

# PROCEDURE



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## Market Manual 3: Metering

# Part 3.7: Totalization Table Registration

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Issue 22.0

This procedure describes the process through which *metering service providers* submit Totalization Tables and approve the tables entered by the *IESO* in the *metering registry*.

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## Related Documents

Document ID	Document Title
MDP_MAN_0003	Market Manual 3: Metering, Part 3.0: Metering Overview
MDP_STD_0004	Wholesale Revenue Metering Standard - Hardware
MDP_STD_0005	Site-Specific Loss Adjustments Standard

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Reference (Section and Paragraph)	Description of Change
Throughout Document	Updated to meet accessibility requirements pursuant to the <i>Accessibility for Ontarians with Disabilities Act</i> .

Archive

## Market Manuals

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The *market manuals* consolidate 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* must prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

## Market Procedures

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The “Metering Manual” is Volume 3 of the *market manuals*, and this document is “Part 3.7: Totalization Table Registration”.

A list of the other component parts of the *metering manual* is provided in “Part 3.0: Metering 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 forms, standards, policies and agreements.

## Conventions

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

- End of Section –



# 1. Introduction

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## 1.1 Purpose

This procedure explains how to register totalization tables with the *IESO*.

## 1.2 Scope

This procedure covers the steps for totalization table registration, which is part of the registration process for *metering installations*. Other procedures in “Market Manual 3: Metering” may need to be performed before, after or in parallel to the steps in this procedure, depending on the activity that is being performed:

1. “Part 3.8: Creating and Maintaining Delivery Point Relationships” describes how the *IESO* creates *delivery points* for both *energy market* and *transmission tariffs* customers. *Delivery points* must be set up by the *IESO* before *meter point* registration can begin. Additional details regarding the creation of *delivery points* for the *energy market* are given in *IESO’s* “Market Manual 1: Market Entry, Maintenance and Exit, Part 1.2: Facility Registration, Maintenance and De-registration”.
2. “Part 3.2: Meter Point Registration and Maintenance”. *Meter point* registration during which the *metering installation* is assessed technically and, once approved by the *IESO*, entered into the *IESO metering registry*.

## 1.3 Overview

A complete overview of the steps in this document appears in Section 2.

## 1.4 Who Should Use This Document

*Transmitters, metering service providers, and metered market participants* should use this procedure to register a totalization table with the *IESO*.

## 1.5 Roles and Responsibilities

The roles and responsibilities, with regard to the tasks associated with the current procedure, of the *market participant* responsible for registering a *facility* consuming *connection station service, metered market participant, metering service provider, transmitter, and the IESO*, are as follows:

The **market participant responsible for registering a facility consuming connection station service energy** is responsible for:

- Submitting an estimate for *energy* consumption associated with *connection station service* to the *IESO*, which shall be stamped by a registered professional engineer and shall be subject to audit by the *IESO*.

The **metered market participant** is responsible for:

- for a *transmission tariffs delivery point* (MMPT) feeding an *embedded generator(s)* built after 1998 that does not participate in the *energy market*, ensuring that the relevant *meter(s)* to be used for *transmission tariffs* only, are registered with the *IESO*.

The **metering service provider** is responsible for:

- submitting totalization tables associated with each *delivery point* associated with a specific *metered market participant*;
- when submitting a new totalization table, identifying all other totalization tables that are affected and communicating with the relevant *metering service providers* to ensure these totalization tables are also re-submitted;
- re-submitting totalization tables, as appropriate; and
- approving the “Site Registration Report” produced by the *IESO*, thus confirming that the totalization table has been correctly entered into the *IESO meter* registry.

The **transmitter** is responsible for:

- verifying the totalization tables submitted by the *metering service provider* for reasonableness and completeness;
- approving the “Site Registration Report” produced by the *IESO*, thus confirming that the totalization table has been correctly entered into the *IESO meter* registry.

The **IESO** is responsible for:

- processing and entering the totalization table into the Meter Data Management System (MDMS) (the *metering registry*); and
- generating the “Site Registration Report” for the relevant *delivery point* on which the *metering service provider* will acknowledge correctness.

## 1.6 Contact Information

If the market participant wishes to contact the IESO, the market participant can contact the IESO Customer Relations via email at [customer.relations@ieso.ca](mailto:customer.relations@ieso.ca) or via telephone, mail or courier to the numbers and addresses provided on the IESO Web site (<https://www.ieso.ca>). If the IESO Customer Relations is closed, telephone messages or emails can be left in relevant voice or electronic IESO mail boxes, which will be answered as soon as possible by Customer Relations staff.

Standard forms that participants must complete for this procedure are listed in Appendix A. These forms are generally available for downloading on the *IESO* Web site.

The Totalization Table Forms must be submitted to the *IESO* using Online *IESO* (<https://online.ieso.ca>).

– End of Section –

## 2. Procedure Overview

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### 2.1 General Outline

The totalization table algebraically maps *meter point* IDs to a *delivery point*. The totalization table also identifies any measurement error correction factors, site specific losses, *station service* load and, if applicable, total loss factors to be applied to *meter* readings at each *meter point*. The *IESO* uses this data, adjusted and summated at the *delivery point*, to:

- settle *metered market participant* transactions in the wholesale *energy market*; and/or
- calculate transmission charges for *transmission tariffs* customers (see also Section 2.3.4 in this manual).

At this time, *metering service providers* are required to supply the information set-out in Appendix B. The *IESO* will further process this information to create the required summary *meters* and enter them into the *meter* registry.

This approach will change for the enduring stage when, on registering a new *meter point* ID, the *metering service provider* must submit a complete totalization table for that *delivery point*. On submitting a new totalization table, an embedded metering service provider must also identify all other totalization tables that are affected and prompt the relevant *metered market participant(s)* to re-submit them. In this document, the term “embedded metering service provider/metered market participant” means those connected to a bus, the *meter* of which is serviced/owned by another *metering service provider/metered market participant*.

The *IESO* uses two types of totalization tables:

1. totalization tables for *energy market delivery points* (EM DP); and
2. totalization tables for *transmission tariffs delivery points* (TT DP) (see Section 2.3.4 in this manual), which are further divided into the following types:
  - totalization tables for Network DPs; and
  - totalization tables for Connection DPs.

Multi-level totalization tables, such as the ones for *facilities* equipped with both bus and feeder metering, and where one or more feeders also supply embedded loads, must be built in the following order:

1. embedded;
2. feeders; and
3. bus.

### 2.2 Important Terms

#### 2.2.1 Delivery Point

The *delivery point* is the logical reference point for *settlements* in the wholesale *energy market*, and for the *transmission tariffs* market. Totalization tables submitted during MI registration are always associated with a *delivery point*. Separate *delivery points* are created for *transmission tariffs* customers, as described in “Part 3.8: Creating and Maintaining Delivery Point Relationships”.

## 2.2.2 Meter Point ID

The *meter point* ID identifies the physical location of the *metering installation* with a unique numerical code. During the registration procedures, the *IESO* assigns the *meter point* ID(s) to the *metering service provider*.

Separate *meter point* IDs are created for the main and the alternate (or *check*) *meter* pertaining to the same installation. However, only main or stand-alone *meters* are considered for totalization.

## 2.2.3 Summary Meter

A summary *meter* is a virtual *meter* created as part of the totalization process. The summary *meter* is a mathematical tool that can summate readings from various *meters* and apply losses, error correction factors, and/or scaling factors to these readings in order to enable the *settlement* at the associated *delivery point*. There are three main scenarios in which summary *meters* are required to be created, as listed below:

1. Recorders that include two or more metering channels that measure active *energy* flow (kWh) in the same direction. Such situations require the creation of separate summary (virtual) *meters* for each metering element involved.
2. Totalization table. In most of the cases, the totalization table is a summary *meter* that considers various physical and/or summary *meters* with MECs, loss factors, and scaling, all applied at different levels (physical *meter* and/or summary *meter*).
3. Summary *meters* associated with an *energy market* DP that are used as contributors for totalization tables associated with a TT DP.

## 2.2.4 Measurement Error Correction (MEC) Factors

MEC factors are calculated in accordance with the process set out in “Part 3.4: Measurement Error Correction”. Although these factors generally apply to a physical *meter*, they can also apply to a summary *meter*. MEC factors must be entered in the totalization table as the calculated MEC factor minus one. Thus, for a calculated MEC factor of 1.005, a value of 0.005 must be entered in the totalization table; a calculated MEC factor of 0.995 must be entered as “-0.005”.

## 2.2.5 Site-Specific Loss Adjustment (SSLA)

SSLA factors are calculated in accordance with the process set out in “Part 3.5: Site Specific Loss Adjustment”. SSLA factors take into account transformation losses. Similar to MEC factors, SSLA factors can be applied to a physical *meter* or to a summary *meter*, as appropriate.

## 2.2.6 Total Loss Factors (TLFs)

TLFs take into account distribution losses for *embedded RWMs* to the *defined meter point*. A TLF, as approved by the *Ontario Energy Board (OEB)* and communicated by the relevant Local Distribution Company (LDC), can be applied to a physical *meter* or to a summary *meter*, as appropriate. The *IESO* will apply the TLF (the value of which will be as approved by the *OEB*) only to the delivered channel of the *meter*. For the received channel, if the value of the TLF has not been agreed upon by the participants (host and embedded), a default value of one (1) will be applied to the received channel.

## 2.2.7 Totalization Table Notes

*Metering service providers* may utilize the notes section of the Totalization Table to clarify instructions to the *IESO* on how a *facility* should be settled.

Totalization Table Notes may include, but are not limited to, the following items:

- applying losses to a *physical meter* or a *summary meter*;
- apportioning *station service* losses between *metered market participants*;
- changes to a MEC, SSLA, or TLF.

## 2.3 Guidelines for Preparing Totalization Tables

### 2.3.1 Estimated Station Services

#### Non-Metered Station Services

The *market participant* responsible for registering a *facility* consuming *connection station service* must submit, when applicable, the *station service* factor in kW (Chapter 9, Section 2.1A of the *market rules*). This factor is submitted using FORM-78 titled, “Connection Facility Station Service – Not Metered by an RWM” by registering a virtual meter. FORM 78 must be stamped and signed by a registered professional engineer (Professional Engineers of Ontario (PEO)). This value is entered on IMO-FORM-1310 “Totalization Table Form” for submission to the *IESO*. When processing IMO-FORM-1310 in MDMS, the *IESO* creates a virtual meter, with a constant, 5-minute interval value representing the *station service* factor.

The following assumptions shall be used in determining the *station service* factor:

- secondary estimated load will be calculated as the sum of the rated value of all connected loads of the equipment in-use at the station, in kW;
- if the percentage usage of the estimated load cannot be determined, the default value to be considered in calculation must be 75%;
- the *station service* load will be calculated up to the *Defined Meter Point* (DMP) as 2.0% higher than usage of the secondary estimated load; and
- the value of the *station service* factor shall be rounded to the nearest kW;
- annual checks must be performed to confirm estimate is still valid.

An example of such calculation is given below:

Total secondary connected load	27.7 kW
Usage of total secondary connected load (75%)	20.77 kW
Total primary estimated load	21.18 kW
<b>Station Service Factor</b>	<b>21 kW</b>

### 2.3.2 Estimated Station Services Using Retail Meters

The *market participant* responsible for registering a *facility* consuming *connection station service* can determine the *station service* factors by using a Measurement Canada approved and sealed *retail meter* to estimate the load.

The main items to consider when using *retail meters* are:

- the estimate must be based on annual consumption determined from the *meter* readings of the *retail meter*;
- the estimate must take into account losses between the location of the *retail meter* to the *Defined Meter Point* (DMP); 1% losses for each level of transformation is acceptable;
- the value of the *station service* factor should be rounded to the nearest kW; and
- annual readings of the *retail meter* must be recorded to confirm estimate is still valid; if the results are different, an updated estimate must be submitted and registered.

The *station service* factor is submitted using FORM-78. Refer to Section 2.3.1.

### 2.3.3 Apportioning Station Service Consumption

The consumption (either metered or non-metered) of *station service* transformers fed from the bus connected directly to the *IESO-controlled grid* must be allocated (excluding an *embedded load facility* or *embedded generation facility*) among all *metered market participants* associated with that *defined meter point*, based on an agreement among all affected *metered market participants*. The *IESO* enters this allocation as submitted by the relevant *metering service providers* via the “Totalization Table Form”.

*Metering service providers* can update allocations for *station service* consumption no more than once in each calendar year, or more frequently if required by the registration of a new *RWM*.

Should one or more of such *metered market participants* fail to agree on the apportionment, the *metering service provider* must use the following methods for apportioning *station service* consumption:

- the whole (100%) consumption will be allocated to the *metered market participant* associated with the *RWM* that includes that consumption; that is, the *RWM* that measures the bus; or
- when there is no bus *RWM*, the *IESO* allocates the *station service* consumption proportionally, based on the number of feeders pertaining to each *metered market participant*. Thus, a *metered market participant* with three feeders connected to a bus with a total of ten feeders must be assigned three tenths of the *station service* consumption. In such cases, the *metering service provider* must enter in the totalization tables the appropriate coefficients while also providing the ratio of breakers used in the calculation.

Any disagreement with regard to the allocation of *station service* consumption must be resolved among the affected parties; if necessary, the issue may be resolved through Dispute Resolution, as described in “Market Manual 2: Market Administration, Part 2.1: Dispute Resolution”.

### 2.3.4 Apportioning Transformation Losses

The transformation losses and/or radial line losses associated with the common power component (i.e. power transformer or radial line) at the *defined meter point* must be allocated among all *metered market participants* pertaining to that *defined meter point*, based on an agreement among all affected *metered market participants*. The *metering service provider* must submit this allocation on the “Totalization Table Form”.

*Metering service providers* can update allocations for transformation losses and/or radial line losses no more than once in each calendar year, or more frequently if required by the registration of a new *RWM*.

Should one or more of such *metered market participants* fail to agree on the apportionment, the following methods for allocating transformation losses must be used:

- the full amount (100%) of transformation losses and/or radial line losses will be allocated to the *metered market participant* associated with the *RWM* that measures the bus; or
- when there is no bus *RWM*, the *IESO* will allocate the transformation losses and/or radial line losses proportionally, based on the number of feeders pertaining to each *metered market participant*. Thus, for a *metered market participant* that is associated with three feeders in a station with a total of ten feeders, the loss coefficients, originally calculated by using one of the two acceptable methods, must be adjusted as follows:
  - Method #1: coefficient “a” must be multiplied by the ratio of breakers, 3/10, while coefficient “b” must be multiplied by the inverse ratio, 10/3;
  - Method #2: coefficient “k<sub>1</sub>” must be multiplied by the inverse ratio of breakers, 10/3, while coefficient “k<sub>3</sub>” must be multiplied by the ratio, 3/10; coefficient “k<sub>2</sub>” remains unchanged.

Regardless of the method used, the *metering service provider* must submit the coefficients already adjusted. The *metering service provider* must also provide the ratio of feeders pertaining to the *metered market participant* associated with the current *delivery point* versus the total number of feeders on the bus.

All *metered market participants* sharing transformation losses and/or radial line losses must agree to the apportionment of transformation losses and/or radial line losses. Where an agreement is reached amongst *metered market participants*, the Method #1 or Method #2 coefficients can be apportioned as per the agreement by either fixed factor loss allocation or dynamic loss allocation as described in the following sections.

#### 2.3.4.1 Fixed Factor Loss Allocation

The fixed factor loss allocation ratio for load losses could be different than the fixed factor loss allocation ratio for no load losses. The agreed amounts shall meet Chapter 9, Section 2.1A.4.2a of the *market rules* whereby the proportions provided by each *metering service provider* shall reflect agreement amongst all applicable *metering service providers* and shall only be accepted by the *IESO* if the proportions provided by all applicable *metering service providers* sum to one.

#### 2.3.4.2 Dynamic Loss Allocation

Dynamic loss allocation is the principle whereby transformation losses and/or radial line losses are apportioned to each *metered market participant* proportionally by applying an apportionment factor. This apportionment factor is based on the ratio of each *metered market participant's* metered consumption to the sum total of consumption by all *metered market participants* sharing the transformation losses and/or radial line losses for the *metered interval*. The greater a *metered market participant's* load for a *metered interval*, the greater the proportion of transformation losses and/or radial line losses that will be attributed to that *metered market participant*.

*Metered market participants* may agree to allocate transformation load losses and/or radial line load losses via dynamic loss allocation, while at the same time allocating the transformation no load losses and/or radial line no load losses via a fixed factor loss allocation.

The allocation ratio for each *metered market participant* is calculated as the ratio of the net active energy pertaining to that specific *metered market participant* to the sum of net active energy of all *metered market participants* sharing the transformation losses and/or radial line losses. These ratios are calculated for each *metering interval*.

$$\text{ratio}_{\text{MMPi}} = \frac{\text{Abs}(\sum \text{Active Energy Delivered}_{\text{MMPi}} - \sum \text{Active Energy Received}_{\text{MMPi}})}{\sum_i^n \text{Abs}(\sum \text{Active Energy Delivered}_{\text{MMPi}} - \sum \text{Active Energy Received}_{\text{MMPi}})}$$

If the sum of net active energy of all *metered market participants* sharing the transformation losses and/or radial line losses is zero, the transformation load losses and/or radial line losses will be allocated equally amongst the *metered market participants*.

$$\text{ratio}_{\text{MMPi}} = \frac{1}{\sum_i^n \text{MMPi}}$$

The allocation ratios will be calculated by the MDMS system using a ‘ratio point’ as part of the totalization table. A ratio point (RP) accepts as inputs the same type of units of measure (kWh, V2h, etc.) in all channels and returns as a result the ratio between the input channel value and the sum of all input channels values. If the sum of all input channels value is zero, the result is 1/number of channels. The ‘ratio point’ is calculated by comparing the individual *meter* input to the total *meter* inputs for the transformation losses and/or radial losses.

$$\text{RP}_{\text{out}i} = \frac{|\text{RP}_{\text{in}i}|}{\sum_1^n |\text{RP}_{\text{in}i}|}$$

Dynamic loss allocation requires an agreement between all *metered market participants* sharing the transformation losses and/or radial line losses. *Metering data* will be available to all *metered market participants* sharing transformation losses and/or radial line losses. The totalization table submitted by each *metered market participant’s metering service provider* will be considered an agreement if each of the totalization tables are consistent and in agreement with one another.

