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Market Manual 5: Settlements

Part 5.5: Physical

Markets Settlement

Statements

Issue 46.0

This procedure describes the processes to issue, retrieve and dispute *physical markets settlement statements*.

Public

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Table of Changes

Reference (Section and Paragraph)	Description of Change
Section 1.6.8	Limiting CMSC Payments for Exporters and Dispatchable Loads - The replacement bid price for <i>dispatchable loads</i> changed from -\$50 to -\$15. The reason for this change is based on the global adjustment (GA) allocation method which went into effect on January 1, 2011, whereby dispatchable loads are no longer charged GA for each MWh of consumption. The proposed effective date of the -\$15/MWh replacement bid price is March 7, 2012.
Section 1.6.9.3	Updated <i>market rule</i> reference from section 3.5.1C to 3.5.1D of Chapter 9.
Section 1.6.19	Added new section entitled, “Renewable Integration - Forecasting” describing the settlement of new forecasting services provided by the <i>IESO</i> .
Section 1.6.20, 1.6.20.1	Added new section entitled, “Adjustment for Self-Induced CMSC Earned by Certain Generating Facilities” and sub-section “Calculation of CMSC Payment Recovery for Steam Unit Offers”. This is the implementation of <i>market rule</i> amendment MR-00252 enabling the <i>IESO</i> to recover inappropriate congestion management settlement credits (CMSC) earned by the steam unit of a combined cycle facility where the steam unit <i>offer</i> is higher than the <i>offer</i> of the unit fuelling the steam unit.

Market Manuals

The *market manuals* consolidate the market procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IESO-administered markets*. Market procedures provide more detailed descriptions of the requirements for various activities than is specified in the *market rules*. Where there is a discrepancy between the requirements in a document within a *market manual* and the *market rules*, the *market rules* shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

Market Procedures

The “Settlements Manual” is Volume 5 of the *market manuals*, where this document forms “Part 5.5: Physical Markets Settlement Statements.”

A list of the other component parts of the “Settlements Manual” is provided in “Part 5.0: Settlements Overview”, in Section 2, “About This Manual”.

Structure of Market Procedures

Each market procedure is composed of the following sections:

1. **“Introduction”**, which contains general information about the procedure, including an overview, a description of the purpose and scope of the procedure, and information about roles and responsibilities of the parties involved in the procedure.
2. **“Procedural Work Flow”**, which contains a graphical representation of the steps and flow of information within the procedure.
3. **“Procedural Steps”**, which contains a table that describes each step and provides other detail related to each step.
4. **“Appendices”**, which may include such items as lists of forms, standards, policies, and agreements.

Conventions

The *market manual* standard conventions are defined in the “Market Manual Overview” document.

In this document, “we” and “us” refers to the *IESO*; “you” refers to *market participants* unless specifically identified otherwise.

– End of Section –

1. Introduction

1.1 Purpose

In this procedure we describe the process to create and issue *preliminary* and *final settlement statements* for the *physical markets*. When we refer to *physical markets* in this procedure, we are describing:

- the *real-time market for energy* (RTE)¹, which consists of:
 - a market for *energy*; and
 - a market for several classes of *operating reserve*;
- *procurement markets*, which consists of:
 - markets for *contracted ancillary services*, including: *reactive support* and *voltage control, regulation service* and *black start capability*;
 - a market for *reliability must-run contracts*; and
- the *transmission rights (TR)* market, except for *settlement amounts* relating to the purchase or sale of a *transmission right* in any round of a *TR auction*².

In this procedure we also describe the process to follow if you disagree with your *preliminary settlement statement* – we will apply any amendments necessary to your *final settlement statement*.

1.2 Scope

This document provides a summary of the interfaces between parties and the steps involved in issuing *preliminary* and *final settlement statements* for the *physical markets*. The procedural work flows and steps serve as a roadmap and reflect the requirements set out in the *market rules* and *IESO* policies and standards.

This procedure contains three parts:

- Section 1 contains a summary of *settlement statements*;
- Section 2 describes the main actions of the procedure in the procedural work flow; and
- Section 3 presents the procedural steps.

This procedure applies only to the *IESO's physical markets*. The procedures for *IESO* financial market *settlement statements* are provided in “Market Manual 5: Settlements, Part 5.7: Financial Markets Settlement Statements”.

¹ The *market rules* specify that the RTE market should also include a *capacity reserve market*. However, this market has been deferred and may be established at a later date.

² The *settlement amounts* relating to the sale or purchase of *transmission rights* in any round of a *TR auction* appear on the financial markets *settlements statement*. See “Part 5.7: Financial Markets Settlement Statement” for details on this *statement*.

1.3 Overview of the Settlement Statement Process

We cover the following topics that comprise the *settlement statements* process:

- issuing and retrieving *preliminary settlement statements*;
- interpreting the *settlement statements* and data files;
- interpreting the *transmission services charge* data files;
- steps to submit queries;
- steps to submit a *notice of disagreement*; and
- issuing and retrieving *final settlement statements*.

A timeline showing the key activities in issuing a *settlement statement* for the *physical markets* is available in “Part 5.0: Settlements Overview”.

1.3.1 Issuing the Preliminary Settlement Statement

We issue a *preliminary settlement statement* for each *trading day* in the *physical markets* on the date specified in the *IESO Settlement Schedule and Payments Calendars (SSPCs)*. See “Part 5.1: Settlement Schedule and Payments Calendars (SSPCs)” for details on the *SSPCs*.

Currently, we issue *preliminary settlement statements* 10 *business days* following the *trading day*. They are generated automatically by our Commercial Reconciliation System (CRS) and are available to you by 17:00 EST on the issue date. A sample timeline to produce and issue a *preliminary settlement statement* is shown in Figure 1-1.

On some *business days* we may issue more than one *settlement statement* for a given *market participant*. This is because *physical markets* trading occurs on Saturdays, Sundays and holidays, which are not considered *business days* under the *market rules*. We issue separate *preliminary settlement statements* for each *trading day* even if *settlement statements* for two or more *trading days* are issued on the same *business day*.

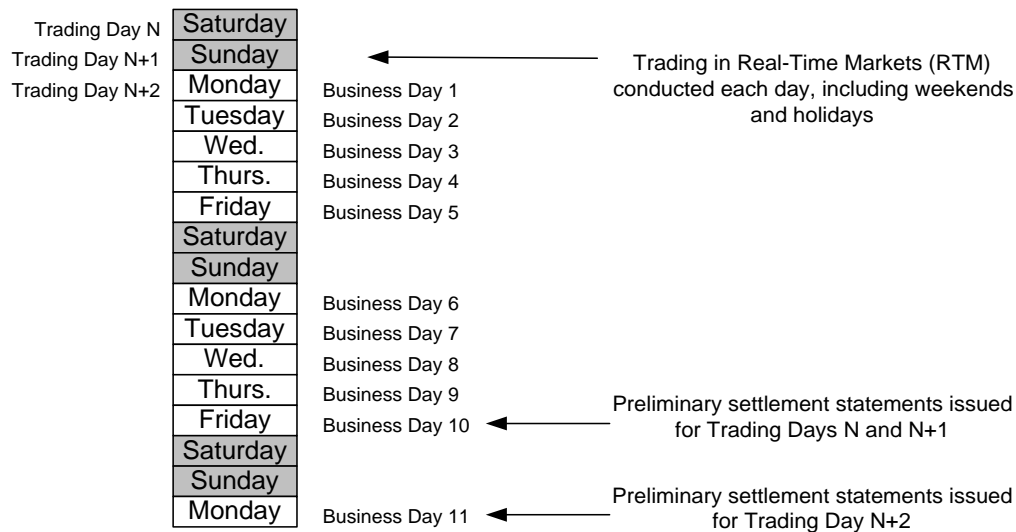


Figure 1–1: Preliminary Settlement Statement Timeline

The *preliminary settlement statement* has two parts:

- a *settlement statement* file: This file contains the *settlement amounts*³ (credit or debit) for your activities in the *physical markets*. It also includes your charges for *transmission services*, which we collect from *market participants* on behalf of the transmission companies. The *settlement statement* file may also contain other charges as required by regulations.
- a companion data file: This file includes *physical bilateral contract data*, zonal prices, schedules, and *bids* and *offers*. This file also includes a number of data files relating to the *transmission services settlement* charges that we make available to *transmission customers* and *transmitters*, as described below. An optional data measurement file is also available.

It is your responsibility to retrieve the appropriate files from the IESO Reports site. These include the Settlement Statement Files, Real-Time Market Data Files, Participant Transmission Tariff Data Files, Transmitter Transmission Tariff Data Files and the Transmitter Reconciliation Data Files. We have identified the steps you should follow to download the *settlement statements* in the “Market Participant Graphical User Interface User’s Guide”, “Quick Take 15: Retrieving Reports via the IESO Reports Site”, and tool simulations available on the IESO Marketplace Training web pages.

You will receive a *preliminary settlement statement* for a *trading day* if you were active⁴ on that day. You will not receive a *preliminary settlement statement* for a particular *trading day* if you were not active on that day.

We consider that a *preliminary settlement statement* has been issued when we have made it accessible to you on the IESO Reports site. If you fail to receive a *preliminary settlement statement* on the date scheduled in the *SSPC*, it is your responsibility to notify us via IESO Customer Relations. We will assume that you have been able to retrieve the *preliminary settlement statement* file and companion data files from the IESO Reports site unless you notify us to the contrary.

When you notify us that we have not issued a *preliminary settlement statement* for a given *trading day* in accordance with the *SSPC*, we will investigate and provide you an explanation. If necessary, we will re-issue the *preliminary settlement statement*.

Our investigation may show that:

- we issued your *preliminary settlement statement*;
- it was accessible via the IESO Reports site on the date specified in the *SSPC*; and
- you failed to properly retrieve it.

In this situation, we will not extend the period within which you can submit a *notice of disagreement*.

However, our investigation may show that:

- we failed to issue your *preliminary settlement statement* on the date specified in the *SSPC*; or
- some error occurred in our systems that made retrieval of the *settlement statement* impossible.

In this situation, we will consider that you have received your *preliminary settlement statement* on the date on which we made your statement accessible to you, and we will extend the period within which you can submit a *notice of disagreement*.

³ Our system summarizes *settlement amounts* by time period (*trading day*, trading hour, trading interval) and location as *charge types*. Items that we refer to as *settlement amounts* in this procedure will be summarized as *charge types* on the *settlement statement* itself.

⁴ You are considered to be an active *market participant* if you have at least one non-zero *settlement amount* on the *trading day* in question. Sometimes a *settlement amount* for a *trading day* may come from adjustments to previous *trading days* or from amounts that you incur indirectly, such as *default levy* amounts.

1.3.2 Interpreting the Settlement Statements and Data Files

Both the *preliminary* and *final settlement statement* files list the *settlement amounts* (credit or debit) for your activities in the *physical markets* for a particular *trading day*. However, they may also contain missing *settlement amounts* or adjustments from prior *trading days*, which may arise from:

- adjustments that have resulted from a *notice of disagreement* (see Section 1.3.5); or
- revisions to *metering data*.

When the *metered market participant* and the *registered market participant* registered for a particular *delivery point* are two different *market participants*,

- the *registered market participant* submits *offers* and receives *dispatches of energy* and *operating reserve*; and
- the *settlement amounts* are applied to the *metered market participant*. The *metered market participant* also receives all supporting data with respect to all *charge types* generated for the *delivery point*.

Your *preliminary* and *final settlement statement* files show allocated quantities of *energy* withdrawn or injected by each of your *registered facilities*. If you have been a party to any physical allocation activities, your allocated quantities of *energy* withdrawn or rejected will have been adjusted accordingly. For more information on the *physical allocation data* process, see “Part 5.2: Meter Data Processing”.

The *preliminary* and *final settlement statement* files are composed of four record sections:

1. **Header Record:** The header record identifies the contents of the file. It includes information such as the statement number, statement type (physical or financial market), *settlement* type (preliminary or final), total due amount for *trading day* and the *billing period* total to date.
2. **Summary Records:** These records provide a summary of all *settlement amounts* and manual line item records in the *settlement statement* file (as set out in record sections 3 and 4 below). One record is provided for each *trading day* and for each type of *settlement amount* reflected in the line item records (see below). Each summary record identifies and describes the type of *settlement amount*, specifies the *trading day* and the total net amount for each type of *settlement amount*, and indicates whether the summary record is an adjustment record.
3. **Settlement Detail Records:** These records provide the details of each of your individual *settlement* line items that are created by our *settlement* system. *Settlement* detail records include information such as:
 - *trading day*;
 - relevant hour(s);
 - time interval, which is dependent upon the type of *settlement amount*;
 - *settlement amounts*;
 - the applicable zone and location IDs;
 - *settlement* type (preliminary or final);
 - quantity of megawatt-hours (MWh) to be billed; and
 - price (in \$/MWh) at which the quantity of megawatt-hours will be billed.

The *trading day* stipulated for each *settlement amount* will not always match the *trading day* specified in the header record. New *settlement* details for prior *trading days* may be included in your *preliminary settlement statement* file and subsequently on a *final settlement statement*. A number of the fields on the *settlement* detail records may have different meanings when used with different *charge types*.

4. **Manual Line Item Records:** This final section of the *settlement statement* includes records that identify each of your manual line items that we have entered⁵.

We will also issue a companion data file with the statement file described above. The data file provides you with the supporting data used to calculate the *settlement amounts* for a particular primary *trading day* in the *physical market*. The data file is composed of the following general sections:

1. A header record providing information such as:
 - statement number;
 - statement type (physical or financial);
 - *settlement* type (preliminary or final); and
 - primary *trading day* for the *settlement statement*;
2. Data elements used to calculate the *settlement amounts*:
 - *physical bilateral contract data*;
 - zonal price data (these records provide the Ontario *energy* prices);
 - schedules data (these records contain the market and *dispatch* schedules data); and
 - *bid* and *offer* data; and
3. *Optional Measurement Data* - this optional file contains net withdrawal or net injection values for each 5-minute trading interval for each *delivery point* defined for *physical market* charges (see Section 1.5 below).

We provide detailed information about *settlement statements* and *settlement* data files in the document “Format Specifications for Settlement Statement Files and Data Files”. You can find this document and sample files on our web-site.

You can use the reference document “IESO Charge Types and Equations” to find additional information about:

- key *settlement* variables;
- *IESO charge types* and equations; and
- the Harmonized Sales Tax (HST).

You can find this document on our web-site.

⁵ Manual line item entries will be less common than the preceding three record types and will not appear within every statement file.

1.3.3 Data Files for Transmission Services Charges⁶

The *preliminary settlement statement* contains a number of charges relating to *transmission services*, which we collect on behalf of transmission companies⁷. We also make a number of data files available to the *transmission customer*⁸ or the *transmitter*, as appropriate, via the IESO Reports site. These data files allow *transmission customers* and *transmitters* to validate the *transmission service charges* that appear on their *settlement statement*.

Transmission Customers

We provide two data files with information relevant to *transmission customers*.

- The “Participant Transmission Tariff Data File⁹” is available to *transmission customers*. This file contains the hourly measurements for each *delivery point* defined for transmission network charges or transmission *connection charges* associated with a specific *market participant*.
- The “Transmission Tariff Peak System Demand Data Report” is available to all *market participants*. This report provides the sum of the hourly measurements across all *delivery points* defined for transmission network charges for each Trading Date / Hour in the reporting month. This report provides transparency to *market participants* regarding the measurements that form the basis for our determination of the peak system *demand* used to calculate *transmission charges*¹⁰.

Transmitters

We provide two data files with information relevant to *transmitters*:

- the “Transmitter Transmission Tariff Data File” which contains:
 - the hourly measurements for every *delivery point* defined for transmission network charges; or
 - transmission *connection charges* for which the *transmitter* is associated as the *transmitter* during the *meter* registration process; and
- the “Transmitter Reconciliation Data File” which contains debit charge details (the *transmitter* uses the information in this file to verify that the *transmission tariff* credits reflect the appropriate collection of *transmission tariff* charges from every *transmission customer* at every *transmission delivery point* as specified by the *transmitter*¹¹).

⁶ The file format specifications for the following data files/reports are provided on our web site:

- Participant Transmission Tariff Data File;
- Transmission Tariff Peak System Demand Data Report;
- Transmitter Transmission Tariff Data File; and
- Transmitter Reconciliation Data File.

⁷ See the reference document “IESO Charge Types and Equations” for more information.

⁸ The *transmission customer* is associated as the *metered market participant* Transmission (MMPT) for one or more *delivery points* defined for transmission network charges or transmission *connection charges*. See the “Market Manual 3: Metering, Part 3.8 Creating and Maintaining Delivery Point Relationships” for more information on this assignment process.

⁹ See the reference document “File Format Specification for Participant Transmission Tariff Data File” for details on this file.

¹⁰ Measurements at specific *delivery points* defined for transmission network charges are listed in each participant’s “Participant Transmission Tariff Data File”. This information is confidential and is not provided to other *market participants*.

¹¹ The collection of *transmission tariff* charges is specified in Chapter 10 of the *market rules*.

1.3.4 Submitting Queries

The *preliminary settlement statement* provides you an opportunity to review, query and formally disagree with the charges or other elements of your statement (except as noted in Section 1.3.5 below).

If you have questions about your *preliminary settlement statement* and data files, you may submit queries to us regarding the file contents (see Section 1.8 below for contact information). Our goal is to respond to your queries within 2 *business days*.

Please note that all queries about the contents of your *settlement statement* and data files are only requests for information. We do not consider queries to represent any formal disagreement with the contents of the *settlement statement* and data files unless you submit a formal *notice of disagreement*. Therefore, we will not modify your *settlement* files if you submit a query.

We will only discuss *settlement statements* queries with contacts registered as “Settlement Statements” or “Main” contacts in our Registration (PLC) system.

1.3.5 Submitting a Notice of Disagreement

If you disagree with a *settlement amount* on your *preliminary settlement statement*, you may submit a *notice of disagreement* (NOD) within four *business days* after the statement has been issued¹². To submit a NOD, you must complete all required sections of the *notice of disagreement* form and send it to us electronically through the NOD user interface on the Internet¹³.

You need a User ID and password to access the NOD user interface. To obtain a User ID:

- download IMO-FORM-1276 v13.0 REV 06-07 “IESO Identify System Access Management” from our web-site;
- complete the form as directed, including selecting the box for access to *Notice of Disagreement* and obtaining the appropriate signatures; and
- return the completed form to us.

We will send you your User ID and password.

If you disagree with an item or calculation in your *preliminary settlement statement* for a single *trading day*, you can submit a *notice of disagreement*. You may not submit a *notice of disagreement* regarding the calculation of:

- the 5-minute *energy market price* for any *dispatch interval* in a given *settlement hour*;
- the 5-minute price for any class of *operating reserve* for any *dispatch interval* in a given *settlement hour*;
- the *energy forward market price* for a given *settlement hour*; or
- the *hourly Ontario energy price* for a given *settlement hour*.

However, you can submit a *notice of disagreement* with respect to the manner in which any of these prices have been applied in the calculation of your *settlement amounts*.

Your *notice of disagreement* may only pertain to one item (or issue). For example, a disagreement about an AQEW (Allocated Quantity of *Energy Withdrawn*) that relates to an incorrect totalization

¹² See Chapter 9, Sections 6.3.10, 6.3.18.1, 6.3.19.1, 6.3.21.2 and 6.3.22.2 of the *market rules*.

¹³ For more information, refer to the document “Notice of Disagreement: A Guide for Market Participants”.

table and to incorrect *meter* readings must be submitted as two separate *notices of disagreement*, so that we can investigate each item or issue. However, when a *notice of disagreement* pertains to input data for multiple *dispatch intervals* on the same *trading day*, you only need to submit one *notice of disagreement*.

The *notice of disagreement* must contain the proposed resolution and supporting documentation.

- If your *notice of disagreement* relates to *metering data*, it must include a *meter* trouble report number. You must enter the *meter* trouble report number (MTR#) in the space provided on the *notice of disagreement* form. The resolution to the *meter* trouble report provides the proposed resolution and supporting documentation required.
- If your *notice of disagreement* pertains to “Settlement Amount Adjustments Resulting from Administration of Prices Due to Failure or Planned Outages of Market Systems or Due to Publication of Incorrect Prices”¹⁴, you must provide a completed IMO-FORM-1549 “Administrative Pricing Event Correction” as an attachment to the *notice of disagreement*.
- For other issues, you must provide the proposed correction and supporting documentation as an attachment to the *notice of disagreement* form. The attachment may be in the form of a table or spreadsheet. Table 1-1: “Data Requirement for Notice of Disagreement Submission” provides a template for the data you must supply for specified *notice of disagreement* issues. If the information you provide in the *notice of disagreement* is incomplete or invalid,
 - the *notice of disagreement* processing may be delayed, or
 - we might reject the submission.

Table 1–1: Data Requirement for Notice of Disagreement Submission

Notice of Disagreement Issue Type	Data Requirements	IESO Data	Participant Data
<i>Physical Bilateral Contract (PBC)</i>	Seller’s <i>Market Participant</i> ID		
	Buyer’s <i>Market Participant</i> ID		
	Location ID of PBC contract		
	Zone ID		
	Trading Hour(s)		
	Trading Interval(s)		
	NEMSC <i>Hourly Uplift</i> Component reallocation flag (Y/N)		
	ORSC <i>Hourly Uplift</i> Component reallocation flag (Y/N)		
	CAPRSC <i>Hourly Uplift</i> Component reallocation flag (Y/N)		
	CMSC <i>Hourly Uplift</i> Component reallocation flag (Y/N)		
CRSSD <i>Hourly Uplift</i> Component reallocation flag (Y/N)			

¹⁴ See Chapter 7, Sections 8.4A.13-8.4A.16 of the *market rules*. See also Section 1.6.7 “Administrative Pricing Event” in this manual.

Notice of Disagreement Issue Type	Data Requirements	IESO Data	Participant Data
	ORSSD <i>Hourly Uplift</i> Component reallocation flag (Y/N)		
	PBC Percent flag		
	Traded Quantity (MWh)		
Schedules, <i>Bids</i> and <i>Offers</i> , <i>Energy</i> , <i>Operating Reserve</i> , CMSC, IOG, or day-ahead or real-time inertie failure, or day-ahead production cost guarantee, or real-time generation cost guarantee, or day ahead withdrawal <i>Settlement Amounts</i>	Location ID		
	Market Type (<i>Dispatch</i> or Market)		
	Scheduling Component (<i>Energy</i> , 10-minute spinning <i>Operating Reserve</i> , 10-minute Non-spinning <i>Operating Reserve</i> , 30-minute <i>Operating Reserve</i> , <i>Capacity Reserve</i> , <i>Schedule of Record</i> , Hour Ahead Pre-dispatch)		
	Trading Hour(s)		
	Trading Interval(s)		
	Scheduled Quantity (MW)		
	Tie Point Zone Number		
	Tie Point Zone ID		
	Reason Code (TLRE, TLRI, OTH, ORA, MrNh, ADQh, NY90, AUTO, {NULL})		
	<i>Bid/Offer</i> Price		
	NERC Tag ID (if an <i>inertie</i> transaction)		
<i>Physical Allocation Data</i>	Allocation from <i>Market Participant</i> ID		
	Allocation to <i>Market Participant</i> ID		
	<i>Delivery Point</i> ID		
	Channel Number		
	PAD Type (Standing, Interval Percentage, Interval Absolute)		
	Hour(s)		
	Interval(s)		
	Quantity (Percent or kWh)		

Samples of the *notice of disagreement* form appear in Appendix B. You should send supporting materials as attachments to the form when you submit the *notice of disagreement* form to us through the NOD user interface.

You can verify that we received your *notice of disagreement* on the Application Status screen of the *notice of disagreement* user interface¹⁵. We will reject the *notice of disagreement* if it is incomplete or invalid¹⁶.

During our initial investigation of the *notice of disagreement*, we will determine whether affected parties exist. For *notices of disagreement* relating to *physical bilateral contracts* or *physical allocation data*, we will notify affected parties that a *notice of disagreement* has been submitted and, following its investigation, any intended actions. Where a *notice of disagreement* relates to a *meter* that is a contributor to a *delivery point* for which the submitting *market participant* is not the *metered market participant*, we will notify the affected party of the proposed resolution when we complete our investigation.

Following our investigation, we will inform you and any affected parties of our intention to undertake one of the following actions:

- if we conclude that no error has occurred in your *preliminary settlement statement*, we will take no further action;
- if we concur fully with your proposed adjustment or correction, we will adjust your corresponding *final settlement statement* if a manual calculation is not required and the deadline for issuing the *final settlement statement* has not arrived;
- if we concur fully with your proposed adjustment or correction and it requires a manual calculation or the deadline for issuing the *final settlement statement* has passed, we will apply the adjustment on the next available month-end *preliminary settlement statement*;
- if we do not concur fully with your proposed adjustment or correction but do conclude that some adjustment is required, we will adjust your corresponding *final settlement statement* if the deadline for issuing the *final settlement statement* has not arrived; or
- if we conclude that some adjustment may be required but that additional time is required to complete our investigation, we will notify you that additional time is required; in addition, within 15 *business days* after we've issued the corresponding *final settlement statement*, we will do one of the following:
 - if we conclude that no error has occurred in your *preliminary settlement statement*, we will take no further action;
 - if we concur fully with your proposed adjustment or correction, we will apply the adjustment on your next available month-end *preliminary settlement statement* accordingly; or
 - if we do not concur fully with your proposed adjustment or correction but do conclude that some adjustment is required, we will advise you of the changes we propose to make; we will also adjust your next available *preliminary settlement statement* accordingly.

We will notify you and any affected parties involved of our intended actions. We also provide you with an opportunity to respond to our intended actions by entering a response on the Details Page in the *notice of disagreement* form and returning it to us. Affected parties may respond by contacting us as stated in the decision letter. We consider any response we receive from you and affected parties prior to closing the *notice of disagreement*.

¹⁵ For more information, refer to "The Applications Status Tool: A User Guide".

¹⁶ There may be circumstances in which we will ask you to provide additional information rather than resubmit the entire *notice of disagreement*. This will be determined on a case-by-case basis and may follow from direct correspondence between us.

If, with reasonable efforts, we are unable to resolve the *notice of disagreement* with you, we will issue the corresponding *final settlement statement* or the next available *preliminary settlement statement* incorporating our decision. You can then pursue the disagreement through the Dispute Resolution process¹⁷.

You must settle an *IESO invoice* regardless of whether you have raised a *notice of disagreement* against a *settlement statement* addressed by that *invoice*¹⁸.

If you do not agree with our decision on your *notice of disagreement*, you may raise a dispute through the Dispute Resolution process. Disputes relating to *settlement statements* must be raised within 20 *business days* after the *final settlement statement* has been issued for the *trading day* to which the dispute pertains.

1.3.6 Issuing the *Final Settlement Statement*

We issue a *final settlement statement* on the date specified in the *SSPC*. This is currently 10 *business days* after we issue the *preliminary settlement statement*¹⁹. The *final settlement statement* is in the same format as the *preliminary settlement statement* and is available by 17:00 EST on the issue date. You may download your *final settlement statement* from the IESO Reports site.

Your *final settlement statement* must include:

- all the information in the *preliminary settlement statement*; and
- any adjustments resulting from the *notice of disagreement* process that were resolved before the *final settlement statements* were issued; these adjustments appear as a credit or debit on your *settlement statement* and on the *settlement statement* of each affected *market participant*.

You may not submit a *notice of disagreement* for the *final settlement statement*. However, in some cases an item or calculation in the *final settlement statement* may either:

- consist of an adjustment to the corresponding *preliminary settlement statement* as a result of a *notice of disagreement*, but does not reflect the agreed-to adjustment; or
- differ in amount from the same item or calculation set forth on the corresponding *preliminary settlement statement*, but the item or calculation on the *final settlement statement* does not have an adjustment flag indicating that an adjustment has been made.

In such cases, you may attempt to resolve the disagreement with us on an informal basis, separate from the formal *notice of disagreement* process. If we cannot resolve the disagreement with you, you may submit the matter to the dispute resolution process and may request, in the *notice of dispute*, that the *arbitrator* order that we undertake a *settlement statement re-calculation*.

If you disagree with any other aspect of the *final settlement statement*, you may submit the matter to the dispute resolution process and may request, in the *notice of dispute*, that we undertake a *settlement statement re-calculation*.

You must submit all *notices of dispute* relating to an item or calculation on a *settlement statement* within 20 *business days* after the *final settlement statement* is issued for that item or calculation.

¹⁷ Refer to the “Market Manual 2: Market Administration, Part 2.1, Dispute Resolution” for more information.

¹⁸ See “Part 5.6, Physical Markets Invoicing” for more details of the invoicing process.

¹⁹ See Chapter 9, Sections 6.3.11, 6.3.18.2 and 6.3.19.1 of the *market rules*.

1.4 Settlement Delays

1.4.1 Delay in Issuing Settlement Statements

We may delay issuing your *preliminary settlement statement* and the subsequent *final settlement statement* for a *trading day* from the dates specified in the *SSPC* where we determine that significant inaccuracies exist. In such a situation, we will *publish* a notice of delay that details:

- the date on which your *preliminary settlement statement* will now be issued;
- the date by which you must raise a *notice of disagreement* with regard to the *preliminary settlement statement*, which will be four *business days* after the date that the *statement* is issued²⁰;
- the date on which your *final settlement statement* will now be issued; and
- whether we intend to invoke the estimated *invoice process*²¹.

If we experience a delay in issuing a *preliminary settlement statement*, it may impact the date that we issue the subsequent *final settlement statement* for that *trading day* as well as *preliminary* and *final settlement statements* for subsequent *trading days*. Where this is the case, we will ensure that the notice of delay applies to the *settlement statements* for each *trading day* impacted by the delay.

The notice of delay will be *published* on our web-site. The notice of delay will also be sent by email to the *settlements* contact of all *market participants*.

1.4.2 Failure of Communication System

If the communication system fails so that we cannot issue *settlement statements* using the *electronic information system*, we will notify your *settlements* contact (assuming network communication is still functional)²². We will assess the value and practicality of issuing statements via an alternate means, considering the nature and extent of the communication problem and the forecast time to restore service. If an alternate means is required, we will specify what it is, and we will issue statements in the same electronic file format that is currently used. These alternate modes of transmission may include:

- compact discs via courier; or
- e-mail (if the *market participant* accepts the confidentiality risks and if the size of the attachment file is feasible).

As is required, we will communicate the information related to Section 1.4.1 and the communication method we will use.

1.5 Optional Measurement Data Records

You can request that optional measurement data records²³ be included in your *settlement* data file. These records contain net withdrawal or net injection values for each 5-minute trading interval for each *delivery point* defined for *physical market* charges.

²⁰ See Chapter 9, Section 6.3.21.2b of the *market rules*.

²¹ See “Part 5.6: Physical Markets Settlement Invoicing” for further details of this process.

²² See Chapter 9, Section 6.1.2 of the *market rules*.

²³ Details about the optional measurement data records can be found in the document “IESO Charge Types and Equation”.

You should be aware that requesting these optional records will increase storage requirements and download times of the data file.

