset at IESO-Control Area (Ontario) Level

Energy Transaction	MWs
RT Import MW - Res4	350
DAM Import MW - Res3	100
Remaining RT Import MW - Res4	**250**

b. Offset *energy* import transactions and *energy* export transactions scheduled in the *real-time market*.

Table D-9: IOG Offset at IESO-Control Area (Ontario) Level

Energy Transaction	MWs
RT Import MW - Res4	250
RT Export MW - Res6	50
RT Export MW - Res7	100
Remaining RT Import MW - Res4	**100**

c. RT import transaction – Res4 was offset:

- 50MW at the *neighbouring electricity system* level, and
- 250MW at the *IESO-control area* (Ontario) level.
- Total IOG_Offset MWs is 300MW.

6. The RT_IOG *settlement amount* for Res4 is determined as follows.

Table D-10: RT_IOG Settlement Amount

Potential_IOG	$8,000
IOG_Offset MWs	300
IOG_Rate	$20

= Max [Potential_IOG - IOG_Offset, 0]
= Max [$8000 - (300 x $20),0]
= $2000

Res4 will receive a *settlement amount* under *charge type* 1927 – Real-Time Intertie Offer Guarantee.

– End of Section –

List of Acronyms

Acronym	Term
AQEW	Allocated quantity of energy withdrawn
CAAC	Capacity Obligation - Availability Charge
CAACT	Capacity Obligation - Availability True-Up
CAADM	Capacity Obligation - Administration Charge
CAAP	Capacity Obligation – Availability Payment
CABOC	Capacity Obligation - Buy-Out Charge
CACC	Capacity Obligation - Capacity Charge
CACD	Capacity Obligation - Capacity Deficiency
CACIF	Capacity Obligation - Capacity Import Call Failure
CACT	Capacity Obligation - Capacity Auction Charges True Up
CADC	Capacity Obligation - Dispatch Charge
CAEOP	Capacity Obligation - Emergency Activation Payment
CAIPA	Capacity Obligation - In-Period Cleared UCAP Adjustment Charge
CATAP	Capacity Obligation - Test Activation Payment
CAU	Capacity Obligation Uplift
BCE	Balancing Credit – Energy
BCOR	Balancing Credit - Operating Reserve
DAM_BC	Day-Ahead Market Balancing Credit
DAM_BCU	Day-Ahead Market Balancing Credit Uplift
DAM_ECR	Day-Ahead Market External Congestion Residual
DAM_GOG	Day-Ahead Market Generator Offer Guarantee
DAM_EXFC	Day-Ahead Market Export Failure Charge
DAM_IMFC	Day-Ahead Market Import Failure Charge
DAM_INFC	Day-Ahead Market Intertie Failure Charge
DAM_MWP	Day-Ahead Market Make-Whole Payment
DAM_NECR	Day-Ahead Market Net External Congestion Residual
DAM_NISLR	Day-Ahead Market Net Interchange Scheduling Limit Residual
DAM_NISRU	Day-Ahead Market Net Interchange Scheduling Limit Residual Uplift
DAM_RLSC	Day-Ahead Market Reference Level Settlement Charge

Acronym	Term
DAM_RLSCU	Day-Ahead Market Reference Level Settlement Charge Uplift
DAM_UPL	Day-Ahead Market Uplift
DRSU	Day-Ahead Market Reliability Scheduling Uplift
ELOC	Energy lost opportunity cost
EXP_EWSC	Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge
EXP_EWSCU	Ex-Post Mitigation for Economic Withholding on Uncompetitive Interties Settlement Charge Uplift
EXP_PWSC	Ex-Post Mitigation for Physical Withholding Settlement Charge
EXP_PWSU	Ex-Post Mitigation for Physical Withholding Settlement Charge Uplift
FCC	Fuel Cost Compensation Credit
FCCU	Fuel Cost Compensation Credit Uplift
GFC	Generator Failure Charge
GFC_GCC	Generator Failure Charge - Guarantee Cost Component
GFC_GCCU	Generator Failure Charge - Guarantee Cost Component Uplift
GFC_MPC	Generator Failure Charge - Market Price Component
GFC_MPCU	Generator Failure Charge - Market Price Component Uplift
HDR	Hourly demand response resource
HORSA	Hourly Operating Reserve Settlement Amount
HPTSA	Hourly Physical Transaction Settlement Amount
HPTSA_NDL	Hourly Physical Transaction Settlement Amount - Non-Dispatchable Load
HVTSA	Hourly Virtual Transaction Settlement Amount
ICLR	Internal Congestion and Loss Residual
INFC	Intertie Failure Charge
INFCU	Intertie Failure Charge Uplift
IOG	Intertie offer guarantee
NISL	Net interchange scheduling limit
OEB	Ontario Energy Board
PBC	Physical bilateral contract
RDRL	Ramp-down rate limited
RLSC	Reference Level Settlement Charge
RLSCU	Reference Level Settlement Charge Uplift

Acronym	Term
RT_ECR	Real-Time External Congestion Residual
RT_ECRU	Real-Time External Congestion Residual Uplift
RT_EXFC	Real-Time Export Failure Charge
RT_GOG	Real-Time Generator Offer Guarantee
RT_GOGU	Real-Time Generator Offer Guarantee Uplift
RT_IMFC	Real-Time Import Failure Charge
RT_INFC	Real-Time Intertie Failure Charge
RT_IOG	Real-Time Intertie Offer Guarantee
RT_IOGU	Real-Time Intertie Offer Guarantee Uplift
RT_LOC_EOP	Real-Time Lost Opportunity Cost Economic Operating Point
RT_MWP	Real-Time Make-Whole Payment
RT_MWPU	Real-Time Make-Whole Payment Uplift
RT_NISLR	Real-Time Net Interchange Scheduling Limit Residual
RT_NISLRU	Real-Time Net Interchange Scheduling Limit Residual Uplift
RT_RDSA	Real-Time Ramp-Down Settlement Amount
RT_RDSAU	Real-Time Ramp-Down Settlement Amount Uplift
RT_RLSC	Real-Time Reference Level Settlement Charge
RT_RLSCU	Real-Time Reference Level Settlement Charge Uplift
SIV	Start indication value
SQEW	Scheduled quantity of energy withdrawn
TR	Transmission right
TRCA	Transmission rights clearing account

– End of Section –

References

Document ID	Document Title
MDP_PRO_0002	Market Rules for the Ontario Electricity Market
PRO-408	Market Manual 1: Connecting to Ontario's Power System, Part 1.5: Market Registration Procedures
TBD	Market Manual 4: Market Operations, Part 4.2: Operation of the Day-Ahead Market
IMP_PRO_0034	Market Manual 4: Market Operations, Part 4.3: Operation of the Real-Time Markets
MDP_PRO_0029	Market Manual 4: Market Operations, Part 4.4: Transmission Rights Auction
MDP_PRO_0030	Market Manual 4: Market Operations, Part 4.5: Market Suspension and Resumption
MDP_PRO_0034	Market Manual 5: Settlements, Part 5.3: Physical Bilateral Contracts
MDP_PRO_0035	Market Manual 5: Settlements, Part 5.6: Non-Market Settlement Programs
PRO-665	Market Manual 5: Settlements, Part 5.10: Settlement Disagreements
IMP_LST_0001	IESO Charge Types and Equations
MAN-44	Market Manual 12: Capacity Auction
TBD	Market Manual 14: Market Power Mitigation, Part 14.1: Market Power Mitigation Procedures
TBD	Market Manual 14: Market Power Mitigation, Part 14.2: Reference Level and Reference Quantity Procedures

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