All *metered market participants* connected to the common power system component (i.e. transformer and/or radial line) and using dynamic loss allocation must be directly connected *metered market participants*.

Samples of dynamic loss allocation models and totalization tables are presented in Appendix H.



### 2.3.4.3 Dynamic No-Load Loss Application

The no-load losses associated with the power component (i.e. power transformer and/or radial lines) at the *defined meter point* are allotted to each *metered market participant* in accordance with “Market Manual 3: Part 3.5: Site-Specific Loss Adjustments”.

The IESO’s loss principles are based on the normal operating conditions of the power system and do not take into account the dynamic energization state of a power component resulting in the application of no-load losses at the *defined meter point*. However, a *metered market participant* under a set of IESO defined conditions can elect a registration arrangement (by updating the totalization table as per Appendix I: 3) to offset any active *energy* incurred as no-load losses under a de-energized state of a power component.

These conditions are limited to *metering installations* where:

1. A registered single line diagram conforming to the power system configuration (as shown in Appendix I: 1) must not have a *disconnect* equipment installed between the power component and the *metering installation*.
2. The incurred no-load losses for power components subject to a dynamic energization state cannot be allocated between multiple *metered market participants*.

A totalization table submitted by a *metering service provider* requesting to apply the dynamic no-load loss application for power components subject to the dynamic energization will be implemented using ratio points as part of the totalization schema.

A ratio point (RP) accepts as inputs the same type of units of measure (kWh, V2h, etc.) in all channels, and returns as a result the ratio between the input channel value and the sum of all input channels values. If the sum of all input channel values is zero, the result is 1/number of channels.

$$\text{If } \sum \text{ input channel values} = 0, \text{ then } \text{RP}_{\text{out}i} = \frac{1}{\sum_1^n |\text{RP}_{\text{in}i}|}$$

$$\text{If } \sum \text{ input channel values} > 0, \text{ then } \text{RP}_{\text{out}i} = \frac{|\text{RP}_{\text{in}i}|}{\sum_1^n |\text{RP}_{\text{in}i}|}$$

Using this logic, in the case of no-load losses, two ratio points (‘RM\_E’ and ‘RM\_V’) will be individually appointed to measure the presence of *energy* and voltage by comparing a zero input signal (on CH1 of a ratio point) to the sum of all active *energy*/voltage channels (on CH2 of a ratio point). Accordingly, the individual ratio point will return an output value of ‘0’ (if the sum of all voltage or *energy* channels is not equal to zero), or an output value of ‘0.5’ (if the sum of all voltage or *energy* channels is equal to zero).

A summary *meter* is then used to multiply the two ratio point outputs with a no-load loss proportionality factor (‘SF’) to establish the applicability or non-applicability of no-load losses at a *defined meter point* (see Appendix I: 2).

The no-load loss proportionality factor (‘SF’) is calculated using the loss coefficients registered for the power component:

- Method #1 (a, b):

$$\text{SF}_{\text{in}} = \frac{4 \times (\# \text{ of elements} \times a \times V_{\text{assumed}}^2)}{20}$$

Or,

- Method #2 ( $k_1, k_2, k_3$ )

$$SF_{in} = \frac{4 \times (k_3)}{20}$$

The no-load loss totalization methodology is summarized as follows:

	$\Sigma \text{ energy} = 0$	$\Sigma \text{ energy} < 0$
$\Sigma \text{ volts} = 0$	NLL not applied	NLL applied
$\Sigma \text{ volts} < 0$	NLL applied	NLL applied

- No-load losses are not applicable, if the sum of active *energy* channels and the sum of voltage channels is equal to zero.
- No-load losses are applicable, if the sum of active *energy* channels and/or the sum of voltage channels is not equal to zero.

Examples of the dynamic no-load loss application model, totalization table and Site Registration Report are presented in Appendix I.

### 2.3.5 Transmission Tariffs (TT) Customers

As established by the *OEB* rate order, the *transmitter* provides the *IESO* with a list of *transmission customers*, identifying the *transmission service* that applies to each: *network service*, *line connection service*, *transformation connection charge*. (Chapter 9, Section 4.1 and Chapter 10, Sections 3.1.3, 5.1.3 and 6.1.3 of the *market rules*)

Separate *delivery points* are created for *network service* and for *connection service* respectively, and totalization tables must be submitted for each. The *connection service delivery point* is used to bill either the *line connection* or transformation connection, or both, depending on the *transmitter's* submission. This is set by the *IESO* in the Customer Data Management System (CDMS).

The rate to be charged for each service is established by an *OEB* rate order. (Chapter 10, Sections 3.4.1, 5.1.1 and 6.1.1 of the *market rules*)

### 2.3.6 Compliance Aggregation

*Market participants* may apply to aggregate *facilities* for bidding purposes. (Details of the Compliance Aggregation Program can be found in “Market Manual 1: Market Entry, Maintenance and Exit, Part 1.2: Facility Registration, Maintenance and De-Registration” and “Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets.”) If the request for aggregation is approved, the *market participant* may elect to implement the Compliance Aggregation Model.

Compliance aggregation is the functionality within MDMS which permits measured generation from multiple *facilities* to be aggregated and then apportioned to the *delivery points* associated with the Compliance Aggregation Model. The apportionment is performed by applying a proportionality factor based on *dispatch instructions* to the aggregation summary meter.

The Compliance Aggregation Model consists of the following elements:

#### Schedule Set

- The schedule set identifies the Shared Meter MSID and Delivery Point ID's associated with the Compliance Aggregation Model.
- Only one *delivery point* may be considered "Primary" (indicated by a 'Y' in the Primary column of the schedule set). The *delivery point* set to "Primary" permits full access to all underlying data of the *delivery point*. A *delivery point* set to 'N' in the "Primary" column of the schedule set permits access to only the calculated values at the *delivery point*.

#### Shared Meter MSID

- The Shared Meter MSID is the summary meter that is used to aggregate the generation output from all *facilities* associated with the Compliance Aggregation Model.

#### SS\_SP Meter Point

- The SS\_SP *Meter Point* is a notional *meter point* that is automatically created when the schedule set is defined in MDMS. A SS\_SP *meter point* is associated with each *delivery point* and the data contained in the SS\_SP *meter point* is a proportionality factor based on the *dispatch instruction* of the individual *facility*. The proportionality factor is calculated by comparing the individual *energy* Real Time Constrained Schedule (RTCS) for each disaggregated *delivery point* to the total RTCS for the schedule set group. The proportionality factor is recorded for each 5 minute interval and is represented as a decimal percentage value. When the total RTCS is zero, the proportionality factor is distributed equally among all SS\_SP *Meter Points* associated with the schedule set. The sum of each interval of all SS\_SP *Meter Points* associated with the schedule set is 1.0.
- Due to routines in the Commercial Reconciliation System (CRS), the SS\_SP *metering data* is not available until the 6<sup>th</sup> calendar day following the *trading day*.

#### SS\_SM Summary Meter

- The SS\_SM Summary Meter is a notional summary meter that is also automatically created when the schedule set is defined in MDMS. The SS\_SM Summary Meter is used to disaggregate the Shared Meter MSID by the SS\_SP *Meter Point*. The SS\_SM Summary Meter disaggregated value is the product of the SS\_SP *Meter Point* and the Shared Meter MSID.
- Because the SS\_SP *metering data* is not available until 6 calendar days after the *trading day*, SS\_SM *metering data* is also only available on the 6<sup>th</sup> calendar day after the *trading day*.

The Compliance Aggregation Model makes reference to two key dates:

#### Implementation Date

- This is the date that the Compliance Aggregation Model will be entered and defined in the MDMS system.

#### Effective Date

- This is the date that the Compliance Aggregation Model will become active in the MDMS system.
- The SS\_SP *metering data* becomes available in CRS on the 6<sup>th</sup> calendar day after the *trading day*.

When developing the Compliance Aggregation Model, the following conditions shall apply:

- A *delivery point* can only be associated with one Compliance Aggregation Model.
- All *delivery points* associated with the Compliance Aggregation Model must have the same *metering service provider*.

Once the *market participant* has received approval to proceed with Compliance Aggregation, a Compliance Aggregation Model will be developed. The Compliance Aggregation Model defines the relationship of the physical *meters*, summary meters and schedule set to the *delivery points*. The Compliance Aggregation Model will be supplied to the *market participant* for review and approval. Once accepted, the *market participant* must complete and submit IESO-FORM-1660 “Acceptance of Compliance Aggregation Model”. Using the Compliance Aggregation Model, the *metering service provider* must prepare and submit “Totalization Table” for each *delivery point* associated with the Compliance Aggregation Model via Online IESO (<https://online.ieso.ca/>). The “Totalization Table” must be received by the *IESO* at least 2 *business days* prior to the implementation date.

On the implementation date, the *IESO* will enter the totalization table into the MDMS system. As a result, the existing structure of the totalization table in the *metering registry* will change and these changes take effect on the start date of the *delivery point*. By completing and submitting IESO-FORM-1660, the *market participant* authorizes the *IESO* to implement the Compliance Aggregation Model and acknowledges that the current Site Registration Report for the affected *delivery points* will no longer be in effect. Typically, there is a 10-day turn-around time between the date the Compliance Aggregation Model is built in MDMS and the time the *IESO* receives the new signed SRR. During this interim period, the Compliance Aggregation Model represents the totalization table in the *metering registry* and is in effect.

### 2.3.7 Meter Disaggregation

*Market participants* may apply to disaggregate *facilities* for bidding purposes. If the request for disaggregation is approved, the *market participant* may elect to implement the Meter Disaggregation Model.

Meter disaggregation is the functionality within MDMS which enables true measured generation, derived from *registered wholesale meter(s)*, to be apportioned to two or more *delivery points* associated with the Meter Disaggregation Model. The apportionment is performed by applying a proportionality factor based on *dispatch instructions* to the aggregation summary meter.

The Meter Disaggregation Model consists of the following elements:

#### Schedule Set

- The schedule set identifies the Shared Meter MSID and Delivery Point ID’s associated with the Meter Disaggregation Model.
- Only one *delivery point* may be considered “Primary” (indicated by a ‘Y’ in the Primary column of the schedule set). The *delivery point* set to “Primary” permits full access to all underlying data of the *delivery point*. A *delivery point* set to ‘N’ in the “Primary” column of the schedule set permits access to only the calculated values at the *delivery point*.

#### Shared Meter MSID

- The Shared Meter MSID is the summary meter that aggregates the total generation output from all *facilities* associated with the Meter Disaggregation Model.

### SS\_SP Meter Point

- The SS\_SP Meter Point is a notional meter point that is automatically created when the schedule set is defined in MDMS. A SS\_SP meter point is associated with each *delivery point* and the data contained in the SS\_SP meter point is a proportionality factor based on the *dispatch instruction* of the individual *facility*. The proportionality factor is calculated by comparing the individual *energy* Real Time Constrained Schedule (RTCS) for each disaggregated *delivery point* to the total RTCS for the schedule set group. The proportionality factor is recorded for each 5 minute interval and is represented as a decimal percentage value. When the total RTCS is zero, the proportionality factor is distributed equally among all SS\_SP Meter Points associated with the schedule set. The sum of each interval of all SS\_SP Meter Points associated with the schedule set is 1.0.
- Due to routines in the Commercial Reconciliation System (CRS), the SS\_SP *metering data* is not available until the 6<sup>th</sup> calendar day following the *trading day*.

### SS\_SM Summary Meter

- The SS\_SM Summary Meter is a notional summary meter that is also automatically created when the schedule set is defined in MDMS. The SS\_SM Summary Meter is used to disaggregate the Shared Meter MSID by the SS\_SP Meter Point. The SS\_SM Summary Meter disaggregated value is the product of the SS\_SP Meter Point and the Shared Meter MSID.
- Because the SS\_SP *metering data* is not available until 6 calendar days after the *trading day*, SS\_SM *metering data* is also only available on the 6<sup>th</sup> calendar day after the *trading day*.

The Meter Disaggregation Model makes reference to two key dates:

#### Implementation Date

- This is the date that the Meter Disaggregation Model will be entered and defined in the MDMS system.

#### Effective Date

- This is the date that the Meter Disaggregation Model will become active in the MDMS system.
- The SS\_SP *metering data* becomes available in CRS on the 6<sup>th</sup> calendar day after the *trading day*.

When developing the Meter Disaggregation Model, the following conditions shall apply:

- A *delivery point* can only be associated with one Meter Disaggregation Model.
- All *delivery points* associated with the Meter Disaggregation Model must have the same *metering service provider*.

Once the *market participant* has received approval to proceed with Meter Disaggregation, a Meter Disaggregation Model will be developed. The Meter Disaggregation Model defines the relationship of the physical *meters*, summary meters and schedule set to the *delivery points*. The Meter Disaggregation Model will be supplied to the *market participant* for review and approval. Once accepted, the *market participant* must complete and submit IESO-FORM-1665 “Acceptance of Meter Disaggregation Model”. Using the Meter Disaggregation Model, the *metering service provider* must prepare and submit IMO-FORM-1310 “Totalization Table Form” for each *delivery point* associated with the Meter Disaggregation

Model. The “Totalization Table Form” must be received by the *IESO* at least 2 *business days* prior to the implementation date.

On the implementation date, the *IESO* will enter the totalization table into the MDMS system. As a result, the existing structure of the totalization table in the *metering registry* will change and these changes take effect on the start date of the *delivery point*. By completing and submitting IESO-FORM-1665, the *market participant* authorizes the *IESO* to implement the Meter Disaggregation Model and acknowledges that the current Site Registration Report for the affected *delivery points* will no longer be in effect. Typically, there is a 10-day turn-around time between the date the Compliance Aggregation Model is built in MDMS and the time the *IESO* receives the newly signed SRR. During this interim period, the Meter Disaggregation Model represents the totalization table in the *metering registry* and is in effect.

## 2.4 Applications Associated with the Creation of Totalization Table

### 2.4.1 Customer Data Management System (CDMS)

The Customer Data Management System (CDMS) is designed to meet the business requirements for the following business groups: System Capability, Market Entry and Metering Installation. The CDMS system is used by the three groups for the creation and maintenance of *facility* technical data:

- Registration of *market participants* and other organization types
- Registration of facilities and resources
- Registration of *metering installations*

The CDMS system maintains relationships between *metered market participants (MMP)*, *metering service providers (MSP)*, *transmitters* and/or *distributors*, and a *delivery point* (resource).

Also, the CDMS system maintains profiles, permissions, privileges and accounts for Meter Service Provider's, and *MMP's*. Once created and validated in CDMS, *metering*-relevant information, such as the *delivery point* relationships, is replicated to other *IESO* systems, such as MDMS.

### 2.4.2 Meter Data Acquisition System (MDAS)

MDAS is the application that the *IESO* uses for registering *metering installations*. *Meter point* IDs that are associated with each physical *meter/recorder* are created in the registration module of MDAS, transmitted to the production module, and then exported to the MDMS application.

### 2.4.3 Meter Data Management System (MDMS)

MDMS is the application that allows the creation of “summary maps” which summate readings from various *meter point* IDs that contribute to a *delivery point* (“metered market participant account”). This application also allows the application of error correction factors and losses, as appropriate. Once processed, these allocated quantities associated with a *delivery point*, which result from “totalized” *meter* readings, are exported to the Commercial Reconciliation system. MDMS is the place where the *meter point* ID that identifies either a physical or a summary meter is associated with a *delivery point* (account), based on the totalization data provided by the *metering service provider*.

MDMS is the *metering database* that includes original *energy* meter readings and creates as required *energy* readings that are loss adjusted and totalized to their respective *delivery points* for *settlement* of the *IESO-administered market*.

## 2.4.4 MDM-Meter Data Reports

MDM-Meter Data Reports allows *market participants* to view and download information about market transactions. *Metering service providers* can also use MDM- Meter Data Reports to check the correctness of the totalization tables entered by the *IESO*, prior to signoff.

## 2.4.5 Commercial Reconciliation

Commercial Reconciliation is the *settlements/billing* system employed by the *IESO*.

## 2.5 Supporting Documentation

### 2.5.1 Submitting the Information

A standard form, “Totalization Table Form”, available on the *IESO*’s Web site as an Excel spreadsheet, must be used for the submission of totalization data for the *energy market delivery point(s)* as well as for the *TT delivery point(s)*. The Excel format allows the *metering service provider* to adjust the number of lines as fit. The *metering service provider* can start the building of the Totalization Table as soon as a new *meter point* has been created and the MEC factors and the SSLA factors have been positively reviewed by the *IESO*. However, the procedure will conclude only after the relevant *meter points* have been registered with the *IESO*. For details see “Market Manual 3: Metering, Part 3.2: Meter Point Registration and Maintenance”.