If you are interested in this option, you should download and complete IMO-FORM-1433, “Request for Optional Measurement Data Records”. Your “Settlement”, “Main”, or “Real Time Market Manager” contact identified in our Registration system must sign the form. Submit the form by fax, mail, or courier to the address or fax number listed in the “Contact Us” section on our web site. Identify on the envelope: **Attention: Settlements.**

1.6 Special Settlement Activities

Special exemptions, rebates and *settlement* programs are available to eligible *market participants*. We describe them in the following sub-sections.

1.6.1 Generation Station Service Rebate

Some *generation facilities* in the *IESO-administered markets* consume *energy* as *generation station service*. *Metered market participants* for certain *generation facilities* are eligible for a reimbursement of the *hourly uplifts* and non-hourly *settlement amounts* related to AQEW consumed as *generation station service*. Refer to Chapter 9, Sections 2.1A.9-2.1A.14 of the *market rules* to find the eligibility requirements and the specific conditions under which this rebate applies.

If you²⁴ believe that your *generation facility* is eligible for a *generation station service* rebate, you should:

- download IMO-FORM-1419 “Application for Designation of a Facility for Generation Station Service Rebate” from our web site;
- complete all applicable sections; and
- submit the form to us.

We will:

- review your application;
- request additional information in order to assess the application, if necessary;
- determine if your *generation facility* meets the requirements for the rebate designation; and
- notify you in writing of our determination.

If you meet the requirement for the rebate designation, we will adjust the *hourly uplifts* and non-hourly *settlement amounts* that may have accumulated at the *generation station service delivery point* during the periods where the eligible *generation facility* was a net injection of *energy* into the *IESO-controlled grid*.

Reimbursement amounts are calculated at month-end and applied to the last *trading day* of the month as a manual line item on the *preliminary settlement statements* and the *final settlement statement* for each *generation facility* as *charge type* 119 – Station Service Reimbursement Credit.

The offsetting *charge type* 169 – Station Service Reimbursement Debit is included on the *preliminary settlement statement* and the *final settlement statement* of all load customers for the last *trading day* of the month.

²⁴ In this Section 1.6.1, “you” refers to a *metered market participant*.

1.6.2 Debt Retirement Charge (DRC)

The *debt retirement charge* (DRC) is charged on the *real-time market settlement statement* to all wholesale *market participants* withdrawing *energy* from the *IESO-controlled grid*. The charge is based on allocated quantity of *energy* withdrawn (AQEW) at each *delivery point*. We must collect and remit payment related to the *debt retirement charge* from you as required by any regulations made under the “*Electricity Act, 1998*”.

1.6.2.1 DRC Exemption

The regulations allow for other collectors and certain other persons to provide *exemption* certificates as described in:

- “Ontario Regulation 493/01 and 494/01”; and
- information guidelines provided by the Ministry of Finance.

If eligible, you can apply to us to be exempt from our collection of the DRC:

- for *energy* you withdraw for your specific *delivery points* to which the *exemption* applies; or
- to all *delivery points* where you withdraw *energy*.

If you wish to be exempt from our collection of the DRC, you should:

- complete the *exemption* certificates as indicated in the regulation; and
- submit the *exemption* certificates by mail or courier to the address provided in the “Contact Us” section on our web site; write on the envelope, “**Attention: Settlements**”; we will acknowledge receipt of the certificate.

1.6.2.2 Reduced Debt Reduction Charge (DRC) Certification

The regulation also identifies specific local utility service areas where *facilities* are eligible for reduced DRC rates.

If your *facilities* qualify for the reduced DRC rates:

- download IMO-FORM-1438 “Application for Reduced Debt Retirement Charge Form” from our web site; and
- submit the completed form by mail or courier to the address provided in the “Contact Us” section on our web-site; write on the envelope, “**Attention: Settlements**”; we will acknowledge receipt of the form.

1.6.3 OPG Rebate Requests for Additional Payments or Returns

The OPG Rebate was paid to eligible *market participants* for the period from May 1, 2006 to April 30, 2009, if the average price of *energy* for OPG’s non-prescribed assets was above a specified price during the applicable *settlement* period. The final payment of the OPG Rebate appeared under *charge type* 112 “Ontario Power Generation Rebate” on the May 31, 2009 *preliminary settlement statement*.

Distributors were required to pass OPG Rebate amounts through to their non-Regulated Price Plan (RPP) customers. Eligible *market participants* received a pro rata share of the OPG Rebate Amount based on their load (AQEW) for the applicable *settlement* period. Payments for these OPG Rebates were based on *distributor* submissions made through the online form “OPG Rebate Quarterly Distribution” that is no longer available as of May 1, 2009.

If you are a *distributor* who made an error in the information that was submitted to us for the distribution of the OPG Rebate and you now require additional funds to pass through to your customers, you may submit a request to us. Your requests will be forwarded to the *OPA* for approval.

If you are a *distributor* and you have received funds that you are unable to distribute to your customers, or that have been returned to you by your customers, you must return these funds to us. Please notify us of the amounts to be returned via the “OPG Rebate Returned to IESO” online *settlements* data entry screen, available on the *IESO* portal.

1.6.4 Real-time Generation Cost Guarantees

The Real-Time Generation Cost Guarantee (RT-GCG) program, commonly referred to as Spare Generation On-line (SGOL), guarantees start-up costs and *minimum run-time* costs to *market participants* who otherwise might not start up their *generation units* in times when they are not certain they will be dispatched sufficiently to recover those costs. RT-GCG is authorized and governed under the *market rules* – refer to sections 2.2, 5.7, and 6.3 of Chapter 7; and section 4.7B of Chapter 9.

In order to qualify for an RT-GCG payment you must pass certain eligibility criteria related to how you:

1. offer your *generation unit* for *dispatch*; and
2. operate your *generation unit* in *real time*.

The *settlement* of an RT-GCG event involves the comparison of certain eligible costs to some market revenues your *generation unit* has received for operating at the *minimum generation block run-time* specified for your *generation unit*. If the market revenue is not sufficient to cover the eligible costs, you are compensated for the amount of the shortfall by way of a RT-GCG payment. The details of eligibility and *settlement* are outlined in the following paragraphs.

The Day-Ahead commitment process and related *settlement* payment includes a Production Cost Guarantee (DA-PCG) payable to eligible *generators* that satisfy their Schedules of Record. The DA-PCG which is described in *Market Manual 9* replaced the previous Day-Ahead Generation Cost Guarantee.

Sections 1.6.4.1 to 1.6.4.3 below describe the RT-GCG submission, eligibility and *settlement*. Section 1.6.4.4 outlines scenarios where the new PCG can interact with a RT-GCG including how *settlement* and eligibility for the RT-GCG are affected.

1.6.4.1 RT-GCG Submission

Your participation in the RT-GCG program is voluntary. To participate, you must provide additional registration data for your *generation facilities*. You can find the registration eligibility requirements in Chapter 7 Sections 2.2, 5.7 and 6.3A of the *market rules* and in “Market Manual 9: Day-Ahead Commitment Process”.

Specifically, the required registration data you must submit for each of your *generation units* to participate in the RT-GCG program is:

- the *minimum loading point*;
- the *minimum generation block run-time*; and
- the *minimum run-time*.

The RT-GCG program allows you to recover certain costs called *combined guaranteed costs* associated with start-up, and operation to the end of the *minimum generation block run-time*, provided that you have not recovered these costs through other market revenues.

To be considered for compensation under RT-GCG, you must provide all of the required information through the “generation cost guarantee” on line data entry screen available on the *IESO* portal. You must submit the following information for an RT-GCG event:

- the trade date;
- the event type (select RT for RT-GCG);
- the *generation unit* name;
- the intended synchronization hour ending (EST) at the time you requested qualification of a RT-GCG start;
- the number of actual ramp intervals required to achieve *minimum loading point* after synchronization. The number of ramp intervals represents the number of five minute intervals used to reach *minimum loading point* from synchronization. For example, if your actual ramp time is 3.25 hours, you would submit 41 intervals.
- the fuel costs for start-up and for ramping to *minimum loading point*; and
- the incremental operation and maintenance (O&M) costs associated with start-up and ramping to *minimum loading point*.

Incremental O&M is a cost associated with breaker close and unit operation. These costs are avoidable if the unit does not start. Incremental O&M excludes costs that are independent of unit operation such as lighting, security, and so on. Incremental O&M costs can be broken down according to the reason they are incurred:

1. For start up and ramp: If the cost is incurred because the unit has started and ramps to *minimum loading point*, this lump sum amount can be submitted.
2. For continuing ongoing production: If there is an additional cost for each hour run or per MWh up to *minimum loading point*, related to injections during *minimum generation block run-time*, this cost should be included in your *minimum generation block run-time offer*.

This submission is due by 17:00 on the sixteenth *business day* following the day of synchronization. The *market rules* allow us to audit any information you submit related to an RT-GCG claim if you receive an RT-GCG payment.

We use the submitted information and the registration information for the *generation unit* when evaluating the RT-GCG eligibility and when we calculate the *settlement*.

1.6.4.2 RT-GCG Eligibility

RT-GCG eligibility criteria can be broken down into two distinct phases of the event as follows:

1. Pre-dispatch Scheduling Eligibility Criteria

We will review the submission and determine if the *generation unit* meets the *pre-dispatch* scheduling requirements as follows:

- the *generation unit* is not already synchronized at the time of publication of the applicable *pre-dispatch schedule*;

- you notified the *IESO* control room, of your intent to qualify for an RT-GCG start, and your intent to synchronize in a particular hour ending and run for at least your *minimum generation block run-time*;
- the *price-quantity pair offer price* corresponding to the *minimum loading point* for all hours of the *minimum generation block run-time* must be the same, until after the *IESO* has constrained the *generation unit*; and
- the *generation unit* must be scheduled in any *pre-dispatch schedule* determined within three hours ahead of the *dispatch hour* (*i.e.* PD-3, PD-2 or PD-1 published at approximately 12 minutes after the hour) for at least half of *minimum generation block run-time*, rounded up, at *minimum loading point* or higher, during the period from the intended synchronization hour ending until the end of the *minimum generation block run-time*, or the end of the *minimum run time*, whichever is earlier.

2. Real-time Scheduling and Operations Eligibility Criteria

We will review the submission and determine if the *generation unit* meets the *real-time* scheduling and operational requirements as follows:

- the *offer prices* corresponding to the *minimum loading point* for the *minimum generation block run-time* are not increased after notifying the *IESO* of your intention to synchronize or after the *IESO* has applied a manual constraint;
- you synchronize your *generation unit* no later than the end of the *dispatch hour*; and
- you run your *generation unit* until the end of the *minimum generation block run-time*.

We identify a *generation unit* start-up for *settlement* purposes by using *revenue metering* results for the applicable *trading day*. The metering results must indicate a change from zero in one interval to a sustained positive value for four consecutive intervals. After a valid start-up has been identified, your *generation unit* is determined to be on-line in an interval where your *revenue metering* results show a positive value.

The *minimum generation block run time*, as defined in the *market rules* Chapter 11, is the minimum number of hours your *generation unit* must operate at *minimum loading point*. You are expected to follow *dispatch*, including operating to *minimum loading point*.

If we de-commit a *generation unit* for *reliability* reasons after synchronization, the *generation unit* is still eligible for guarantee payments. You should still submit all the information noted above for the RT-GCG event. The costs submitted should represent the costs incurred prior to de-commitment. However, you are not eligible for guarantee payments if the *generation unit* fails to run until the end *minimum generation block run-time* for any other reason.

We evaluate the eligibility of an RT-GCG claim when the *settlement* data for the *final settlement statement* are available in the Commercial Reconciliation System.

1.6.4.3 RT-GCG Settlement

RT-GCG Payments - Costs

The *settlement* of an RT-GCG event involves the comparison of certain eligible costs to some market revenues your *generation unit* has received for operating to the end of the *minimum generation block run-time* specified for your *generation unit*. Chapter 9, Section 4.7B of the *market rules* describes the calculation of the costs, revenues, and the RT-GCG payment.

The total *combined guaranteed costs* will be calculated by the *IESO* and will be the sum of the following costs:

- the submitted fuel costs and incremental O&M costs for start-up and ramp to *minimum loading point*; and
- the *offer price* associated with the real-time *dispatch* multiplied by the *energy* injected, to a maximum of the *minimum loading point*, during the period from the beginning of the *minimum generation block run-time* until the earlier of the end of the *minimum generation block run-time*, or the end of the *minimum run time*.

The *minimum generation block run-time* starts with the first interval after we add the submitted number of actual ramp hours to the valid start-up interval.

RT-GCG Payments - Revenues

Revenues are calculated for the period from start-up until the earlier of the end of the *minimum generation block run-time*, or the *end* of the *minimum run time*. The end of the *minimum generation block run-time* is the first interval after we add the submitted number of actual ramp intervals and the *minimum generation block run-time* to the valid start-up interval.

The revenues included in the calculation are:

- revenue from *energy sales* up to the *minimum loading point*²⁵ and
- *congestion management settlement credits* (CMSC) associated with Allocated Quantity of Energy Injected (AQEI) up to the *minimum loading point*²⁶.

When costs exceed the revenues associated with a start, you are paid the difference as an RT-GCG payment.

The RT-GCG *settlement amounts* are calculated at month-end, and applied as a manual line item on the next applicable *preliminary settlement statement* using the *charge type* 133 “Real-time Generation Cost Guarantee Payment”. RT-GCG calculations are only included in the current *invoice* for days that have gone final since the last *invoice* was prepared. RT-GCG payments are recovered through an uplift charged to loads and exports through *charge type* 183 “Generation Cost Guarantee Recovery Debit”.

²⁵ We use the value for *minimum loading point* that is in our Market Entry database corresponding to the *start-up time*.

²⁶ *Ibid*

1.6.4.4 Interaction between RT-GCG and PCG

In some cases the day-ahead schedule may interact with a RT-GCG event. These independent events may link back to one *generation unit* start-up. In these situations, some additional evaluations and calculations will be required for the RT-GCG event. Below are three scenarios and their respective treatment with respect to eligibility and *settlement*.

Scenario 1: RT-GCG Precedes DA Schedule of Record: No Overlap

In this scenario, a *generation unit* starts-up before the first hour of their day-ahead Schedule of Record with sufficient time to complete a RT-GCG run immediately or shortly prior to the first hour of the day-ahead Schedule of Record. In this situation, the end of the RT-GCG event can match exactly with the start of the day-ahead Schedule of Record or the *generation unit* can stay on line for a period between the RT-GCG event and the start of the day-ahead Schedule of Record. In either case both events can be tied back to a single *generation unit* start-up. Figures 1a and 1b below depict the two possible situations in this scenario.

Figure 1a - RT-GCG Precedes DA Schedule of Record: No Overlap - No gap between events

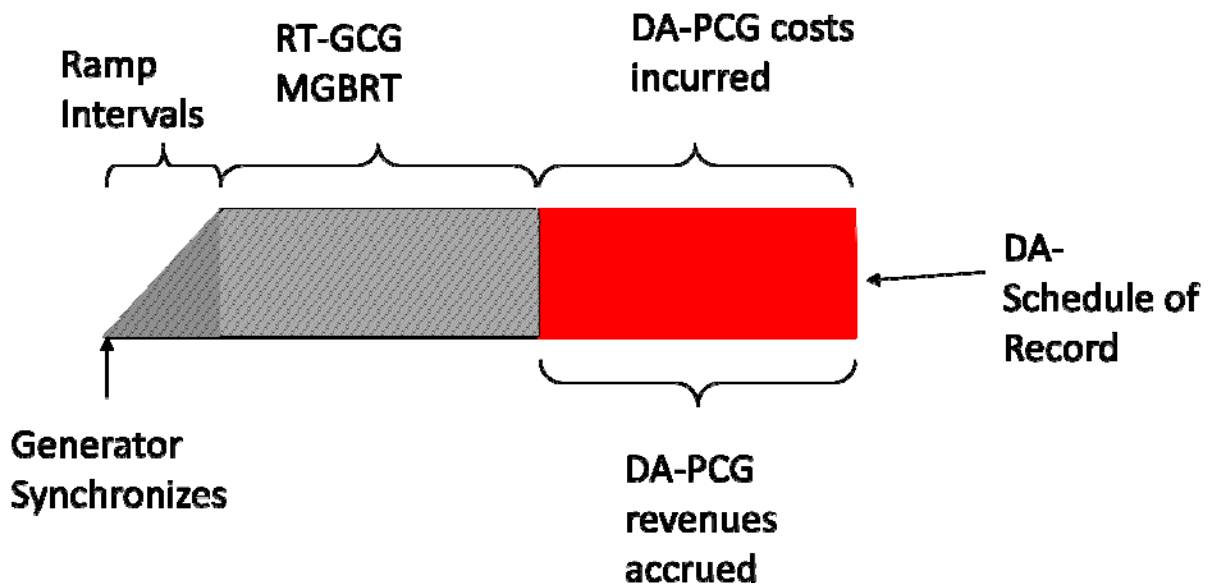
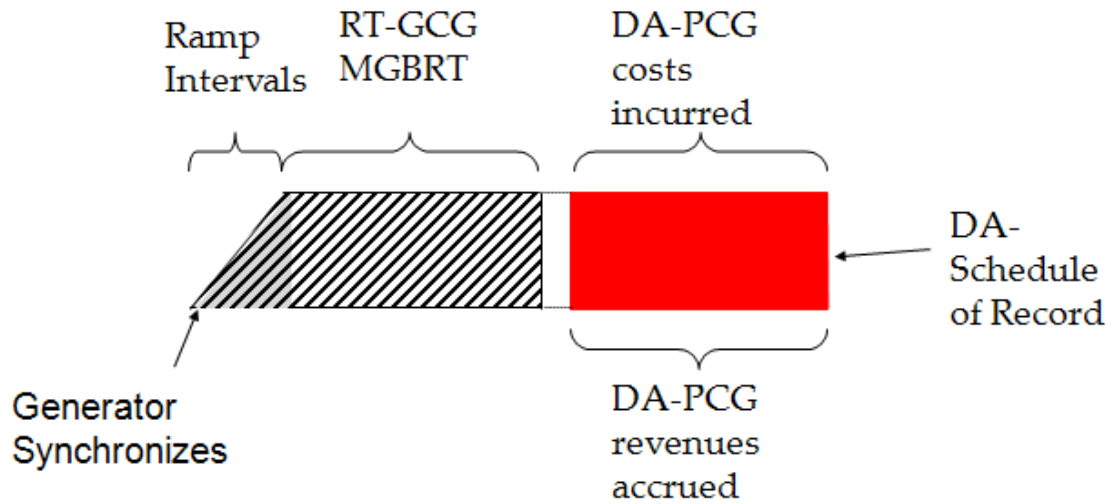


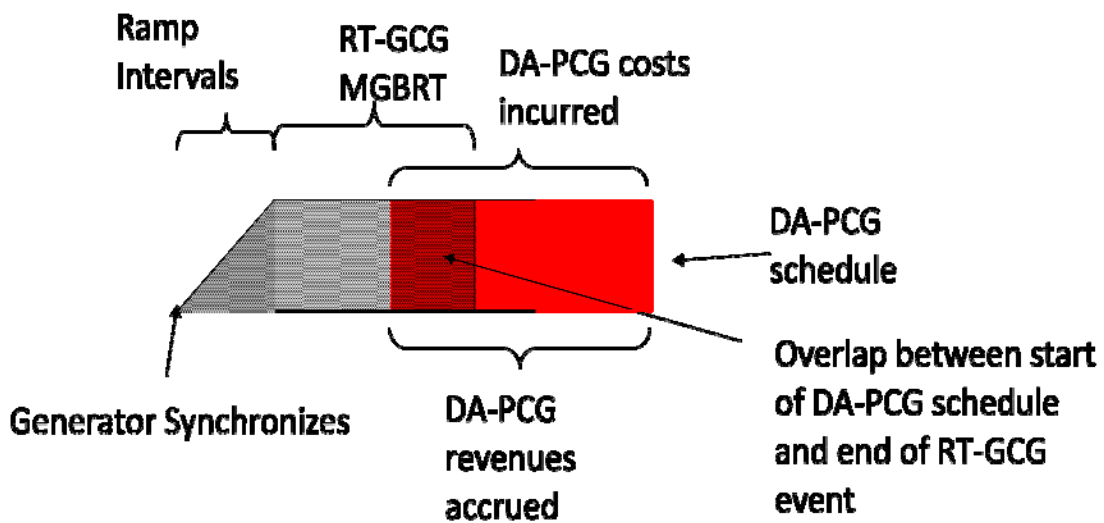
Figure 1b - RT-GCG Precedes DA Schedule of Record: No Overlap - Gap between events



Scenario 2: RT-GCG Precedes DA Schedule of Record: With Overlap

In this scenario, a *generation unit* starts-up before the first hour of their day-ahead Schedule of Record, however, the combination of ramp time and *minimum generation block run-time* means the RT-GCG event will overlap with the day-ahead Schedule of Record. In this scenario both events can be tied back to a single *generation unit* start-up. Figure 2 below depicts this scenario.

Figure 2 - RT-GCG Precedes DA Schedule of Record: With Overlap



Scenario 3: RT-GCG Interacts with Withdrawn Schedule of Record

This scenario is similar to Scenarios 1 and 2 such that the *generation unit* starts ahead of the Schedule of Record in order to participate in the RT-GCG program, however in this scenario the *generator* has taken the appropriate actions to withdraw from the day-ahead Schedule of Record and the withdrawal is for reasons within the *generator's* control. This withdrawal may be for all or a portion of the day-ahead Schedule of Record, the result being that the *generator* is not eligible for a DA-PCG *settlement* and further may be subject to a Day Ahead Generator Withdrawal Charge. If the withdrawal of the *generation unit* is for reasons not within the control of the *generator*, then the *generator* continues to be eligible for the DA-PCG *settlement* for the completed hours of the day-ahead schedule, resulting in *settlement* treatment comparable to scenarios 1 or 2 above.

Principles for Eligibility and Settlement:

- 1) The outcome of the day-ahead process is a Schedule of Record for the next day based on the three part day-ahead bids. These schedules are carried forward into real-time processes with constraints up to *minimum loading point* applied. Similar to manual constraints that are applied in real-time, usually as a result of invoking a RT-GCG start, these PCG constraints will not be considered in RT-GCG Pre-dispatch eligibility.
- 2) In scenarios 1 and 2 above, where both the DA-PCG event and the RT-GCG event can be tied to the same *generation unit* start-up, and the fuel costs for start-up and ramping to *minimum loading point* along with the related incremental O&M costs are eligible for inclusion in the DA-PCG *settlement*, these costs will not be considered in the assessment of the RT-GCG *settlement*.

The *generator* will indicate zero for these costs in the RT-GCG submission through the *IESO* in this situation. In the event that the RT-GCG event interacts with a DA-PCG event under scenarios 1 and 2 as described above, and the submitted start-up fuel and O&M costs submitted are not zero, these submitted costs will be deemed as unreasonable and *settlement* of the RT-GCG event will not include these costs, unless strong evidence exists to the contrary.

If the fuel costs for start-up and ramping to *minimum loading point* along with the related incremental O&M costs are not eligible for inclusion in the DA-PCG *settlement*, these costs will be considered in the assessment of the RT-GCG *settlement* and submitted through the *IESO* portal.

- 3) In scenario 3 above, where the *generation unit* is not eligible for a DA-PCG *settlement*, the fuel costs for start-up and ramping to *minimum loading point* along with the related incremental O&M costs will be included in the assessment of the RT-GCG *settlement*. These costs will be submitted as part of the RT-GCG claim in the *IESO* portal.

The table below provides the details for the *submission*, eligibility, and *settlement* of the any RT-GCG claim under the three potential scenarios where there is interaction with a Day-Ahead PCG event.

		RT-GCG Precedes day-ahead Schedule of Record: <i>No Overlap</i> (Scenario 1)	RT-GCG Precedes day-ahead Schedule of Record: <i>With Overlap</i> (Scenario 2)	RT-GCG Precedes withdrawn day-ahead Schedule of Record (Scenario 3)
RT-GCG Submission	<ul style="list-style-type: none"> the trade date; the event type (select RT for RT-GCG); the <i>generation unit</i> name; 	No change	No change	No change
	<ul style="list-style-type: none"> the intended synchronization hour ending (EST) 	No change	No change	No change
	<ul style="list-style-type: none"> the number of actual ramp intervals required to achieve <i>minimum loading point</i> 	No change	No change	No change
	<ul style="list-style-type: none"> the fuel costs of start-up and of ramping to <i>minimum loading point</i>; the incremental O&M costs associated with start-up and ramping to <i>minimum loading point</i>. 	The treatment and submission of fuel costs for start-up and for ramping to <i>minimum loading point</i> are outlined in Principle (2) above.	The treatment and submission of fuel costs for start-up and for ramping to <i>minimum loading point</i> are outlined in Principle (2) above.	No change
Eligibility	<ul style="list-style-type: none"> the <i>generation unit</i> is not already synchronized at the time of <i>publication</i> of the applicable <i>pre-dispatch schedule</i>; 	No change	No change	No change
	<ul style="list-style-type: none"> you notified the <i>IESO</i> control room, of your intent to qualify for an RT-GCG start, and run for at least your <i>minimum generation block run-time</i>; 	No change	No change	No change
	<ul style="list-style-type: none"> the <i>price-quantity pair offer</i> price corresponding to the <i>minimum loading point</i> for all hours of the <i>minimum generation block run-time</i> must be the same 	No change	No change	No change
	<ul style="list-style-type: none"> the <i>generation unit</i> must be scheduled in any <i>pre-dispatch schedule</i> determined within three hours ahead of the <i>dispatch hour</i> (<i>i.e.</i> PD-3, PD-2 or PD-1) for at least half of <i>minimum generation block run-time</i>, at 	<i>Pre-dispatch Schedules</i> with either manual or PCG constraints	<i>Pre-dispatch Schedules</i> with either manual or PCG constraints	<i>Pre-dispatch Schedules</i> with either manual or PCG constraints

		RT-GCG Precedes day-ahead Schedule of Record: No Overlap (Scenario 1)	RT-GCG Precedes day-ahead Schedule of Record: With Overlap (Scenario 2)	RT-GCG Precedes withdrawn day-ahead Schedule of Record (Scenario 3)
	<i>minimum loading point</i> hour ending at the end of the <i>minimum generation block run-time</i> , or the end of the <i>minimum run time</i> , whichever is earlier	applied will not be considered	applied will not be considered	applied will not be considered
	<ul style="list-style-type: none"> the <i>offer</i> prices corresponding to the <i>minimum loading point</i> for the <i>minimum generation block run-time</i> are not increased after notifying the <i>IESO</i> of your intention to synchronize or after the <i>IESO</i> has applied a manual constraint; 	No change	No change	No change
	<ul style="list-style-type: none"> you synchronize your <i>generation unit</i> no later than the end of the <i>dispatch hour</i>; and 	No change	No change	No change
	<ul style="list-style-type: none"> you run your <i>generation unit</i> until the end of the <i>minimum generation block run-time</i>. 	No change	No change	No change
RT-GCG Cost	<ul style="list-style-type: none"> the submitted fuel costs and incremental O&M costs for start-up and ramp to <i>minimum loading point</i>; 	The treatment and submission of fuel costs for start-up and for ramping to <i>minimum loading point</i> are outlined in Principle (2) above.	The treatment and submission of fuel costs for start-up and for ramping to <i>minimum loading point</i> are outlined in Principle (2) above.	No change
	<ul style="list-style-type: none"> the <i>offer</i> price associated with the real-time <i>dispatch</i> multiplied by the <i>energy</i> injected, to a maximum of the <i>minimum loading point</i>, during the period from the beginning of the <i>minimum generation block run-time</i> until the earlier of the end of the <i>minimum generation block run-time</i>, or the end of the <i>minimum run time</i> 	No change	Cost from start of MGBRT to start of DA-PCG event	No change

		RT-GCG Precedes day-ahead Schedule of Record: <i>No Overlap</i> (Scenario 1)	RT-GCG Precedes day-ahead Schedule of Record: <i>With Overlap</i> (Scenario 2)	RT-GCG Precedes withdrawn day-ahead Schedule of Record (Scenario 3)
RT-GCG Revenues	<ul style="list-style-type: none"> • Revenues are calculated for the period from start-up until the earlier of the end of the <i>minimum generation block run-time</i>, or the <i>end of the minimum run time including</i>: • <i>energy sales up to the MLP</i> • <i>CMSC associated with AQEI up to the MLP</i> 	No change	Revenue from start up to start of DA-PCG event	No change

1.6.5 Administrative Pricing Event

This section applies only when an “Administrative Pricing Event” does not exceed 48 *dispatch intervals* and the *market schedules* and prices were established by the “copy forward/back” methods²⁷.

For situations where *administrative prices* were applied beyond 48 *dispatch intervals*, please refer to “Market Manual 4.3: Real Time Scheduling of the Physical Markets”.

Where an “Administrative Pricing Event” does not exceed 48 *dispatch intervals*, some *market participants* may not be adequately compensated²⁸. Should this occur, you may only submit a *notice of disagreement* within four *business days* after your *preliminary settlement statement* has been issued to request *settlement amount* adjustments.

- For the case where you receive negative CMSC amounts, and all conditions stated in Chapter 7, Sections 8.4A.13 and 8.4A.14 of the *market rules* are met, we will apply *settlement amount* adjustments that offset the original negative CMSC amounts. The adjustments will appear under *charge types* 105, 106, 107 or 108 on the corresponding *final settlement statement*. If the deadline for issuing the *final settlement statement* has passed, the adjustment will appear on the next available month-end *preliminary settlement statement*.
- For the case where you were not compensated enough in the net *energy market settlement*, and all conditions stated in Chapter 7, Section 8.4A.15, 8.4A.16 of the *market rules* are met, we will apply additional compensation adjustments, based on the equations found in the Chapter 7, Section 8.4A.16, as the case may be. Compensation will appear under *charge type* 113 on the corresponding *final settlement statement*. If the deadline for issuing the *final settlement statement* has passed, the adjustment will appear on the next available month-end *preliminary settlement statement*, and it will appear with a separate item listed for each *delivery point*, and *dispatch interval*. In the same *preliminary settlement statement*, we will recover all paid compensations from the market (on a pro-rata basis across all withdrawals), under *charge type* 163.

Sections 8.4A.13 and 8.4A.15 of the *market rules* further specify that we are not required to perform the analysis if either the CMSC adjustment or the additional compensation adjustment is not material.

The total hourly CMSC adjustment or the total hourly additional compensation for a given *delivery point* must equal or exceed a materiality threshold amount of \$ 50.00 per hour, per *delivery point* and the submission total must exceed \$400.00 for each administrative pricing event request.

Specifically, in cases where the CMSC adjustment request or the additional compensation request falls below the threshold amount, we will not perform any further analysis and will not apply any adjustments.

Please refer to the Section 1.5 “Submitting a *Notice of Disagreement*” in this *market manual* for a description of guidelines and supporting documentation (the *market participant* must submit IMO-FORM-1549 along with a *notice of disagreement*) that must be provided as part of the *notice of disagreement* process.

²⁷ See Chapter 7, Section 8.4A.5 of the *market rules*.