Once completed, the “Totalization Table Form” will be submitted to the *IESO* as an Excel file [uploaded in Online IESO](#).

Details with regard to the information contained in the form, as well as the way this data is to be entered is given in Appendix B. A sample totalization is presented in Appendix C.

### 2.5.2 Confirming Correctness of the Totalization Tables

Once the *IESO* has entered the totalization tables in MDMS, based on the information submitted by the *metering service provider*, a “Site Registration Report”, will be generated by the *IESO* in Online IESO. Upon receiving the above Report from the *IESO*, the *metering service provider* must verify the data, resolve any issues with the *IESO*, and approve the report in Online IESO. Upon receiving the approved “Site Registration Report” for a newly-created *delivery point*, the *IESO* will activate the billing process for the relevant *metered market participant*, as detailed in “Part 3.8: Creating and Maintaining Delivery Point Relationships”.

The *transmitter* must also approve the “Site Registration Report” for *transmission tariffs delivery point*.

## 2.6 Maintaining Totalization Tables

There is no maintenance process as such for totalization tables as these must be resubmitted whenever one of the following changes occur:

- creation, modification or de-registration of relevant *meter point* IDs;
- change of relevant MEC, TLF and/or SSLA;
- change in allocation of *station service* consumption or Transformation Losses; and
- change of any other item that appears on the “Totalization Table Form”. The only exception to this rule is the change of *metered market participant* or *metering service provider* for a *delivery*

*point*. Since such changes are first captured in the CDMS tool and thus reflected automatically in the relevant Totalization Table, there is no need for resubmission.

When resubmitting a totalization table, the *metering service provider* must highlight the items that have been revised using the following conventions:

- Green for creation,
- Yellow for modifications,
- Red for de-registration.

## 2.7 Site Registration Report

The Site Registration Report (SRR) reflects all the parameters of the “Totalization Table Form” submission except for the *metered market participant* and the *metering service provider* relationships. Once signed-off by the *metering service provider* (and the *Transmitter*, if applicable) the SRR becomes an official document to which the *settlement* for that *delivery point* will be *invoiced*. A sample SRR is presented in Appendix E.

The SRR may contain up to seven sections. Please note that there can be only one summary meter attached to a *delivery point* at any one time. We will call this summary meter THE summary meter. The seven sections are:

- 1 Report Title
  - contains the site registration report for the subject *Delivery Point* and contains the date and time when the Site Registration Report was generated by MDMS. The report title will be displayed on the top of every page.
- 2 Meter Tree Picture
  - a picture layout of the configuration of physical meters, summary meters, THE summary meter and the *delivery point*. The picture layout also represents *meter(s)*, summary meter(s), THE summary meter and *delivery point* that can be viewed and can be downloaded in MDM- Meter Data Reports.
- 3 The *delivery point* associated to THE summary meter from a start date to an end date.
  - Note: A ‘no end date’ indicates THE summary meter is active, therefore the *delivery point* is active. A specific end date will indicate that THE summary meter and the contribution from all associated meters and summary meters below have been end dated. In other words, the *delivery point* will not be settled after the specified end date.
- 4 Channel Summary for THE summary meter
  - the make-up of THE summary meter. THE summary meter will indicate:  
 Listing of channels :1), 2), 3,) 4)  
 interval length :5 or 15 minute  
 type of *meter*: Summary channel, M (Main) channel, or S (Standalone)channel  
 Unit of Measurement (UOM) :1=kwh, 3=kvarh)  
 Direction of Power Flow :I=Import/delivered/withdrawal, E=Export/received/injection  
 Voltage Code : None = no losses applied  
                   : a 3 digit character  
 Note: Assumed Voltage, Assumed PF, CT ratio, VT ratio and ServiceType :D=Delta, or W=Wye) are displayed only if Voltage Code exist and Method 1 losses are applied.



## 5 Detailed Channel Information for THE Summary Meter

- Each channel of THE summary meter contains the mapping of all meters and summary meters.
- Each channel of THE summary meter will list the contributors including the parameters in 3 above.
- The plus sign indicates the metering data contribution is additive to THE summary meter's channel. A minus sign indicates the metering data contribution is subtractive to THE summary meter's channel.
- The percentage indicates the amount of *metering data* contributing to THE summary meter's channel. 100% indicates all the *metering data* is contributing where as 50% indicates only half of the *metering data* is contributing.
- The *meter* or summary meter's id.
- The channel number.
- The start date and end date. Again, an end date will indicate that the contribution from all associated meters and/or summary meters below will no longer have effective *metering data* after the specified end date. A 'null' indicates no end date.
- Interval length, type of *meter*, Unit of measurement, Power Flow direction, Voltage Code.
- An indent indicates that another layer of *meter* or summary meter is contributing.

## 6 Voltage Code Information

- If a voltage code exists at the *meter* or summary meter, the 3 character voltage code will be listed. Underneath the listing will contain:  
Precedence number—indicates the order to apply the losses  
Loss Factor code ---indicates the loss factor number and type of loss factor. Fixed loss is used for MEC, DLF, TLF. Equation loss is used for method 1 and method 2.  
The start date and end date. An end date of – (dash) indicates no end date.

Actual value—a Fixed loss will indicate the word Factor and then the percentage value. Method 1 will indicate I4H, I2H, V4H, V2H, and a constant. Normally, method 1 will indicate coefficients for I2H and V2H. The remaining parameters will have Zero values. Method 2 will indicate the coefficients for KVA2H, KVAH and a constant.

Once approved, the SRR becomes one of the official documents from which an *invoice* will be generated.

– End of Section –

## 3. Procedural Work Flow

The diagrams in this section represent the flow of work and information related to the Totalization Table Registration procedure between the *IESO*, the primary external participant involved in the procedure, and any other parties.

The steps illustrated in the diagrams are described in detail in Section 4.

The acronym “PWF” stands for Procedural Workflow.

**Table 3–1: Legend for Procedural Work Flow Diagrams**

<b>Legend</b>	<b>Description</b>
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.

Labels marked TTBL-xx represent letters the *IESO* sends to the *metering service provider* at various steps in the process.

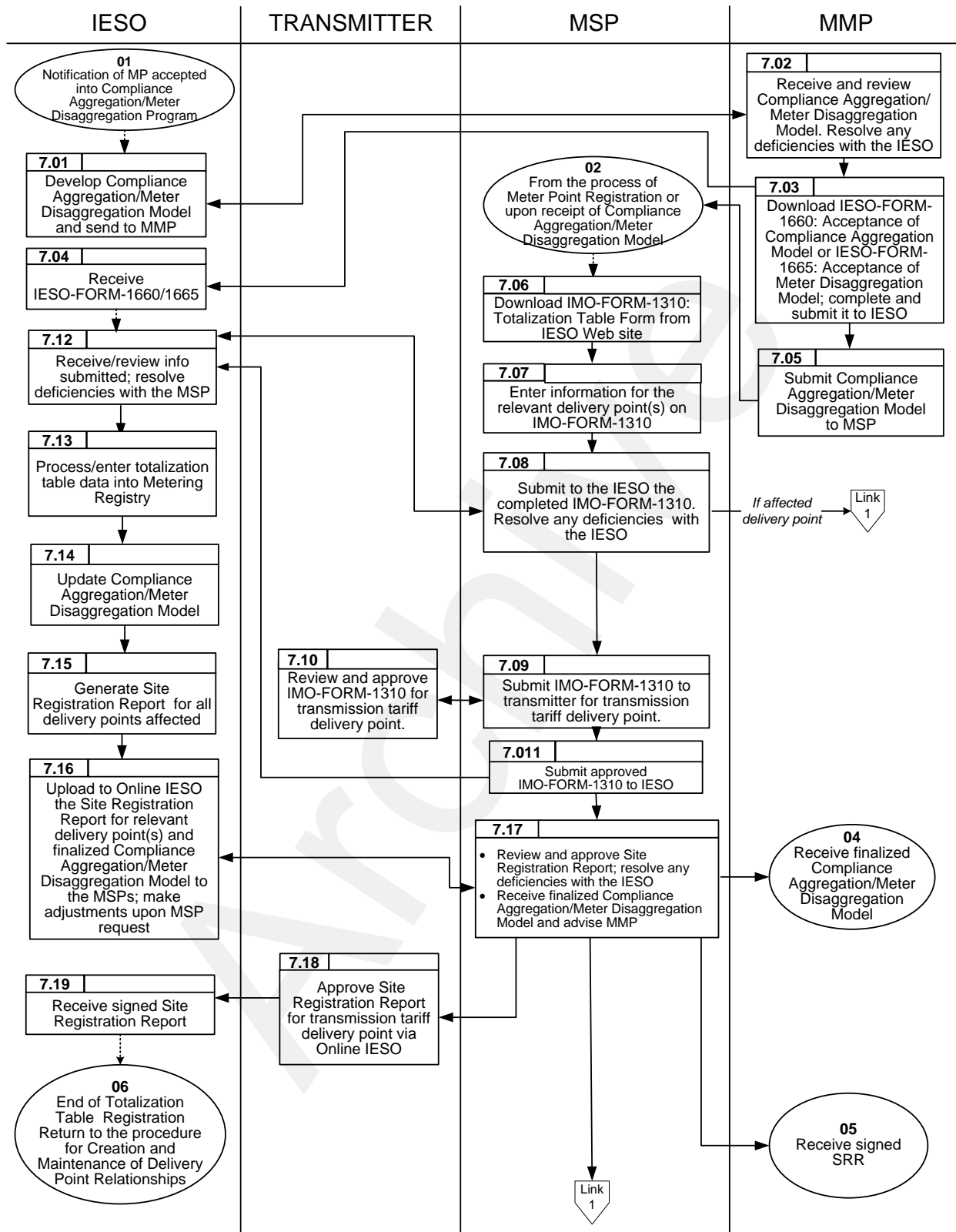


Figure 3-1: Work flow for Totalization Table Registration

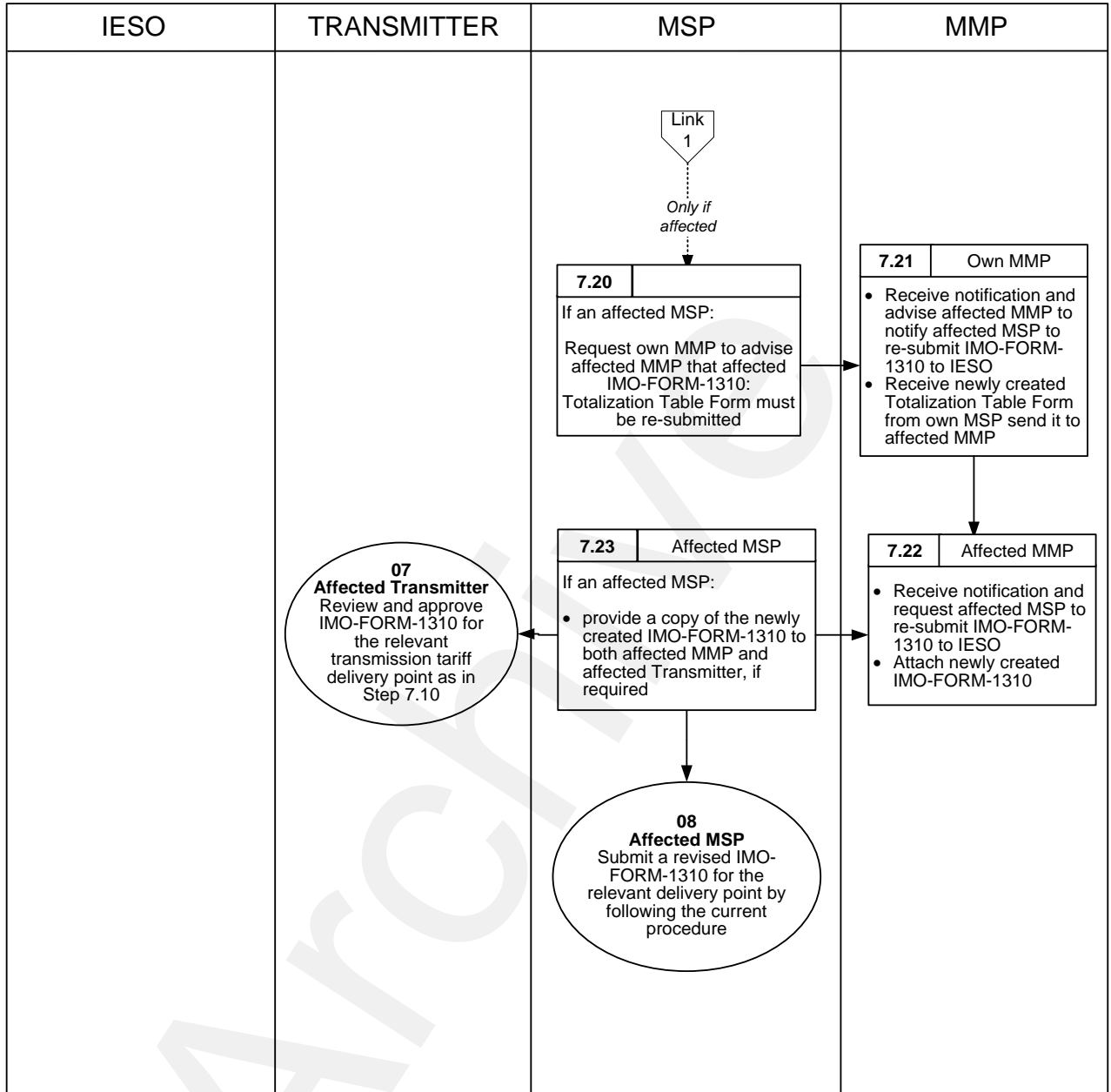


Figure 3–1: Work Flow for Totalization Table Registration (continued)

– End of Section –

## Appendix A: Forms

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This appendix contains a list of forms used in the Totalization Table Registration procedure, which are available on the *IESO* Web site ([www.ieso.ca](http://www.ieso.ca)). The forms included are listed in the table below.

Form Name	Form Number
Connection Facility Station Service Form	FORM-78
Totalization Table Form	IMO_FORM_1310 (Excel spreadsheet)
Acceptance of Compliance Aggregation Model	IESO_FORM_1660
Acceptance of Meter Disaggregation Model	IESO_FORM_1665

– End of Section –

# Appendix B: Guidelines for Completing the Totalization Table Form

## General Overview

The information submitted to the *IESO* relates to physical *meters* that contribute to the *settlement* at a specific *delivery point*. These physical *meters* are then used by the *IESO* as contributors to summary (virtual *meters*) associated with the *delivery point*. In the enduring stage, the *metering service provider* will, however, submit complete totalization tables, ready for input into MDMS. The *metering service provider* must submit the information, electronically, on an Excel spreadsheet that can be downloaded from the *IESO* Web site. The standard spreadsheet form contains three distinct areas: general information (at the top), *energy market*, and *transmission tariffs*.

The general information area, at the top of each form, includes the following fields:

- **Facility Name:** enter the name of *facility* as recorded on the SLD and the “SLD-Submission Form” submitted for *meter point* registration;
- **Effective Date:** enter the estimated date when *settlement* at the *delivery point* must start; note that the real date for starting *settlements* is the date when *metered market participant* relationships for *delivery point* are accepted by the *IESO*, see “Market Manual 3: Metering, Part 3.8: Creating and Maintaining Delivery Point Relationships”;
- **Metering Service Provider ID:** enter the ID assigned to the *metering service provider* during *metering service provider* registration;
- **Prepared by:** enter the name of *metering service provider’s* staff who prepared the information;
- **Ratio of Breakers for (enter the metered market participant name and #):** enter the number of breakers pertaining to each *metered market participant* involved and the total number of feeder breakers; and
- **Non-Metered Station Service (kW):** enter the value previously submitted as per Section 2.3.1.

The detailed information to be entered in **Area A: *energy market*** includes the following:

- **Metered Market Participant:** enter the *metered market participant #* , as above;
- **Delivery Point ID (energy):** enter the *delivery point* at which the above *metered market participant* is settled, as recorded on the SLD and the “SLD-Submission Form” submitted for *meter point* registration;
- **Summary 1:** to be completed by *IESO*, for now;
- **Summary 2:** to be completed by *IESO*, for now;
- **Meter Point ID:** enter the ID of the physical *meter* (contributor) as assigned during *meter point* registration or enter none for *station service*;
- **Channel No:** enter the channel number of the physical *meter*; only kWh and kVARh channels are required;
- **Operator + or -:** enter “+” if the reading of the *meter* is to be added or “-” if subtracted;
- **U of M** enter the unit of measure (kWh or kVARh);
- **Energy Flow Direction:** enter the direction of *energy* (“DEL” for delivered, “REC” for received);

- **Description of Measured Circuit:** identify the physical location of the *meter* as specified on the relevant SLD submitted during the process of *meter point* registration (Ex: Pine TS-T4);
- **Ratio (scaling):** leave blank for 100% allocation of *metering data*. A value of .5 would indicate to allocate 50% of the *metering data*;
- **MEC:** enter MEC value as per Section 2.2.4;
  - **Assumed Voltage<sup>1</sup>:** enter value of assumed secondary voltage;
  - **Assumed PF\*:** enter value for the assumed power factor, two decimal digits are required;
  - **Service Type\*:** enter “D” for 3-wire, delta service or “W” for 4-wire, wye service;
  - **CT Ratio\*:** enter the current transformer’s ratio in use;
  - **VT Ratio\*:** enter the voltage transformer’s ratio in use;
- **Coefficients for Transformation Losses and/or Radial Line,** as follows (enter already adjusted values, as per Section 2.2.5):
 

**Transformation:**

  - a ( $V^2$ )
  - b ( $I^2$ )

**Radial line:**

  - e ( $V^2$ )
  - f ( $I^2$ )
- **Coefficients for Transformation Losses and/or Radial Line** (for three winding transformers, enter already adjusted values, as per Section 2.2.5) as follows:
 

**Transformation:**

  - k<sub>1</sub>
  - k<sub>2</sub>
  - k<sub>3</sub>

**Radial line:**

  - k<sub>1</sub>
  - k<sub>2</sub>
  - k<sub>3</sub>
- **TLF (for embedded metered market participants only):** enter Total Loss Factor as per Section 2.2.6.

The detailed information to be entered in **Area B: transmission tariffs** includes the following:

- **MMPT Name:** enter the *Market Participant* name and number who is the *transmission customer*;
- **MMPT#:** enter the *Market Participant #* , as above;
- **DP ID:** enter the TT *delivery point* IDs, as submitted on the SLD and “SLD-Submission Form”;
- **Summary 3:** to be completed by the *IESO*, for now;

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<sup>1</sup> Required only when loss coefficients “a” and “b” and/or “e” and “f” are used.

- **Summary 4:** to be completed by the *IESO*, for now;
- **Meter Point ID:** enter the ID of the physical *meter* (contributor) as assigned during *meter point* registration or enter none for *station service*;
- **Channel No:** enter the channel number of the physical *meter*; only kWh and kVARh channels are required;
- **Operator + or -:** enter “+” if the reading of the *meter* is to be added or “-” if subtracted;
- **U of M** enter the unit of measure (kWh or kVARh);
- **Energy Flow Direction:** enter the direction of *energy* (“DEL” for delivered, “REC” for received);
- **Description of Measured Circuit:** identify the physical location of the *meter* as specified on the relevant SLD (Ex: Pine TS-T4).

The rest of the fields in the *transmission tariffs* area (the hatched columns) must be filled only if the associated *meters* (*meter points*) are used exclusively for *transmission tariffs*; otherwise, there is no need to populate them. If the *meter point* ID is the same as for the *energy market*, then all the hatched cell information will apply.

However, this information (such as SSLA, MEC and TLF factors) can be added at the Meter Service Provider’s discretion.

**Note:** *Meter point* IDs pertaining to *meters* that will be used for TT calculations, only, must be marked by an asterisk. Such *meters* are associated with *embedded generators* built after 1998 and that do not participate in the *energy market*. It is the responsibility of the host MMPT to ensure that such *meters* are properly registered with the *IESO*.

– End of Section –



# Appendix C: Example of Totalization

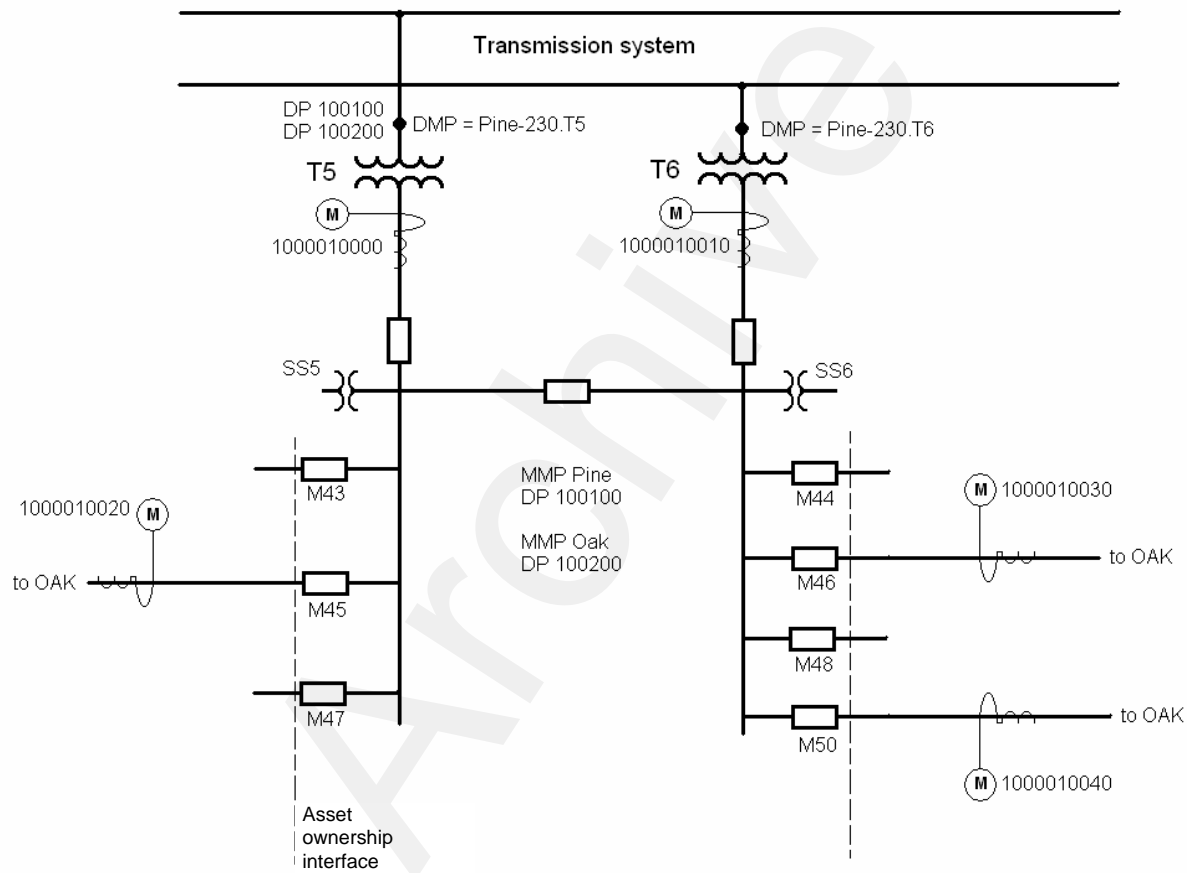


Figure C-1: Single Line Diagram for Pine TS T5/T6

**Table C-1: Totalization Table Form**

**TOTALIZATION TABLE FORM**



Facility Name: Pine TS  
 Effective Date: 01-Oct-00  
 MSP ID: 1000  
 Prepared By (MSP): Tom Jones  
 IESO Build By:

Breaker Ratio	T <sub>1</sub>		T <sub>2</sub>		T <sub>3</sub>	
	MMP Feeders	Total Feeders T5/T6	MMP Feeders	Total Feeders	MMP Feeders	Total Feeders
MMP1: Pine	4	7				
MMP2: Oak	3	7				

Non-metered Station Service (kW) SS5+SS6 = 15kW

**A. ENERGY MARKET**

Date	Full SSLA			
	k1	k2	k3	
01-Oct-00	T5-T6	0.0192	-0.173	104.41

MMP #	DP ID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	Ud/M	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P/L	Service Type	CT Ratio	PT Ratio	Transformation		Radial Line			TLF							
																	a(V <sup>2</sup> )	b(I <sup>2</sup> )	e(V <sup>2</sup> )	f(I <sup>2</sup> )	k <sub>1</sub>		k <sub>2</sub>	k <sub>3</sub>					
1	100100			100001000	1	+	kWh	del	T5																				
				100100C99	2	+	kVARh	del	T5																				
					3	+	kWh	rec	T5																				
					4	+	kVARh	rec	T5																				
					1	+	kWh	del	T6																				
					2	+	kVARh	del	T6																				
					3	+	kWh	rec	T6																				
					4	+	kVARh	rec	T6																				
					1	.	kWh	del	M45																				
					2	.	kVARh	del	M45																				
					3	.	kWh	rec	M45																				
					4	.	kVARh	rec	M45																				
					1	.	kWh	del	M46																				
					2	.	kVARh	del	M46																				
					3	.	kWh	rec	M46																				
					4	.	kVARh	rec	M46																				
					1	.	kWh	del	M50																				
					2	.	kVARh	del	M50																				
					3	.	kWh	rec	M50																				
					4	.	kVARh	rec	M50																				
				20	1	.	kWh	del	SS_Pine	0.429																			

**Table C-1: Totalization Table Form (continued)**

2	100200	100200C99	1000010020	1	+	kWh	del	M45									0.0448	-0.173	44.747								
			1000010020	2	+	kVARh	del	M45																			
			1000010020	3	+	kWh	rec	M45																			
			1000010020	4	+	kVARh	rec	M45																			
			1000010030	1	+	kWh	del	M46											0.0448	-0.173	44.747						
			1000010030	2	+	kVARh	del	M46																			
		100200E	1000010030	3	+	kWh	rec	M46																			
			1000010030	4	+	kVARh	rec	M46																			
			1000010040	1	+	kWh	del	M50												0.0448	-0.173	44.747					
			1000010040	2	+	kVARh	del	M50																			
			1000010040	3	+	kWh	rec	M50																			
			1000010040	4	+	kVARh	rec	M50																			
				20	1	+	kWh	del	SS_Pine		0.429																

**Table C-1: Totalization Table Form (continued)**

**B. TRANSMISSION TARIFF**

	MMPT Name
MMPT1	Pine
MMPT2	Oak

MMPT #	DP ID	Summary 1	Summary 2	Meter Point ID	Change No.	Operator (tariff)	Units	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Factor	CT Ratio	PT Ratio	Transformation		Radial Line		Transformation			Radial Line			TLF			
																	a(V <sup>2</sup> )	b(I <sup>2</sup> )	e(V <sup>2</sup> )	f(I <sup>2</sup> )	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>				
1	100101			100001000	1	+	kWh	del	T5																					
				100001000	3	+	kWh	rec	T5																					
				1000010010	1	+	kWh	del	T6																					
				1000010010	3	+	kWh	rec	T6																					
				1000010020	1	-	kWh	del	M45																					
		100101N	100100EE	1000010020	3	-	kWh	rec	M45																					
				1000010030	1	-	kWh	del	M46																					
				1000010030	3	-	kWh	rec	M46																					
				1000010040	1	-	kWh	del	M50																					
				1000010040	3	-	kWh	rec	M50																					
			20	1	-	kWh	del	SS_Pine																						
	100102				100001000	1	+	kWh	del	T5																				
					100001000	3	+	kWh	rec	T5																				
					1000010010	1	+	kWh	del	T6																				
					1000010010	3	+	kWh	rec	T6																				
					1000010020	1	-	kWh	del	M45																				
		100102C	100100EE	1000010020	3	-	kWh	rec	M45																					
					1000010030	1	-	kWh	del	M46																				
					1000010030	3	-	kWh	rec	M46																				
					1000010040	1	-	kWh	del	M50																				
				1000010040	3	-	kWh	rec	M50																					
			20	1	-	kWh	del	SS_Pine																						
2	100201			1000010020	1	+	kWh	del	M45																					
				1000010020	3	+	kWh	rec	M45																					
				1000010030	1	+	kWh	del	M46																					
		100201N	100200E	1000010030	3	+	kWh	rec	M46																					
				1000010040	1	+	kWh	del	M50																					
	100202				1000010040	3	+	kWh	rec	M50																				
					20	1	+	kWh	del	SS_Pine																				
					1000010020	1	+	kWh	del	M45																				
					1000010020	3	+	kWh	rec	M45																				
		100202C	100200E	1000010030	3	+	kWh	rec	M46																					

Note: Hatched cells to be completed for meters used exclusively for Transmission Tariffs

- End of Section -

# Appendix D: Metering - Settlement Principles

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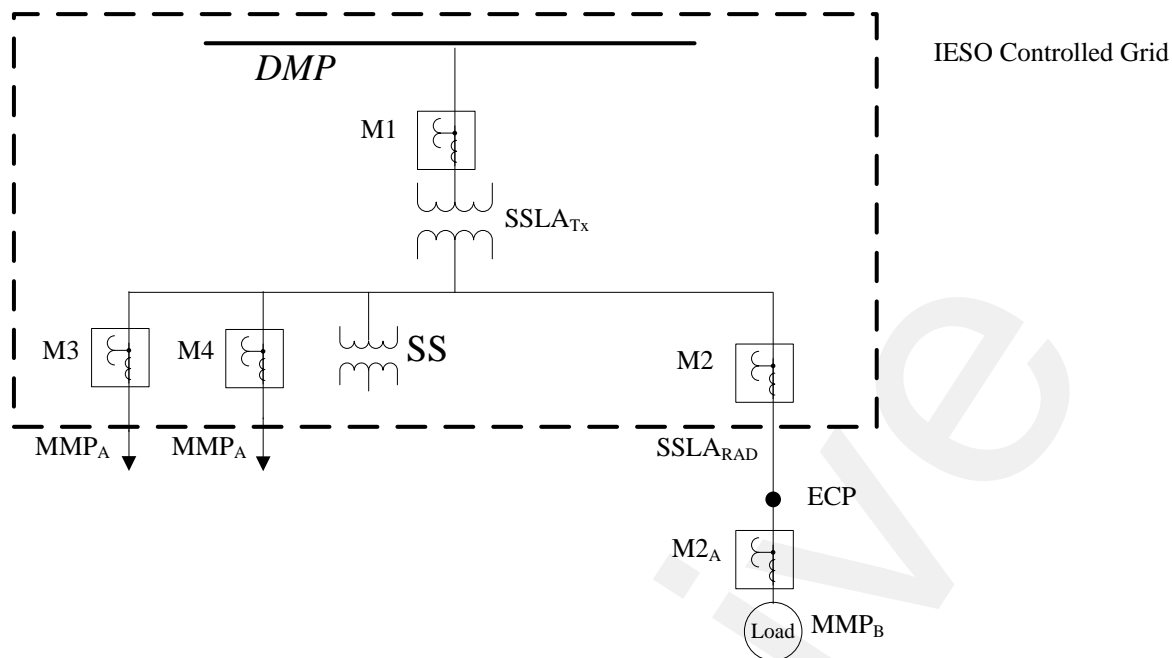
## Metering - Settlement Principles

This Appendix provides examples of the application of principles utilized by the *IESO* in settling the wholesale market. These examples are not intended to be exhaustive of circumstances that may arise and may not reflect *market participants'* commercial arrangements or agreements with other *market participants* or other third parties. If *market participants* have particular requirements or encounter circumstances not covered in the examples, or if *market participants* believe the examples are not appropriate, they should contact the *IESO* prior to submission of the totalization table. *Metered market participants* and their *metering service providers* are responsible for ensuring that the applications of the principles are appropriate to their situation.

*Metered market participants* are also responsible for ensuring that their respective *OEB* approved loss factors such as the TLF are applied in a manner consistent with their respective rate orders.

The *IESO* is not responsible or liable for any commercial arrangements or other agreements between *market participants* such as *MMPs*, *MSPs*, *transmitters*, *distributors* and *generators*, or between *market participants* and other third parties. In addition, as noted above, the examples in this Appendix may not reflect these arrangements or agreements. If *market participants* have particular commercial arrangements or agreements not covered in the examples or where they believe the examples are not appropriate, they should contact the *IESO* prior to submission of the totalization table.

### A. General Arrangement – Note Variations of Layout Used in all Cases



#### Definitions

M1 – Primary RWM

M2<sub>A</sub> – Embedded RWM

M2, M3 & M4 – RWM

SS - station service (note location may vary)

SSLA<sub>TX</sub> - site specific loss adjustment in kWh – transformer

SSLA<sub>RAD</sub> - site specific loss adjustment in kWh - radial line loss

Where there is sharing of losses and station service, MMP<sub>A</sub> share Y, MMP<sub>B</sub> share Z, then

$$SSLA_{TX} = SSLA_Y + SSLA_Z$$

$$SS = SS_Y + SS_Z$$

ECP - embedded connection point

TLF - total loss factor (per OEB)

DMP - defined meter point

TT - transmission tariff

Agreement - means an SSLA<sub>TX</sub> and SS allocation agreement between Metered Market Participants

No agreement - means Market Rules Ch 9 default values for SSLA<sub>TX</sub> and SS

MMP - metered market participant, may be A, B etc

Tap - means a physical line tap for load, whether temporary, or permanent, or emergency

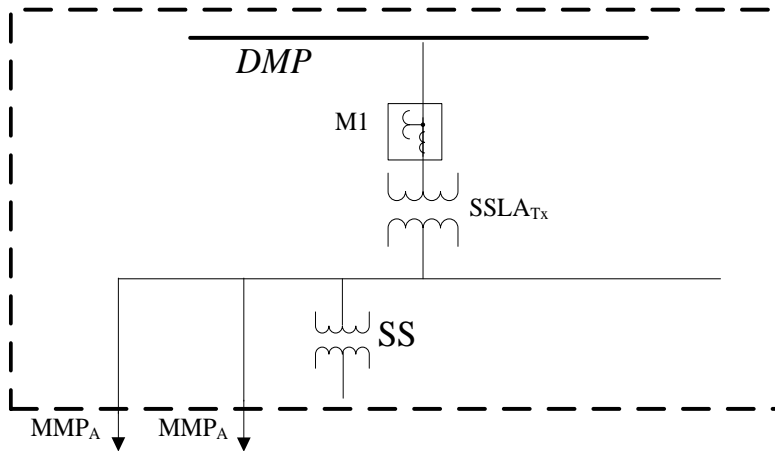
Notes:

1. SSLA<sub>Y</sub> and SSLA<sub>Z</sub> are loss component values (kWh) calculated from application of Y & Z to the loss code for each interval and represents their share of the losses.
2. SS<sub>Y</sub> and SS<sub>Z</sub> is the application of the ratios of Y and Z to the total station service load, also in kWh.