²⁸ See Chapter 7, Section 8.4A.13, 8.4A.14, 8.4A.15 and 8.4A.16 of the *market rules*.

1.6.6 Transmission Service Charges for Embedded Generation

If, as a host *transmission customer*, you have an *embedded generation facility* that:

- was approved after October 30, 1998;
- is not separately registered as a *generation facility* in the *IESO-administered markets*;
- meets the applicable Ontario Transmission Rate Schedule requirement; and
- is rated at greater than or equal to 1 MW (2 MW for renewable *generators*²⁹) and less than 20 MW,

then you may choose to meet the existing wholesale *metering installation* standards or to use the alternative standard in Chapter 6 Section 4.5 of the *market rules*. The alternative standard allows the host *transmission customer* to register a *meter point* for the *embedded generation facility* without a corresponding wholesale physical *meter*.

A *transmission customer* that chooses the alternative *metering installation* standard for *embedded generation* must determine the annual adjustment dollar value for the applicable *transmission service charges*. The adjustment amount must be agreed to by the *transmitter* and submitted to us. In the event that we do not receive this information in a timely manner, we will use the installed *maximum continuous rating* (as registered) for the *embedded generation facilities* to determine an adjustment amount.

1.6.6.1 Calculation Methodology

Line and transformation connection service charges need to be calculated monthly for all *delivery points* with *embedded generation facilities* registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the *market rules*).

On a monthly basis, the host *transmission customer* will:

- download the *participant transmission tariff* data file;
- add the hourly generation values for the *embedded generator* to the hourly demand data for the *delivery point* associated with the *embedded generation*; and
- determine the new monthly maximum hourly peak value for the *delivery point* and compare it to the settled monthly maximum hourly peak value; if the new peak is higher, then:
- calculate the incremental line connection service charges (if applicable) by multiplying the line connection tariff by the incremental peak value; and
- calculate the incremental transformation connection service charges (if applicable) by multiplying the transformation connection tariff by the incremental peak value.

On an annual basis, the host *transmission customer* must sum all monthly line and transformation connection service charges and obtain agreement of the *transmitter* to the proposed adjustment, if any. Submit the totals to us online via the Settlements community of the *IESO* portal within 3 months following calendar year end.

²⁹ Renewable generation refers to electricity produced by wind, solar, small hydroelectric, biomass, bio-oil, bio-gas and landfill gas.

1.6.7 Regulated Price Plan, Regulated Generation, NUG Payments and Newly Contracted Generation

The “Electricity Restructuring Act, 2004” (Bill 100) introduced a number of important changes to the electricity market that affect both the *IESO* and *market participants*. These changes include:

- the establishment of the *Ontario Power Authority (OPA)*;
- a regulated payment to *generators* prescribed by regulations;
- payments to *Ontario Electricity Finance Corporation (OEFC)* for non-utility *generator (NUG)* contract amounts;
- payments to *OPA* for renewable generation and for clean generation and demand-side projects awarded as a result of an Request for Proposal (RFP) process;
- the establishment of regulated *consumer* prices beginning in April 2005, known as the Regulated Price Plan (RPP) (RPP prices are set by the *Ontario Energy Board (OEB)* from time to time); and
- the creation of a “Global Adjustment” amount, which is the difference between the contract amounts and market payments for OPG regulated generation, NUG generation and RFP contracted generation and demand-side management.

Implementing these changes required the creation of new *charge types* within our *settlements* system. The *charge types* are listed in the “IESO Charge Types and Equations” manual and are comprised of charges that are payable to or from *market participants* with, in most cases, the corresponding offsets payable by the *OPA*.

ONTARIO REGULATION 398/10 made under the *ELECTRICITY ACT, 1998* Amending O. Reg. 429/04 enacted in October 2010 significantly changed the Global Adjustment, creating two classes of *market participants* with different approaches to the distribution of the global adjustment costs. The regulation further added the costs related to *distributor* developed conservation and demand management programs to the Global Adjustment pool.

1.6.7.1 Regulated OPG Nuclear and Baseload Hydroelectric Generation

Under the “Electricity Restructuring Act, 2004” and subsequent regulations, OPG’s nuclear and baseload hydroelectric assets will receive a regulated price. OPG’s regulated assets include:

- DeCew Falls I and II;
- the Niagara River plants – Sir Adam Beck I, II, and Pumped Generating Station;
- the R.H. Saunders Hydroelectric Generating Station on the St. Lawrence River;
- the Pickering Nuclear Generating Station consisting of Pickering A and Pickering B; and
- the Darlington Nuclear Generating Station.

We have created two *charge types* to implement the adjustments for nuclear generation and for baseload hydroelectric generation. The adjustments are the difference between:

- the *market prices* paid to regulated hydroelectric generation and nuclear generation using the existing *settlements* process; and
- the regulated fixed rate that the regulated nuclear generation and a portion of output of the regulated hydroelectric generation should receive.

In essence, the adjustment is the difference between the amount OPG would have received at *market prices* and the amount calculated at regulated prices. The *settlement* of the hydroelectric generation

assets includes an adjustment based on the average *market prices* for the month. We use *charge type* 144 “Regulated Nuclear Generation Adjustment Amount” to adjust payments to OPG with respect to the regulated nuclear generating stations, and *charge type* 145 “Regulated Hydroelectric Generation Adjustment Amount” to adjust payments to OPG with respect to the regulated hydroelectric generating stations.

Amounts calculated under *charge types* 144 and 145 will be set off against *OPA*, using the corresponding *charge types* 194 and 195 respectively. The regulated nuclear generation amounts (i.e., *charge types* 144 and 194) are automatically generated by CRS and appear as *settlement* details on both OPG’s and *OPA*’s *preliminary* and *final settlement statements*. The regulated hydroelectric generation amounts (i.e., *charge types* 145 and 195) are calculated monthly and included as manual line items on both OPG’s and *OPA*’s *settlement statements*.

1.6.7.2 OEFC Adjustment

Section 78.2 of Bill 100 states that the *OEFC* will be paid contract amounts for all NUG output. We use current *settlement* processes to pay *OEFC* at wholesale *market prices* for all NUG output delivered to the *IESO-controlled grid*. The difference between the monies paid out by *OEFC* to all NUGs and the monies received from us and *distributors* (embedded NUGs) for all NUG output is submitted to us on a monthly basis using the on-line form on the *IESO* portal “NUG Adjustment Amount Information”.

OEFC also submits amounts related to a contingent support agreement between *OEFC* and OPG relating to the Lambton and Nanticoke coal-fired stations.

The monthly amount submitted by *OEFC* is included as a manual line item on *OEFC*’s *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month. The *charge type* used is 143 “NUG Contract Adjustment Settlement Amount”.

To balance the market, the corresponding setoff, *charge type* 193 “NUG Contract Adjustment Balancing Amount”, is entered as a manual line item on *OPA*’s *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

1.6.7.3 Clean Generation and Demand-Side Projects Settlement

The *OPA* has entered into procurement contracts with certain suppliers for clean *energy* supply and demand-side management or demand response, to promote the use of clean *energy* and to assist the government in achieving its goals in electricity conservation.

The difference between the contracted price and the wholesale *market price*, with respect to the clean generation or load reduction contracts, is settled by the *OPA*. The *OPA* submits this difference to us on a monthly basis using the on-line form on the *IESO* portal “Global Adjustment Amount Information” and we include it as a manual line item on *OPA*’s *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month. The *charge type* is 1400 “OPA Contract Adjustment Settlement Amount”.

The corresponding setoff, *charge type* 1450 “OPA Contract Adjustment Balancing Amount”, is entered as a manual line item on the *OPA*’s *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month to balance the market.

1.6.7.4 Renewable Generation Settlement

The OPA has entered into procurement contracts for renewable generation with certain suppliers. The difference between the contracted price and the wholesale *market price*, with respect to the renewable generation contracts, is settled by the OPA. The OPA submits this difference to us as per Section 1.6.7.3.

1.6.7.5 Renewable Generation Connection Compensation

Details relating to the implementation of a new cost recovery framework established by the Green Energy Act are set out in Ontario Regulation 330/09. This new framework allows local distribution companies to recover certain costs associated with the connection of new renewable generation to their local *distribution system* from all electricity *consumers* in Ontario (i.e., renewable generation contracted after the OEB issued its revised cost responsibility rules on October 21, 2009). These costs are approved by the OEB.

The portion of aggregate renewable generation connection compensation that you are charged is determined by your net volume of electricity withdrawn (AQEW) from the *IESO-controlled grid* during the month, plus, if you are a licensed *distributor*, the volume of embedded generation you are reporting using the on-line form on the *IESO* portal, divided by the sum of all amounts (net electricity withdrawn and embedded generation) for every *market participant*. (The volume of electricity supplied to Fort Frances Power Corporation Distribution Inc. by Abitibi-Consolidated Inc. is excluded from the calculation).

The portion of aggregate renewable generation connection compensation that each eligible *distributor* receives is determined by the OEB.

Charge type 1413 “Renewable Generation Connection - Monthly Compensation Settlement Credit” will appear on the *preliminary settlement statement* and *final settlement statement* of each eligible local distribution company for the last *trading day* of the month.

The corresponding debit, *charge type* 1463 “Renewable Generation Connection - Monthly Compensation Settlement Debit”, is included on the *preliminary settlement statement* and *final settlement statement* of all load customers for the last *trading day* of the month to balance the compensation credit.

1.6.7.6 Conservation and Demand Management Programs

Under section 78.5 of the *Ontario Energy Board Act, 1998*, the *IESO* must make payments to a *distributor* (“LDC”) or the OPA for amounts approved by the OEB relating to conservation and demand management (CDM). Specifically, these payments relate to the recovery of costs for Board-approved CDM initiatives that are undertaken by LDCs to meet the CDM targets set out in their licenses, and to associated performance incentives. The *IESO* will make these payments, as directed by the OEB, through *charge type* 1416 “Conservation and Demand Management – Compensation Settlement Credit”. These payments will be recovered through the Global Adjustment.

Charge type 1416 “Conservation and Demand Management – Compensation Settlement Credit” will appear on the *preliminary settlement statement* and *final settlement statement* of each eligible LDC for the last *trading day* of the month.

1.6.7.7 Regulated Price Plan

The Regulated Price Plan is an *OEB*-mandated pricing mechanism for low-volume and designated *consumers*. There are two distinct Regulated Price Plans – one for customers with conventional *meter* systems and another for customers with time-of-use (or “smart”) *meters*.

The conventional *meter* plan sets a lower fixed price for *energy* consumption up to a monthly threshold amount, with consumption above this level at a higher price. The *OEB* adjusts both the threshold amount and prices every six months. The two six-month periods are referred to as the winter season (November 1 – April 30) and the summer season (May 1 – October 31).

The smart *meter* plan establishes prices for *energy* based on when the *energy* is consumed. The basic unit is a week. As with the conventional *meter* RPP, the *OEB* adjusts prices every six months to coincide with the winter and summer seasons. *Energy* consumption during a week falls into three categories with respect to both prices and consumption times.

The three categories are:

- On-peak;
 - Mid-peak; and
 - Off-peak.
1. On-peak times reflect those times on weekdays when average *demand* is highest. The on-peak periods are weekdays from 7:00 to 11:00 and from 17:00 to 21:00 in the winter and from 11:00 to 17:00 in the summer.
 2. Mid-peak consumption refers to the shoulder periods between on-peak and off-peak times. The mid-peak periods are weekdays from 11:00 to 17:00 in the winter and weekdays from 7:00 to 11:00 and from 17:00 to 21:00 in the summer. All other times (weekdays from 21:00 to 7:00, on weekends and holidays) are off -peak.
 3. Generally, off-peak times refer to consumption overnight on weekdays, and on weekends and holidays.

Distributors must calculate the difference between the payments received from regulated *consumers* subject to RPP and the wholesale cost of power, including the amount of the Global Adjustment allocated to the RPP portion of a *distributor*'s load. Submissions by *distributors* to us are processed as manual line items in *settlement statements* and monthly *invoices*. We use two *charge types*, “Regulated Price Plan Settlement Amount” (*charge type* 142) and “Regulated Price Plan Retailer Settlement Amount” (*charge type* 149) for processing *distributor* submissions. RPP eligible *consumers* are defined by regulation.

Distributors that are *market participants* must submit the information to us online noting the amount of the claim for each category. The *IESO* portal is used to submit all information required from the *distributor*, embedded *distributor* or participating *retailer* to balance the market. *Settlement* data must be submitted to us monthly, as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. We process this information so that the *preliminary settlement statement* for the last *trading day* of the month indicates a *charge type* 142 and 149 entry, with the category noted in the Comments field.

We adjust *settlement amounts* for directly *connected consumers* who are eligible for the RPP for the net volume of electricity withdrawn from the *IESO-controlled grid* not covered by *physical bilateral contracts*.

The corresponding setoffs, *charge types* 192 “Regulated Price Plan Balancing Amount” and 199 “Regulated Price Plan Retailer Balancing Amount”, are entered as manual line items on the *OPA’s preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month to balance the market.

Declaration Required for Designated Consumers

“Regulations 435/02, 43/04 and 433/02” define ‘designated *consumer*’. Wholesale *market participants* who qualify as ‘designated *consumers*’, must inform us by submitting the on-line form “Declaration of Designated Consumer” located on the *IESO* portal. *Market participants* who satisfy us that they qualify as designated *consumers* are settled at the RPP rate.

Opt-Out Provisions

Eligibility of *market participants* to opt out of the RPP is based on the following provision:

- directly-connected load-consuming *market participants* meeting the regulated definition of “low-volume *consumers*” or “designated *consumers*” may opt out of RPP for all *registered facilities* for which they play the role of a *metered market participant* provided the *facilities* have interval metering.

Market participants must inform us in writing if they wish to exercise this option.

1.6.7.8 Global Adjustment

We make adjustments to *settlement amounts* monthly to reflect the portion of the Global Adjustment allocated to each *market participant* with load in Ontario. The total Global Adjustment for a month is the sum of the charges shown below:

Charge Type #	Charge Type
143	OEFC Adjustment Settlement Amount
144	Regulated Nuclear Generation Adjustment Amount
145	Regulated Hydroelectric Generation Adjustment Amount
1330 - 1336	Demand Response Program - DR2
1340 - 1348	Demand Response Program - DR3
1400	OPA Contract Adjustment Settlement Amount
1410	Renewable Energy Standard Offer Program Settlement Amount
1411	Clean Energy Standard Offer Program Settlement Amount
1412	Feed-In Tariff Program Settlement Amount
1414	Hydroelectric Contract Initiative Settlement Amount
1416	Conservation and Demand Management – Compensation Settlement Credit

Market Participant Classes

Your portion of the Global Adjustment depends on the amount of load you withdraw from the *IESO controlled grid*. There are two classes of *market participants* as related to the distribution of the Global Adjustment.

Class A Market Participants

Class A Market Participants are defined by the following criteria:

- The *market participant* is neither a licensed *distributor* nor a regulated *consumer*.
- The *market participant* was a *market participant* throughout the applicable Base Period.
- The *market participant's* maximum hourly demand for electricity in a month, as determined by the *IESO*, exceeds an average of 5 megawatts for the applicable Base Period.
- The total volume of electricity, as determined by the *IESO*, supplied by the *market participant* to the *IESO-controlled grid* or to the distribution systems of licensed *distributors* during the applicable base period did not exceed the total volume of electricity the *market participant* withdrew from the *IESO-controlled grid* or the distribution systems of licensed *distributors* during that base period.

Demand in these references refers to Allocated Quantity of Energy Withdrawn (AQEW) from the *IESO controlled grid*.

Class B Market Participants

All other *market participants* who consume electricity, excluding licensed *distributors*, are considered Class B Market Participants.

Global Adjustment Periods

There are two periods that relate to the *settlement* of the Global Adjustment. The Base Period is the period during which the load pattern of the *market participant* will determine potential Class A qualification. The Adjustment Period is the *settlement* period over which that Class A qualification will be applied. The Base Periods and related Adjustment Periods for 2011 and beyond are shown below:

Base Period	Adjustment Period
May 1, 2010 to October 31, 2010	January 1, 2011 to June 30, 2011
May 1, 2010 to April 30, 2011	July 1, 2011 to June 30, 2012
May 1, 2011 to April 30, 2012	July 1, 2012 to June 30, 2013
May 1, (Year X) to April 30, (Year X+1)	July 1, (Year X+1) to June 30, (Year X+2)

Global Adjustment Settlement

Class A Market Participants and Distributors with Class A Consumers

Class A *market participants* and *distributors* with Class A *consumers* will be apportioned their share of the total Global Adjustment amount each month in a defined Adjustment Period based on a “Peak Demand Factor” calculation based on their load pattern in the related Base Period.

The *IESO* will determine, for the appropriate Base Period, the five hours where *market participants* (including *distributors*) withdrew the greatest total net volume of electricity from the *IESO-controlled grid*. These hours must be on different days. The determination of the peak hour will be based on hourly Allocated Quantity of Energy Withdrawn (AQEW) from the *IESO controlled grid* net of several adjustments.

The adjustments include:

- a) the net volume withdrawn at the Sir Adam Beck Pump Generating Station;
- b) the net volume withdrawn by Fort Frances Power Corporation under its *physical bilateral contract* with Abitibi-Consolidated Hydro Limited Partnership; and
- c) the net volume withdrawn by *market participants* in the course of providing *ancillary services* in accordance with the *market rules*.

The Peak Demand factor for a Class A *market participant* will be based on their consumption coincident with the five peak hours identified for the Base Period. The Peak Demand Factor will be calculated as follows:

$$\begin{aligned} \text{Peak Demand Factor} &= \frac{\sum_{\text{Peak Hours}} \text{Coincident Class A Market Participant Consumption}}{\sum_{\text{Peak Hours}} \text{Peak System Consumption}} \end{aligned}$$

Where

Peak System Consumption for the Peak Hour

= AQEW + *Embedded Generation* in licensed *distributors* - Beck Pump Generating Station AQEW - Fort Frances Power Corporation *physical bilateral contract* amount – AQEW related to the provision of *ancillary services* as defined in the *market rules*.

The coincident peak consumption amounts for Class A *market participants* or for *distributors* with Class A *consumers* will be determined from AQEW values derived for *settlement* in the Base Period. *Distributors* will be asked to submit the amount of Class A *consumer* load coincident with peak hours at the end of the appropriate Base Period along with the embedded generation in their distribution territory coincident with the peak hours.

The Global Adjustment assigned to a Class A *market participant* or *distributors* with Class A *consumers* for a month in the Adjustment Period will be determined by multiplying the Peak Demand Factor by the total Global Adjustment for the month.

Market participants and *consumers* identified as Class A for the first two Base Periods have the option to elect classification as Class B customers. Class A customers electing this option should provide written notice to the *IESO* or the *distributor* by December 15, 2010 for the first Base Period and June 15, 2011 for the second.

Class B Market Participants and Distributors

Class B *market participants* will be assigned a portion of the total Global Adjustment for any month based on the net volume of electricity withdrawn from the *IESO-controlled grid* for the month.

All *generators* will be considered Class B *market participants* when consuming electricity from the *IESO controlled grid*. Some *generators* that consume electricity either when providing *ancillary services* or for consumption related to the Beck Pump Generating Station will have this amount netted off their total consumption.

Distributors will be assigned a portion of the Global Adjustment based on the net volume of electricity withdrawn from the *IESO-controlled grid* for the month plus embedded generation in their territory less Class A *consumer* consumption in the month. The *distributor* data submission to the *IESO* for each month will be expanded from the current embedded generation to include Class A *consumer* consumption. This submission will continue to be submitted to the *IESO* by the fourth *business day* after the month-end using the *embedded generation* form on the *IESO* portal enhanced to include the Class A *consumer* consumption.

The total amount of Global Adjustment assigned to all Class B *market participants* and licensed *distributors* will exclude the Global Adjustment allocated to Class A *market participants* and licensed *distributors* with Class A *consumers*.

The total Class B consumption for the month will be calculated as follows:

Total Class B Load = *Total AQEW* + Embedded Generation in licensed *distributors* - Beck Pump Generating Station AQEW - Fort Frances Power Corporation under its *physical bilateral contract* amount – AQEW related to providing *ancillary services* – AQEW of Class A *market participants* and LDC Class A *consumers*.

Class B Rates

The *IESO* will be calculating and posting a Class B Global Adjustment rate for *distributors* to use in settling with their Class B *Consumers*. This rate will be published in a given month three times which are as follows:

- 1) First Estimate – Calculated on the last *business day* of the previous month.
- 2) Second Estimate – Calculated on the last *business day* of the month.
- 3) Actual Class B rate – Calculated on the 10th *business day* of the following month.

The estimated rates will be based on estimates of the Class B Global Adjustment amounts and Class B consumption. The Final rate will be calculated based on actual values for the month.

The estimated Class B Global Adjustment amount and Class B Consumption will be calculated as shown below for the First Estimate.

Class B Global Adjustment Amount	Class B Consumption
Estimated Global Adjustment for the previous month (For March use Estimate for February)	Estimated Load for the month
Plus/Minus corrections for the estimates used in previous month calculations	Plus/Minus Corrections to Estimates from previous month calculations
Multiplied by [1- Total Peak Demand Factors for current Adjustment Period]	Plus Embedded Generation values used in the settlement of the month two months prior (Estimate for March based on submission for January)
	Minus Class A Market Participant and Consumer load used in the settlement of the month two months prior
	Minus Fort Frances load for the month
	Minus Sir Adam Beck PGS load used in the settlement of the month two months prior
	Minus Load associated with the provision of Ancillary Services used in the settlement of the month two months prior

The rate will be calculated (to the nearest cent) as:

$$\text{Class B Global Adjustment Amount} \div \text{Class B Consumption}$$

The estimated Class B Global Adjustment amount and Class B Consumption will be calculated as shown below for the Second Estimate.

Class B Global Adjustment Amount	Class B Consumption
Estimated Global Adjustment for the month	Estimated Load for the month
Plus/Minus Final Adjustment of previous months Global Adjustment	Plus/Minus Corrections to Estimates from previous month calculations
Plus/Minus corrected Global Adjustment for prior periods (results from Global Adjustment distributions corrections related to revenue metering adjustments for prior periods)	Plus Embedded Generation values used in the settlement of the previous month
Multiplied by [1- Total Peak Demand Factors for current Adjustment Period]	Minus Class A Market Participant and Consumer load used in the settlement of the previous month
	Minus Fort Frances load for the month.
	Minus Sir Adam Beck PGS load used in the settlement of the previous month.
	Minus Load associated with the provision of Ancillary Services used in the settlement of the previous month.

The rate will be calculated (to the nearest cent) as:

$$\text{Class B Global Adjustment Amount} \div \text{Class B Consumption}$$

The Class B Global Adjustment amount and Class B Consumption will be calculated as shown below for the Actual rate.

Class B Global Adjustment Amount	Class B Consumption
Preliminary Global Adjustment for the month	Preliminary Settlement Load for the month
Plus/Minus Final Adjustment of previous months Global Adjustment	Plus/Minus Corrections to Estimates from previous month calculations
Plus/Minus corrected Global Adjustment for prior periods (results from Global Adjustment distributions corrections related to revenue metering adjustments for prior periods)	Plus Embedded Generation values used in the settlement of the month
Multiplied by [1- Total Peak Demand Factors for current Adjustment Period]	Minus Class A Market Participant and Consumer load used in the settlement of the month
	Minus Fort Frances load for the month
	Minus Sir Adam Beck PGS load used in the settlement of the month
	Minus Load associated with the provision of Ancillary Services used the settlement of the month.

The rate will be calculated (to the nearest cent) as:

$$\text{Class B Global Adjustment Amount} \div \text{Class B Consumption}$$

Class A Market Participant/Consumer Changes in the Adjustment Period

There are a number of potential situations where the *settlement* of Class A *consumers* and Class A *market participants* can change over the Adjustment Period.

- 1) Class A customer ceases operation.
- 2) Class A customer moves either from being a *market participant* to a *distributor* customer or vice-versa.
- 3) A Class A customer's load changes ownership in full or in part.
- 4) A Class A customer elects to become a Class B customer due to "Extraordinary Circumstances" under provisions set out in the regulation.

In the event that any of these situation comes about the *distributor* must inform the *IESO*, or alternatively, the *IESO* must inform the *distributor*, as soon as possible so the Peak Demand Factors can be recalculated.

Monthly Settlement

The *settlement amount* for Class A *market participants* or *distributors* with Class A *consumers* will be included on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month under *charge type* 147 “Class A Global Adjustment Settlement Amount”.

The *settlement amount* for Class B *market participants* or *distributors* will be included on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month under *charge type* 148 “Class B Global Adjustment Settlement Amount”.

The corresponding set-offs are *charge type* 196 “Global Adjustment Balancing Amount” and *charge type* 197 “Global Adjustment - Special Programs Balancing Amount”. *Charge type* 196 is included on the *OPA’s preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month. *Charge type* 197 is balanced by the *IESO* at the end of the month for the portion of the Global Adjustment that relates to Special Programs not administered by the *OPA*.

1.6.7.9 OPA Administration Charge

The “OPA Administration Charge”, *charge type* 754, is a fee levied against all load in Ontario based on AQEW. Every *market participant* who has AQEW attributed to it during the preceding month pays the *OPA* Administration Charge based on its AQEW and the *OPA* fee. The *OEB* sets the *OPA* fee annually. *Charge type* 754 appears on your *preliminary* and *final settlement statements* for the last *trading day* of the month.

The corresponding setoff, *charge type* 704 “OPA Administration Credit”, is payable to the *OPA* on its *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

1.6.8 Limiting CMSC Payments for Exporters and Dispatchable Loads

Exporters and *dispatchable loads* may be eligible for CMSC payments from the marketplace when they submit negative bids and are *constrained on* by the *IESO*. To minimize uplift costs for Ontario *consumers*, the *IESO*, under Section 3.5.6A, Chapter 9 of the *market rules*, may adjust any bid price associated with an exporter or *dispatchable load facility* for calculating CMSC payments under the following conditions:

1. The bid price is less than the replacement bid prices determined by the *IESO* (i.e. -\$125/MWh for exporters and -\$15/MWh for *dispatchable loads*); and
2. The bid price is less than the applicable *energy* market price (i.e. the zonal clearing price at the *intertie* for exporters or the Ontario market clearing price for *dispatchable loads*).

When these two conditions are met, the *IESO* may adjust the negative bid price to the *lesser* of the replacement bid prices determined by the *IESO* and the applicable *intertie* or Ontario market clearing price.

Exporters may submit a *notice of disagreement* and a suggested replacement price to recover their costs in cases where,

- a) the negative bid is adjusted to the replacement bid price set by the *IESO* (i.e. -\$125/MWh); and
- b) the export transaction is settled in the neighbouring market at a negative price that is less than the replacement bid price set by the *IESO*; and

- c) the total value of unrecovered costs (i.e. CMSC not paid due to the replacement bid) for the trade date that is the subject of the submitted *notice of disagreement* exceeds \$1,000.

Dispatchable loads may submit a *notice of disagreement* for any trade date in a month where,

- a) the combined preliminary hourly and daily uplifts for a trade date reported on the *IESO* website exceeds \$2.50/MWh; and
- b) the negative bid is adjusted to the replacement bid price set by the *IESO* (i.e. -\$15/MWh); and
- c) the total value of unrecovered costs (i.e. CMSC not paid due to the replacement bid) for the trade date that is the subject of the submitted *notice of disagreement* exceeds \$1,000.

The *notice of disagreement* should provide details of the transaction including evidence to support the suggested replacement price and the value of the requested compensation.

1.6.9 Adjustment for Facility-Induced CMSC

Under Section 3.5.1A of Chapter 9 of the *market rules*, a *market participant* is not entitled to congestion management *settlement credits* (CMSC) where these are the result of the *facility's* own equipment or operational limitations under certain circumstances. Such situations include a *dispatchable load facility* which does not fully or accurately respond to *dispatch instructions* or where the bid ramp rate is below the specified threshold. The *market rules* enable us to:

- avoid making the CMSC payments entirely; or
- completely recover such payments after the fact from the *dispatchable load*.

This procedure describing recovery of deviation-induced CMSC also applies when the *dispatchable load* has a bid price equal to the *maximum market clearing price (MMCP)*. In such circumstances, not only is a *dispatch* deviation the likely cause of the *dispatch*, but according to Section 3.3.18 of Chapter 7 of the *market rules*, and as elaborated in Section 1.3.4 of “Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets”, this price indicates the load is to be treated as *non-dispatchable* and, therefore, it is not eligible for CMSC.

1.6.9.1 Assessment

The following business rules identify the criteria we use when recovering constrained-off CMSC paid to *dispatchable load facilities*.

- Business Rule 1 – Materiality

Constrained-off CMSC is allowed for an interval if the total amount of CMSC paid during that *trading day* to that *dispatchable load* is less than \$4000. The daily total includes negative CMSC.

- Business Rule 2 – *Non-Dispatchable* Portion of Load

Constrained-off CMSC is not allowed for an interval if it is paid for portions of the schedule where the load has *bid + MMCP*, indicating that it is *non-dispatchable* in that range. This business rule applies unless CMSC is allowed because of materiality (Business Rule 1).

- Business Rule 3 – *Dispatch Deviation*

Constrained-off CMSC is not allowed for an interval if the current 5-minute constrained schedule exceeds the *revenue meter* value in the previous interval plus 2.5 minutes of ramping. This business rule will be applied unless CMSC is allowed because:

- of materiality (Business Rule 1); or
- the load has been constrained-off economically (see Definition 1 below); or
- *operating reserve* has been activated (see Definition 2 below); or
- the load is ramping (see Definition 3 below); or
- the load has been manually dispatched down for *reliability* (see Definition 4).

- Business Rule 4 – *Facility Off-Line or Unable to Follow Dispatch Instructions*

Constrained-off CMSC is not allowed for an interval if the constrained schedule is 0 MW and consumption is less than 1 MW, or if consumption is 0 MW. This business rule will be applied unless CMSC is allowed because:

- of materiality (Business Rule 1); or
- the load has been constrained-off economically (see Definition 1); or
- *operating reserve* has been activated (see Definition 2); or
- the load has been manually dispatched down for *reliability* (see Definition 4).

The business rules are supported by the following definitions:

- Definition 0 – *constrained off event*.

A *constrained off event* comprises one or more consecutive intervals where:

- *market schedule* > constrained schedule; and
- *market schedule* > AQEW.

- Definition 1 – *economically constrained off*

A *dispatchable load* is considered to be ‘economically constrained-off’ in an interval if the relevant nodal price is greater than or equal to the *bid* price for either the current interval, the next interval or the previous interval. The inequality is applied to the last MW constrained-off.

- Definition 2 – *operating reserve* activation (ORA)

A *dispatchable load* is considered to be *dispatched* in an interval as part of an activation of *operating reserve* if:

- its constrained schedule is labelled with the reason code ‘ORA’; or
- the interval is 1-3 intervals in advance of an interval where its schedule is labelled with the ‘ORA’ code; or
- the interval is 1-3 intervals after an interval where its schedule is labelled with the ‘ORA’ code.