3. The ECP is equivalent to the DMP for an embedded *facility*. ECP is used for simplicity.
4. The *transmission tariffs* are strictly based on the applicable Ontario Transmission Rate Schedules.
5. The assumption is the TLF includes the *station service* load.
6. An embedded participant has a TLF but no *station service* load or transmission charge.
7. Directly connected to a HONI Transformer Station (TS) means the LDC feeder is directly connected to the TS bus inside the fence - no TLF, and the LDC is the TT customer.
8. An embedded participant is defined as per the *Market Rules*.
9. A participant is either embedded or directly connected, not both.
10. 1A directly connected participant is defined by the transmission connection agreement.
11. *Market Participants* shall ensure that their TLFs are being applied appropriately. The *IESO* is not party to the individual LDCs TLF calculations and is not responsible for their misapplication.
12. The *transmitter* is responsible for the *station service* metering.
13. The participant that owns the majority of the feeders is responsible for the loss calculation, unless they cause a calculation to be performed.
14. The TLF is used to settle both the *energy* consumed and transmission charges.
15. The principles are based on TLFs not including any measurement error correction (MEC). These are applied separately to the meter reading.
16. TLF factors are dependent on power flow direction. For the delivered channel, the TLF approved by *OEB* rate order will be applied. For the received channel, a default value of one (1) will be applied. Any value other than the default value must be agreed by the participants.

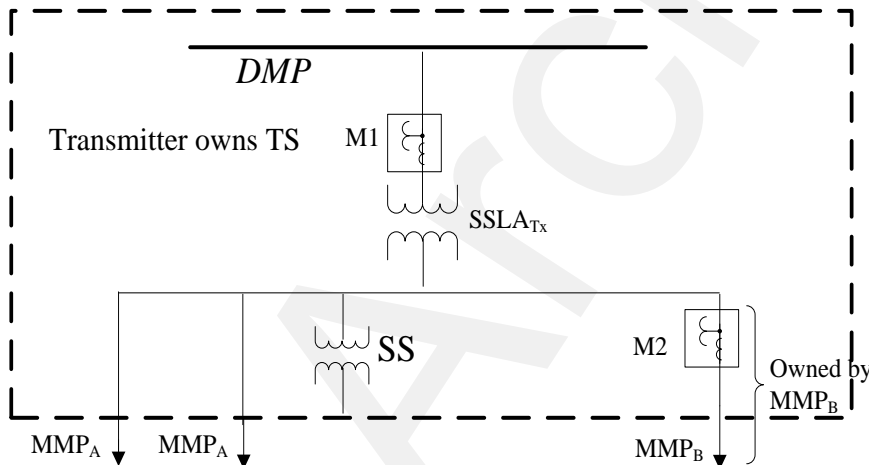
### 1. High Side Meter

Assumption:  $MMP_A$  is the only participant



Total Energy	=	M1	M1 captures all losses and <i>station service</i>
$MMP_A$ Energy	=	M1	
$MMP_A$ TT	=	M1	

### 2a. High Side Meter + $MMP_B$ Directly Connected to the TS bus with the feeder meter



$MMP_A$  and  $MMP_B$  are directly connected to the TS bus inside the fence  
 $MMP_A$  and  $MMP_B$  are *transmission customers*

#### 2a.1. Agreement on Losses

$MMP_A$ Energy	=	$M1 - (M2 + SS_Z + SSLA_Z)$
$MMP_A$ TT	=	$M1 - (M2 + SS_Z + SSLA_Z)$
$MMP_B$ Energy	=	$M2 + SS_Z + SSLA_Z$
$MMP_B$ TT	=	$M2 + SS_Z + SSLA_Z$



**2a.2 No Agreement on Losses (MMP<sub>B</sub> gets zero losses)**

$$SS_Z = 0, SSLA_Z = 0$$

$$MMP_A \text{ Energy} = M1 - M2$$

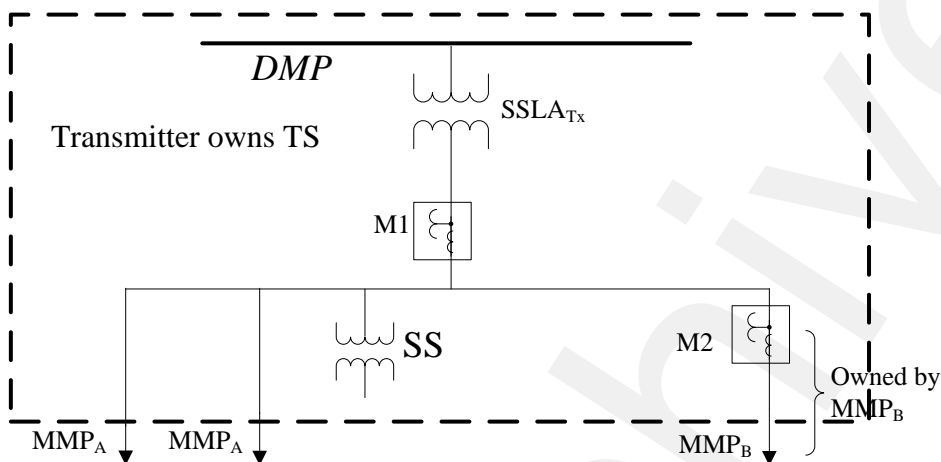
$$MMP_A \text{ TT} = M1 - M2$$

$$MMP_B \text{ Energy} = M2$$

$$MMP_B \text{ TT} = M2$$

Note:

1. MMP<sub>B</sub> provides the loss calculation

**2b. Bus Meter + MMP<sub>B</sub> Directly Connected to the TS bus with feeder meter**

- MMP<sub>A</sub> and MMP<sub>B</sub> are directly connected to the TS bus inside the fence
- MMP<sub>A</sub> and MMP<sub>B</sub> are *transmission customers*

**2b.1 Agreement on Losses**

$$MMP_A \text{ Energy} = M1 + SSLA_{TX} - (M2 + SS_Z + SSLA_Z)$$

$$MMP_A \text{ TT} = M1 + SSLA_{TX} - (M2 + SS_Z + SSLA_Z)$$

$$MMP_B \text{ Energy} = M2 + SS_Z + SSLA_Z$$

$$MMP_B \text{ TT} = M2 + SS_Z + SSLA_Z$$

**2b.2 No Agreement on Losses (MMP<sub>B</sub> gets zero losses)**

$$SS_Z = 0, SSLA_Z = 0$$

$$MMP_A \text{ Energy} = M1 + SSLA_{TX} - M2$$

$$MMP_A \text{ TT} = M1 + SSLA_{TX} - M2$$

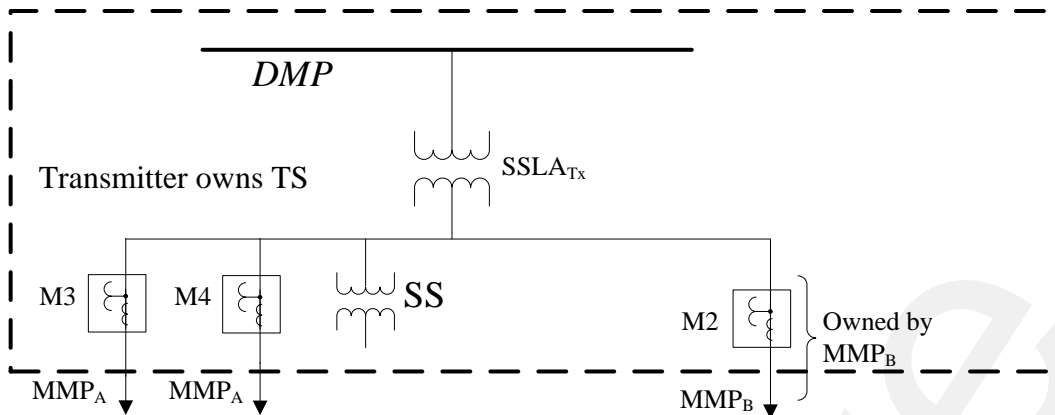
$$MMP_B \text{ Energy} = M2$$

$$MMP_B \text{ TT} = M2$$

Notes:

1. MMP<sub>A</sub> provides the loss calculation.

### 3. Feeder Meters – MMPA and MMPB Directly Connected to TS Bus



- $MMP_A$  and  $MMP_B$  are directly connected to the TS bus inside the fence
- $MMP_A$  and  $MMP_B$  are *transmission customers*

#### 3.1 Agreement on Losses

$$\begin{aligned} MMP_A \text{ Energy} &= M3+M4+SS_Y+SSLA_Y \\ MMP_A \text{ TT} &= M3+M4+SS_Y+SSLA_Y \\ MMP_B \text{ Energy} &= M2+SS_Z+SSLA_Z \\ MMP_B \text{ TT} &= M2+SS_Z+SSLA_Z \end{aligned}$$

#### 3.2 No Agreement on Losses ( $MMP_B$ gets zero losses)

Based on breaker count of 3 breakers

Same as above (with agreement) except losses calculated using

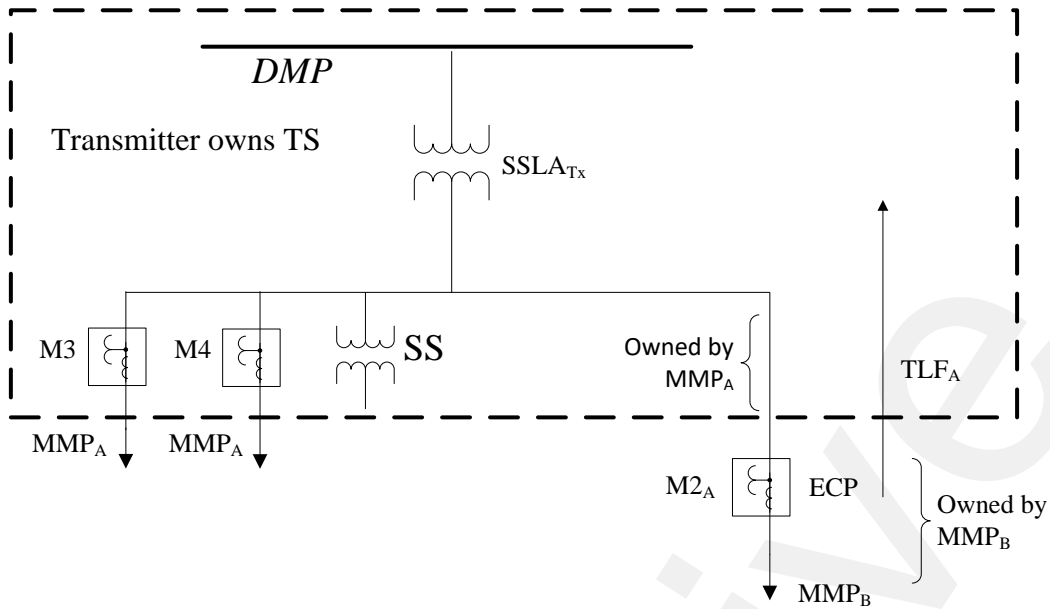
$$Y=2/3$$

$$Z=1/3$$

Notes:

1.  $MMP_A$  provides the loss calculation.

**4. Feeder Meters – MMP<sub>B</sub> embedded in MMP<sub>A</sub> Feeder**



- MMP<sub>A</sub> is the *transmission customer*
- MMP<sub>B</sub> is embedded in MMP<sub>A</sub> feeder

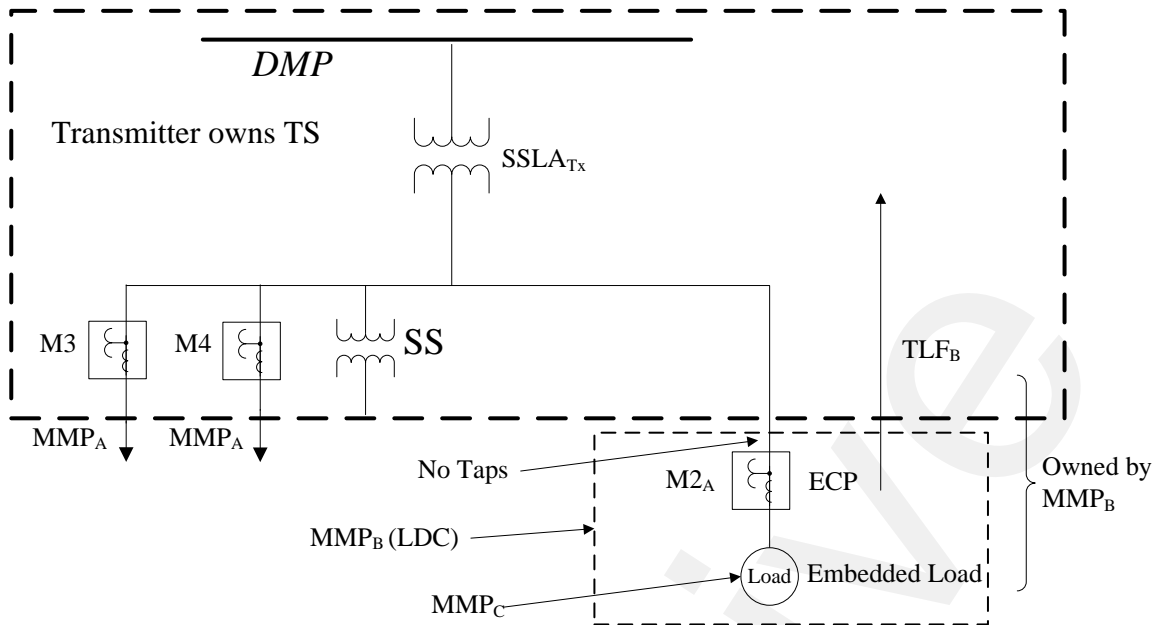
**4.1 No Agreement on Losses is required**

MMP <sub>A</sub> Energy	=	M3+M4+SS <sub>Y</sub> +SSLA <sub>Y</sub>
MMP <sub>A</sub> TT	=	M3+M4+SS <sub>Y</sub> +SSLA <sub>Y</sub> +M2 <sub>A</sub> .TLF <sub>A</sub>
MMP <sub>B</sub> Energy	=	M2 <sub>A</sub> .TLF <sub>A</sub> per <i>OEB</i>

Notes:

1. The TLF may have more than one value depending on the *OEB* approved rate -for example it may have a smaller value for an ECP close to the TS, and larger values further away from the TS e.g. HONI TLF.
2. MMP<sub>A</sub> provides the loss calculation.
3. Share Y = 2/3 based on breaker count used by MMP<sub>A</sub>

**5. MMP<sub>A</sub> and MMP<sub>B</sub> Directly Connected, MMP<sub>C</sub> Embedded in MMP<sub>B</sub>**



- MMP<sub>A</sub> and MMP<sub>B</sub> are directly connected to the TS bus inside the fence
- MMP<sub>A</sub> and MMP<sub>B</sub> are *transmission customers*

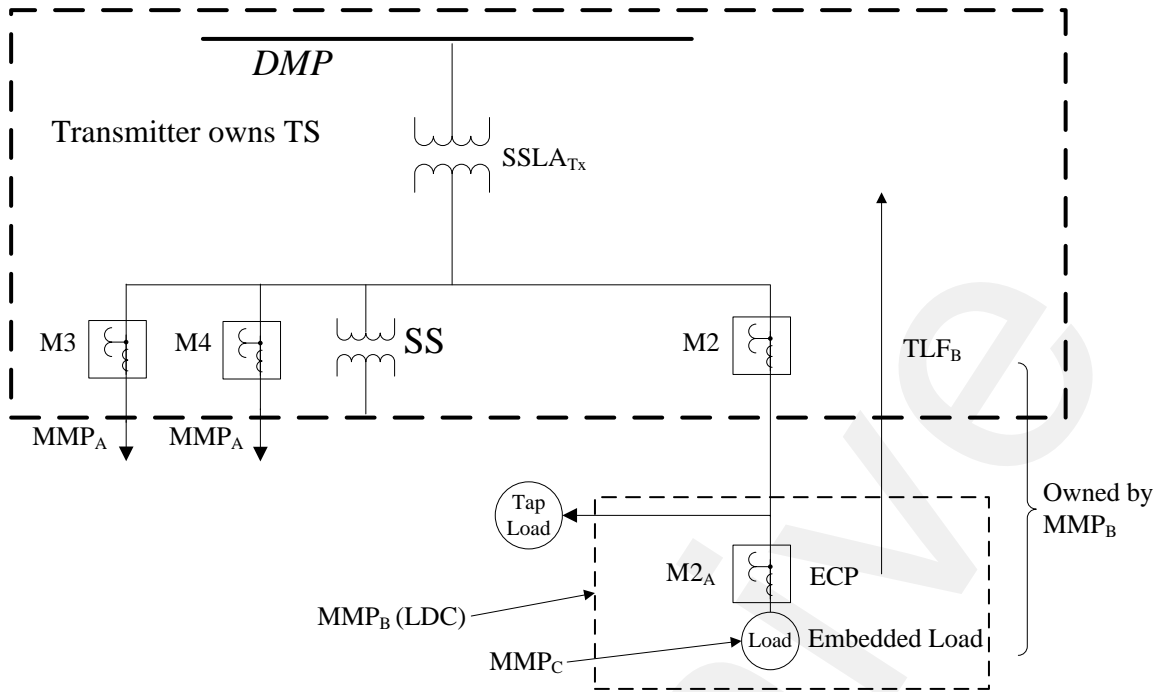
**5.1 No Agreement on Losses is required**

MMP <sub>A</sub> Energy	=	M3+M4+SSY+SSLAY
MMP <sub>A</sub> TT	=	M3+M4+SSY+SSLAY
MMP <sub>B</sub> TT	=	M2 <sub>A</sub> .TLF <sub>B</sub>
MMP <sub>C</sub> Energy	=	M2 <sub>A</sub> .TLF <sub>B</sub> per <i>OEB</i>

Notes:

1. MMP<sub>B</sub> provides the loss calculation.
2. Loss share Y=2/3 based on breaker count used by MMP<sub>A</sub>

**6a. MMPA and MMPB Directly Connected, MMPC Embedded in MMPB – Feeder Meters**



- MMP<sub>A</sub> and MMP<sub>B</sub> are directly connected to the TS bus inside the fence
- MMP<sub>A</sub> and MMP<sub>B</sub> are *transmission customers*
- MMP<sub>A</sub> and MMP<sub>B</sub> are the two parties that have to agree on losses

**6a.1 Agreement on Losses**

MMP <sub>A</sub> Energy	=	M3+M4+SS <sub>Y</sub> +SSLA <sub>Y</sub>
MMP <sub>A</sub> TT	=	M3+M4+SS <sub>Y</sub> +SSLA <sub>Y</sub>
MMP <sub>B</sub> Energy	=	M2+SS <sub>Z</sub> +SSLA <sub>Z</sub> -M2 <sub>A</sub> .TLF <sub>B</sub>
MMP <sub>B</sub> TT	=	M2+SS <sub>Z</sub> +SSLA <sub>Z</sub>
MMP <sub>C</sub> Energy	=	M2 <sub>A</sub> .TLF <sub>B</sub> per <i>OEB</i>

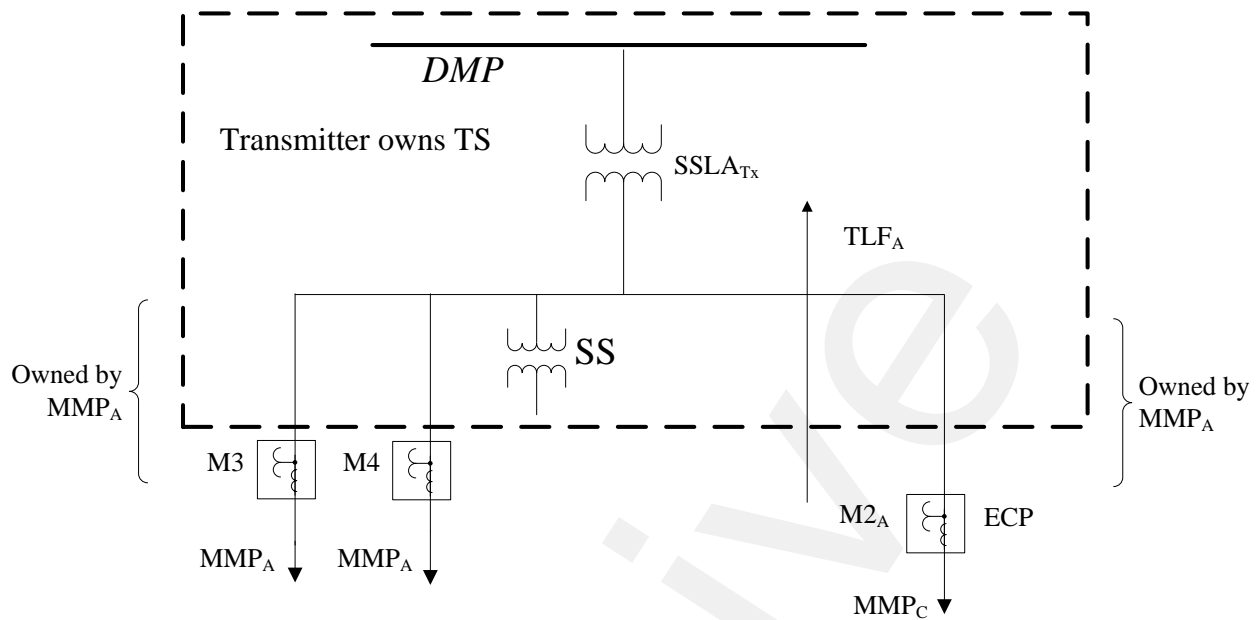
**6a.2 No Agreement on Losses is required**

Same as above except A's loss factor is based on 2/3 and B's is on 1/3.

Notes:

1. MMP<sub>A</sub> provides the loss calculation.

## 6b. MMP<sub>B</sub> and MMP<sub>C</sub> Embedded



- MMP<sub>B</sub> and MMP<sub>C</sub> have moved outside the fence
- MMP<sub>B</sub> and MMP<sub>C</sub> are both embedded in MMP<sub>A</sub> feeders
- MMP<sub>A</sub> is the *transmission customer*

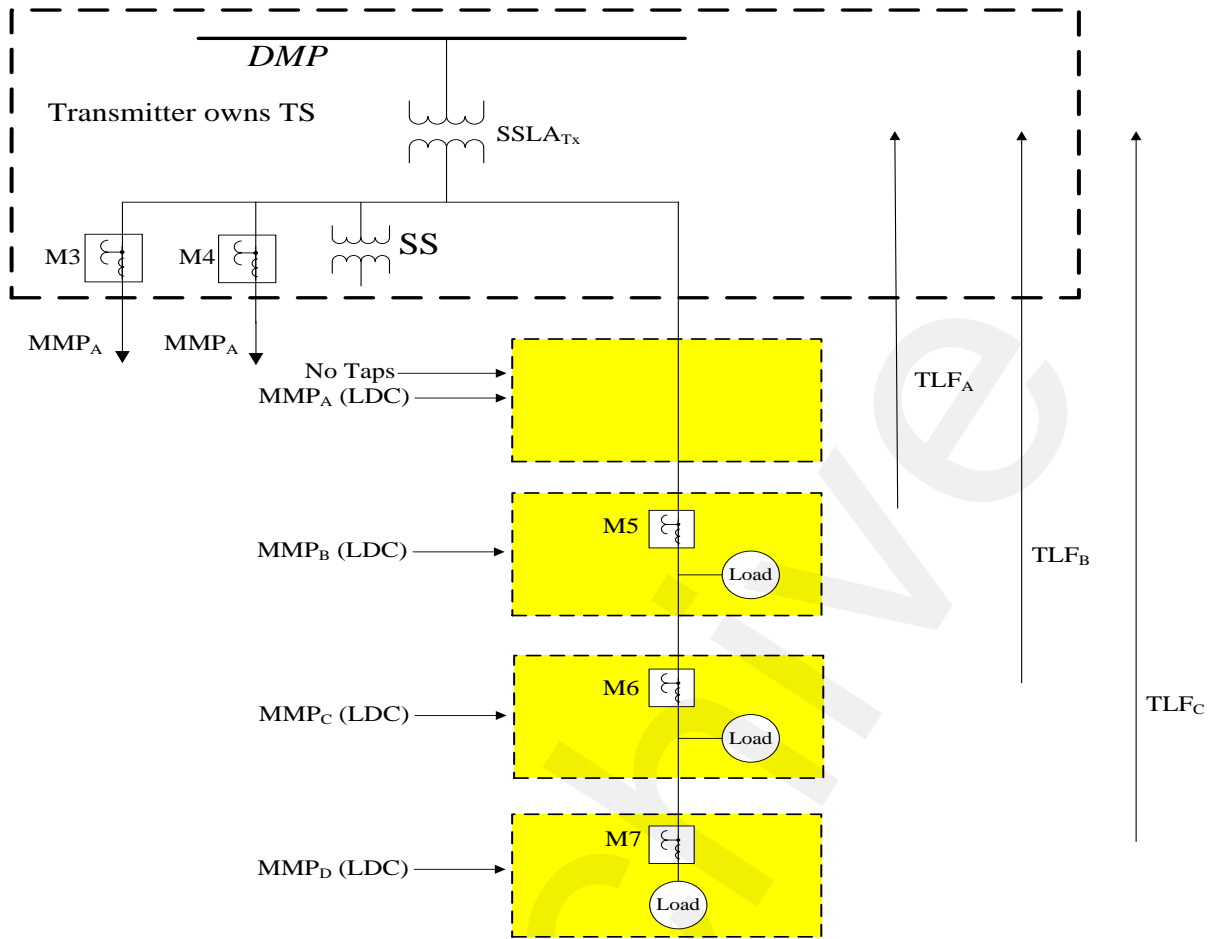
### 6b.1 Agreement on Losses

$$\begin{aligned}
 \text{MMP}_A \text{ TT} &= \text{M3.TLF}_A + \text{M4.TLF}_A + \text{M2}_A.\text{TLF}_A \\
 \text{MMP}_B \text{ Energy} &= \text{M3.TLF}_A + \text{M4.TLF}_A \text{ per } OEB \\
 \text{MMP}_C \text{ Energy} &= \text{M2}_A.\text{TLF}_A \text{ per } OEB
 \end{aligned}$$

Notes:

1. No SSLA calculation required
2. No *station service* metering required

**7a. Multiple Embedded Distributors with taps**



- $MMP_A$  is directly connected to the bus inside the fence
- $MMP_B$ ,  $MMP_C$  and  $MMP_D$  are embedded
- $MMP_A$  is a *transmission customer*

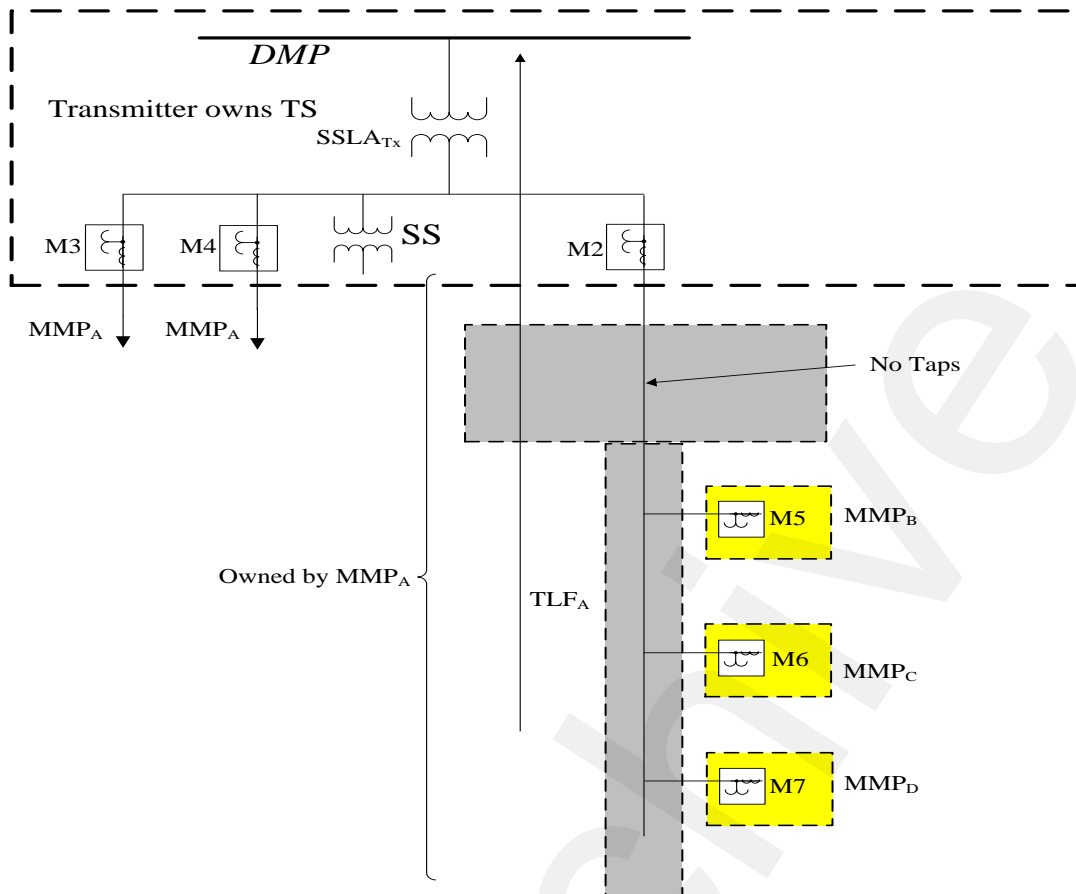
**7a.1 No Agreement on Losses is required**

$MMP_A$ Energy	=	$M3+M4 + SS_Y+SSLA_Y$
$MMP_A$ TT	=	$M3+M4 + M5.TLF_A+SS_Y+SSLA_Y$
$MMP_B$ Energy	=	$M5.TLF_A - M6.TLF_B$ per <i>OEB</i>
$MMP_C$ Energy	=	$M6.TLF_B - M7.TLF_C$ per <i>OEB</i>
$MMP_D$ Energy	=	$M7.TLF_C$ per <i>OEB</i>

Notes:

1.  $MMP_A$  provides the loss calculation.

## 7b. Embedded Distributors in Parallel



- $MMP_A$  is directly connected
- $MMP_A$  is a *transmission customer*
- $MMP_B$ ,  $MMP_C$  and  $MMP_D$  are embedded

### 7b.1 No Agreement on Losses is required

$$MMP_A \text{ Energy} = M3 + M4 + M2 + SS + SSLA_{TX} - M5.TLF_A - M6.TLF_A - M7.TLF_A$$

$$MMP_A \text{ TT} = M3 + M4 + M2 + SS + SSLA_{TX}$$

$$MMP_B \text{ Energy} = M5.TLF_A \text{ per } OEB$$

$$MMP_C \text{ Energy} = M6.TLF_A \text{ per } OEB$$

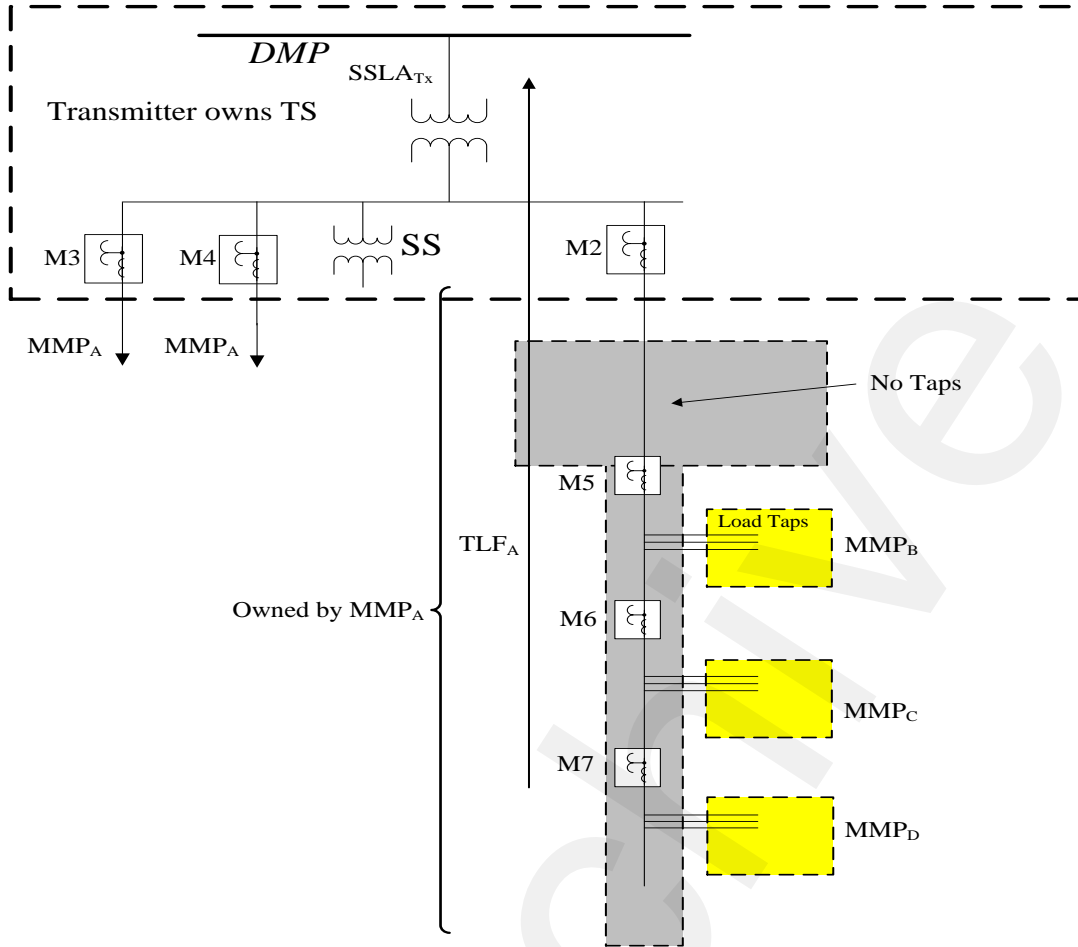
$$MMP_D \text{ Energy} = M7.TLF_A \text{ per } OEB$$

Notes:

1.  $MMP_A$  provides the loss calculation.