- Definition 3 – ramping

A *dispatchable load* is considered to be ‘ramping’ in an interval if it is one of the first 3 intervals of the second hour when ramping-up, or if it is one of the last 3 intervals of the first hour when ramping down. A *generation unit* is considered to be ramping up or ramping down in an hour when the unconstrained schedule differs between consecutive hours.

- Definition 4 – manually *constrained off* for *reliability*

A *dispatchable load* is considered to be ‘manually *constrained off* for *reliability*’ if our control room logs indicate that we needed to constrain off the load for system or local requirements.

1.6.9.2 Timing of the Facility-Induced CMSC Processing and Adjustment

Effective December 1, 2007, the CMSC adjustment for a *dispatchable load* will be calculated for each interval and applied to the *preliminary settlement statement* for that *trading day* via *charge type* 1050 “Self-Induced Dispatchable Load CMSC Clawback”.

1.6.9.3 Limiting Constrained Off CMSC for Dispatchable Loads

If you are the *market participant* for a *dispatchable load*, you are not entitled to *constrained off* CMSC payments related to ramping, if you change your operating behavior as a result of conditions and/or actions at your *dispatchable load facility*, and not due to conditions on the *IESO-controlled grid*. Under sections 3.5.1D and 3.5.2, Chapter 9 of the *market rules*, the withholding of *constrained off* CMSC payments is limited to *bid* changes that result in changes to the *facility’s market schedule* and targets *constrained off* CMSC that is as a result of the *dispatchable load* ramping up or down.

The decision rules for ramping up or down are as follows:

A *dispatchable load* is considered to be ramping down if:

- There is a decrease in the constrained schedule between interval 9 and 12 of the current hour; and
- The unconstrained schedule in interval 12 of the current hour is greater than the unconstrained schedule in interval 1 of the next hour; and
- There is a change in the *bid* lamination between the current and the next hour.

A *dispatchable load* is considered to be ramping up if:

- There is an increase in the constrained schedule between interval 12 of the previous hour and interval 3 of the current hour; and
- The unconstrained schedule in interval 12 of the previous hour is less than the unconstrained schedule in interval 1 of the current hour; and
- There is a change in the *bid* lamination between the previous and next hour.

These rules apply unless CMSC is allowed for the hour because of:

- Materiality (defined in Section 1.6.9.1 by ‘Business Rule 1 – Materiality’); or
- The load has been *constrained off* economically in an interval (defined in Section 1.6.9.1 by Business Rule 4, ‘Definition 1 – economically constrained off’); or
- *Operating reserve* has been activated (defined in Section 1.6.9.1 by Business Rule 4, ‘Definition 2 – operating reserve activation’); or

- The load has been manually dispatched down for *reliability* (defined in Section 1.6.9.1 by Business Rule 4, ‘Definition 4 – manually constrained off for *reliability*’).

Under section 3.5.1D Chapter 9 of the *market rules*, the *IESO* will recover *constrained off* CMSC payment related to ramping of any remaining portion of *constrained off* CMSC payment net of “Self-Induced Dispatchable Load CMSC Clawback” *charge type* 1050 to *dispatchable loads*. The business rules in Section 1.6.9.1 will continue to recover *constrained off* CMSC on an interval basis with the charges appearing on the *preliminary settlement statement* for that *trading day*. The remaining *constrained off* CMSC for *dispatchable loads* will be recovered through manual adjustments (*charge type* 1050) appearing on the month-end *settlement statements*.

1.6.10 Real-time Import Failure Charges and Export Failure Charges

The *market rules* no longer treat *intertie* transaction failures as solely a compliance matter. You will be assessed a *settlement* charge for import and export failures to compensate the market for *intertie* transaction failures that fail for reasons that are within your control, i.e., not “bona fide and legitimate”. The *market rules* allow for compliance actions which may include both imposing a financial penalty or recovering any *settlement amounts* (such as *transmission rights* payments, congestion management *settlement* credits or other *settlement amounts*) that were inappropriately gained or avoided by a *market participant*. When *intertie* transaction failures are for bona fide and legitimate reasons, you are exempt from failure charges.

The Day-Ahead Commitment Process (DACP) includes a day-ahead import failure *settlement* charge (DA-IFC), a day-ahead export failure charge (DA-EFC) and a day-ahead linked wheel failure charge (DA-LWFC). Refer to “Market Manual 9: Part 9.5 Settlement of the DACP” for details on the DA-IFC, DA-EFC and DA-LWFC, and Chapter 7, Section 7.5.8B and Chapter 9, Sections 3.8B, 3.9 and 4.8 of the *market rules*.

1.6.10.1 Intertie Transaction Reason Codes and Resultant Settlement Treatment

When we manually alter an import or export schedule, we apply one of seven ‘reason codes’ to apply the appropriate *settlement* treatment. These reason codes are defined in Table 3–5 of the *IESO* Technical Interface document “Format Specifications for Settlement Statement Files and Data Files” (IMP_SPEC_0005). Refer to “Market Manual 4: Market Operations, Part 4.3: Real-time Scheduling of the Physical Markets” for more information regarding the application of reason codes to import and export schedules.

Table 1–2 contains the reason codes and the resulting treatment of CMSC and the day-ahead and real-time failure charges.

For failed imports and exports:

- “Yes” indicates a failure meeting the criteria of a bona fide and legitimate reason for failure as described in Chapter 7, Section 7.5.8B in the *market rules* allowing the transaction to be exempt from the failure charge; and
- “No” indicates a failure not meeting the criteria of a bona fide and legitimate reason as described in the *IESO market rules*, exposing the transaction to the failure charge.

Table 1–2: Failure Reason Codes and Settlement Treatment

Code Entered	DSO Treatment	Resulting Treatment			
		CMSC Treatment	DA IFC Exempt (Import)	RT IFC Exempt (Import)	RT EFC Exempt (Export)
OTH	Constrained Schedule equal to Market Schedule	Nc	No	Nc	No
TLRe	Constrained Schedule equal to Market Schedule	Nc	Yes	Yes	Yes
TLRi	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	Yes	Yes	Yes
ORA	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	No (2)	n/a	Yes
MrNh (1)	Constrained Schedule equal to Market Schedule	Nc	No	Yes	Yes
ADQh (1)	Constrained Schedule equal to Market Schedule	Nc	No (2)	Yes	Yes
NY90 (1)	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	No (2)	n/a	n/a
AUTO	Constrained Schedule not necessarily equal to Market Schedule	Yes or No based on DSO schedule	No (2)	n/a	n/a
Notes:					
(1)	The MrNh, ADQh and NY90 Codes are new codes intended to improve the accuracy in applying codes when manual adjustments are made.				
(2)	Exceptions to this treatment for the Real-time Offer Price Test				

Characteristics of the real-time import and *real-time export* failure charges include the following.

1. RT import failure charges and RT export failure charges apply to all import/export transactions on all *IESO* interfaces that fail between hour-ahead *pre-dispatch* and real-time. The intertie failure charge is limited, in the case of imports, to the Ontario real-time *energy market price*, and in the case of exports, to the *pre-dispatch* Ontario price. The import failure charge is the mirror image of the export failure charge.
2. The import transaction may be exempted from these failure charges if we determine or you demonstrate that the failure of the day-ahead import transaction to flow in real-time is caused by bona fide and legitimate reasons. Generally, these reasons for import failure are beyond your control or due to our errors or actions or those of an external system operator. These reasons may be determined by our operations, or you can submit them to us for assessment through the *notice of disagreement* (NOD) process. Refer to Section 1.5.
3. We calculate the real-time import failure charge to a maximum import charge capped at a value proportional to the Ontario Market Clearing price for the interval. It is triggered when the adjusted real-time price is greater than the *pre-dispatch* price during the hour of failure.
4. We calculate the real-time export failure charge to a maximum export charge capped at a value proportional to the *pre-dispatch* Ontario price for the hour. It is triggered when the adjusted real-time price is less than the *pre-dispatch* price during the hour of failure.
5. We calculate an hourly applicable price bias adjustment factor used in both the real-time import and export failure charges. The price bias adjustment factor compensates for systematic differences between the *pre-dispatch* and real-time price. For example, there are systematic differences between the *pre-dispatch* and real-time price as a result of using Ontario *demand* forecast peak in PD versus the average in real-time price calculations. See Appendix D for a description of the methodology we use to calculate the bias adjustment factor.

For example:

Real-time Import Failure Charge: = Min [Max[0, ((RT Ont MCP + Import Bias Adjustment factor) – PD Ont MCP) * MWh deviation], Max (0, RT Ont MCP) * MWh deviation]

Real-time Export Failure Charge: = Min[Max[0, ((PD Ont MCP – RT Ont MCP – Export Bias Adjustment factor) * MWh deviation], Max (0, PD Ont MCP) * MWh deviation]

Example 1: PD price = \$100
 RT price = \$120
 Adjustment factor = \$5
 Volume failed = 100 MW

RT Import Failure Charge = minimum of [$\$120 + \$5 - \$100$]*100 MW or ($\$25 * 100$ MW)
 = \$2500

Example 2: PD price = \$100
 RT price = \$80
 Adjustment factor = \$5
 Volume failed = 100 MW

RT Export Failure Charge = minimum of [$\$100 - \$80 - \$5$]*100 MW or ($\$100 * 100$ MW)
 = \$1500

6. The *settlement amount* is only payable from you to the *IESO-administered markets*. Payments of these *settlement amounts* to you under any other circumstances are not allowed. These *settlement amounts* are administered under *charge types* 135 “Real-time Import Failure Charge” and 136 “Real-time Export Failure Charge”.
7. We distribute *settlement amounts* collected under these charges on a pro-rata basis to *market participants* with allocated quantities of *energy* withdrawn (AQEW, including export transactions) at the time for which the charge was assessed. This is distributed as a new component of *hourly uplift* in *charge type* 186 “Intertie Failure Charge Rebate”. Refer to Chapter 9, Sections 3.9 and 4.8 of the *market rules*.
8. The *intertie* failure charge rebate is a new *charge type* that submits a new component of *hourly uplift* for distribution to the market. It distributes proceeds from the RT import failure charge (RT-IFC), the RT export failure charge (RT-EFC) and the DA import failure charge (DA-IFC) (net of any reductions for the *intertie* failure charge reversal (IFC-REV)).
9. This *hourly uplift* can be transferred as part of a *physical bilateral contract*. Refer to “Market Manual 5, Settlements, Part 5.3: Submission of Physical Bilateral Contact Data”.

1.6.11 Standard Offer Program (SOP)

1.6.11.1 Renewable Energy Standard Offer Program (SOP)

The *Ontario Power Authority (OPA)* and *Ontario Energy Board (OEB)* developed a Renewable Energy Standard Offer Program (RESOP) for small *generators* that use renewable resources. These *generators connect* to electricity *distribution systems* at *distribution voltages* (50kV or less).

Standard offer program projects have a maximum size of 10 megawatts (MW), and may include any renewable resource type that qualifies as a renewable resource in the Renewable Energy Supply II

RFP including wind, small hydro-electric, solar, and some bio-mass. No minimum project size was proposed.

As of October 1, 2009, the Renewable Energy Standard Offer Program was replaced by the Feed-in Tariff Program (FIT Program) under the Clean Energy Act³⁰. New renewable *energy* supply projects will come under the umbrella of the new FIT Program and the *OPA* will no longer accept new RESOP applications. Projects that have already been approved under RESOP will continue according to their contracts. The terms and conditions of executed contracts, including the rates, will be unaffected by the new FIT Program.

This section sets out how the *IESO* settles the Renewable Energy Standard Offer Program on behalf of the *OPA*, the *OEB* and Program participants. To the extent of any inconsistency between the provisions of the Renewable Energy Standard Offer Program rules and this section, the Renewable Energy Standard Offer Program rules shall govern.

The Standard Offer Program provides a “standard price” which eligible *generators* receive by simply complying with the eligibility criteria. Contract terms are typically for 20 years. For the first year of commercial operation, all eligible renewable resource type projects (except solar photovoltaic) will be paid a base rate of 11.13 cents per kilowatt hour for all kilowatt hours delivered. Projects that can demonstrate *generation* control are eligible for an additional 3.52 cents per kilowatt hour for all electricity delivered during on-peak hours. For solar photovoltaic projects, a price of 42 cents per kilowatt hour is established to conduct price discovery on this technology.

Under the standard offer program, *generators* are paid directly for every kilowatt hour of electricity produced at the price set out in their standard offer contract. *Distributors* must calculate the difference between the contracted payments to standard offer program participants and the wholesale *market price* for the same volume of electricity. *Distributors* submit this difference to us monthly via the *IESO* portal noting the amount of the claim for each category. Information required from both the *distributor* and embedded *distributor* is submitted via the *IESO* portal.

Submit Standard Offer Program claims to us monthly as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. This submission is made using the on-line form “Renewable Energy Standard Offer Program” accessible on the *IESO* portal. We process this information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicates a *charge type* 1410 “Renewable Energy Standard Offer Program Settlement Amount” with the category noted in the Comment field.

The corresponding setoff, *charge type* 1460 “Renewable Energy Standard Offer Program Balancing Amount”, is entered as a manual line item on the *OPA*’s *settlement statements* for the last *trading day* of the month to balance the market.

1.6.11.2 Feed-in Tariff Program (FIT)

The *Ontario Power Authority (OPA)* has entered into procurement contracts under the Feed-in Tariff (FIT) Program with certain suppliers to encourage renewable *generation* to participate in a variety of technologies and their respective applications. The Feed-in Tariff Program will support renewable *energy* generating alternatives including wind, biomass, small hydro and solar photovoltaic. For suppliers that are directly *connected* to the *IESO-controlled grid*, the *OPA* will settle these contracts directly. For suppliers (i.e., *generators*) embedded within a *distribution system*, the *distributors* will settle these contracts with the *embedded generators*.

³⁰ The Clean Energy Act was introduced in the Ontario Legislature on February 23, 2009.

This section sets out how the *IESO* settles the Feed-in Tariff Program on behalf of the *OPA* and Program participants. To the extent of any inconsistency between the provisions of the Feed-in Tariff Program Rules and this section, the Feed-in Tariff Program Rules shall govern.

Distributors must calculate the difference between the amount paid to the supplier for electricity produced calculated at wholesale *market prices*, and the amount calculated at the contract price. The adjustment can be either positive or negative, charged or paid to the *distributors* who will settle the contracts with the individual suppliers. *Distributors* submit this difference to us monthly via the *IESO* portal online *settlement* form “Feed-in Tariff Program“.

Submit Feed-in Tariff Program claims to us monthly as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. This submission is made using the on-line form “Feed-in Tariff Program” accessible on the *IESO* portal. We process the information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicates a *charge type* 1412 “Feed-in Tariff Program Settlement Amount” with the category noted in the Comment field.

The corresponding setoff, *charge type* 1462 “Feed-in Tariff Program Balancing Amount”, is entered as a manual line item on the *OPA’s settlement statements* for the last *trading day* of the month to balance the market. The Feed-in Tariff Program Balancing Amount charge can be either a payment by the *OPA* to the *IESO* to compensate it for payments it makes for this Feed-in Tariff Program, or a payment by the *IESO* to the *OPA* to pass on amounts collected under *charge type* 1412. The *OPA* charge or credit will be offset through the Global Adjustment.

1.6.11.3 Hydroelectric Contract Initiative (HCI)

The *Ontario Power Authority (OPA)* has entered into procurement contracts under the Hydroelectric Contract Initiative (HCI) with qualified existing hydroelectric *generation facilities* to increase Ontario’s supply of clean, renewable *generation*. The HCI supports new contracts for hydroelectric *facilities* that are *connected* to the *IESO-controlled grid* but not owned by OPG. For large *facilities* (generally ≥ 10 MW) that are directly *connected* to the *IESO-controlled grid*, the *OPA* will settle these contracts directly. For small *facilities* (generally < 10 MW) embedded within a *distribution system*, the *distributors* will settle these contracts with the participating *embedded generators*.

This section sets out how the *IESO* settles the Hydroelectric Contract Initiative on behalf of the *OPA* and Program participants. To the extent of any inconsistency between the provisions of the HCI rules and this section, the HCI rules shall govern.

Distributors must calculate the difference between the amount paid to the participating *embedded generators* for electricity produced calculated at wholesale *market prices*, and the amount calculated at the contract price. The adjustment can be either positive or negative, charged or paid to the *distributors* who will settle the contracts with the individual *generators*. If you are a *distributor* who has a participating *generation facility*, please contact *IESO* Customer Relations for instructions on submitting HCI claims at: customer.relations@ieso.ca.

Submit HCI claims to us monthly as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. This submission is made using the on-line form “Hydroelectric Contract Initiative” accessible on the *IESO* portal. We process the information as a manual line item so that the *settlement statements* for the last *trading day* of the month and monthly *invoices* indicate a *charge type* 1414 “Hydroelectric Contract Initiative Settlement Amount”.

The corresponding setoff, *charge type* 1464 “Hydroelectric Contract Initiative Balancing Amount”, is entered as a manual line item on the *OPA’s settlement statements* for the last *trading day* of the month to balance the market. The Hydroelectric Contract Initiative Balancing Amount charge can be either

a payment by the *OPA* to the *IESO* to compensate us for payments we make for this HCI, or a payment by the *IESO* to the *OPA* to pass on amounts collected under *charge type* 1414. The *OPA* charge or credit will then be balanced out through the Global Adjustment.

1.6.12 CMSC Adjustment for Replacement Offer Events

Generators who experience a *forced outage* at a hydroelectric *generation facility* or who experience a *forced outage* of a gas turbine at a combined cycle *generation facility*, an *enhanced combined cycle facility*, or a *cogeneration facility* are allowed to submit revised *dispatch data* for a related *generation facility*. We expect to receive revised *dispatch data* for the next *dispatch hour*. In some instances, the revised *dispatch data* will not be effective until the subsequent *dispatch hour* if the *forced outage* occurs too near the end of the current *dispatch hour* to meet timelines for *dispatch data* submission.

In the interim period before the revised *dispatch data* is processed by market systems, we must accept the replacement *energy* from the related *generation facility* for the *facility* that has been forced out, provided there is no adverse impact on the *reliability* of the *IESO-controlled grid*. The replacement *energy* is limited to the original *energy* as scheduled for the *facility* experiencing the *forced outage*.

Any congestion management *settlement credit* payments to the related *generation facility* during the interim period will be limited to an estimate of what would have been received by the *generation facility* experiencing the *forced outage*³¹.

We take the following steps in estimating the amount of CMSC that would have been received by the *facility* experiencing the *forced outage* and in applying the CMSC adjustments during a replacement offer event.

- Determine the ‘reference interval’.
The reference interval is the interval during a replacement offer event immediately before the interval where:
 - the *market schedule* or the constrained schedule declines in response to the failure of the original *generation facility*; or
 - the related *generation facility* is constrained on, whichever comes first.
- Determine the ‘CMSC limit’.
The CMSC limit is the total CMSC paid to the original *generation facility* and the related *generation facility* during the reference interval.
- Determine the ‘End of the replacement offers period’.
The replacement offers period ends when the market tools process the revised *dispatch data*. Typically, we expect this to be at the end of the current *dispatch hour*. In some instances, the *forced outage* occurs too near the end of the current hour to allow new *offers* to be submitted, and the replacement offers period will extend to the end of the next *dispatch hour*.
- Determine the ‘CMSC paid’.
The CMSC paid includes the amount of CMSC paid to the original *generation facility* and the amount paid to the related *generation facility* during each interval from the first interval after the reference interval until the end of the replacement offers period.
- Calculate and apply the CMSC adjustment.
The CMSC adjustment in each interval is the difference between the ‘CMSC paid’ and ‘CMSC limit’ during the replacement offer event according to:

³¹ See Chapter 9, Sections 3.5 and 4.8 of the *market rules*

CMSC (adj) = Min (0, - (CMSC paid – CMSC limit))

- a) when ‘CMSC paid’ > ‘CMSC limit’, then the difference is clawed back;
- b) when ‘CMSC limit’ > ‘CMSC paid’, then the CMSC adjustment is zero and no entry appears on your *settlement statement*.

The adjustment is applied as a manual entry to *charge type* 105 “Congestion Management Settlement Credit for Energy” for each applicable interval of the replacement resource. The adjustment is rebated back to *market participants* as a single manual entry to *charge type* 155 “Congestion Management Settlement Uplift” for each replacement offer event.

1.6.13 Compensation Resulting from an SPS Activation

If you are a *market participant* with a *dispatchable generation facility* that is not a *quick start facility* and that is part of a *Special Protection System (SPS)*, you may apply to the *IESO* for compensation if that *facility* is tripped offline as a result of the activation of the *SPS*.

The amount of compensation that may be claimed is the equivalent of up to the first two hours of constrained off congestion management *settlement* credit payments that would otherwise be calculated if the *facility* had been constrained down to zero and its circuit breaker had remained closed.

We calculate an *SPS* compensation amount for up to 24 intervals starting with the interval in which your *generation facility* was tripped offline. We will perform a CMSC-like calculation for each interval of the 24 consecutive compensation intervals using the *market schedule* set to the value in the interval preceding the trip and the constrained schedule set to 0 MW. We will take into account any CMSC that was already paid (or charged in the case of negative CMSC) during the compensation period.

To apply for compensation if your *generation facility* is tripped offline following an *SPS* activation, submit your claim by email directly to customer.relations@ieso.ca.

1.6.14 Northern Industrial Electricity Rate Program (NIERP)

The Ministry of Northern Development, Mines and Forestry (MNDMF) has created and administers the northern industrial electricity rate program (NIERP) to assist Northern Ontario’s largest industrial electricity *consumers* by providing a rebate incentive for the development and implementation of long term efficiency and sustainability measures. NIERP replaces the Northern Pulp and Paper Electricity Transition Program (NPPETP) that concluded on September 30th, 2010 (refer to Appendix G).

NIERP is a rebate incentive program with an average annual investment of \$150 million per year over three fiscal years (starting April 1, 2010 ending March 31, 2013). NIERP participants enter a conditional funding agreement with MNDMF and rebates are subject to meeting and maintaining all eligibility and program requirements.

The *IESO* is contracted by MNDMF to provide *settlement* services. We use *charge type* 121 “Northern Industrial Electricity Rate Program Settlement Amount” for the NIERP payments to participants and we recover NIERP payments from the MNDMF through *charge type* 171 “Northern Industrial Electricity Rate Program Balancing Amount”³².

³² Refer to “IESO Charge Types and Equations” and “Format Specifications for Settlement Statement Files and Data Files”, located on the Technical Interfaces page of our web site for details of these *charge types*.

Refer to the NIERP program rules for eligibility requirements and payment conditions available on the MNDMF web site at:

http://www.mndmf.gov.on.ca/northern_development/business_support/northern_industrial_electricity_rate_program_e.asp

1.6.15 OPA's Demand Response (DR3) Program³³

The *Ontario Power Authority (OPA)* is implementing a contractual load reduction program for *market participants*, LDC-connected participants and aggregators who are capable of providing a net electricity load reduction of at least 5 MW and, for aggregators, 25 MW. Refer to the OPA's DR3 Contract, Program Rules and related Manuals on their web site for full details.

This section sets out how the *IESO* settles the DR3 Program on behalf of the OPA and DR3 Program participants. To the extent of any inconsistency between the provisions of the DR3 Program rules and this section, the DR3 Program rules shall govern.

DR3 participants are paid a monthly Availability Payment for being available to reduce their load during the Hours of Availability and a Utilization Payment for their actual load *curtailment* when directed by us. Given that as a DR3 participant, you may have more than one DR3 Contract Schedule for a given Settlement Account; your payment will be based on the total Monthly Contracted MWs for all such DR3 Contract Schedules and the weighted average of each of the applicable rates.

The DR3 program also includes an Availability Over-Delivery Payment to encourage higher than contracted *demand* reduction in response to an Open Standby Notification.

Settlement payments are subject to Performance Set-Offs for both Availability and Utilization for failure to comply with DR3 Contract terms including:

- maintaining a Reliability Rate of at least 85% for each interval;
- confirming in a timely manner when required by us to do so; or
- confirming at least 85% of the Monthly contacted MW for a Confirmed Hour.

Additionally, DR3 participants will be subject to an Availability Payment Set-Off for:

- not being fully available for *curtailment*;
- any days that they declare a planned non-performance event; or
- failing to deliver *meter* data in a timely manner.

1.6.15.1 Settlement of Demand Response Payments

How Availability Payments are Settled

Each month, you will receive an Availability Payment for each Settlement Account based on the Hours of Availability, Monthly Contracted MW and the Adjusted Availability Rate as described in the DR3 Contract. The Adjusted Availability Rate is the weighted average of the rates for all Contract Schedules for a given Settlement Account and adjusted for premium zones and discount zones.

We calculate Availability Payments once a month in the month following the contract month and apply them as a manual line item to the last *trading day* of the month following the contract month.

³³ In this section, "you" refers to a DR3 participant.

We use *charge type* 1340 “On behalf of *OPA* for the DR3 Program - Availability Payment Settlement Amount” for Availability Payments to participants.³⁴

Where you have multiple DR3 Contract Schedules at a given Settlement Account, these DR3 Contract Schedules are aggregated into one manual line item for *settlement* purposes.

We recover availability payments through *charge type* 1390 “Demand Response 3 Availability Payment Balancing Amount”.

How Availability Over-Delivery Payments are Settled

When you receive an Open Standby Notification, you may respond to us that you are available to deliver more MWs or reduce load for a longer period than agreed to in your DR3 Contract Schedule. In this case, you are entitled to receive an Over-Delivery Payment for each over-delivery hour in a Contract Month.

In each hour, the Confirmed MWs are limited to the lesser of the Monthly Contracted MW plus 15 MW or 130% of the Monthly Contracted MW. In addition, the number of activations is limited to an additional 7 times if the Maximum Contract Hours is 100 and an additional 14 times if the Maximum Contract Hours is 200, for each calendar year.

We calculate Availability Over-Delivery Payments once a month in the month following the Contract Month and apply them as a manual line item to the last *trading day* of the month following the Contract Month.

We use *charge type* 1341 “On behalf of *OPA* for the DR3 Program - Availability Over-Delivery Payment Settlement Amount” for the monthly Availability Over-Delivery Payments to participants³⁵.

We recover Over-Delivery Payments through *charge type* 1391 “Demand Response 3 Availability Over-delivery Balancing Amount”.

How Utilization Payments are Settled

You are paid for the amount of load reduction you actually provide for a DR3 activation for each Settlement Account based on the Actual Activated MWh and the Utilization Rate as described in the Contract.

The Actual Activated MWhs are the metered reduction for the Activation Period. We will calculate your load reduction and *settlement* from the data you submit, according to your M&V Plan. For load reduction payments, the total reduction cannot exceed the confirmed reduction for the period plus the lesser of an additional 15 MWh or 15% of the Activation MW per hour of the Activation Period. In addition, the number of activations is limited to an additional 7 times if the Maximum Contract Hours is 100 and an additional 14 times if the Maximum Contract Hours is 200, for each calendar year.

We calculate Utilization Payments once a month in the month following the contract month and apply them as a manual line item to the last *trading day* of the month following the contract month. We use *charge type* 1343 “On behalf of *OPA* for the DR3 Program - Utilization Payment Settlement Amount” for Utilization Payments to participants.³⁶

Utilization Payments are not made when an Activation Notice is sent by us and you are using one of the Planned Non-Performance Events at the Settlement Account.

³⁴ Refer to “IESO Charge Types and Equations” and “File Format Specification for Settlement Statement Files and Data files” located on the Technical Interfaces page of the IESO Web site for details of these *charge types*.

³⁵ Ibid

³⁶ Ibid

Utilization Payments are recovered through *charge type* 1393 “Demand Response 3 Utilization Payment Balancing Amount”.

How We Process Your Meter Data

As part of the DR3 application, participants submit an M&V Plan for each Settlement Account. We calculate a Baseline for each and every Activation Hour. For DR3 participants that are not *IESO administered market participants*, we will use:

- your weekly retail revenue *meter* data submitted by 15:00 EST on the first *business day* of the following week; and
- revisions to the weekly data received by 15:00 EST on the last *business day* of the month following the completed contract month.

For DR3 participants that are *market participants*, we will use your revenue metering data that we’ve collected as part of our market *settlement process*.

The Baseline calculation may be adjusted using the measured *demand* prior to the *Curtailed* hour as described in Exhibit B of the DR3 Contract.

We verify the actual *metering data* against the M&V Plan and our calculations.

Calculating Performance Set-Offs

Delivery of your load reduction amount is subject to performance criteria. Performance criteria consist of:

1. **Reliability:** If you do not achieve an average reduction (Reliability Rate) during any 5-minute interval in the hour of at least 85% of the Activated MW, or if you are Not Fully Available for Curtailment you will be subject to reliability Performance Set-Offs. Performance Set-Offs for below-standard reliability applies to both availability and utilization payments whereas not being fully available for *curtailment* applies only to the availability payment.

Calculating Your Reliability Rate:

Due to the importance of reliable load reduction for assessing and managing the *IESO-controlled grid*, you are required to maintain a Reliability Rate for each Settlement Account of at least 85% for each interval of an Activation Hour. The Reliability Rate is calculated for each 5-minute interval and the rate for any interval cannot exceed 100%.

For Settlement Accounts that include more than one contract schedule, your Reliability Rate is based on your actual *curtailment* as a percentage of the aggregated Activation MW.

2. **Timely Confirmation:** If a Confirmation is required by us and you do not submit or submit a Confirmation late, both availability and utilization payments are subject to set-offs. The severity of the set-off will depend on how late the Confirmation is received.
3. **Low Confirmation:** If the Confirmed MWs are less than 95% of the Monthly Contracted MW for a Confirmed Hour, a Performance Set-Off will be calculated for each confirmed hour. This Set-Off will apply even if the actual load reduction is equal to or greater than the Monthly Contracted MW.

If more than one of the set-offs listed above apply to a Settlement Account, only the highest availability set-off amount shall be applied against your availability payment and similarly, only the highest Utilization Set-Off shall be applied against your Utilization Payment.

A Performance Set-Off Factor is included in the performance set-off calculations and is described in the *OPA* DR3 Contract.

We calculate Performance Set-Offs to be applied once a month at month-end as a manual line item for the last *trading day* of the month. We use *charge type* 1342 “On behalf of *OPA* for the DR3 Program - Availability Set-Off Payment Settlement Amount” to recover Availability Payments from participants and *charge type* 1344 “On behalf of *OPA* for the DR3 Program - Utilization Set-Off Payment Settlement Amount” to recover Utilization Payments from participants.³⁷

We use *charge type* 1392 “Demand Response 3 Availability Set-Off Payment Balancing Amount” and *charge type* 1394 “Demand Response 3 Utilization Set-Off Payment Balancing Amount” to balance Performance Set-Off amounts.

Additional Availability Set-Offs

In addition to the Performance Set-Offs described above wherein only the highest availability set-off amount shall be applied against your availability payment there are two availability set-offs that will be applied independently of whether or not other set-offs exist.

1. **Planned Non-Performance Availability Set-Off:** The Planned Non-Performance Availability Set-Off is calculated based on the impact to the *electricity system* of a DR3 participant’s planned unavailability. The severity of the set-off will depend on whether the participant would have been asked to curtail on the day they chose to be unavailable for *curtailment*.