**7c. Embedded Distributors in Parallel (Meters Located Between LDC Taps)**



- $MMP_A$  is directly connected
- $MMP_A$  is a *transmission customer*
- $MMP_B$ ,  $MMP_C$  and  $MMP_D$  are embedded

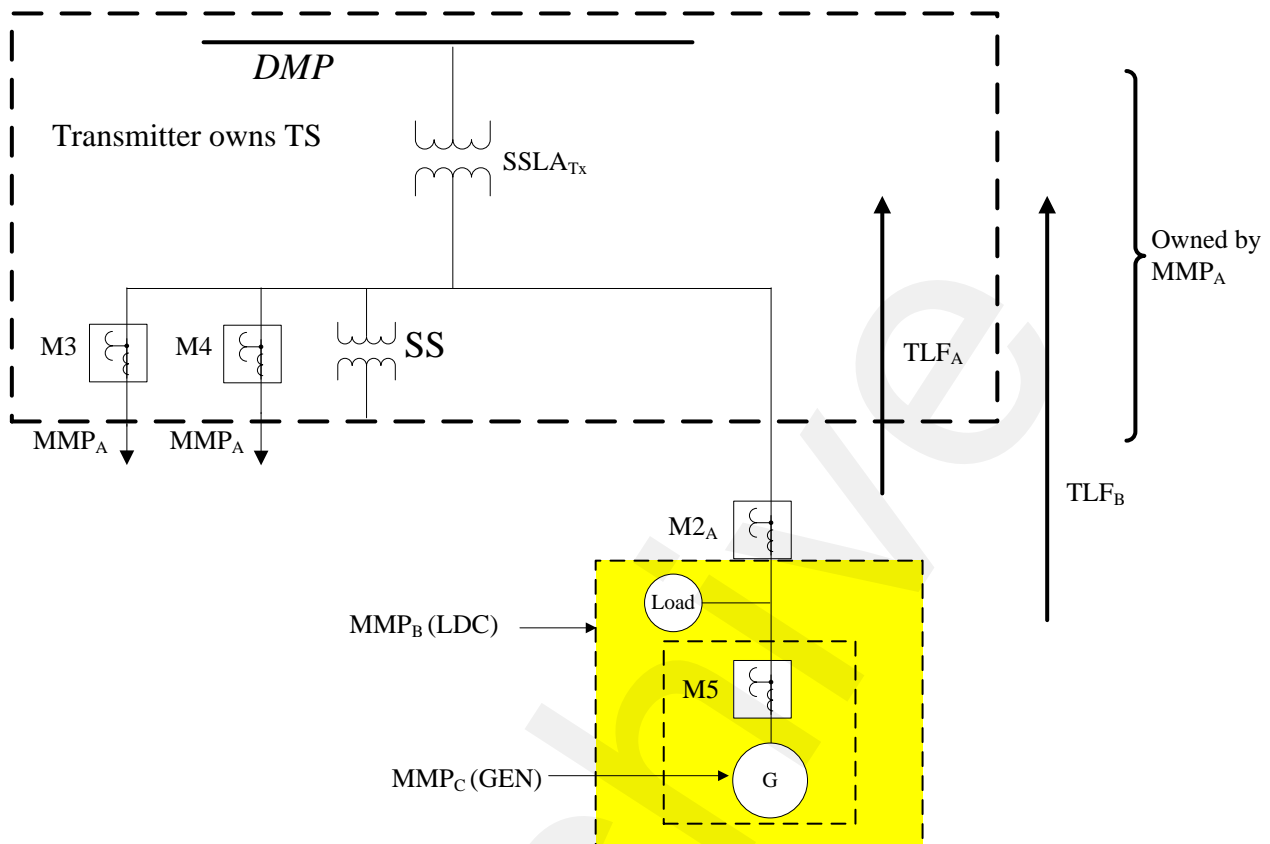
**7c.1 No Agreement on Losses is required**

$MMP_A$ Energy	=	$M3+M4+M2+SS+SSLA_{TX} - M5.TLF_A$	
$MMP_A$ TT	=	$M3+M4+M2+SS+SSLA_{TX}$	
$MMP_B$ Energy	=	$M5.TLF_A - M6.TLF_A$	per <i>OEB</i>
$MMP_C$ Energy	=	$M6.TLF_A - M7.TLF_A$	per <i>OEB</i>
$MMP_D$ Energy	=	$M7.TLF_A$	per <i>OEB</i>

Notes:

1.  $MMP_A$  provides the loss calculation.

### 8a. Embedded Generator in an Embedded Distributor – Feeder Meters



- $MMP_A$  is directly connected
- $MMP_A$  is a *transmission customer*
- $MMP_B$ ,  $MMP_C$  and  $MMP_D$  are embedded

#### 8a.1 No Agreement on Losses is required

$MMP_A$ Energy	=	$M3+M4+SS_Y+SSLA_Y$	
$MMP_A$ TT	=	Check the appropriate transmission rate schedule for details	
$MMP_B$ Energy	=	$M2_A.TLF_A - (M5C_{12}.TLF_B + M5C_{34}.LF)$	see note 2, 3 & 6
$MMP_C$ Energy	=	$M5_{12}.TLF_B$ (delivered channels 1 & 2) = $M5C_{12}.TLF_B$	per <i>OEB</i>
	=	$M5_{34}.LF$ (received channels 3 & 4) = $M5C_{34}.LF$	see note 2 & 3
	=	$M5C_{12}.TLF_B + M5C_{34}.LF$	

Note:

1. The *embedded generator* is an *energy market* participant.
2. A default loss factor (LF) value of 1.0 will be used. Values other than 1.0 will be used if specified and agreed to by all parties.
3.  $M5C_{12}$  and  $M5C_{34}$  are direction dependent (ch 1 & 2 delivered, ch 3 & 4 received).
4.  $MMP_A$  provides the loss calculations.

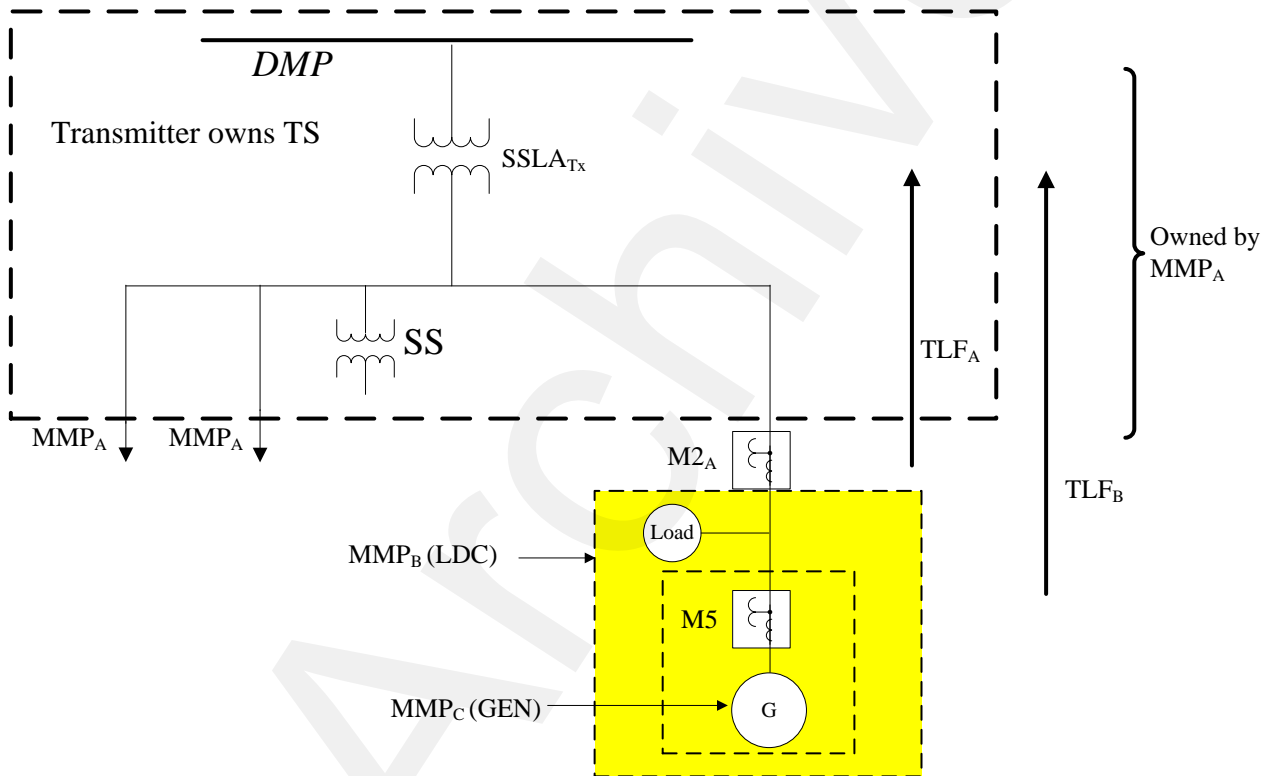
5.  $MMP_A$  responsible for *station service* metering
6. If the *Generator* output is higher than  $MMP_B$  load,  $MMP_A$  should install feeder metering or agree with  $MMP_B$  the loss factor (LF1) to be applied to  $M2_A C_{34}$  (Refer to example 8.b.2.). The *IESO* will not accept loss factors that negatively impact the Market.

Example of *transmission tariff settlement*:

Using Ontario Transmission Rate Schedules and assuming a non-renewable *generator* > 1 MW or a renewable *generator* > 2 MW

$$\begin{aligned}
 MMP_A \text{ TT network} &= M3+M4+SS_Y+SSLA_Y + M2_A.TLF_A \\
 MMP_A \text{ TT connection} &= M3+M4+SS_Y+SSLA_Y + M2_A.TLF_A + M5C_{34}.LF
 \end{aligned}$$

### 8b. Embedded Generator in an Embedded Distributor – Bus Meter



- $MMP_A$  is directly connected
- $MMP_A$  is a *transmission customer*
- $MMP_B$  and  $MMP_C$  are embedded

**8b.1 No Agreement between MMP<sub>A</sub> and MMP<sub>B</sub> is required if:**

During normal operating conditions the load is greater than the *generator* output.

M2<sub>A</sub> registers non-zero values on Ch # 1 and zero values on Ch # 3.

MMP <sub>A</sub> Energy	=	M2+SSL <sub>A</sub> -M2 <sub>A</sub> .TLF <sub>A</sub>	
MMP <sub>A</sub> TT	=	Check the appropriate transmission rate schedule for details	
MMP <sub>B</sub> Energy	=	M2 <sub>A</sub> .TLF <sub>A</sub> - (M5C <sub>12</sub> .TLF <sub>B</sub> + M5C <sub>34</sub> .LF)	see note 4
MMP <sub>C</sub> Energy	=	M5 <sub>12</sub> .TLF <sub>B</sub> (delivered channels 1 & 2) = M5C <sub>12</sub> .TLF <sub>B</sub> M5 <sub>34</sub> . LF (for received channels 3 & 4) = M5C <sub>34</sub> .LF = M5C <sub>12</sub> .TLF <sub>B</sub> + M5C <sub>34</sub> .LF	per <i>OEB</i> see note 2

**8b.2 An agreement between MMP<sub>A</sub> and MMP<sub>B</sub> is required if:**

see note 3

During normal operating conditions the *generator* output is greater than the load.

M2<sub>A</sub> registers zero values on Ch # 1 and non-zero values on Ch # 3.

MMP <sub>A</sub> Energy	=	M2+SSL <sub>A</sub> - (M2 <sub>A</sub> C <sub>12</sub> .TLF <sub>A</sub> + M2 <sub>A</sub> C <sub>34</sub> .LF1)	see note 3
MMP <sub>A</sub> TT	=	Check the appropriate transmission rate schedule for details	
MMP <sub>B</sub> Energy	=	M2 <sub>A</sub> 12.TLF <sub>A</sub> (delivered channels 1 & 2) = M2 <sub>A</sub> C <sub>12</sub> .TLF <sub>A</sub> M2 <sub>A</sub> 34. LF <sub>1</sub> (for received channels 3 & 4) = M2 <sub>A</sub> C <sub>34</sub> .LF <sub>1</sub>	see note 3
	=	(M2 <sub>A</sub> C <sub>12</sub> .TLF <sub>A</sub> + M2 <sub>A</sub> C <sub>34</sub> .LF1) - (M5C <sub>12</sub> .TLF <sub>B</sub> + M5C <sub>34</sub> .LF)	see note 4
MMP <sub>C</sub> Energy	=	M5 <sub>12</sub> .TLF <sub>B</sub> (delivered channels 1 & 2) = M5C <sub>12</sub> .TLF <sub>B</sub> M5 <sub>34</sub> . LF (received channels 3 & 4) = M5C <sub>34</sub> .LF	per <i>OEB</i> see note 2 & 4
	=	M5C <sub>12</sub> .TLF <sub>B</sub> + M5C <sub>34</sub> .LF	

Note:

1. The *embedded generator* is an *energy market* participant.
2. A default loss factor (LF) value of 1.0 will be used. Values other than 1.0 will be used if specified and agreed to by all parties.
3. Based on agreement, loss factor (LF<sub>1</sub>) is applied. If an agreement does not exist, LF<sub>1</sub>=TLF<sub>A</sub> (Refer to example 8.a.1).
4. M5C<sub>12</sub> and M5C<sub>34</sub> are direction dependent (ch 1 & 2 delivered, ch 3 & 4 received).
5. MMP<sub>A</sub> provides the loss calculations.
6. MMP<sub>A</sub> responsible for *station service* metering

Example of *transmission tariff settlement*:

Using Ontario Transmission Rate Schedules and assuming a non-renewable *generator* > 1 MW or a renewable *generator* > 2 MW

MMP<sub>A</sub> TT network =M2+SSLA

MMP<sub>A</sub> TT connection =M2+SSLA+ M5C<sub>34</sub>.LF

– End of Section –

# Appendix E: Example of a Site Registration Report (SRR)

Site Registration Report [Search](#)

Legend: Delivery Point Summary Metering System Meter Point

Delivery point 105522 is associated with 105522E from Wed Mar 21 00:00:00 EST 2001 with no end date

Channel summary for 105522E

- 1) 5 minute, Summary channel, UOM 01, Power Flow DEL
- 2) 5 minute, Summary channel, UOM 03, Power Flow DEL
- 3) 5 minute, Summary channel, UOM 01, Power Flow REC
- 4) 5 minute, Summary channel, UOM 03, Power Flow REC

Detailed channel information for 105522

```
+ 100% of 105522E: Channel 1: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - no end date
5 minute, Summary channel, UOM 01, Power Flow DEL

+ 100% of 0200696080: Channel 1: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - Mon Jun 30 23:59:59 EST 2003
15 minute, S channel, UOM 01, Power Flow DEL
Losses:
018 DateRange Sun Oct 01 00:00:00 EST 2000 - no end date
Parameters:
Assumed Voltage: Assumed PF: DateRange Wed Apr 18 08:59:23 EST 2001 - no end date
CT/PT/Service Type:
CT: 0 VI: 0 Service Type: DateRange Thu Jan 01 00:00:00 EST 1998 - Thu Feb 12 23:59:59 EST 2015

+ 100% of 1000004400: Channel 1: Contribution DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
5 minute, M channel, UOM 01, Power Flow DEL
Losses:
E60 DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
Parameters:
Assumed Voltage: Assumed PF: DateRange Fri Jul 11 09:01:34 EST 2003 - no end date
CT/PT/Service Type:
CT: 120 VI: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
CT: VI: Service Type: D DateRange Sun Feb 01 00:00:00 EST 2015 - no end date

+ 100% of 105522E: Channel 2: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - no end date
5 minute, Summary channel, UOM 03, Power Flow DEL

+ 100% of ZERO: Channel 2: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - Mon Jun 30 23:59:59 EST 2003
5 minute, S channel, UOM 03, Power Flow DEL
Parameters:
Assumed Voltage: Assumed PF: DateRange Wed Mar 20 15:36:20 EST 2002 - no end date
CT/PT/Service Type:
CT: 0 VI: 0 Service Type: DateRange Thu Jan 01 00:00:00 EST 1998 - no end date

+ 100% of 1000004400: Channel 2: Contribution DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
5 minute, M channel, UOM 03, Power Flow DEL
Losses:
E60 DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
Parameters:
Assumed Voltage: Assumed PF: DateRange Fri Jul 11 09:01:34 EST 2003 - no end date
CT/PT/Service Type:
CT: 120 VI: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
CT: VI: Service Type: D DateRange Sun Feb 01 00:00:00 EST 2015 - no end date

+ 100% of 105522E: Channel 3: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - no end date
5 minute, Summary channel, UOM 01, Power Flow REC

+ 100% of ZERO: Channel 3: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - Mon Jun 30 23:59:59 EST 2003
5 minute, S channel, UOM 01, Power Flow REC
Parameters:
Assumed Voltage: Assumed PF: DateRange Wed Mar 20 15:36:20 EST 2002 - no end date
CT/PT/Service Type:
CT: 0 VI: 0 Service Type: DateRange Thu Jan 01 00:00:00 EST 1998 - no end date

+ 100% of 1000004400: Channel 3: Contribution DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
5 minute, M channel, UOM 01, Power Flow REC
Losses:
E60 DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
Parameters:
Assumed Voltage: Assumed PF: DateRange Fri Jul 11 09:01:34 EST 2003 - no end date
```

```

CT/PT/Service Type:
  CT: 120 VI: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
  CT: VI: Service Type: D DateRange Sun Feb 01 00:00:00 EST 2015 - no end date
+ 100% of 105522E: Channel 4: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - no end date
  5 minute, Summary channel, UOM 03, Power Flow REC
+ 100% of ZERO: Channel 4: Contribution DateRange Wed Mar 21 00:00:00 EST 2001 - Mon Jun 30 23:59:59 EST 2003
  5 minute, S channel, UOM 03, Power Flow REC
Parameters:
  Assumed Voltage: Assumed PF: DateRange Wed Mar 20 15:36:20 EST 2002 - no end date
CT/PT/Service Type:
  CT: 0 VI: 0 Service Type: DateRange Thu Jan 01 00:00:00 EST 1998 - no end date
+ 100% of 1000004400: Channel 4: Contribution DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
  5 minute, M channel, UOM 03, Power Flow REC
Losses:
  E60 DateRange Tue Jul 01 00:00:00 EST 2003 - no end date
Parameters:
  Assumed Voltage: Assumed PF: DateRange Fri Jul 11 09:01:34 EST 2003 - no end date
CT/PT/Service Type:
  CT: 120 VI: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
  CT: VI: Service Type: D DateRange Sun Feb 01 00:00:00 EST 2015 - no end date

```

---

Loss code information

```

Loss Code 018
  Precedence 1, D28_(018) (Fixed Loss), 2000-10-01 00:00:00 - no end date, Del Factor 3.40%, Rec Factor 3.40%
Loss Code E60
  Precedence 1, ILF-CAMPBELLMINES_(E60) (Fixed Loss), 2003-07-01 00:00:00 - no end date, Del Factor 3.40%, Rec Factor 3.40%

```

---

Ratio Point information

---

Generated by Oracle Utilities on Thu Mar 26 14:04:33 EST 2015

## 1 Report Title

- The Site Registration Report is for *delivery point* 105522 that was generated by MDMS on Thursday March 26, 14:04:33 Eastern Standard Time 2015.