We calculate the Planned Non-Performance Availability Set-Offs to be applied once a month at month-end as a manual line item for the last *trading day* of the month. We use *charge type* 1345 “On behalf of *OPA* for the DR3 Program - Planned Non-Performance Event Set-Off Settlement Amt” to recover Availability Payments from participants. We use *charge type* 1395 “Demand Response 3 Planned Non-Performance Event Set-Off Balancing Amount” to balance Planned Non-Performance Set-Off amounts.

2. **Meter Data Set-Off:** The Meter Data Set-Off will be applied against the Availability Payment if a complete set of weekly data for a Settlement Account is not received by the *IESO* by 15:00 EST of the first *business day* of the following week. The amount of the Set-Off for the first occurrence will be 20% of the Availability Payment prorated for the week and will increase in severity thereafter.

We use *charge type* 1346 “On behalf of *OPA* for the DR3 Program - Meter Data Set-Off Settlement Amount” to recover Availability Payments from participants. Meter Data that is not received by the fourth week after the deadline shall be considered to be a Performance Breach. We use *charge type* 1396 “Demand Response 3 Meter Data Set-Off Balancing Amount” to balance Meter Data Set-Off amounts.

1.6.15.2 Breach of Contract

Material Non-Performance Events leading to a Performance Breach are described in the DR3 Program Rules in Section 5.4. In the event of a Performance Breach, the Availability Payment for the Contract Month following the month in which the Performance Breach occurs shall be withheld.

For further details with respect to breaches in performance, refer to your *OPA* DR3 Contract.

³⁷ Ibid

1.6.16 OPA's Demand Response (DR2) Program³⁸

The *Ontario Power Authority (OPA)* is implementing a contractual load shifting program for participants who are capable of shifting a load of between 5.0 MW and 125.0 MW from the On-Peak Period to the off-peak period. Participants in DR2 will choose to load shift for a four to twelve hour period.

This section sets out how the *IESO* settles the DR2 Program on behalf of the *OPA* and DR2 Program participants. To the extent of any inconsistency between the provisions of the DR2 Program rules and this section, the DR2 Program rules shall govern.

The On-Peak Period refers to the hours between 7:00 am and 7:00 pm EPT³⁹ during business days only. You may select a time period of four to twelve consecutive hours for your "On-Peak Contract Period". Refer to the *OPA's* DR2 Program Rules for full details.

As a DR2 participant, you are paid a monthly Availability Payment for being available for load shifting. In addition to the Availability Payment, you are also entitled to Utilization Payments when your *energy* savings from load shifting are less than the guaranteed *energy* savings threshold set by the *OPA*. The *OPA* will publish, from time to time, the minimum weekly *HOEP* differential rates between each hour on-peak and the average off-peak price.

As a DR2 participant, you are obliged under your contract with the *OPA*, to load shift according to your DR2 Schedule(s). Each DR2 Schedule specifies the quantity of MW that you have contracted to load shift, your on-peak contract period, the term of the schedule (one, three or five years), and the relevant *settlement* account to be used for the purposes of *settlement*. The *settlements* of DR2 Schedules are based on the total contracted MW for all DR2 Schedules at the same *settlement* account and the applicable compensation rates.

Settlement payments are subject to Performance Set-Offs for both Availability and Utilization for failure to comply with DR2 Contract terms including:

- maintaining a Required Reliability Ratio of at least 90% during the shoulder seasons and at least 95% during the summer and winter seasons;
- failing to confirm, or confirming late, as required by us; or
- confirming less than 90% during the shoulder seasons and 95% during the summer and winter seasons of the contacted MW for an hour.

Additionally, DR2 participants will be subject to an Availability Payment Set-Off for:

- any days that they declare a planned non-performance event; or
- failing to deliver *meter* data in a timely manner.

Note: *Generation* is not permitted as a means of contributing towards load shifting under DR2.

³⁸ In this section, "you" refers to a DR2 participant.

³⁹ EPT means Eastern Prevailing Time, being either Eastern Standard Time or Eastern Daylight Savings Time, as in effect from time to time.

1.6.16.1 Settlement of Demand Response Payments

How Availability Payments are Settled

Each month, you will receive an Availability Payment for each Settlement Account based on your Contracted MWs and the Availability Rate as described in the DR2 Program Rules. Should a participant have multiple DR2 Schedules for the same Settlement Account, the Availability Rate applicable is the weighted average of the availability rates for all of the DR2 Schedules and similarly, the Contracted MWs are the sum total of all your contract schedules.

We calculate Availability Payments once a month in the month following the contract month and apply them as a manual line item to the last *trading day* of the month following the contract month. We use *charge type* 1330 “On behalf of OPA for the DR2 Program - Availability Payment Settlement Amount” for Availability Payments to participants.⁴⁰

Where you have multiple DR2 Schedules at a given Settlement Account, these DR2 Schedules are aggregated into one manual line item for *settlement* purposes.

We recover availability payments through *charge type* 1380 “Demand Response 2 Availability Payment Balancing Amount”.

How Utilization Payments are Settled

In addition to your monthly availability payment, you are entitled to receive a Utilization Payment if your weekly *energy* savings are less than the guaranteed minimum amount published by the OPA. The payment is based on your actual load reduction during each On-Peak contract period, and the difference between the Minimum Weekly HOEP Differential Rate and the Actual Weekly HOEP Differential.

Utilization Payments are limited to the lesser of the confirmed MWs or actual load reduction up to the total contracted MWs.

We calculate Utilization Payments once a month in the month following the contract month and apply them as a manual item to the last *trading day* of the month following the contract month. We use *charge type* 1332 “On behalf of OPA for the DR2 Program - Utilization Payment Settlement Amount” for Utilization Payments to participants.⁴¹

We recover utilization payment through *charge type* 1382 “Demand Response 2 Utilization Payment Balancing Amount”.

How We Process Your Meter Data

As part of the DR2 application, participants must submit a Measurement & Verification Plan (M&V Plan) for each Settlement Account. Load shifting is determined by comparing your actual on-peak consumption to your baseline consumption. The calculation of your baseline is described in the OPA DR2 Program Rules.

⁴⁰ Refer to “IESO Charge Types and Equations” and “File Format Specification for Settlement Statement Files and Data Files” located on the Technical Interfaces page of the IESO Web site for details of these *charge types*.

⁴¹ Ibid

All load shifting must be metered using wholesale or retail revenue meters that meet Measurement Canada standards. For DR2 participants that are not *IESO administered market participants*, we will use:

- your retail revenue hourly *meter* data submitted by 15:00 EST on the first *business day* of the following week; and
- revisions to the metering data received by 15:00 EST on the last *business day* of the contract month following the event.

For DR2 *participants* that are *market participants*, we will use your revenue metering data that we've collected as part of our market *settlement* process.

We verify the actual *metering data* against the M&V Plan and our calculations.

Calculating Performance Set-Offs

Shifting load from the On-Peak Contract Period to the Off-Peak Period is a contractual obligation and subject to performance criteria. Performance criteria consist of:

1. **Reliability:** You are required to provide a minimum level of reliability with respect to load shifting of 95% during the summer and winter seasons and 90% during the Shoulder Seasons. This applies to each Settlement Account for both an Actual MW Reliability Ratio for each On-Peak Contract hour and an Actual MWh Reliability Ratio for each On-Peak Contract Period. Any reliability ratios less than the seasonal rates of 95% and 90% are subject to both availability and utilization payment set-offs.
2. **Timely Confirmation:** Confirmation of the contracted MW for each On-Peak contract hour is only required if there is a change in the quantity of MW and/or the duration of the contract period. If a Confirmation is required by us and you fail to notify us or if you notify us after the Confirmation deadline, you are subject to availability and utilization payment set-offs. The severity of the set-off will depend on how late the Confirmation is received.
3. **Low Confirmation:** If your Confirmed MWs are less than 95% of the contracted MW during the summer and winter seasons and 90% of the contracted MW during the shoulder seasons for one or more On-Peak Contract Hours, a Performance Set-Off will be calculated for each applicable On-Peak Contract Hour. This Set-Off will apply even if the actual quantity of MW is equal to or greater than the Contracted MW.
4. **Non-Performance:** A Performance Set-Off will be calculated based on the operating state of the *electricity system* when a DR2 participant takes a Planned Non-Performance event. Unlike items 1 through 3 above, however, Planned Non-Performance set-offs apply only to the availability payment.

If more than one of the set-offs listed above apply to a *settlement* account, only the highest availability set-off amount shall be applied against your availability payment (one of items 1 – 4) and similarly, only the highest utilization set-off (one of items 1 – 3) shall be applied against your utilization payment.

We calculate Performance Set-Offs to be applied once a month at month-end as a manual line item for the last *trading day* of the month. We use *charge type* 1331 “On behalf of OPA for the DR2 Program - Availability Set-Off Settlement Amount” to recover Availability Payments from participants and *charge type* 1333 “On behalf of OPA for the DR2 Program - Utilization Set-Off Settlement Amount” to recover Utilization Payments from participants.⁴²

⁴² Ibid

We use *charge type* 1381 “Demand Response 2 Availability Set-Off Balancing Amount” and *charge type* 1383 “Demand Response 2 Utilization Set-Off Balancing Amount” to balance Performance Set-Off amounts.

Processing Meter Data Set-Offs

In addition to the Performance Set Offs, a Meter Data Set-Off will be applied against the Availability payment for a Settlement Account if you fail to submit the weekly *meter* data for a Settlement Account to us by 15:00 EST on the first *business day* of the following week. The amount of the Set-Off for the first occurrence will be 20% of the Availability Payment pro-rated for the week and will increase in severity thereafter.

We use *charge type* 1334 “On behalf of *OPA* for the DR2 Program - Meter Data Set-Off Settlement Amount” to recover Availability Payments from participants. Meter data not received by the fourth week after the deadline shall be considered a Performance Breach. We use *charge type* 1384 “Demand Response 2 Meter Data Set-Off Balancing Amount” to balance Meter Data Set-Off amounts.

1.6.16.2 Total Monthly Payment

The total amount payable each month, (i.e., the sum of all Availability payments and Utilization payments less any Set-Offs) to each DR2 participant is adjusted by multiplying the monthly total by the Implied Load Shift Ratio. Details for determining the Implied Load Shift Ratio, including the Load Shift Credit, are in Section 7.5 of the DR2 Program Rules.

1.6.16.3 Breach of Contract

Material Non-Performance Events leading to a Performance Breach are described in the DR2 Program Rules in Section 6.7. In the event of a Performance Breach, the Availability Payment for all of the DR2 Schedules at that Settlement Account for the Contract Month following the month in which the Performance Breach occurs shall be withheld.

For further details with respect to breaches in performance, refer to the *OPA* DR2 Program Rules.

1.6.17 Conservation Assessment Recovery

The *IESO* is introducing a “Conservation Assessment Recovery” charge as a result of a recent Ontario government regulation. The regulation allows the *IESO* to recover the amount it is assessed with respect to the expenses incurred and expenditures made by the Ministry of Energy and Infrastructure for its *energy* conservation and renewable *energy* programs. The assessed amount shall be recovered in three payments on the month-end *settlements* for April, May and June 2010 from non-local distribution company (non-LDC) loads.

We are collecting the assessed amount through *charge type* 1415 “Conservation Assessment Recovery”. The amounts charged to each affected *market participant* will be pro-rated based on their total Allocated Quantity of Energy Withdrawn (AQEW) for 2009 and the AQEW of all affected *market participants*.

1.6.18 Ontario Clean Energy Benefit

The Ontario Clean Energy Benefit (OCEB) was established by the Ministry of Energy to provide financial assistance to Ontarians to help them with the increased costs of upgrading and modernizing the *energy* infrastructure. The OCEB provides *consumers* with eligible accounts with a monthly 10% rebate off the applicable portion of their electricity bills as described in the *Ontario Clean Energy Benefit Act, 2010*, and [Ontario Regulation 495/10](#). The rebate applies for a five-year period from January 1, 2011 to December 31, 2015.

Ontario Regulation 495/10 directs the *IESO* to reimburse *market participant distributors* for the 10% financial assistance that is provided to *consumers* that have eligible accounts with them; with any of their wholly-embedded *distributors*; and with any licensed retailers that use retailer-consolidated billing and that conduct business in their service area or the service area of any of their wholly-embedded *distributors*. This regulation also directs the *IESO* to reimburse unit sub-meter providers⁴³ for the 10% financial assistance provided by them on their fees and charges for unit sub-metering that appear on invoices issued by them to *consumers* that are entitled to receive financial assistance.

Market participant distributors and unit sub-meter providers must submit their claims for reimbursement to us monthly no later than the fourth business day after the last *trading day* of the month. The *settlement* amount for *market participant distributors* and unit sub-meter providers will be included on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month under *charge type* 9992 “Ontario Clean Energy Benefit (-10%) Program Settlement Amount”. The corresponding set-off is *charge type* 1465 “Ontario Clean Energy Benefit (-10%) Program Balancing Amount”. *Charge type* 1465 is balanced by the *IESO* through a charge to the Ministry of Energy on their *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

Distributors that are *market participants* must submit OCEB claims to us via the on-line form “Ontario Clean Energy Benefit (-10%) – LDC”. In order to obtain reimbursement from the *IESO*, unit sub-meter providers must be registered in the wholesale electricity market and submit OCEB claims to us using the on-line form “Ontario Clean Energy Benefit (-10%) – Unit Sub-Meter Provider” that is also accessible on the *IESO* portal. A guide to help unit sub-meter providers to prepare their OCEB claims is available at: <http://www.ieso.ca/imoweb/pubs/oceb/OCEB-Unit-Sub-Metering-Guide.pdf>.

1.6.19 Renewable Integration - Forecasting

The *IESO* has established forecasting services as a procured service to accommodate *variable generation* from wind and solar resources. Forecasting services relating to *variable generation* implements one of the key principles of the *IESO*’s ‘Renewable Integration Initiative’ to integrate the influx of renewable generation into the *IESO-administered markets*.

The *settlement* of the forecasting charges follows the *IESO*’s existing *physical market* invoicing process and timelines. Costs paid to the forecasting entities are treated as a procured service charge and recovered through a month-end non-hourly uplift charge to *consumer* loads and exports. *Charge type* 1600 “Forecasting Service Settlement Amount” will appear on the forecasting entity’s *preliminary settlement statement* and *final settlement statement* for the last trading day of the month. The corresponding setoff, *charge type* 1650 “Forecasting Service Balancing Amount”, is included as

⁴³ A unit sub-meter provider is a person licensed by the *OEB* to engage in unit sub-metering, being activities in relation to unit sub-meters in multi-unit complexes. Unit sub-meter means a unit meter that is installed by a unit sub-meter provider in a unit of a multi-unit complex where the multi-unit complex is connected to a bulk meter.

a manual line item on the *settlement statements* of all load and export customers for the last *trading day* of the month .

For more information on the *IESO's* Renewable Integration Initiative, refer to the following link:
http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20110309-Final_Design_Principles.pdf.

1.6.20 Adjustment for Self Induced CMSC Earned by Certain Generating Facilities

If you are the *market participant* for a dispatchable *generating facility*, the *IESO* may recover “self-induced” congestion management *settlement credit* (CMSC) payments from *generators* under three specific scenarios. Self-induced CMSC payments occur as the result of actions taken by the *generator* and/or conditions at, or involving, the *generation facility* and not by conditions on the *IESO-controlled grid*. As such, these CMSC payments are not consistent with the intent of CMSC payments. The three scenarios are:

- A *generation facility* that is eligible for a real-time generation cost guarantee (RT-GCG), disqualifies itself for the guarantee but could receive self-induced CMSC payments as a result;
- A *generation facility* that either:
 - i. is unable to follow *IESO dispatch* instructions, and/or
 - ii. is *constrained on* or *constrained off* by the *IESO*, at the request of the *generator*, for safety, legal, regulatory, environmental or equipment damage reasons; could receive self-induced CMSC payments as a result.
- A *generation facility* (e.g. a steam turbine) fueled by another *generation facility* (e.g. a gas turbine) could receive self-induced CMSC payments as a result of the relationship between the facilities' *offer* prices and constraints applied by the *IESO* to recognize the operational dependencies of the two facilities. More specifically, this occurs when the steam unit *offer* is higher than the *offer* of the unit fuelling the steam unit.

CMSC earned by the *generating facility* in these specific scenarios is considered inappropriate as these payments are not consistent with the original intent of CMSC.

IESO staff will investigate these instances on an on-going basis and will notify you of the applicable CMSC recovery. You will have 5 *business days* to respond to the *IESO's* notification if you disagree. If you do not respond within 5 *business days*, the CMSC included in the *IESO's* notice shall be recovered.

The CMSC recovery is applied as a manual entry to *charge type* 105 “Congestion Management Settlement Credit for Energy” on your *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month. The adjustment is rebated back to *market participants* as a single manual entry to *charge type* 155 “Congestion Management Settlement Uplift” on the *preliminary settlement statement* and *final settlement statement* for the last *trading day* of the month.

1.6.20.1 Calculation of CMSC Payment Recovery for Steam Unit Offers

When the *IESO* identifies a situation involving an inappropriate CMSC payment made to a *market participant* resulting from high steam unit *offers*, the *IESO* may recover that CMSC payment. If the *IESO* intends to recover the CMSC payments made to the steam unit, the *IESO* will prorate each output MW of the steam unit back to the *price-quantity pair* of the contributing combustion turbine unit to calculate the appropriate steam unit *offer*. The *IESO* will then recalculate the appropriate amount of CMSC based on the appropriate steam unit *offer*, and recover the inappropriate CMSC. The method by which the steam unit *offer* is calculated is identified below:

Steam Turbine (ST) is constrained to its operational minimum based on the number of combustion turbines (CTs) synchronized for Real-time Generation Cost Guarantee (RT-GCG)

- If one CT unit is offered/running at *minimum loading point* (MLP)
 - ST is operating at 1X1 MLP, the *offer* price should be no more than the CT MLP *offer* price
- If one CT unit is offered/running at above MLP
 - If the ST is operating above 1X1 MLP because the CT is operating above MLP, the *offer* price should be the CT MLP *offer* up to the ST MLP, then the next lamination of steam MWs should be offered at the next lamination of the CT *offer*.
- If two CT units are offered/running at MLP
 - The lowest cost combustion turbine unit (CT₁) MLP price would be used up to the ST 1X1 MLP, and the next lowest combustion turbine unit (CT₂) MLP price would be used up to the ST 2X1 MLP.
- If two CT units are offered/running at above MLP, causing steam injections above the 2X1 MLP:
 - The lowest cost combustion turbine (CT₁) MLP *offer* would be used up to the ST 1X1 MLP, and the next lowest cost combustion turbine unit (CT₂) MLP price would be used up to the 2X1 MLP.
 - Above the 2X1 MLP, both CTs are considered to contribute equally to the steam injections, therefore above the 2X1 MLP; a weighted average price of the two contributing CTs would be used.

Example

CT₁: gas unit, 100 MW MLP. Offer 100 MW @ \$50, and up to 150 MW @ \$54

CT₂: gas unit, 100 MW MLP. Offer 100 MW @ \$52, and up to 150 MW @ \$56

ST: steam unit, 1X1 MLP 60 MW, 2X1 MLP 100 MW, max 160 MW. Offer \$200 for all injections.

The steam unit is considered to be fuelled by the lowest cost resource running.

- Figure 1 - If one combustion turbine (CT₁) is offered/running at MLP
 - ST is operating at 1X1 MLP (60 MW)
 - offer price should be no more than the CT₁ MLP offer price = \$50

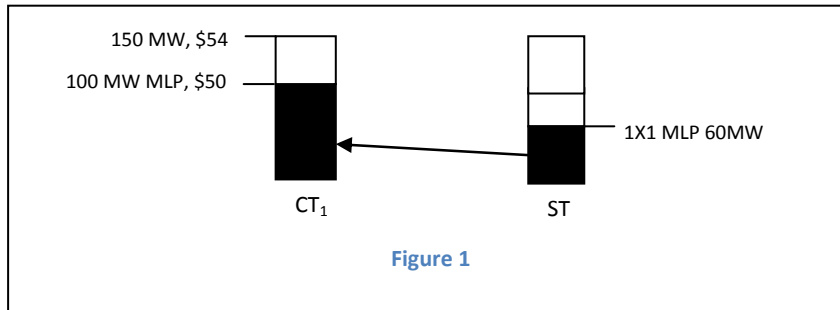


Figure 1

- Figure 2 - If one combustion turbine (CT₁) is offered/running at above MLP
 - ST is operating above 1X1 MLP (say 100 MW for example)
 - Offer price up to 1X1 MLP (60 MW) should be no more than the CT₁ MLP offer price of \$50
 - Offer price for the 40 MW above 1X1 MLP should be the next lamination of CT₁ offer (\$54)
 - Weighted average offer price for ST becomes $[(\$50*60MW)+(\$54*40MW)]/(60MW+40MW)= \$51.60$

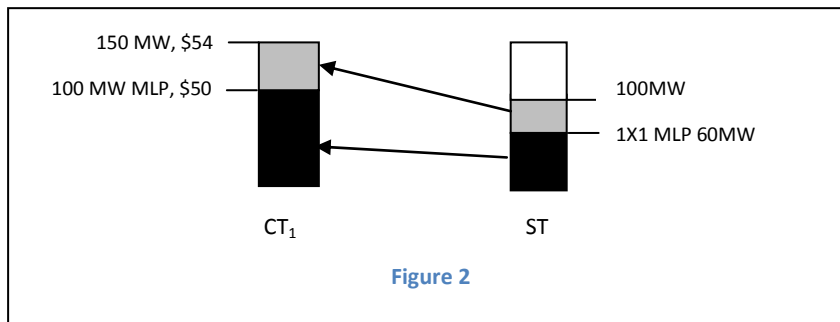


Figure 2

- Figure 3 - If two combustion turbines are offered/running at MLP.
 - Up to 1X1 MLP (60 MW) the ST *offer* price should be \$50 (CT₁)
 - Up to the 2X1 MLP (100 MW) the ST *offer* price should be \$52 (CT₂)
 - Weighted average *offer* price for steam unit becomes

$$[(\$50*60MW)+(\$52*40MW)]/(60MW+40MW)= \$50.80$$

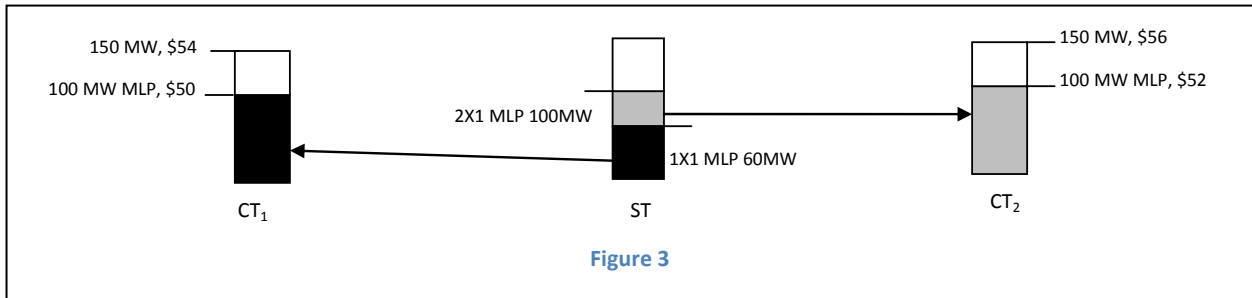


Figure 3

- Figure 4 - If two combustion turbines are offered/running at above MLP, causing steam injections above the 2X1 MLP (CT₁=150MW, CT₂=110 MW, steam injections of 140 MW)
 - Up to the 2X1 MLP of 100 MW, the *offer* price for the steam unit would be \$50.80 as above.
 - Above the 2X1 MLP, both combustion turbines are considered to contribute equally to the steam injections. The weighted average CT₁ and CT₂ price is

$$[(\$54*50MW)+(\$56*10MW)]/(50MW+10MW) = \$54.33$$
 - The weighted average ST *offer* would be $[(\$50.80*100MW)+(\$54.33*40MW)]/140 = \$51.81$

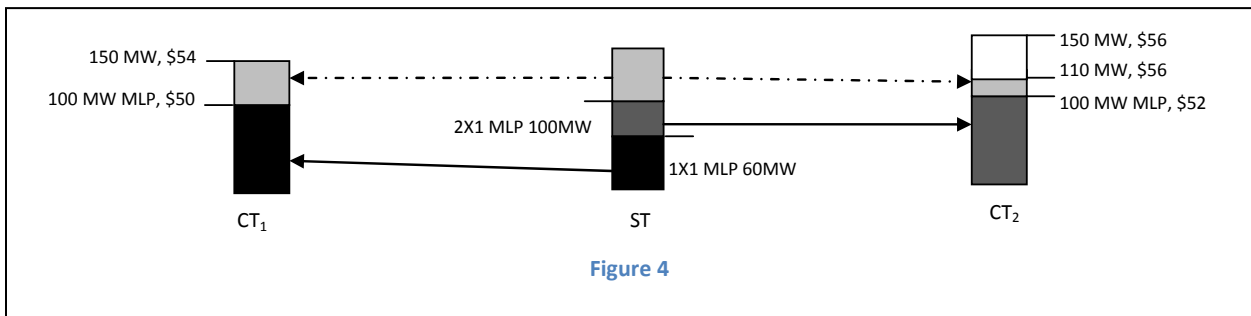


Figure 4

1.7 Roles and Responsibilities

Responsibility for *settlement statements* is shared among:

- *market participants*, who are responsible for:
 - downloading and reviewing *preliminary* and *final settlement statement* files and companion data files;
 - notifying us if a *preliminary* or *final settlement statement* file and the companion data files are not issued following the schedule identified in the *SSPC*;
 - identifying errors in the *preliminary settlement statements* and data files and providing a *notice of disagreement*; and

- downloading and submitting required documentation for special exemptions, rebates and refunds.
- the *IESO*, which is responsible for:
 - processing the special exemptions, rebates and refunds;
 - issuing *preliminary settlement statement* files and companion data files for each *trading day* of the *physical markets*;
 - responding to queries received from the *market participants* pertaining to the *preliminary settlement statement* files and companion data files;
 - investigating and responding to a *notice of disagreement* received from a *market participant*;
 - applying adjustments as required to the *preliminary settlement statement* files and companion data files;
 - issuing *final settlement statements* for each *trading day* of the *physical markets*; and
 - dealing with inquiries related to adjustments as shown in *final settlement statements*.

1.8 Contact Information

As part of the participant authorization and registration process, applicants identify contacts within their organization that address specific areas of market operations. For real-time *energy settlement statements*, this contact will most likely be the *Settlements Statements Market Contact Type* as indicated by Registration in the MPI (MP Contacts screens). If you have not identified a specific contact, we will try to contact the ‘main contact’ identified during the participant authorization process.

We will try to contact these individuals for activities within this procedure, unless alternative arrangements have been set up between us and the *market participant*. For more information on MPI Registration and the participant authorization process, see “Market Entry, Maintenance and Exit, Part1.1-Participant Authorization Maintenance and Exit”.

If you wish to contact us, you can reach our *Customer Relations* department at customer.relations@ieso.ca or via telephone, mail or courier to the numbers and addresses on our web site (www.ieso.ca- or click on 'Have a question?' to go to the 'Contacting the IESO' page). If *Customer Relations* is closed, you can leave telephone messages or emails, which will be answered as soon as possible by Customer Relations staff.

Appendix A lists the forms you need for this procedure – most forms are available on our web site. Please send signed forms and supporting documentation to us by mail or courier, using the address on our web site or on the form. Please identify the subject as: **Physical Markets Settlements Statements**.

– End of Section –

2. Procedural Work Flow

The diagrams in this section represent the flow of work and information related to the *physical markets settlement statement* procedure between the *IESO* and *market participants*.

Table 2–1: Legend for Work Flow Diagrams

Legend	Description
Oval	An event that triggers task or that completes task. Trigger events and completion events are numbered sequentially within procedure (01 to 99)
Task Box	Shows reference number, party responsible for performing task (if “other party”), and task name or brief summary of task. Reference number (e.g., 1A.02) indicates procedure number within current <i>market manual</i> (1), sub-procedure identifier (if applicable) (A), and task number (02)
Solid horizontal line	Shows information flow between the <i>IESO</i> and external parties
Solid vertical line	Shows linkage between tasks
Broken line	Links trigger events and completion events to preceding or succeeding task

2.1 Preliminary Settlement Statements

Each *business day* (10 *business days* after each *trading day* in the *physical markets* in accordance with the *SSPC*), our Commercial Reconciliation System generates the *preliminary settlement statement* for that *trading day*. The steps in the following diagram describe how we issue the *preliminary settlement statement*, and the process for you to review and submit a *notice of disagreement* to us regarding the statement.

Figure 2-1 is described in detail in Section 3.1, Table 3-1.

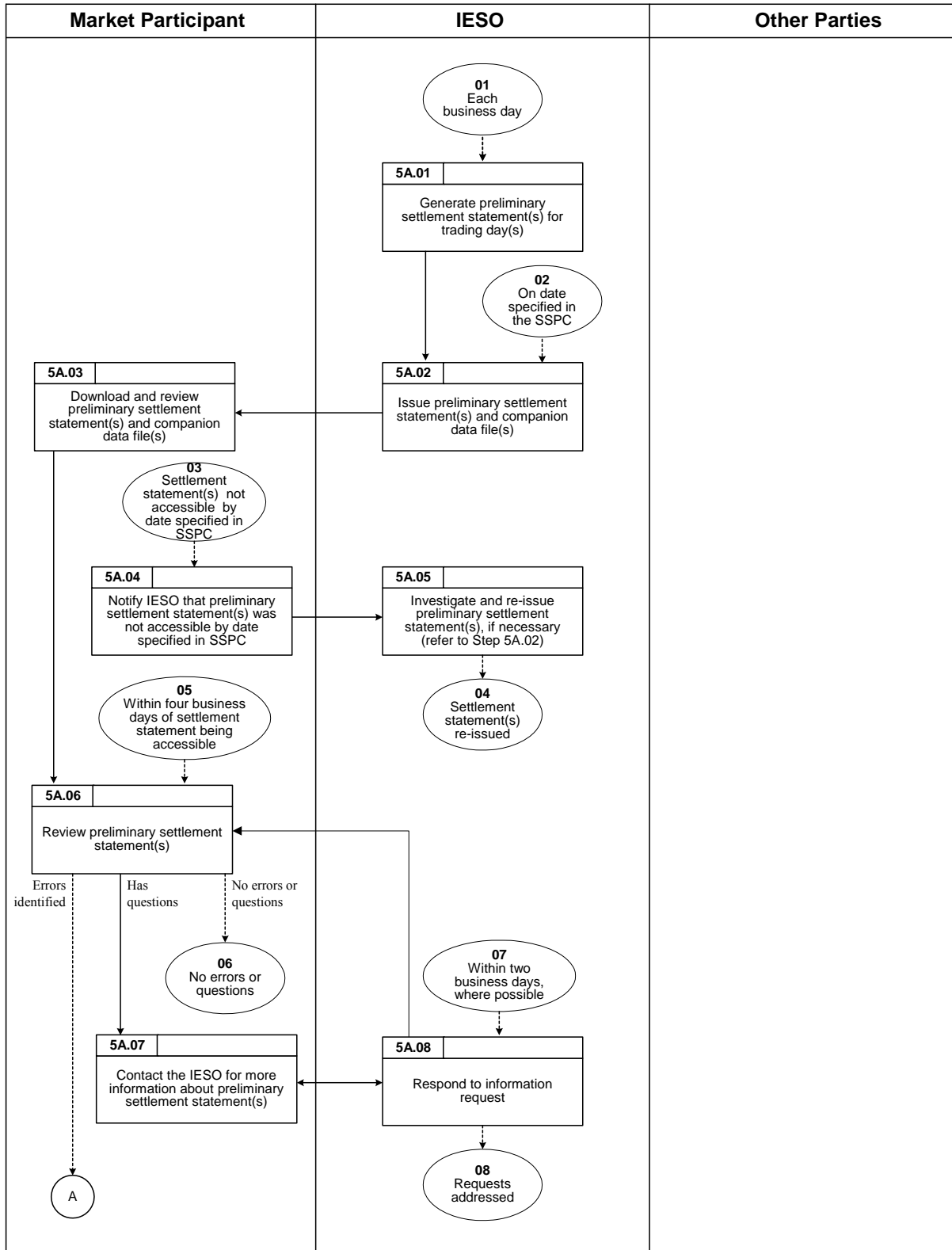


Figure 2–1: Work flow for Preliminary Settlement Statements

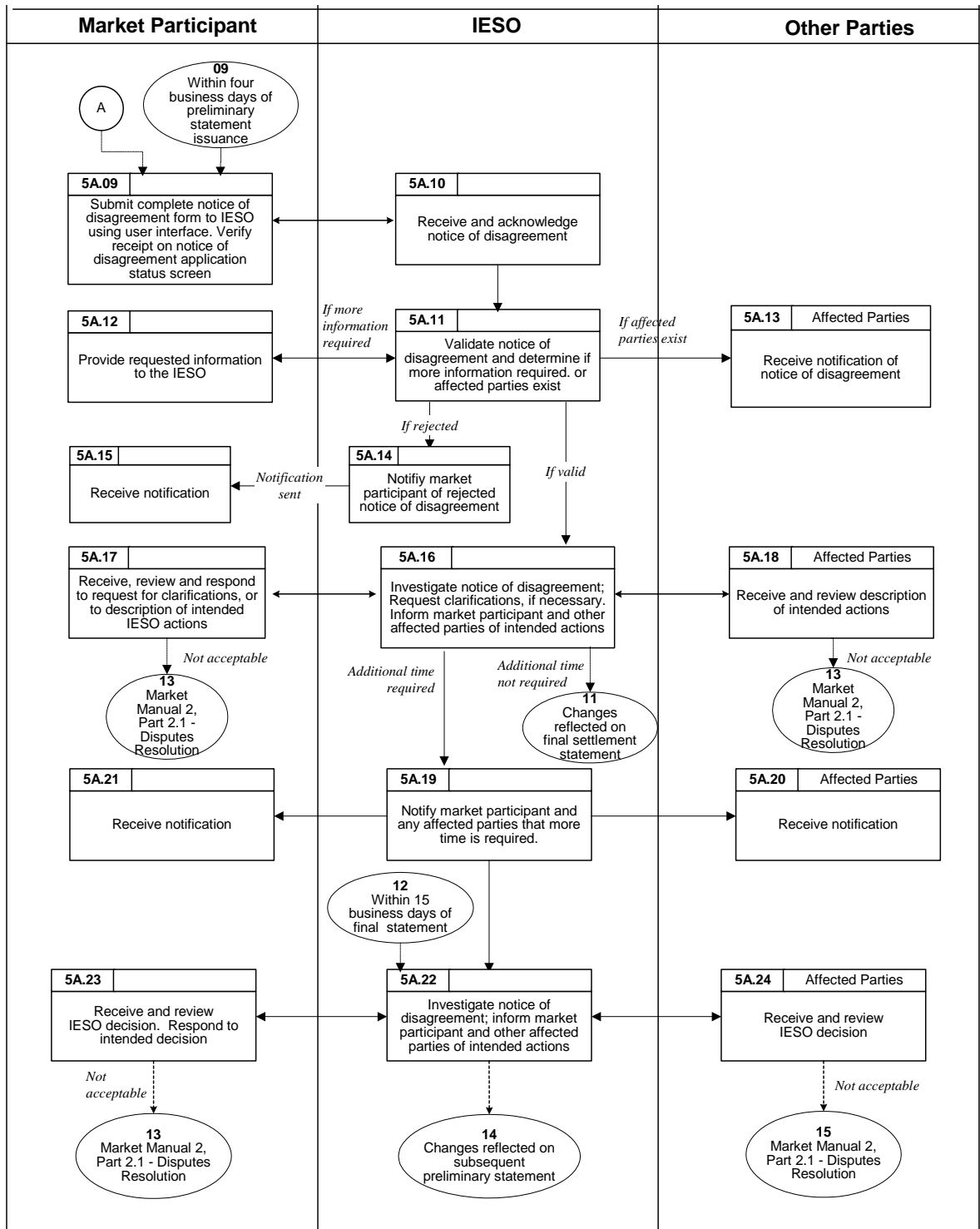


Figure 2-1: Work flow for Preliminary Settlement Statements (continued)

2.2 Retrieving Final Settlement Statements

Each *business day*, in accordance with the *SSPC*, our Commercial Reconciliation System generates a *final settlement statement* for a *trading day* in the *physical markets*. The *final settlement statement* contains all of the *settlement line items* provided in the *preliminary settlement statement* plus any adjustment line items to the *preliminary settlement statement*. The steps in Figure 2-2 illustrate the process involving issuing and receiving the *final settlement statement*, and are described in detail in Section 3.2, Table 3-2.

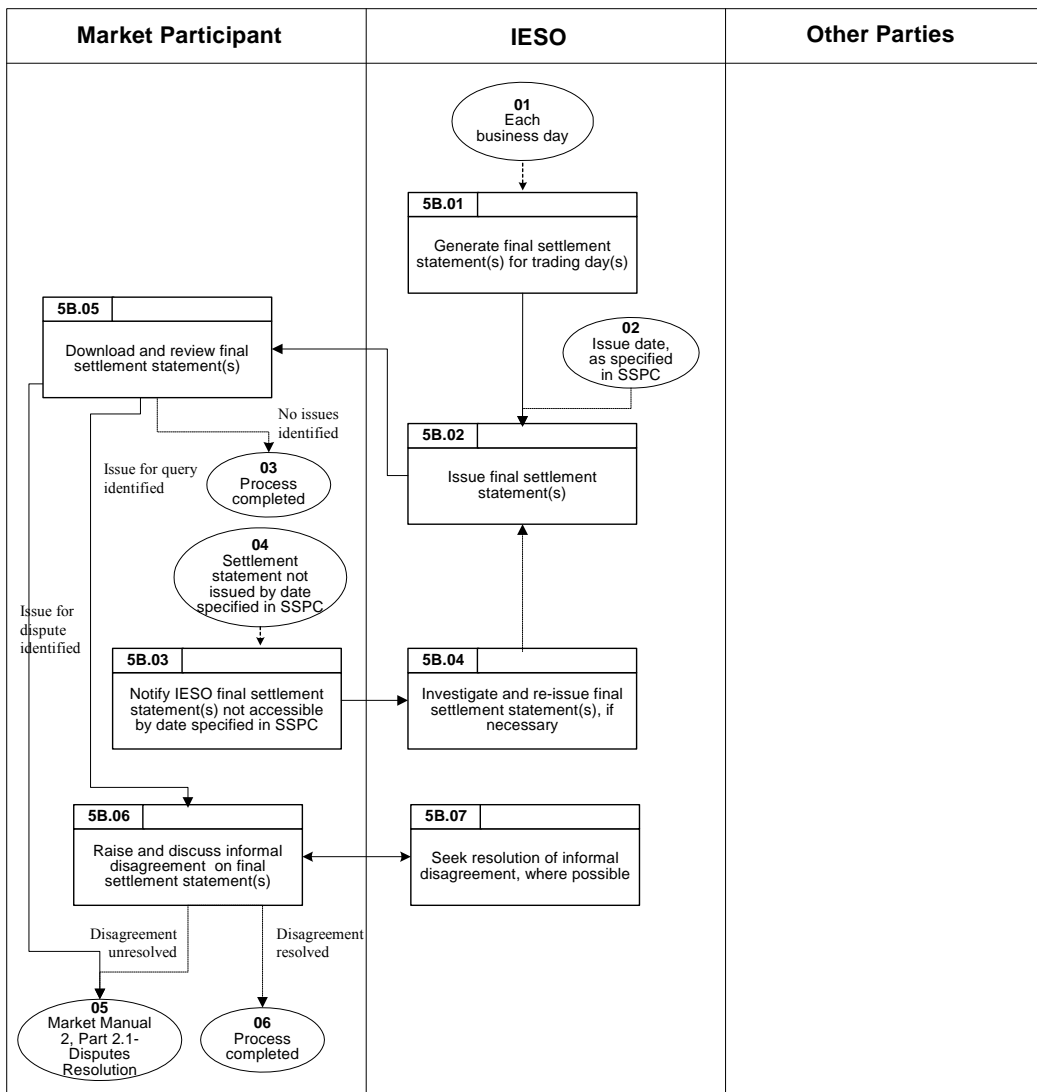


Figure 2–2: Work flow for Retrieving Final Settlement Statements

2.3 Designating Facility for Generation Station Service Rebate

Metered market participants must apply for the designation of *generation facility* as eligible for the *Generation Station Service Rebate*. The steps in Figure 2-3 illustrate the process for designating a *generation facility* as eligible for *Generation Station Service Rebate*, and are described in detail in Section 3.3, Table 3-3.

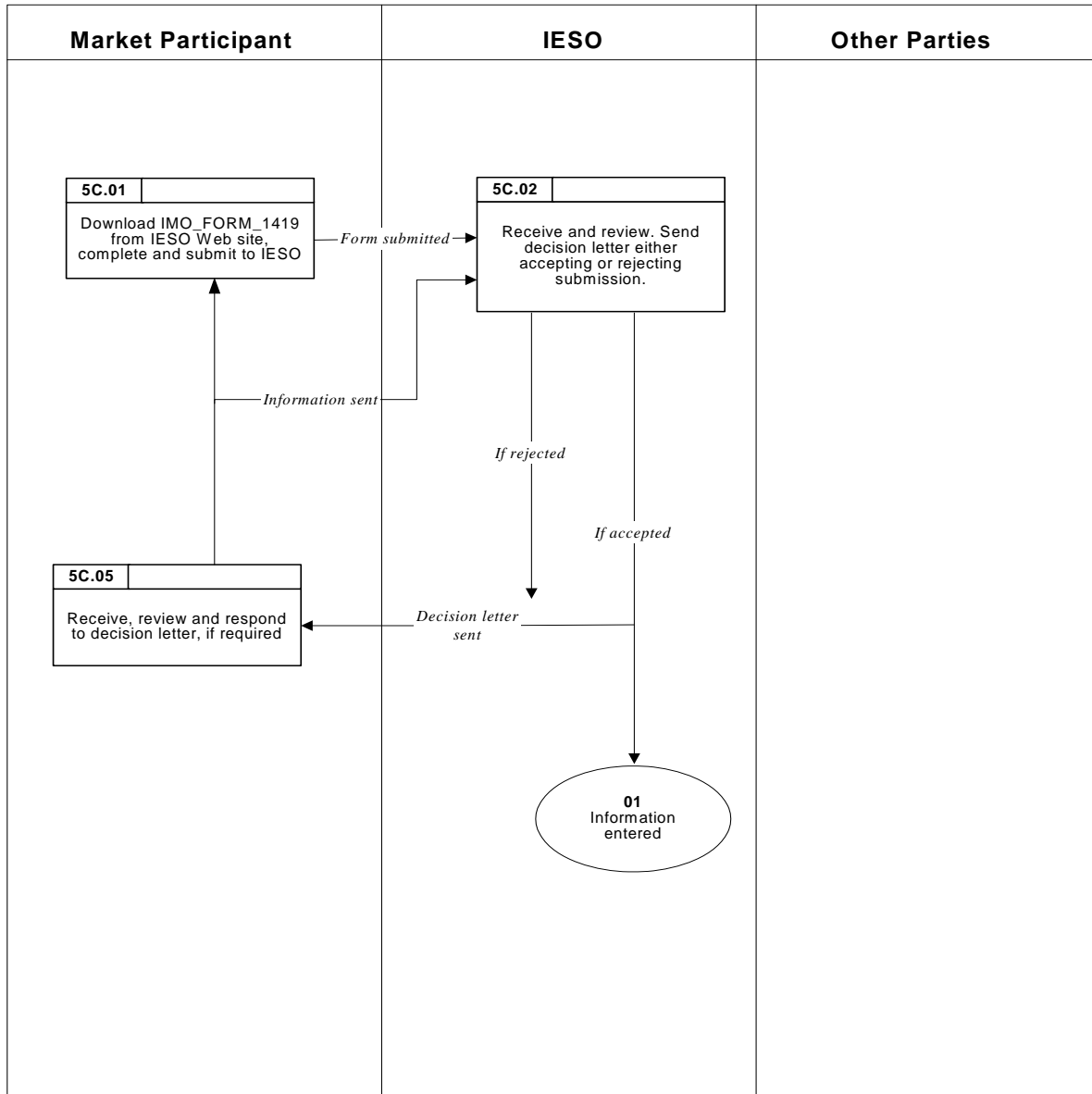


Figure 2–3: Work flow for Designating Facility for Generation Station Service Rebate

2.4 Intentionally Left Blank

Figure 2-4: Intentionally Left Blank

2.5 Submitting DRC Exemption Certificate

If you are exempt from DRC, you must submit exemption certificates to us. The steps in Figure 2-5 illustrate the process for submitting a DRC exemption certificate to us, and are described in detail in Section 3.5, Table 3-5.

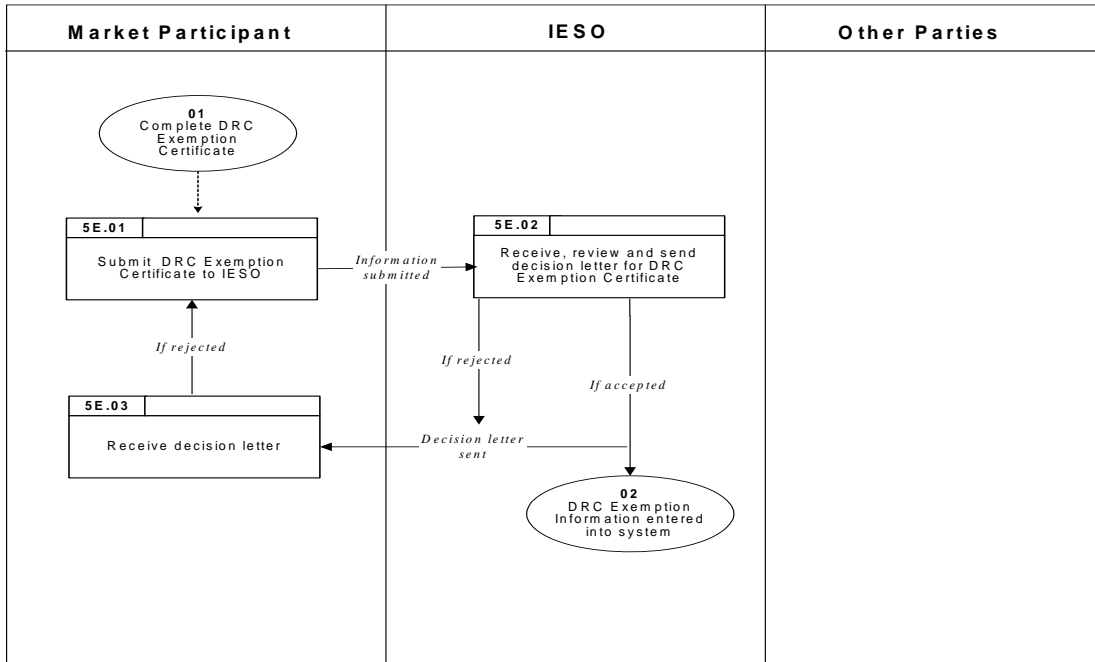


Figure 2–5: Work flow for Submitting DRC Exemption Certificate

2.6 Submitting Reduced DRC Certification

You must submit reduced DRC certification form to us. The steps in Figure 2-6 illustrate the process for submitting reduced DRC certification information to us, and are described in detail in Section 3.6, Table 3-6.

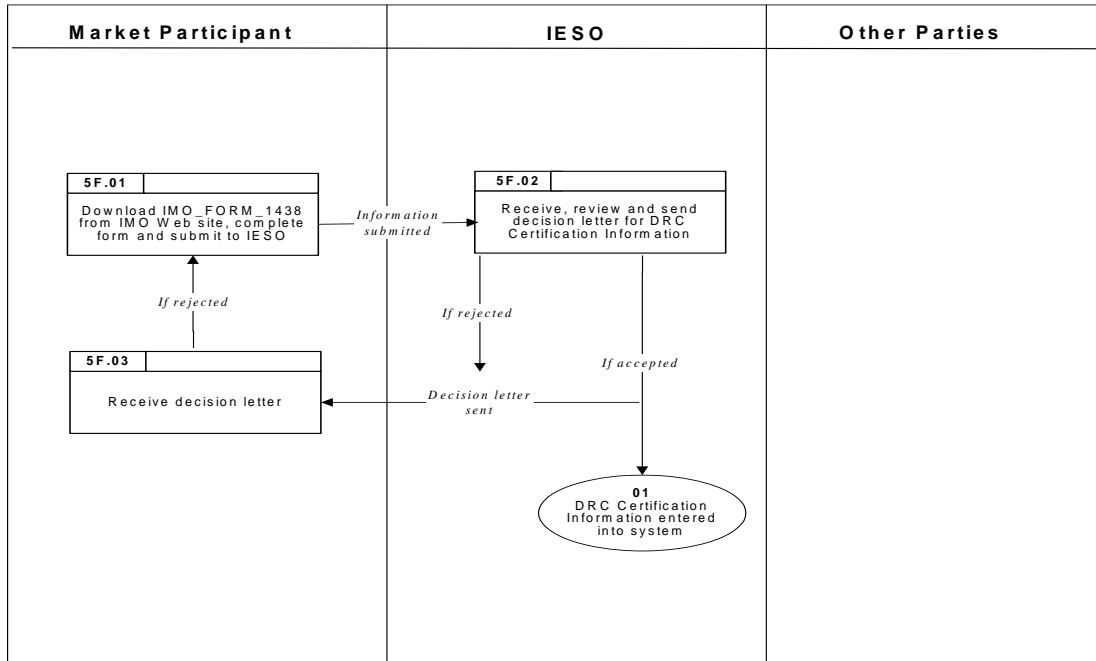


Figure 2–6: Work flow for Submitting Reduced DRC Certification Information

2.7 Submitting Optional Measurement Data Records

You may submit a request for optional measurement data records to be included in the *settlement* data file. The steps in Figure 2-7 illustrate the process for submitting a request for optional measurement data records to us, and are described in detail in Section 3.7, Table 3-7.

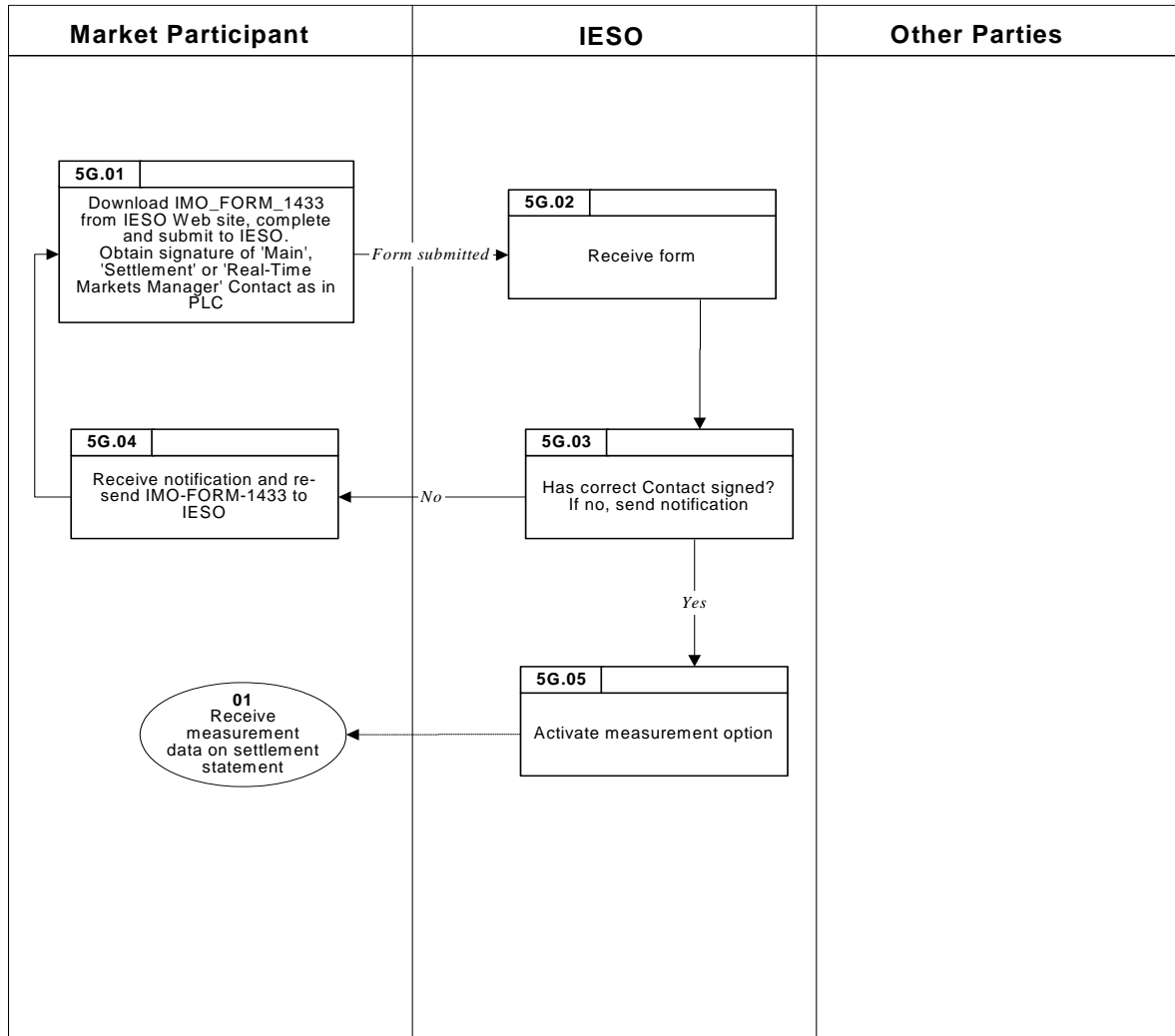


Figure 2–7: Work flow for Submitting Optional Measurement Data Records

2.8 Intentionally Left Blank

Figure 2-8: Intentionally Left Blank

2.9 Declaration of Designated Consumer

If you meet the criteria for a ‘designated consumer’, as defined in “Bill 4 *An Act to amend the Ontario Energy Board Act 1998 with respect to energy pricing*” and regulations, you must make a declaration to us. The steps in Figure 2-9 illustrate the process for notifying us of such an assignment(s) and are described in detail in Section 3.9, Table 3-9.

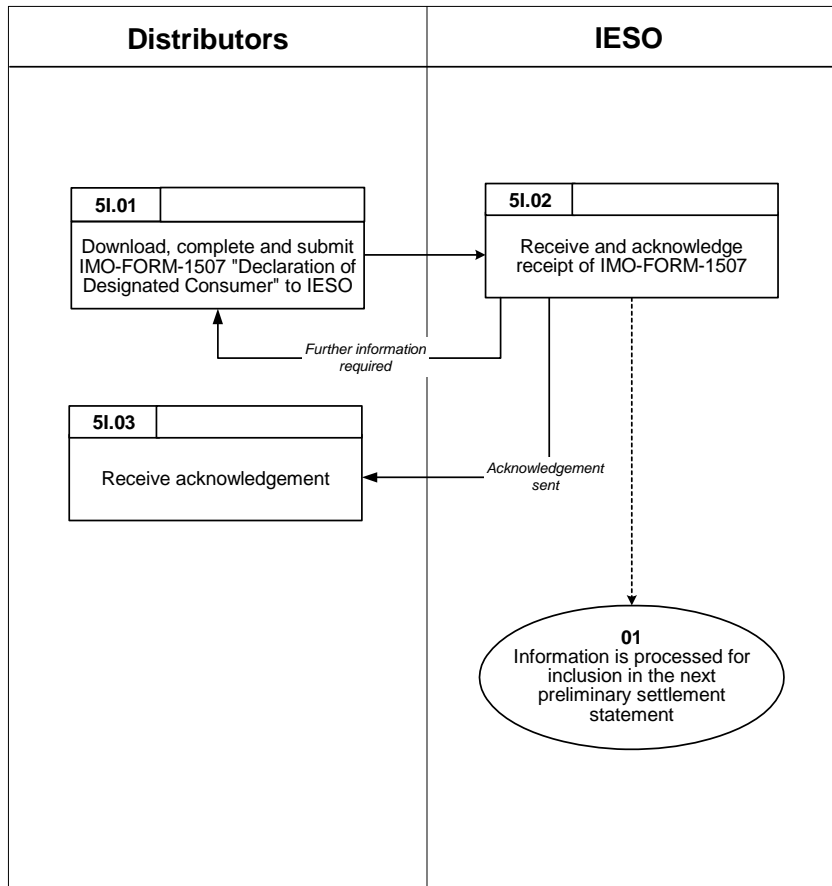


Figure 2–9: Work flow for Declaration of Designated Consumer

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Figure 2–10: Intentionally Left Blank

2.11 Submitting Transmission Service Charges for Embedded Generation

Annually, *transmission customers* must, for each *embedded generation facility* for which a *metering point* has been registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the *market rules*), submit annual adjustment dollar values for the applicable *transmission service charges*. Submit via the *IESO* portal within three months of the calendar year end. If we do not receive this information in a timely manner, we will use the installed *maximum continuous rating* (as registered) for the *embedded generation facilities* to determine an adjustment amount. The steps in Figure 2-11 illustrate the process for notifying us of such an assignment(s) and are described in detail in Section 3.11, Table 3-11.

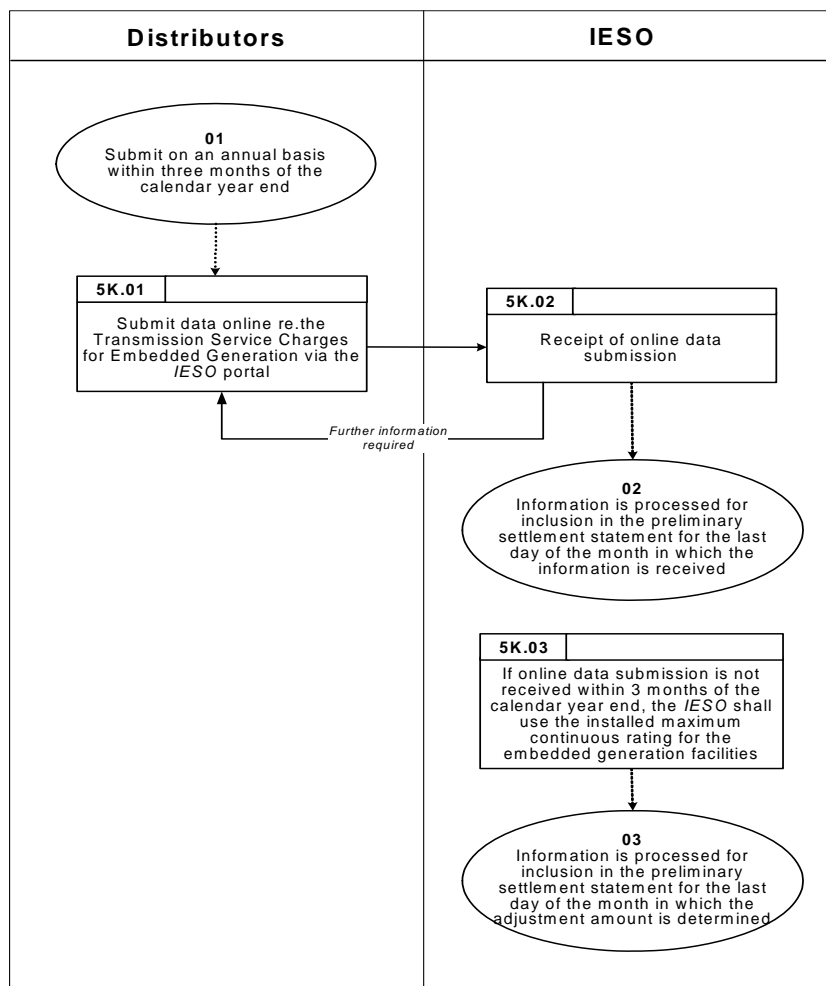


Figure 2–11: Work flow for Submitting of Transmission Service Charges for Embedded Generation

2.12 Workflow for Submitting NUG Adjustment Amount Information

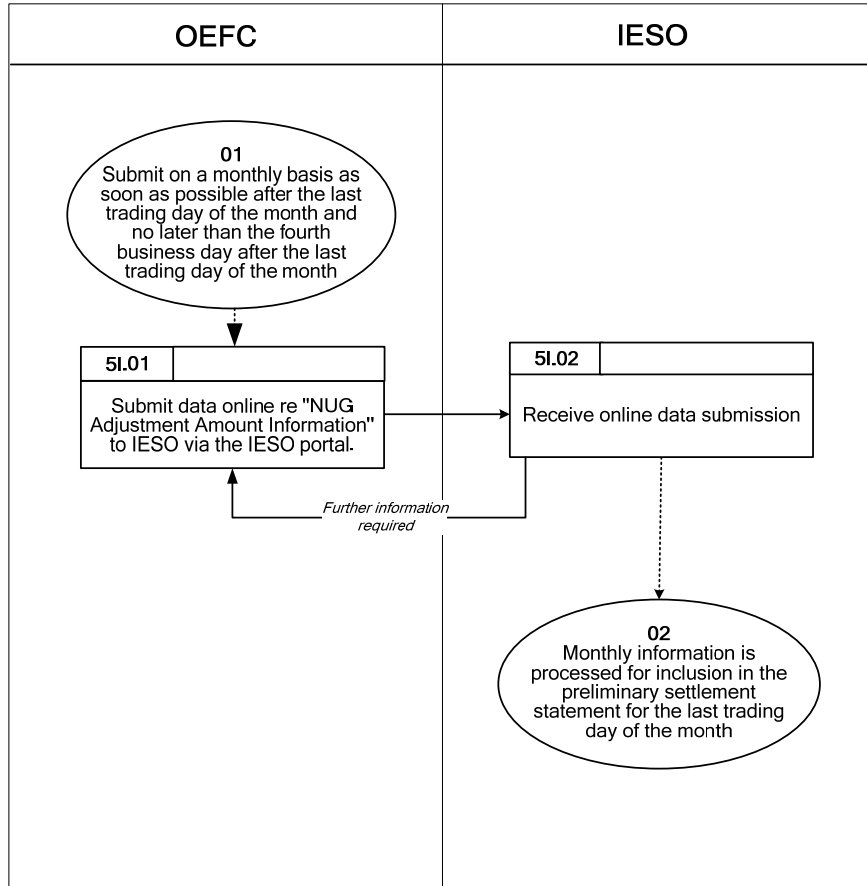


Figure 2–12: Workflow for Submitting NUG Adjustment Amount Information

2.13 Workflow for Submitting Embedded Generation and Regulated Price Information

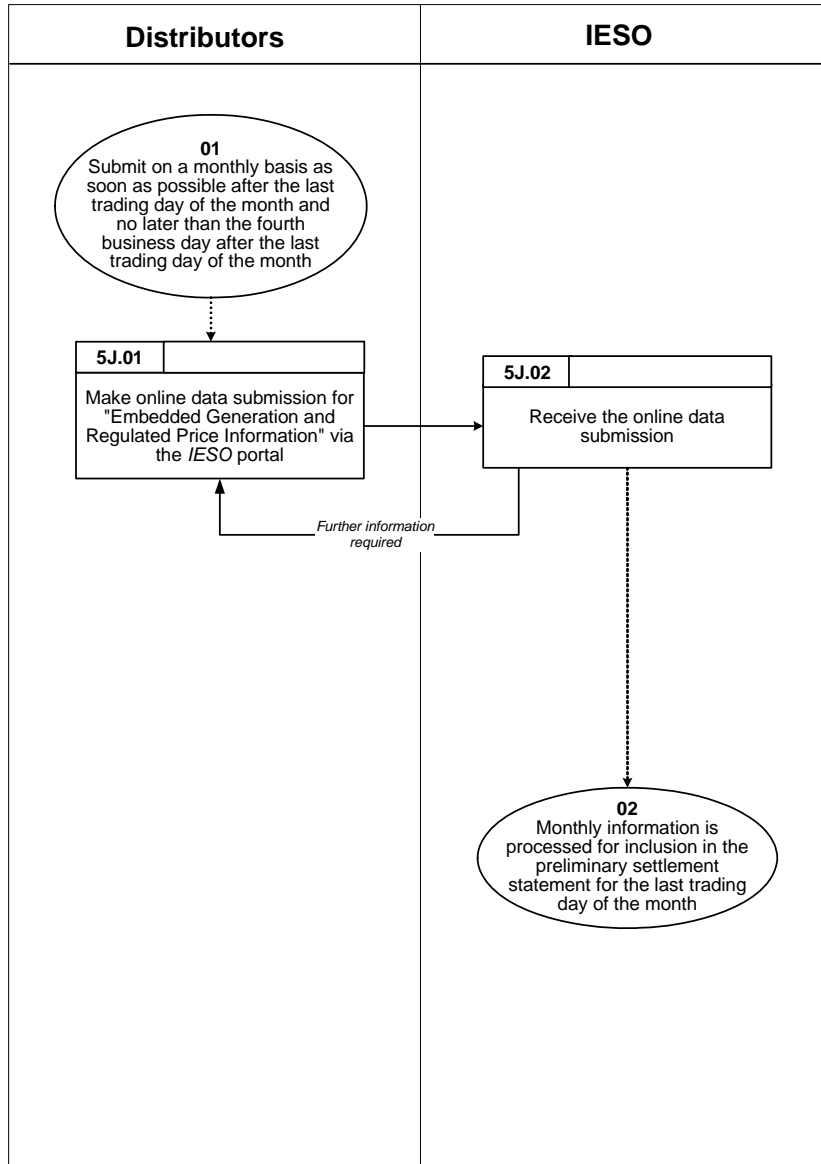


Figure 2–13: Workflow for Submitting Embedded Generation and Regulated Price Information

– End of Section –

3. Procedural Steps

This section contains detail on the tasks (steps) that comprise the *settlement statements* procedure. The steps in the following tables are illustrated in Section 2.

The tables contain seven columns, as follows:

Ref

The numerical reference to the task.

Task Name

The task name as identified in Section 2.

Task Detail

Detail about the task.

When

A list of all the events that can trigger the task to begin.

Resulting Information

A list of the information flows that may or must result from the task.

Method

The format and method for each information flow.

Completion Events

A list of all the circumstances in which the task is considered complete.

3.1 Retrieving Preliminary Settlement Statements

Each *business day*, *market participants* should retrieve the *preliminary settlement statement* and data files and review them to determine whether possible errors exist.

Steps shown in the following table are illustrated in Section 2.1, Figure 2-1.

Table 3–1: Procedural Steps for Retrieving Preliminary Settlement Statements

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.01	Generate <i>preliminary settlement statement(s)</i> for <i>trading day(s)</i> .	We generate the <i>preliminary settlement statement</i> file(s) and companion data files for each <i>trading day</i> for each <i>market participant</i> . <i>Preliminary settlement statements</i> may be issued for more than one <i>trading day</i> on a given <i>business day</i> .	Every <i>business day</i> .	None.	None.	<i>Preliminary settlement statement</i> generated.
5A.02	Issue <i>preliminary settlement statement(s)</i> and companion data files(s).	We issue the <i>preliminary settlement statement</i> file(s) and companion files which have a non-zero <i>settlement amount</i> for that <i>trading day(s)</i> .	By 17:00 EST on the date specified in the <i>SSPC</i> .	<i>Preliminary settlement statement</i> file and companion data files.	Via the <i>IESO Report Site</i> ⁴⁴	<i>Preliminary settlement statement</i> issued.

⁴⁴ Refer to the “Outbound Automated Document Application Programming Interface” if using an application programmable interface (API) to retrieve reports from the IESO Reports site.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.03	Download and review <i>preliminary settlement statement(s)</i> and companion data files.	The <i>market participant</i> downloads the <i>preliminary settlement statement</i> file(s) and companion data files from the IESO Report site and reviews the data.	After Step 5A.02.	None.	None.	<i>Preliminary settlement statement</i> file(s) and companion data files downloaded to the <i>market participant's</i> system.
5A.04	Notify us that <i>preliminary settlement statement(s)</i> was not accessible by date specified in <i>SSPC</i> .	The <i>market participant</i> notifies our <i>Customer Relations</i> that the <i>preliminary settlement statement</i> file(s) and companion data files were not issued, or otherwise accessible, within the established timeframe.	<i>Preliminary settlement statement(s)</i> not issued in established timeframe.	Notification that <i>preliminary settlement statement(s)</i> not issued.	E-mail or telephone.	Notification that <i>preliminary settlement statement(s)</i> not issued received by the <i>IESO</i> .
5A.05	Investigate and re-issue <i>preliminary settlement statement(s)</i> , if necessary (refer to Step 5A.02).	We investigate and re-issue the <i>preliminary settlement statement</i> file(s) and companion data files for a given <i>trading day</i> if the investigation determines that this is necessary.	After Step 5A.04.	<i>Preliminary settlement statement</i> file(s) and companion data files.	<i>IESO</i> Report site ⁴⁵ , e-mail or fax	<i>Preliminary settlement statement(s)</i> issued and verified by the <i>market participant</i> .
5A.06	Review <i>preliminary settlement statement(s)</i> .	The <i>market participant</i> reviews the <i>preliminary settlement statement</i> file(s) and companion data files to identify possible errors.	Following Step 5A.03.	None.	None.	Review of <i>preliminary settlement statement(s)</i> completed by the <i>market participant</i> and any errors or queries identified.

⁴⁵ Ibid.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.07	Contact us for more information about <i>settlement statement(s)</i> .	The <i>market participant</i> submits a query to our <i>Customer Relations</i> requesting additional information pertaining to the <i>preliminary settlement statement</i> file(s) and companion data files.	After Step 5A.06 if the <i>market participant</i> has questions.	Query.	Via the <i>IESO Customer Relations</i> : (905) 403-6900; or customer.relations@ieso.ca	Query regarding <i>settlement statement(s)</i> submitted to us.
5A.08	Respond to information request.	We respond to the query submitted by the <i>market participant</i> .	After Step 5A.07 and within two <i>business days</i> , where possible.	Query response.	E-mail or telephone.	Query response given to <i>market participant</i> .
5A.09	Submit completed <i>notice of disagreement</i> form to us using user interface. Verify receipt on <i>notice of disagreement</i> Application Status screen.	If an error is found in the <i>preliminary settlement statement</i> , the <i>market participant</i> completes and submits the <i>notice of disagreement</i> using our user interface. See Appendix B for examples of the interface. The <i>market participant</i> can verify that we received the <i>notice of disagreement</i> by checking the Application Status screen.	After Step 5A.06 if the <i>market participant</i> has found errors and within four <i>business days</i> of issuing of <i>preliminary settlement statement</i> .	Completed <i>notice of disagreement</i> form.	<i>IESO</i> user interface.	<i>Notice of disagreement</i> submitted to us.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.10	Receive & acknowledge <i>notice of disagreement</i> .	We receive and acknowledge receipt of the <i>notice of disagreement</i> submitted by the <i>market participant</i> .	After Step 5A.09.	Acknowledgement of <i>notice of disagreement</i> . (NOD ID number, date and time of receipt stamp.)	Application Status screen.	We acknowledge receipt of <i>notice of disagreement</i> .
5A.11	Validate <i>notice of disagreement</i> and determine if more information required or affected parties exist.	We validate the <i>notice of disagreement</i> submitted by the <i>market participant</i> and reject the submission if it is not complete or does not address aspects of the <i>settlement statement</i> on which a <i>notice of disagreement</i> can be raised. We may request additional information or clarifications from the <i>market participant</i> during its preliminary review of the <i>notice of disagreement</i> . We also determine if other <i>market participants</i> are potentially affected by the <i>notice of disagreement</i> and if the <i>notice of disagreement</i> issue relates to a <i>physical bilateral contract</i> or <i>physical allocation data</i> notifies them by fax.	After Step 5A.10.	A determination whether: <ul style="list-style-type: none"> the <i>notice of disagreement</i> is valid or invalid; additional information is required; and affected parties exist. 	If additional information is required: E-mail reminder to view letter attached to the <i>notice of disagreement</i> form. If affected parties: letters faxed to affected parties and copy attached to <i>notice of disagreement</i> form.	We send a notification to the <i>market participant</i> if the <i>notice of disagreement</i> is invalid or if further information is required (Step 5A, 12). We send a notification to any affected parties (Step 5A.13).

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.12	Provide requested information to us.	The <i>market participant</i> must provide any requested information of clarifications to us within the timeframe specified in the notification. <i>Market participants</i> who fail to provide the requested information within the required timeframe may invalidate their <i>notice of disagreement</i> .	After Step 5A.11, if additional information or clarifications required.	Requested information or clarifications.	Attach requested information to <i>notice of disagreement</i> form.	<i>Market participant</i> submit requested information or clarifications to us.
5A.13	Receive and review <i>notice of disagreement</i> details.	The affected <i>market participant(s)</i> reviews the notification.	After Step 5A.11, if affected parties exist.	Notification of <i>notice of disagreement</i> .	Fax.	Affected party receives notification from us describing <i>notice of disagreement</i> .
5A.14	Notify <i>market participant</i> of rejected <i>notice of disagreement</i> .	We determine the submission is rejected and notifies the <i>market participant</i> .	After Step 5A.11.	Notification of rejection of <i>notice of disagreement</i> .	<i>Notice of disagreement</i> form. Email reminder to view letter attached to <i>Notice of disagreement</i> form.	<i>Market participant</i> notified of rejected <i>notice of disagreement</i> .
5A.15	Receive notification.	The <i>market participant</i> receives rejection notification.	After Step 5A.14.	Notification of rejection of <i>notice of disagreement</i> .	None.	<i>Market participant</i> received notification of rejected <i>notice of disagreement</i> .
5A.16	Investigate <i>notice of disagreement</i> . Request clarifications, if necessary. Inform <i>market participant</i> and other affected	We request clarification from the <i>market participant</i> , if required, as part of our investigation. The <i>market participant</i> must provide any requested information or	After Step 5A.11.	<ul style="list-style-type: none"> We request clarifications, if required. We issue decision on <i>notice of disagreement</i>. 	If additional information or additional time is required: E-mail reminder to view letter attached to the <i>notice of disagreement</i> form. If affected parties: letters	Our notification of decision for <i>notice of disagreement</i> . Adjustments, if any, on <i>final settlement statement</i> .

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
	parties of intended actions.	<p>clarifications to us within the timeframe specified in the notification. <i>Market participants</i> who fail to provide the requested information within the required timeframe may invalidate their <i>notice of disagreement</i>.</p> <p>We use the information provided in the <i>notice of disagreement</i>, and any other available information, to investigate the subject matter of the disagreement and inform the <i>market participant</i> of its intended actions in response to the <i>notice of disagreement</i>. We also notify any affected parties of its intended actions.</p> <p>We may also request additional time to investigate the <i>Notice of Disagreement</i>.</p>		<ul style="list-style-type: none"> Adjustments, if any, for disputed <i>trading day</i>. Where applicable, a determination that additional time is required to investigate the <i>notice of disagreement</i>. 	<p>faxed to affected parties and copy attached to <i>notice of disagreement</i> form.</p> <p>Adjustments, if any, resulting from our investigation of the <i>Notice of Disagreement</i>, and <i>Market Participant</i> feedback (5A.17 and 5A.18), appear on the <i>final settlement statement</i> for the disputed <i>trading day</i> disagreement.</p>	<p>Where additional time is required to process the <i>notice of disagreement</i>, a notification to the <i>market participant</i> and any affected parties (5A.19).</p>
5A.17	Receive, review, and respond to, description of intended actions. Respond to intended decision.	The <i>market participant</i> receives a description of our intended actions, and has an opportunity to respond to the decision.	Simultaneous with Step 5A.16.	Response.	E-mail reminder to view letter attached to the <i>notice of disagreement</i> form. Response via <i>notice of disagreement</i> form.	Intended actions accepted, provide comments to us if disagree, or disagreement pursued through Dispute Resolution process.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.18	Receive and review description of intended actions.	Affected parties receive a description of our intended actions and have an opportunity to respond to our decision.	Simultaneous with Step 5A.16.	None.	Fax. Response via fax, phone or email.	Intended actions accepted, provide comments to us if disagree, or disagreement pursued through Dispute Resolution process.
5A.19	Notify <i>market participant</i> and any affected parties that more time is required.	If additional time is required to investigate the <i>notice of disagreement</i> , then we notify the <i>market participant</i> and any affected parties that more time is required.	Following Step 5A.18.		E-mail reminder to view letter attached to the <i>notice of disagreement</i> form. Fax to affected parties.	We send notification that additional time is required to <i>market participant</i> and any affected parties.
5A.20	Receive notification.	Other affected parties receive notification that more time is required.	Following Step 5A.19.	None.	Fax.	Receipt of notification that additional time is required.
5A.21	Receive notification.	<i>Market participant</i> receives notification that more time is required.	Following Step 5A.19.	None.	E-mail reminder to view letter attached to the <i>notice of disagreement</i> form.	Receipt of notification that additional time is required.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.22	Investigate <i>notice of disagreement</i> ; inform <i>market participant</i> and other affected parties of intended actions.	<p>We use the information provided in the <i>notice of disagreement</i>, and any other available information, to investigate the subject matter of the disagreement and inform the <i>market participant</i> of its intended actions in response to the <i>notice of disagreement</i>.</p> <p>We also notify any affected parties of its intended actions. Adjustments, if any, resulting from our investigation of the <i>notice of disagreement</i>, and <i>market participant</i> feedback (5A.23 and 5A.24), appear on the next available <i>preliminary settlement statement</i>.</p>	After Step 5A.19. When we require additional time, it must communicate its decision within 15 <i>business days</i> of the <i>final settlement statement</i> for the disputed <i>trading day</i> .	<p>IESO decision on <i>notice of disagreement</i>.</p> <p>Adjustments, if any, for disputed <i>trading day</i>.</p>	<p>E-mail reminder to view letter attached to the <i>notice of disagreement</i> form.</p> <p>Fax to affected parties.</p>	<p>Our notification of decision for <i>notice of disagreement</i>.</p> <p>Adjustments, if any, on next available <i>preliminary settlement statement</i>.</p>
5A.23	Receive and review our decision. Respond to intended decision.	The <i>market participant</i> receives a description of our intended actions, and has an opportunity to respond to our decision.	Simultaneous with Step 5A.22.	Response.	Response via the <i>notice of disagreement</i> form.	Intended actions accepted, response provided to us, if disagreement, or disagreement pursued through Dispute Resolution process.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5A.24	Receive and review decision.	Affected parties receive a description of our intended actions and have an opportunity to respond to our decision.	Simultaneous with Step 5A.22.	None.	Fax. Response via fax, phone or email.	Intended actions accepted, response provided to us, if disagreement, or disagreement pursued through Dispute Resolution process.

3.2 Final Settlement Statements

Market participants should retrieve the *final settlement statement*. The steps shown in the following table are illustrated in Section 2.1, Figure 2-2.

Table 3–2: Procedural Steps for Retrieving Final Settlement Statements

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5B.01	Generate <i>final settlement statement(s)</i> for <i>trading day(s)</i> .	We generate a <i>final settlement statement(s)</i> , incorporating any final adjustments. <i>Final settlement statements</i> may be issued for more than one <i>trading day</i> on a given <i>business day</i> .	Each <i>business day</i> .	None.	None.	<i>Final settlement statement(s)</i> issued.
5B.02	Issue <i>final settlement statement(s)</i> .	We issue the <i>final settlement statement(s)</i> for a given <i>trading day(s)</i> for each <i>market participant</i> who has a non-zero <i>settlement amount</i> for that <i>trading day(s)</i> .	By 17:00 EST on the date specified in the <i>SSPC</i> .	<i>Final settlement statements</i> file(s) and companion data files.	IESO Report site ⁴⁶	<i>Final settlement statement(s)</i> issued.
5B.03	Notify us <i>final settlement statement(s)</i> not accessible by date specified in <i>SSPC</i> .	The <i>market participant</i> notifies us that the <i>final settlement statement(s)</i> was not issued or otherwise accessible in the established timeframe.	After Step 5B.02 if <i>final settlement statement(s)</i> not issued by date specified in <i>SSPC</i> .	Notification that <i>final settlement statement(s)</i> not issued.	E-mail or telephone.	Notification that <i>final settlement statement(s)</i> not issued submitted to the <i>IESO</i> .

⁴⁶ Ibid.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5B.04	Investigate and re-issue <i>final settlement statement(s)</i> , if necessary.	We investigate and re-issue the <i>final settlement statement(s)</i> for a given <i>trading day</i> , if the investigation determines that this is necessary.	After Step 5B.03.	<i>Final settlement statements</i> file(s) and companion data file.	IESO Report site ⁴⁷ .	<i>Final settlement statement(s)</i> re-issued by the IESO.
5B.05	Download and review <i>final settlement statement(s)</i> .	The <i>market participant</i> downloads the <i>final settlement statement(s)</i> from the IESO Report Site and reviews the statement for issues. Where an issue is identified that: <ul style="list-style-type: none"> • consists of an adjustment to the corresponding <i>preliminary settlement statement</i> resulting from a <i>notice of disagreement</i> and that does not reflect the agreement between us and the <i>market participant</i> as to the adjustment; or differs in amount from the same item or calculation set forth on the corresponding <i>preliminary settlement statement</i> and is not an item or calculation identified on the <i>final settlement statement</i> as being associated with an adjustment flag (indicating that an 	After Step 5B.05.	None.	None.	<i>Final settlement statement(s)</i> downloaded. See “Market Manual 2: Market Administration, Part 2.1 Dispute Resolution” for details of the dispute resolution process.

⁴⁷ Ibid.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
		<ul style="list-style-type: none"> • adjustment has been made), the <i>market participant</i> may raise an inquiry with us. <p>Alternatively, where an issue is not resolved, the <i>market participant</i> may raise a dispute, within 20 <i>business days</i> of the issue date of the <i>final settlement statement</i>.</p>				
5B.06	Raise and discuss informal disagreement on <i>final settlement statement(s)</i> .	<p>The <i>market participant</i> raises an informal disagreement on the <i>final settlement statement(s)</i> (as outlined in Step 5B.05) with us and discusses this with us.</p> <p>If the issue is resolved, no further action is taken by the <i>market participant</i>.</p> <p>If the issue is not resolved, the <i>market participant</i> may decide to pursue the issue through the dispute resolution process, within 20 <i>business days</i> of the issue date of the <i>final settlement statement</i>.</p>	Following Step 5B.05, when a disagreement is identified.	Informal Disagreement, if required.	Telephone, e-mail, fax.	Issue resolved or submitted for dispute resolution. See “Market Manual 2: Market Administration, Part 2.1 Dispute Resolution” for details of the dispute resolution process.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5B.07	Seek resolution of informal disagreement, where possible.	We seek a resolution of the informal disagreement raised by the <i>market participant</i> .	Following Step 5B.06.	Discussion with <i>market participant</i> .	Telephone, e-mail, fax.	Issue resolved or submitted for dispute resolution. See "Market Manual 2: Dispute Resolution" for details of the dispute resolution process.

3.3 Designating Facility for Generation Station Service Rebate

Metered market participants should retrieve IMO-FORM-1419 “Application for Designation of a Facility for Generation Station Service Rebate” in order to apply for a rebate. The steps shown in the following table are illustrated in Section 2.3, Figure 2-3.

Table 3–3: Procedural Steps for Designation of Facility for Generation Station Service Rebate

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5C.01	Download IMO-FORM-1419 from our web site, complete and submit to us.	<i>Metered market participant</i> downloads “Application for Designation of a Facility for Generation Station Service Rebate” (IMO-FORM-1419) from our web site. The <i>metered market participant</i> completes the form and submits it to us.	When the <i>metered market participant</i> believes a <i>generation facility</i> is eligible for rebate of <i>generation station service</i> .	<i>Metered market participant</i> has applied for designation of a <i>facility</i> as eligible for <i>generation station service</i> rebate.	Fax, mail or courier.	Form submitted.
5C.02	Receive and review. Send decision letter either accepting or rejecting submission.	We receive, review and send a letter to the <i>metered market participant</i> indicating whether the submission is complete or information is required (acceptance or rejection).	After Step 5C.01.	Application for designation of a <i>facility</i> .	Fax.	Form received and reviewed. A decision letter is sent to the <i>metered market participant</i> either accepting or rejecting the submission.
5C.03	Receive, review and respond to decision letter, if required.	<i>Metered market participant</i> receives and reviews our decision. If more information is required, the <i>metered market participant</i> resubmits the application.	After receiving the decision letter.	None.	Fax, if required.	<i>Metered market participant</i> received letter accepting or rejecting designation for <i>generation station service</i> rebate.

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Table 3-4: Intentionally Left Blank

3.5 Submitting DRC Exemption Certificate

Market participants must register with the Ministry of Finance as indicated in “Regulation 493/01 and 494/01” and submit DRC exemption information to us in order to be exempt from the *debt retirement charge*.

The steps shown in the following table are illustrated in Section 2.5, Figure 2-5.

Table 3–5: Procedural Steps for Submission of DRC Exemption Certificate

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5E.01	Submit DRC Exemption Certificate to us.	<i>Market participant</i> submits hard copy of DRC exemption certificate as indicated in the Ministry of Finance procedure.	When DRC exemption certificate is complete.	Exemption certificate.	Mail or courier.	DRC exemption certificate submitted to us.
5E.02	Receive, review and send decision letter for DRC Exemption Certificate.	We receive DRC exemption certificate, review it for completeness and send a decision letter either accepting the certificate or rejecting it.	Upon receipt.	Decision letter “IESO Decision Letter – Settlements” (IESO-FORM-1460).	Fax.	DRC exemption certificate received, reviewed and decision letter sent to <i>market participant</i> .
5E.03	Receive decision letter.	<i>Market participant</i> receives decision letter from us. If the information was incomplete, the <i>market participant</i> revises the information and resubmits it to us.	After Step 5E.02.	None.	Fax.	Decision letter received by <i>market participant</i> .

3.6 Submitting Reduced DRC Certification Information

Market participants must complete the reduced DRC certification to be charged the reduced DRC rate as indicated by the Ministry of Finance “Regulation 493/01”.

The steps shown in the following table are illustrated in Section 2.6, Figure 2-6.

Table 3–6: Procedural Steps for Submission of Reduced DRC Certification Information

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5F.01	Download IMO-FORM-1438 from our web site, complete form and submit to us.	<i>Market participant</i> downloads the Reduced DRC Certification form, completes it and submits it to us.	Prior to <i>trading day</i> the DRC reduced rate should apply.	Reduced DRC Certification.	Mail or courier.	Reduced DRC Certification submitted.
5F.02	Receive, review and send decision letter for DRC Certification Information.	We receive the “Reduced Debt Retirement Charge (DRC) Certification” (IMO-FORM-1438), review it for completeness and send a decision letter either accepting or rejecting the information.	Upon receipt.	Decision letter Form 1460.	Fax.	Decision letter sent to <i>market participant</i> .
5F.03	Receive decision letter.	<i>Market participant</i> receives decision letter. If the information was incomplete, the <i>market participant</i> revises the information and resubmits it to us.	After Step 5F.02.	None.	Fax.	Decision letter received by <i>market participant</i> .

3.7 Submitting Request for Optional Measurement Data Records

Market participants may request optional measurement data records to be included in the *settlement* data file.

The steps shown in the following table are illustrated in Section 2.7, Figure 2-7.

Table 3-7: Procedural Steps for Submission of Optional Measurement Data Records

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5G.01	Download IMO-FORM-1433 from our web site, complete and submit to us. Obtain signature of 'Main', 'Settlement' or 'Real-Time Markets Manager' Contact as in PLC.	<i>Market participant</i> downloads the form, completes it and submits it to us. The <i>market participant</i> ensures it is signed by one of 'Main', 'Settlement' or 'Real-Time Markets Manager' contacts.	When <i>market participant</i> determines that optional measurement data records are needed.	<i>Market participant</i> has requested optional measurement data records.	Fax, mail or courier.	Request for optional measurement data records submitted.
5G.02	Receive form.	We receive completed form for request for optional measurement data records.	After 5G.01.			Form received.
5G.03	Has correct Contact signed? If no, send notification.	We verify that form is complete and verify the signing contact is correct as in PLC. If not, we inform the <i>market participant</i> .	After 5G.02.	Completed request for optional measurement data records.	If required, email.	Completed request for optional measurement data records.
5G.04	Receive notification and re-send IMO-FORM-1433.	<i>Market participant</i> receives notification that the incorrect contact has signed the form. The form is corrected and re-sent as in 5G.01.	After 5G.04.	Completed request for optional measurement data records.	Fax, mail or courier.	<i>Market participant</i> is aware of incorrect contact and has submitted a correct form.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5G.05	Activate measurement option.	We will include optional measurement data records with <i>settlement</i> data files.	After successful 5G.03.	Optional measurement data records included in <i>settlement</i> data files.		<i>Market participant</i> receives optional measurement data records.

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Table 3–8: Intentionally Left Blank

3.9 Declaration of Designated Consumers

Market participants meeting the ‘designated consumer’ criteria (as defined in “Bill 4 An Act to amend the Ontario Energy Board Act, 1998 with respect to energy pricing” and the regulations) may inform us of this.

The steps shown in the following table are illustrated in Section 2.9, Figure 2-9.

Table 3–9: Procedural Steps for Declaration of Designated Consumers

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5I.01	Download, complete and submit IMO-FORM-1507 “Declaration of Designated Consumer” to us.	<i>Market participants</i> download IMO-FORM-1507 from our web site, complete the Form and submit it to us. The sender ensures the proper signatures are included.	As a <i>market participant</i> becomes eligible.	Declaration of designated consumer is made.	Email, followed by Fax with signature of signing authority.	Declaration information is sent to us.
5I.02	Receive and acknowledge receipt of IMO-FORM-1507.	We receive and send an acknowledgement of receipt of the IMO-FORM-1507 from eligible <i>market participants</i> . In the event further information is required, the <i>market participant</i> is requested to re-submit the form.	Upon receipt of information.	Acknowledgement.	Email.	Information received by us and acknowledgement sent to <i>market participant</i> .
5I.03	Receive acknowledgement.	<i>Market participants</i> receive acknowledgement of our receipt of IMO-FORM-1507.	After step 5I.02.	None.	Email.	Acknowledgement received.

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Table 3–10: Intentionally Left Blank

3.11 Submitting Transmission Service Charges for Embedded Generation

For each *embedded generation facility* for which a *metering point* has been registered under the Alternative Metering Installation Standards for Embedded Generation Facilities (Chapter 6, Section 4.5 of the *market rules*) *transmission customers* will submit adjustment dollar values for the applicable *transmission service charges*. *Settlement* data must be submitted online via the *IESO* portal within three months of the calendar year end. In the event that the *IESO* does not receive this information in a timely manner, we will use the installed *maximum continuous rating* (as registered) for the *embedded generation facilities* to determine an adjustment amount.

Steps shown in the following table are illustrated in Section 2.11, Figure 2-11.

Table 3–11: Procedural Steps for Submission of Transmission Service Charges for Embedded Generation

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5K.01	Submit Transmission Service Charges for Embedded Generation online via the <i>IESO</i> portal.	<i>Transmission Customers</i> submit information online via the Settlements community of the <i>IESO</i> portal. Line and Transformation Connection Service Charges need to be calculated for all <i>delivery points</i> with <i>embedded generation facilities</i> registered under the Alternative Metering Installation Standards for Embedded Generation Facilities. The sender ensures adjustment amounts are agreed to by the <i>transmitter</i> .	Annually, as soon as possible after the last day of the calendar year and no later than three months after calendar year end.	Annual adjustment dollar values for the applicable <i>transmission service charges</i> associated with <i>embedded generation facilities</i> registered under the Alternative Metering Installation Standards for Embedded Generation Facilities.	Submitted via the <i>IESO</i> portal.	Annual adjustment information is sent to us.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5K.02	Receipt of online data submission.	We receive the online data submission from <i>transmission customers</i> . In the event further information is required, the <i>distributor</i> is requested to re-submit the form.			<i>IESO</i> portal.	Information received by us.
5K.03	If the online data submission is not received within 3 months of the calendar year end, we will use the installed <i>maximum continuous rating</i> for the embedded <i>generation facilities</i> .	In the event that we do not receive a data submission within three months of the calendar year end, We will use the installed <i>maximum continuous rating</i> for the <i>embedded generation facilities</i> (provided to us at the time of the <i>meter point</i> registration) to calculate the applicable <i>transmission service charges</i> .	Annually, as soon as possible after the expiration date (three months after calendar year end) for <i>transmission customer</i> submissions has expired.	Annual adjustment dollar values for the applicable <i>transmission service charges</i> associated with <i>embedded generation facilities</i> registered under the Alternative Metering Installation Standards for Embedded Generation Facilities	Internal <i>IESO</i> calculation.	Annual adjustment information is calculated by us.

3.12 Submitting NUG Adjustment Amount Information

Each month, *OEFC* submits information to the *IESO* for the difference between NUG contract costs and wholesale market payments for NUGs.

Steps shown in the following table are illustrated in Section 2.12, Figure 2-12.

Table 3–12: Submission of NUG Adjustment Amount Information

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5I.01	Submit “NUG Adjustment Amount Information” online via the <i>IESO</i> portal.	<i>OEFC</i> submits information online via the Settlements community of the <i>IESO</i> portal.	Within four <i>business days</i> after the last <i>trading day</i> of every month.	Monthly adjustment for any differences between the contract price for NUG output and the <i>market price</i> for NUG output for the previous month. Monthly forecast NUG rate in \$/MWh for the current month. Monthly forecast NUG production in MW for the current month.	<i>IESO</i> Portal.	Declaration information is sent to us.
5I.02	Receipt of online data submission.	We receive the online data submission from <i>OEFC</i> . In the event further information is required, the <i>OEFC</i> is requested to re-submit the data.	Upon receipt of information.	Acknowledgement.	<i>IESO</i> Portal.	We receive information.

3.13 Submitting Embedded Generation and Regulated Price Information

Each month, *distributors* submit information to us for residual differences between the regulated price and the wholesale *market price* plus global adjustment for regulated *consumers* within the *distribution system*. The *distributor* also must submit information provide by *retailers* and embedded *distributors*.

Steps shown in the following table are illustrated in Section 2.13, Figure 2-13.

Table 3–13: Procedural Steps for Submission of Embedded Generation and Regulated Price Information

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
5J.01	Submit data for Embedded Generation and Regulated Price Information online via the <i>IESO</i> portal.	<p><i>Distributors</i> submit information online via the Settlements community within the <i>IESO</i> portal.</p> <p><i>Distributors</i> enter amounts for various differences to make them and the following agents whole:</p> <ul style="list-style-type: none"> •Embedded <i>distributors</i>, •Participating <i>retailers</i> using <i>distributor</i>-consolidated billing, •Participating <i>retailers</i> using retailer-consolidated billing. <p><i>Distributors</i> must report embedded generation and distribution to Class A <i>consumers</i>.</p>	Within four <i>business days</i> after the last <i>trading day</i> of every month.	<p>Monthly adjustments for any differences between:</p> <ul style="list-style-type: none"> • the regulated price and <i>market price</i> plus global adjustment for regulated <i>consumers</i>; • the <i>market price</i> and contract price for participating <i>retailers</i> with <i>distributor</i>-consolidated billing; • the regulated price and contract price for participating <i>retailers</i> with <i>retailer</i>-consolidated 	Submitted via <i>IESO</i> portal.	Monthly adjustment information is sent to us.

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
				billing; and <ul style="list-style-type: none"> • the daily global adjustment and the monthly global adjustment. Monthly amount distributed to Class A consumers for the previous month and forecast amount of embedded generation distributed to Class A consumers for the current month.		
5J.02	Receive online data submission.	We receive the <i>settlement</i> data submitted online from <i>distributors</i> via the Settlements community within the <i>IESO</i> portal. In the event further information is required, the <i>distributor</i> is requested to re-submit online via the <i>IESO</i> portal.			<i>IESO</i> portal.	Information received by the <i>IESO</i> .

– End of Section –

Appendix A: Forms

This appendix contains a list of forms used in the *physical markets settlement statements* process, which are available on the *IESO* Web site (<http://www.ieso.ca>). The forms included are as follows:

Form Name	Form Number
IESO Workflow Access and User Identification	IMO-FORM-1314
Application for Designation of a Facility for Generation Station Service Rebate	IMO-FORM-1419
Request for Optional Measurement Data Records	IMO-FORM-1433
Reduced Debt Retirement Charge (DRC) Certification	IMO-FORM-1438
IESO Decision Letter - Settlements	IMO-FORM-1460
Declaration of Designated Consumer	IMO-FORM-1507
Administrative Pricing Event Correction	IMO-FORM-1549
Real-time Generation Cost Guarantee and Day-ahead Production Cost Guarantee Data Form	IMO-FORM-1552

– End of Section –

Appendix B: Notice of Disagreement Form

The following screen captures show the *notice of disagreement* screens that *market participants* use to register and track a *notice of disagreement*.



Figure B-1: NOD Home Screen

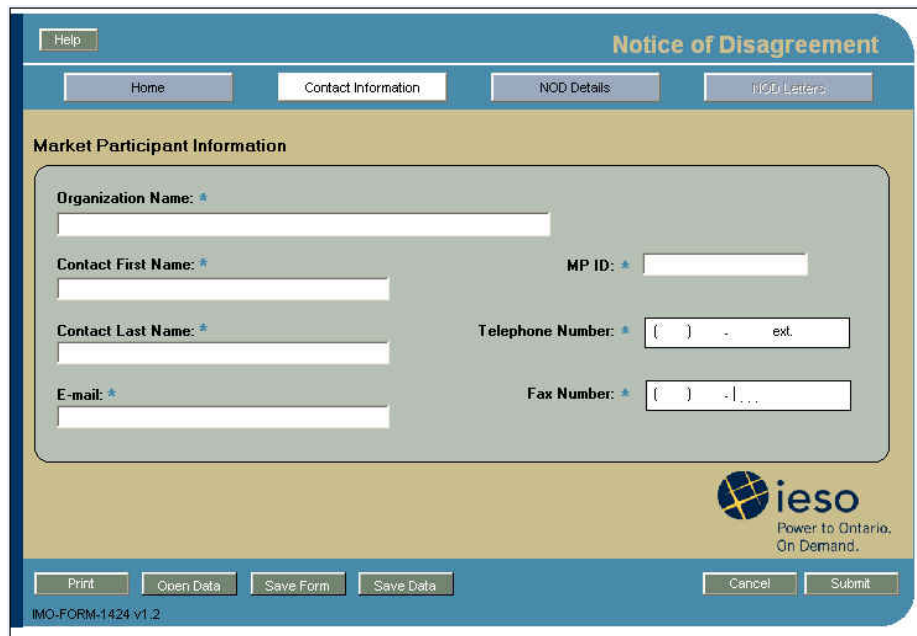


Figure B-2: NOD Contact Information

Press SPACEBAR or ENTER to activate and use this control
Notice of Disagreement

Home
Contact Information
NOD Details
NOD Letters

Trade Date: *
Statement Issue Date: *
Statement ID: *

Override

MSP Name:
MSP ID#:

MTR#:

Note: If this NOD is related to metering data, this section must be completed.

Subject of NoD: *
Market Type:

MP File No:
Disagreement Type:

Reason for Disagreement: * (Please use insert button to attach files.)

Enter your reasons here:

Reason for Disagreement History:

NoD ID:

Date and Time Received:

Final Statement Date:

Status:

Power to Ontario.
On Demand.

Print
Open Data
Save Form
Save Data
Cancel
Submit

IMO-FORM-1424-v1.2

Figure B–3: NOD Detail Screen

– End of Section –

Appendix C: IESO Charge Types Applicable to the Authorized Charge

Note: The provisions of this appendix do not apply for any period beginning after March 31, 2005. The provisions of this appendix have been retained in the event that a re-calculation of the *energy* uplifts for any period prior to April 1, 2005 is necessary.

This appendix contains a list of *IESO charge types* included in the authorized charge defined in “Ontario Regulation 436/02”. This set of charges is derived from the “IESO Charge Types and Equations” excluding:

- charges that are payable as defined by “Ontario Regulation 436/02 2(3)” (commodity charge, the *Debt Retirement Charge* and the *Transmission Services Charges*);
- charges identified by the Ontario *Energy Board* (deemed non-recurrent wholesale market service charges);
- charges payable to *market participants*;
- charges applicable to specific participants for products supplied to us; and
- charges not active in the market.

Table C-1: IESO Charge Types Included in the 0.62 Monthly Calculation

Charge Type Number	Charge Type Name
0150	Net Energy Market Settlement Uplift
0155	Congestion Management Settlement Uplift
0168	TR Market Shortfall Debit
0170	Local Market Power Rebate
0182	Hour-Ahead Dispatchable Load Offer Guarantee
0183	Generation Cost Guarantee Recovery Debit
0184	Demand Response Debit
0250	10 Minute Spinning Market Reserve Hourly Uplift
0252	10 Minute Non-Spinning Market Reserve Hourly Uplift
0254	30 Minute Operating Reserve Market Hourly Uplift
0450	Black Start Capability Settlement Debit
0452	Reactive Support and Voltage Control Settlement Debit
0454	Regulation Service Settlement Debit
0550	Must-Run Contract Settlement Debit
0753	Rural Rate Settlement Charge
9990	IESO Administration Charge

– End of Section –

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

The real-time failure charge calculation for imports and exports includes the difference between the *pre-dispatch* and the real-time Ontario *energy* prices during the hour of the failure. Including transaction failures, there are many factors that contribute to the *pre-dispatch* to real-time price differences. The purpose of the price bias adjustment factors is to adjust this charge by the forecast value of the difference between the *pre-dispatch* and the real-time Ontario *energy* price that is due to the systematically caused differences (C. 9, S. 3.8C.7).

The following methodology does not specifically isolate the price difference due to the systematic differences, but we will use it as a proxy until we are technically able to isolate this contribution or improve on the present methodology to meet this goal.

We provide these price bias adjustment factors to help you assess your exposure to the *settlement* charge for the upcoming *settlement* periods.

The following calculation method produces twenty-four hourly factors that apply for a three-month period. These three-month periods are aligned with the seasons. New factors will apply to the next calendar year.

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 twenty-fourth hour of the last day of the third month in the block.

We use 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 *pre-dispatch* to real-time Ontario *energy* price differences, 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.

We calculate the price bias adjustment factors 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 of each year since market opening. This results in data sets that are hourly, seasonal, and yearly.

Frequency distributions for these data sets are created. We determine the median values of the frequency distributions. The median value is defined as the middle value of this distribution. More

specifically, there are the same numbers of observations to the left and to the right of the median value of the frequency distribution.

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 weighing factors, we determine a price bias adjustment for each hour of the day for a three month block.

The use of weighing factors allows us to establish the best forecast by enabling the price bias adjustment factors to reflect short term and long term influences on the *pre-dispatch* to real-time Ontario *energy* price differences. The weighting factor assignments are at our discretion.

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

We will post the price bias adjustment factors on our web site in advance of their effective *trading day*.

– End of Section –

Appendix E: Expired Settlement Calculations Kept for Purposes of Re-Calculation

E.1 Fixed Energy Rate Program

Note: The provisions of this section do not apply for any period beginning after March 31, 2005. The “Electricity Restructuring Act, 2004” (also referred to as Bill 100) replaced the Fixed Energy Rate Program described below, with *charge types* 140/190 being replaced by *charge types* 142/192. The provisions of this section have been retained in the event that a re-calculation of the *energy* rate for any period prior to April 1, 2005 is necessary.

“Bill 4 An Act to amend the *Ontario Energy Board Act, 1998*” with respect to electricity pricing and regulations passed pursuant to “Bill 4”, fix the commodity price for *energy* at 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh (net of any *energy* purchased under *physical bilateral contracts*) (uncovered *energy*) for “low-volume *consumers*” and “designated *consumers*” (as defined in “Bill 4”). A fixed *energy* rate will not take the place of the *hourly Ontario energy price (HOEP)* or *energy market price (EMP)* for existing calculations. The fixed *energy* rate will be implemented via a supplementary process which consists of a calculation of the offset necessary to adjust the commodity price to the equivalent of 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh. This offsetting amount is included as a new item on *preliminary* and *final settlement statements* and monthly *invoices* under *charge type* 140, “Fixed Energy Rate Settlement Amount”. (Chapter 9, Sections 1.2.1 and 1.2.2 of the *market rules*)

All charges associated with *charge type* 140 require a corresponding off-set *charge type* in order to balance the market. This corresponding new *charge type* 190 “Fixed Energy Rate Balancing Amount” will be debited or credited to the Ontario Electricity Financial Corporation (*OEFC*). (Refer to “*IESO Charge Types and Equations*” and “*Format Specifications for Settlement Statement Files and Data Files*”, located on the Technical Interfaces page of the *IESO* Web site, for details of these *charge types*.) *Market participants’ settlement statements* will reflect additions of new Manual Line Items as detailed in these two new *charge types*.

E.1.1 Declaration Required for Designated Consumers

A ‘designated consumer’ has been defined in “Bill 4” and “Regulations 435/02, 43/04 and 433/02”. Wholesale *market participants* who qualify as ‘designated consumers’ must inform us by completing and submitting a declaration using IMO-FORM-1507 “Declaration of Designated Consumer” located on our web site. *Market participants* who satisfy us that they qualify as designated consumers will be settled at the fixed *energy* rate of 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh and a fixed 0.62 cents per kWh for the designated charges prescribed by government regulation (described in Section E.2 below).

E.1.2 IESO Market Participants that are Low-Volume or Designated Consumers

Fixed *energy* rate adjustments for eligible *market participants* covered under *charge type* 140 apply to net *energy* withdrawals, not covered by a *physical bilateral contract*, from the *IESO-administered market*. The net *settlement amount* results in an effective rate equivalent to the fixed price for all eligible uncovered *energy* transactions. Eligible *market participants' settlement statements* will be adjusted as follows:

- CRS will create a 140 detailed (DP) record that is incorporated in the *settlement statement* that will, together with the 101 detailed (DP) record, apply an effective fixed rate of 5.5 cents per kWh; and
- a manual adjustment is applied at the end of the month to apply a rate of 4.7 cents per kWh for *energy* withdrawals up to 750 kWh.

E.1.3 Distributor Claims

Regulations have been passed that provide for month-end adjustments for *distributors*. The purpose of the adjustments will be to offset the differences that arise from *distributors* settling with us at the *market price* and charging 4.7 cents per kilowatt hour up to and including 750 kWh per month and 5.5 cents per kilowatt hour in excess of the 750 kWh to low-volume *consumers* and designated *consumers*.

Eligible *distributors* that are *market participants* must submit the relevant information to us using IMO-FORM-1562 “Bill 4 Submission of Information Required for Monthly Fixed Prices” denoting the amount of the claim for each category. This form is used for all the information required from the *distributor*, embedded *distributor*⁴⁸ or participating *retailer*⁴⁹ to balance the market. IMO-FORM-1562 must be submitted on a monthly basis to us as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month. We process this information so that the *preliminary settlement statement* for the last *trading day* of the month will indicate a *charge type* 140 entry with the Comments field noting the relevant category as follows:

- adjustment for low-volume and designated *consumers* billed by a *distributor*;
- adjustment for low-volume and designated *consumers* supplied by embedded generation billed by a *distributor*;
- adjustment for low-volume and designated *consumers* billed by an embedded *distributor*;
- adjustment for low-volume and designated *consumers* supplied by embedded generation billed by an embedded *distributor*;
- adjustment for participating *retailers* using *distributor-consolidated* billing;
- adjustment for participating *retailers* using *distributor-consolidated* billing, within an embedded *distributor*;
- adjustment for participating *retailers* using *retailer-consolidated* billing; and
- adjustment for participating *retailers* using *retailer-consolidated* billing, within an embedded *distributor*.

⁴⁸ “Embedded *distributor*” is classified by regulation, where it is assumed to take the meaning described in the *OEB* “Retail Settlement Code”.

⁴⁹ *Ibid.*

E.1.4 Opt Out Provisions

Eligibility of *market participants* to opt out of the Fixed Energy Rate Program is based on the following provision:

- *directly-connected* load-consuming *market participants* meeting the regulated definition of “low-volume *consumers*” or “designated *consumers*” may opt out of the Fixed Energy Rate Program for all *registered facilities* for which they play the role of a *metered market participant* provided they have interval *metering*.

Market participants must inform us in writing if they wish to exercise this option.

E.2 Authorized Charge for the Operation of the IESO-Administered Markets

Note: The provisions of this section do not apply for any period beginning after March 31, 2005, as their operation expired as of that date. Accordingly, *charge types* 141 & 191 are no longer applicable for any such period. The provisions of this section have been retained in the event that a re-calculation of the authorized charge for any period prior to April 1, 2005 is necessary.

Effective December 2002, “Regulation 436/02” establishes a fixed charge of 0.62 cents per kWh for the operation of the *IESO-administered markets*, operation of the *IESO-controlled grid* and the rate protection provided under Section 79 of the “*Ontario Energy Board Act, 1998*” for rural and remote *consumers* (defined as the ‘authorized charge’). The authorized charge applies to *distributors*, low-volume *consumers* and designated *consumers* who are *market participants*. The relevant *IESO charge types* (refer to Appendix C: “IESO Charge Types Applicable to the Authorized Charge”) will continue to appear on daily *settlement statements* in the usual manner. On the *preliminary* and *final settlement statement* for the last *trading day* of the month, we will total these specified charges and apply an adjustment for the month to ensure that the authorized charge of 0.62 cents per kWh has been applied for all AQEW.

The authorized charge is applied to *settlement statements* as follows:

- CRS will calculate a monthly value that is incorporated into *preliminary* and *final settlement statements* for the last *trading day* of the month as detailed (DP) records.

Distributors are required to submit to us the wholesale market charges associated with the *energy* purchased from *embedded generators*. Again, IMO-FORM-1562 “Bill 4 Submission of Information Required for Monthly Fixed Prices” must be submitted on a monthly basis to us as soon as possible after the last *trading day* of the month and no later than the fourth *business day* after the last *trading day* of the month.

The adjustment to the uplift charges will appear on the *settlement statements* for the last *trading day* of each month. This offsetting amount is included as a new item on *settlement statements* and *invoices* under *charge type* 141 “Fixed Wholesale Charge Rate Settlement Amount”.

All charges associated with *charge type* 141 require a corresponding off-set *charge type* in order to balance the market. This corresponding new *charge type* 191 “Fixed Wholesale Charge Rate Balancing Amount” will be debited or credited to the Ontario Electricity Financial Corporation (OEFEC). *Market participants’ settlement statements* will reflect additions of new manual line items as detailed in these two new *charge types*.

– End of Section –

Appendix F: OPG Rebate

F.1 OPG Rebate

Note: The provisions of this Appendix do not apply for any period beginning after April 30, 2009. The provisions of this Appendix have been retained in the event that a re-calculation of the OPG Rebate for any period prior to May 1, 2009 is necessary.

F.1.1 OPG Rebate Calculation

In accordance with our *Independent Electricity System Operator Licence*, we are required to pay the OPG rebate to you if the average price of *energy* for OPG's non-prescribed assets is above a specified price during the applicable Settlement Period. The OPG Rebate is in effect until April 30, 2009.

The OPG Rebate payment is calculated and distributed quarterly to eligible *market participants*, if warranted. Table 1–2 summarizes the Settlement Periods and submission deadlines.

The OPG Rebate amount payable by OPG:

For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly payments to the IESO, beginning with the OPG Rebate Payment on the October 31, 2006 settlement statement as follows:

$$\text{OPG Rebate amount} = \text{Sum over all hours } [(HOEP - ORL) \times (ONPAO \times 0.85 - PAA) + (PAP - PAORL) \times PAA]$$

Ontario Power Generation's quarterly payments are based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This continues until the final quarter ending April 30, 2009. Where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG by the IESO and any such amount will be carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation in service as of January 1, 2006, excluding Lennox Generating Station, and excluding stations whose generation output is subject to a contract with the *Ontario Power Authority (OPA)* in the form of a hydroelectric *energy* supply agreement [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*], that are not prescribed assets under Section 78.1 of the "*Ontario Energy Board Act, 1998*" as amended by the "*Electricity Restructuring Act, 2004*".

HOEP is the *Hourly Ontario Energy Price* as determined by the IESO.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion, or that is subject to a contract with the *OPA* in the form of a hydroelectric *energy* supply agreement, [entered into by the *OPA* and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*] is to be excluded from ONPAO.

Incremental Output is defined as:

generation output x (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.

ORL is the Ontario Power Generation Revenue limit.

For the period May 1, 2006 to April 30, 2007 ORL is equal to \$46/ MWh.

For the period May 1, 2007 to April 30, 2008 ORL is equal to \$47/ MWh.

For the period May 1, 2008 to April 30, 2009 ORL is equal to \$48/ MWh.

PA is the Pilot Auction administered by the *Ontario Power Authority* in the first half of 2006.

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.

For the period May 1, 2006 to April 30, 2007 PAORL is equal to \$51/ MWh.

For the period May 1, 2007 to April 30, 2008 PAORL is equal to \$52/ MWh.

For the period May 1, 2008 to April 30, 2009 PAORL is equal to \$53/ MWh.

PAP is the weighted average auction price in \$/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

F.1.2 OPG Rebate Payment

If eligible, you will receive a pro rata share of the OPG Rebate Amount based on your allocated quantity of *energy* withdrawn for the applicable *settlement* period. Your OPG Rebate payment appears under *charge type* 112 "Ontario Power Generation Rebate". If the calculated amount of the OPG Rebate is negative, we will not make any rebate payments.

Since the OPG Rebate is already included in the Regulated Price Plan rates established by the *OEB* for *energy*, you will not receive the OPG rebate if:

- You are a *market participant* that is a low-volume or designated *consumer*, as defined in the “*Electricity Act*” and its associated regulations; or
- You are a customer of a *distributor* and a low-volume or designated *consumer*.

Distributors are required to submit information to us in advance of OPG Rebate payments to allow us to determine their OPG Rebate amount. This submission requirement is described below in Section 1.6.3.3.

F.1.2.1 Distributor Submission Requirement

Market participants that are *distributors* must submit information to us prior to the distribution of the OPG Rebate. We use this information to calculate the OPG Rebate amount for the *distributor*.

For the applicable quarter, *distributors* must advise us of the volume of *energy* withdrawn from the *IESO-controlled grid* that is associated with *consumers* who are not being charged the Regulated Price Plan (RPP) price for their electricity consumption.

The quantity provided must account for the volumes associated with any embedded *distributors* in the *distributor’s* service area.

Distributors must submit the Ontario Power Generation Rebate - Quarterly Distributor information to us online. Table F-1 summarizes the submission deadlines for this information. Enter these volumes, rounded to the nearest kWh (3 decimal places on an MWh), via the Settlements community within the *IESO* portal.

F.1.2.2 Pass-Through of Rebate

Some *market participants* are required to pass OPG Rebate amounts through to their customers. If you are required to do this, any pass-through amounts that you are unable to distribute or that are returned to you by your customers must be returned to us. Please notify us of the amounts to be returned via the ‘OPG Rebate Returned to IESO’s *settlements* data entry screen of the *IESO* portal.

Table F-1: Summary of Deadlines

OPG Rebate for:	Deadline for Submission of the OPG Rebate Quarterly Distribution Energy Volume	Applicable Settlement Period (AQEW Totals and Data Required on Form Pertains to):	For Distributors: Include Low Volume and Designated Consumers Known as of:	Rebate Payment to Eligible MPs on Settlement Statement for Trading Day (if warranted):
For the Period from May 1, 2006 to April 30, 2009:				
Quarters ending July 31	<i>3 business days</i> before October 31	May 1 – July 31	mid – October	October 31
Quarters ending October 31	<i>3 business days</i> before January 31	August 1 – October 31	mid – January	January 31
Quarters ending January 31	<i>3 business days</i> before April 30	November 1 – January 31	mid – April	April 30
Quarters ending April 30	<i>3 business days</i> before July 31	February 1 – April 30	mid – July	July 31

– End of Section –

Appendix G: Northern Pulp and Paper Electricity Transition Program

G.1 Northern Pulp and Paper Electricity Transition Program (NPPETP)

Note: The provisions of this Appendix do not apply for any period beginning after September 30, 2010. The provisions of this Appendix have been retained in the event that a re-calculation of the Northern Pulp and Paper Electricity Transition Program (NPPETP) for any period prior to October 1, 2010 is necessary.

We have signed a memorandum of understanding with the Ministry of Natural Resources (MNR) to provide *settlement* services for their Northern Pulp and Paper Electricity Transition Program (NPPETP).

The NPPETP is a new transfer payment (conditional grant) program of \$140 million over 3 years, providing transitional electricity assistance to pulp and paper firms in northern Ontario. We use *charge type* 111 “Northern Pulp and Paper Mill Electricity Transition Program Settlement Amount” for the NPPETP payments to participants, and we recover NPPETP payments from the MNR through *charge type* 161 “Northern Pulp and Paper Mill Electricity Transition Program Balancing Amount”⁵⁰.

This section sets out how the IESO settles the NPPETP on behalf of the MNR and NPPETP participants. To the extent of any inconsistency between the provisions of the NPPETP rules and this section, the NPPETP rules shall govern.

To be eligible for this program, pulp and paper mills must:

- consume a minimum of 50,000 purchased megawatt hours (MWh) annually;
- be located in Northern Ontario (north of Parry Sound); and
- apply for the program with the MNR, providing an implementation plan describing how they will lower their electricity costs over the three-year transition period (MNR will conduct audits to ensure compliance).

NPPETP payments to participants are paid quarterly and are subject to the following conditions.

- Adjustments resulting from revisions to a participating mill’s AQEW in any quarter will be reflected in an adjustment to the rebate in the following quarter.
- If the weighted average *hourly Ontario energy price (HOEP)* falls below \$46.20 per MWh for the period beginning October 1st and ending September 30th of the following year, the rebate for that period will be reduced proportionally. If the weighted average *HOEP* for the 12-month period falls to \$30.00 per MWh, there will be no rebate for that year.

⁵⁰ Refer to “IESO Charge Types and Equations” and “Format Specifications for Settlement Statement Files and Data Files”, located on the Technical Interfaces page of our web site, for details of these *charge types*.

- We calculate the total rebate for the year for each mill in the final quarter of the year. The calculation takes into account the participant's actual consumption (up to 1,000,000 MWh), and any reduction resulting from a weighted average *HOEP* for the year of less than \$46.20 per MWh. We compare the rebate calculated for the year to the sum of the rebates paid for the first three quarters of the year. The last quarterly rebate for each of the participating mills reflects the difference, either a credit or debit.

We encourage eligible candidates to contact the MNR for further details.

– End of Section –

References

Document ID	Document Title
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
MDP_PRO_0014	Market Manual 1: Market Entry, Maintenance & Exit, Part 1.1: Participant Authorization, Maintenance and Exit
MDP_PRO_0017	Market Manual 2: Market Administration, Part 2.1: Dispute Resolution
MDP_MAN_0005	Market Manual 5: Settlements, Part 5.0: Settlements Overview
MDP_PRO_0031	Market Manual 5: Settlements, Part 5.1: Settlement Schedule and Payments Calendars (SSPCs)
MDP_PRO_0032	Market Manual 5 Settlements, Part 5.2: Metering Data Processing
MDP_PRO_0034	Market Manual 5, Settlements, Part 5.3: Submission of Physical Bilateral Contact Data
MDP_PRO_0035	Market Manual 5: Settlements, Part 5.6: Physical Markets Settlement Invoicing
MDP_PRO_0036	Market Manual 5: Settlements, Part 5.9: Settlement Payment Methods and Schedule
MDP_PRO_0046	Market Manual 5: Settlements, Part 5.7: Financial Markets Settlement Statements
MDP_PRO_0047	Market Manual 5: Settlements, Part 5.8: Financial Markets Settlement Invoicing
MDP_PRO_0027	Market Manual 4: Market Operations, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets
IMP_PRO_0034	Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets
IMP_PRO_0057	Market Manual 3: Metering, Part 3.8 Creating and Maintaining Delivery Point Relationships
IMO_MAN_0024	Market Manual 6: Participant Technical Reference Manual
IESO_MAN_0080	Market Manual 9: Part 9.5. Settlement for Day-Ahead Commitment Process
IMO_GDE_0002	HST Guide for IESO Transactions
IMO_GDE_0003	Market Participant Graphical User Interface User's Guide
IMP_GDE_0100	Notice of Disagreement: A Guide for Market Participants

Document ID	Document Title
IMP_GDE_0103	The Applications Status Tool: A User Guide
	Guide to the <i>IESO</i> Portal
	Guide to Online Data Submission via the <i>IESO</i> Portal
IMP_LST_0001	IESO Charge Types and Equations
IMP_SPEC_0005	Format Specifications for Settlement Statement Files and Data Files
IMP_SPEC_0006	File Format Specification for Participant Transmission Tariff Data Files
IMP_SPEC_0007	File Format Specification for Transmitter Transmission Tariff Data File
IMP_SPEC_0008	File Format Specification for Transmitter Reconciliation Data File
IMO_SPEC_0009	Generation Station Service Reimbursement File: File Format Specification
IMO_SPEC_0100	Outbound Automated Document Application Programming Interface
IMP_REP_0016	Transmission Tariff Peak System Demand Data Report
IMP_AGR_0013	Settlement Agreement between Ontario Power Generation Inc. and the Independent Electricity Market Operator
Quick Take 15	Retrieving Reports via the IESO Reports Site
<i>IESO</i> Step-by-Step Guide	IESO Interactions for Unit Sub-Metering Providers
	OEB Retail Settlement Code
	Ontario Energy Board Act, 1998
	Legislation Bill 4 "An Act to amend the Ontario Energy Board Act 1998 with respect to energy pricing".
	Legislation Bill 100 "Electricity Restructuring Act, 2004"
	Order-in-Council 141/2006
	Regulation 42/04 (Under the Ontario Energy Board Act, 1998)
	Regulation 43/04 (Under the Ontario Energy Board Act, 1998)
	Regulation 339/02 (Under the Ontario Energy Board Act, 1998) "Electricity Pricing"
	Regulation 341/02 (Under the Ontario Energy Board Act, 1998) "Compensation and Set-Offs Under Part V of the Act"
	Regulation 342/02 (Under the Ontario Energy Board Act, 1998) "Payments to the IMO"

Document ID	Document Title
	Regulation 433/02 (Under the Ontario Energy Board Act, 1998) "Electricity Pricing"
	Regulation 435/02 (Under the Ontario Energy Board Act, 1998) "Payments re Section 79.4 of the Act"
	Regulation 436/02 (Under the Ontario Energy Board Act, 1998) "Payments re Various Electricity-Related Charges"
	Regulation 427/04 "Payments to the Financial Corp. re Section 78.2 of the Act"
	Regulation 428/04 "Payments re Section 79.4 of the Act"
	Regulation 398/10 enacted in October 2010 Amending Ontario Regulation 429/04 "Adjustments Under Section 25.33 of the Act"
	Regulation 430/04 "Payments re Section 25.33 of the Act"
	Regulation 431/04 "Payments re Section 25.34 of the Act"
	Section 78.3 of the (Ontario Energy Board) Act
	Section 78.4 of the (Ontario Energy Board) Act
	Section 78.5 of the (Ontario Energy Board) Act
	Regulation 53/05 made under "OEB Act, 1998" re "Payments under Section 78.1 of the Act"
	Regulation 95/05 made under "OEB Act, 1998" re "Classes of Consumers and Determination of Rates"
	Regulation 98/05 made under "OEB Act, 1998" re "Payments re Various Electricity-Related Charges"
	Regulation 330/09 made under "OEB Act, 1998" re "Cost recovery regarding section 79.1 of the Act"
	Regulation 66/10 made under "OEB Act, 1998" re "Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs".
	Regulation 495/10 made under "Ontario Clean Energy Benefit Act, 2010".

- End of Document -