## 2 Meter Tree Picture

- *Meter* 00200696080 contributes to summary meter 105522E.
- *Meter* ZERO contributes to summary meter 105522E.
- *Meter* 1000004400 contributes to summary meter 105522E.
- THE summary meter 105522E contributes to *Delivery Point* 105522.

## 3 The *delivery point* associated to THE summary meter from a start date to an end date.

*Delivery Point* 105522 has THE summary meter 105522E contributing starting on Wednesday, March 21 at 00:00 hours Eastern Standard Time (EST) 2001 with no end date.

## 4 Channel Summary for THE summary meter.

- the makeup of The summary meter 105522E is as follows:

Listing of channels	ch1	ch2	ch3	ch4
Interval length	5 mins	5 mins	5 mins	5 mins
Type of meter	Summary	Summary	Summary	Summary
Unit of Measurement	kWh	kVARh	kWh	kVARh
Direction of Power Flow	Delivered	Delivered	Received	Received
Voltage Code (None)	no losses	no losses	no losses	no losses

- Assumed Voltage, Assumed PF, CT ratio, VT ratio and ServiceType (D=Delta, or W=Wye) since there is no Voltage Code the above is not printed.

## 5 Detailed Channel Information for THE Summary Meter

- THE summary meter 105522E of channel 1 with parameters; 5 minute intervals, is a summary meter, Unit of Measure 01 (kWh), Power Flow DEL (Delivered), no losses applied receives metering data contributions from:
  - meter* 0200696080 of channel 1 adds all of the *metering data* that started on Wednesday, March 21 at 00:00 hours (EST) 2001 and has Monday, June 30 at 23:59:59 EST 2015 for the end date. The *meter* consists of the following parameters; 15 minute intervals, is a Standalone (S) meter, Unit of Measure 01 (kWh), and Power Flow DEL (Delivered). Losses with a voltage code 018 starting Sunday, October 01 00:00:00 EST 2000 and no end date, no assumed voltage or assumed power factor (PF), a current transformer (CT) ratio of 0, a voltage transformer (VT) ratio of 0 with a starting date of Thursday, January 01 00:00:00 EST 1998 and an end date of Thursday, February 12 23:59:59 EST 2015.
  - meter* 1000004400 of channel 1 adds all of the *metering data* that started on Tuesday, July 01 at 00:00 hours (EST) 2003 and has no end date. The *meter* consists of the following parameters; 5 minute intervals, is a Main (M) meter, Unit of Measure 01 (kWh), and Power Flow DEL (Delivered). Losses with a voltage code E60 starting Tuesday, July 01 00:00:00 EST 2003 and no end date, no assumed voltage or assumed power factor (PF), a current transformer (CT) ratio of 120, a voltage transformer (VT) ratio of 366, and a service type delta (D) with a starting date of Wednesday, June 25 09:18:00 EST 2003 and an end date of Saturday, January 31 23:59:59 EST 2015. A CT ratio undefined, a VT ratio undefined, and a service type D with a starting date of Sunday, February 01 00:00:00 EST 2015 and no end date.
- THE summary meter 105522E of channel 2 with parameters; 5 minute intervals, is a summary meter, Unit of Measure 03 (kVARh), Power Flow DEL (Delivered), no losses applied receives *metering data* from:
  - Same logic as described for channel 1 with the addition of the ZERO meter channel because meter 0200696080 only has a single channel 1
- THE summary meter 105522E of channel 3 with parameters; 5 minute intervals, is a summary meter, Unit of Measure 01 (kWh), Power Flow REC (Received), no losses applied receives *metering data* from:
  - Same logic as described for channel 1 with the addition of the ZERO meter channel because meter 0200696080 only has a single channel 1

- THE summary meter 105522E of channel 4 with parameters; 5 minute intervals, is a summary meter, , Unit of Measure 03 (kVARh), Power Flow REC (Received), no losses applied receives *metering data* from:

Same logic as described for channel 1 with the addition of the ZERO meter channel because meter 0200696080 only has a single 1

#### 6 Voltage Code Information

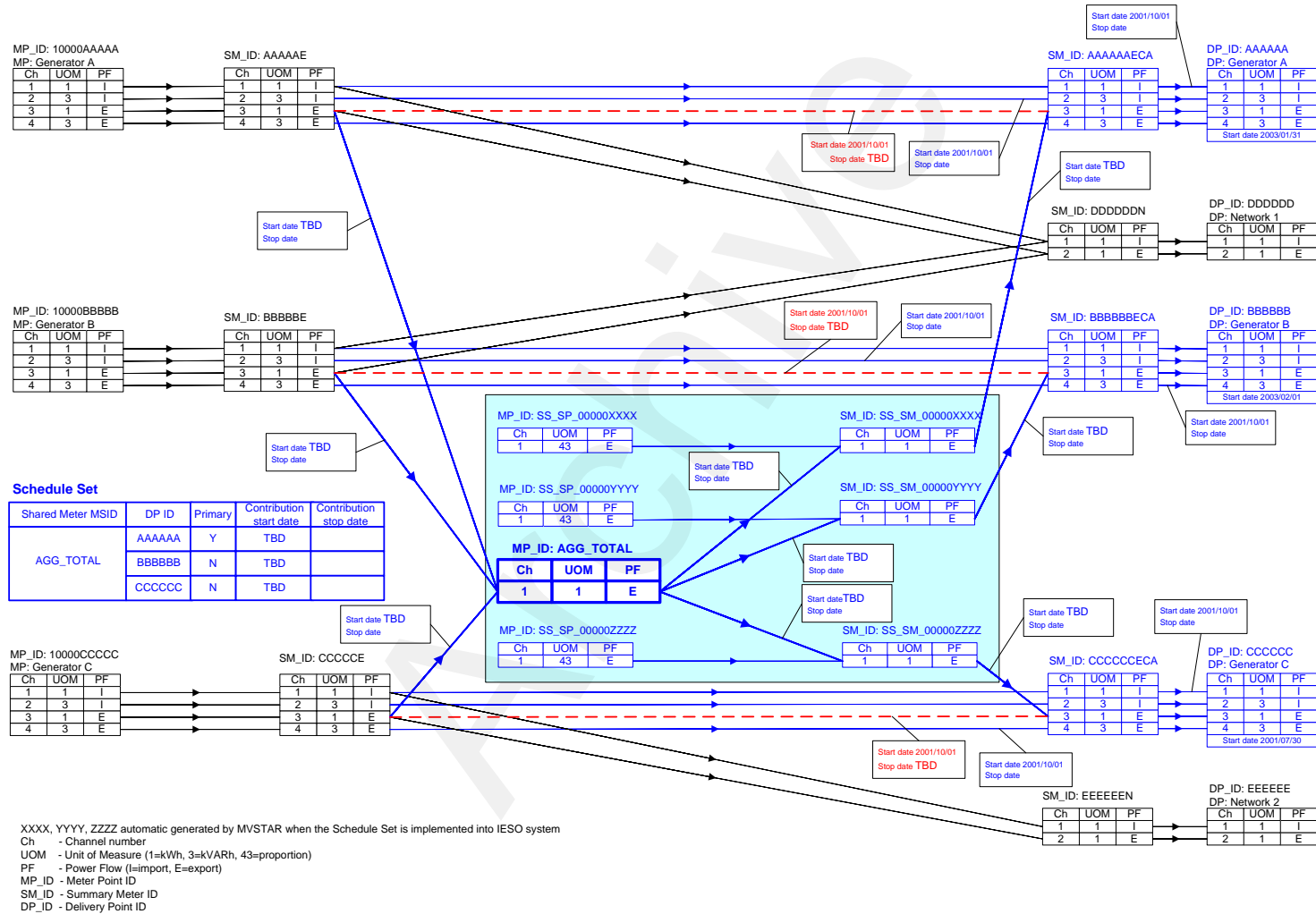
Voltage Code 018 uses loss factor D28 that is a TLF (fixed loss) with a start date of 2000-10-01 at 00:00 hours with no end date. The Delivered factor is 3.4% and the Received factor is 3.4% which reflects the TLF of 0.034 from the “Totalization Table Form”.

Voltage Code E60 uses loss factor TLF-CAMPBELLMINES that is a TLF (fixed loss) with a start date of 2003-07-01 at 00:00 hours with no end date. The Delivered factor is 3.4% and the Received factor is 3.4% which reflects the TLF of 0.034 from the “Totalization Table Form”.

– End of Section –

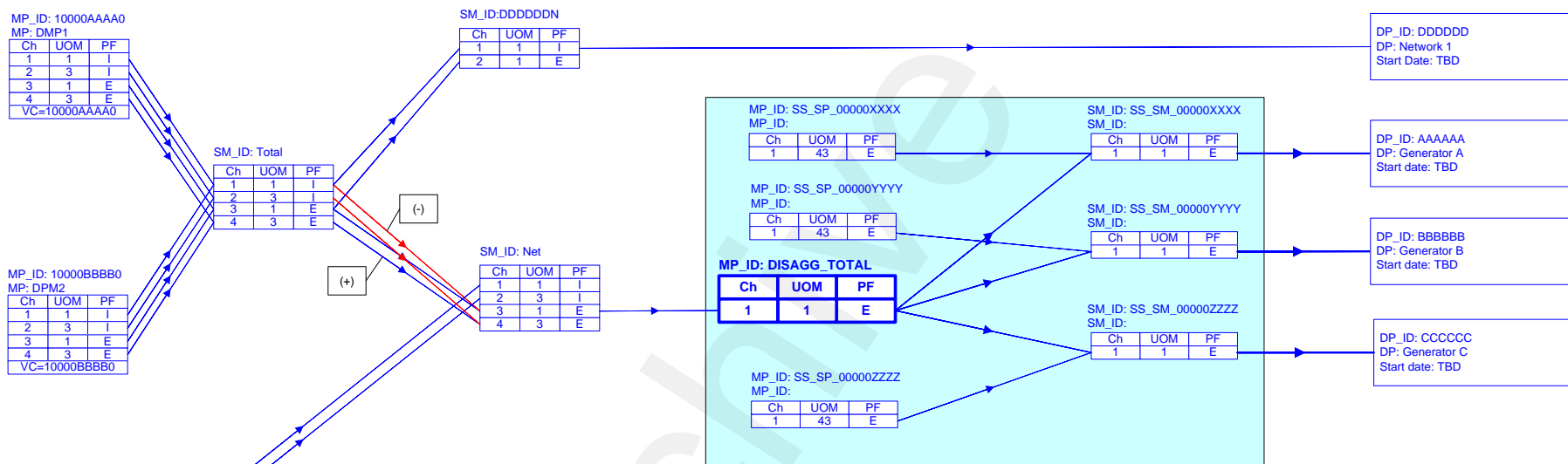


# Appendix F: Example of a Compliance Aggregation Model



- End of Section -

# Appendix G: Example of a Meter Disaggregation Model



MP\_ID: ZERO  
MP: ZERO

Ch	UOM	PF
1	1	I
2	3	I
3	1	E
4	3	E

XXXX, YYYY, ZZZZ automatic generated by MVSTAR when the Schedule Set is implemented into IESO system  
 Ch - Channel number  
 UOM - Unit of Measure (1=kWh, 3=kVARh, 43=proportion)  
 PF - Power Flow (I=import, E=export)  
 MP\_ID - Meter Point ID  
 SM\_ID - Summary Meter ID  
 DP\_ID - Delivery Point ID  
 VC - Voltage Code

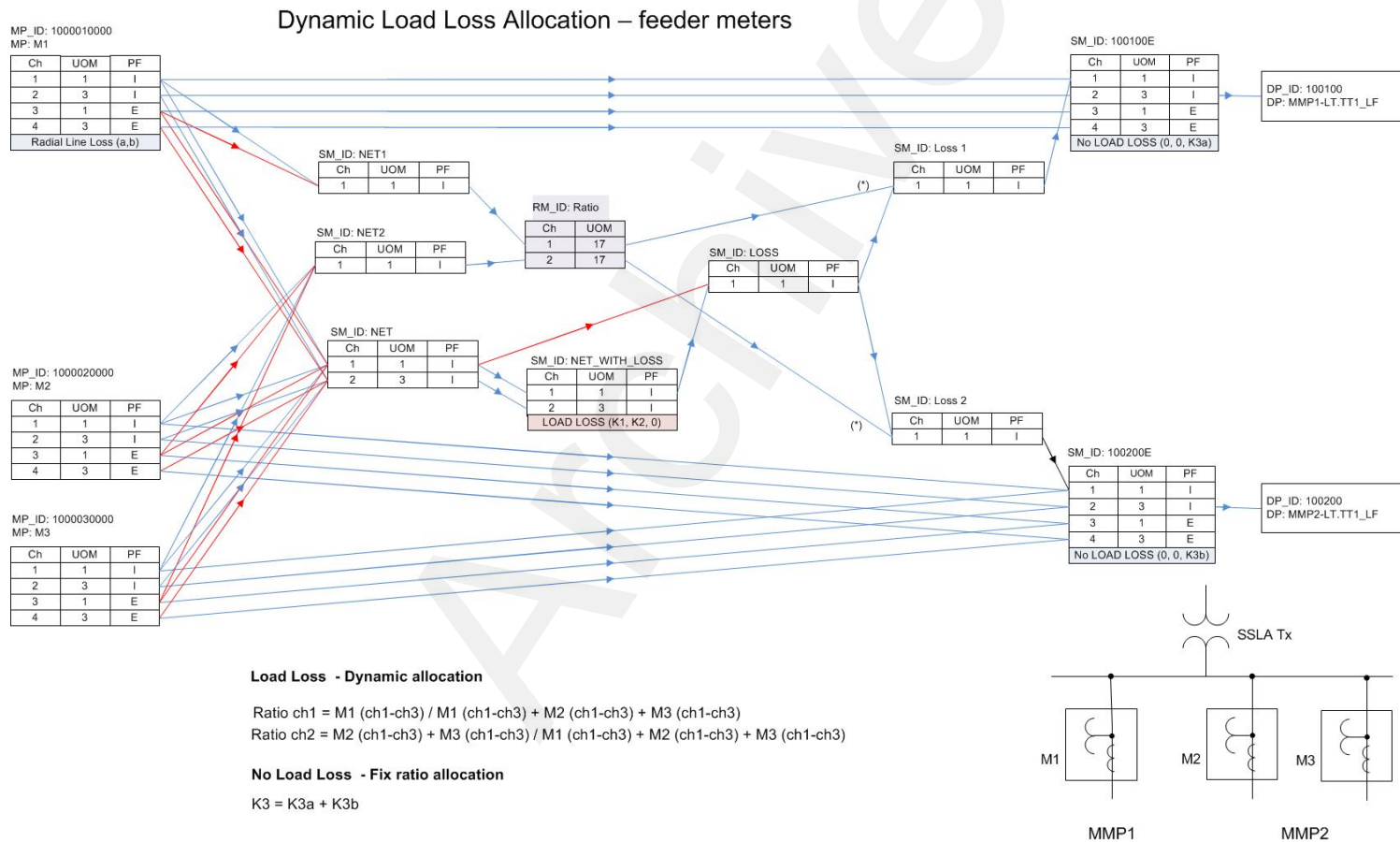
Schedule Set

Shared Meter MSID	DP ID	Primary	Contribution start date	Contribution stop date
DISAGG_TOTAL	AAAAAA	Y	TBD	
	BBBBBB	N	TBD	
	CCCCCC	N	TBD	

- End of Section -

# Appendix H: Loss Dynamic Allocation - models and totalization tables

## a. Feeder meters





**TOTALIZATION TABLE FORM**

**Facility Name** Transformer TS  
**Effective Date** TBD  
**MSP ID**  
**Prepared By**

<b>MMP Name</b>	<b>Breaker Ratio</b>		T1
	MMP Feeders	Total Feeders	
MMP1	1	3	
MMP2	2		

Non-metered Station Service (kW) 0

Factor	k1	k2	k3
T1 total	0.0373	0.0468	112.73
MMP1	Dynamic	Dynamic	37.5766
MMP2	Dynamic	Dynamic	75.1533

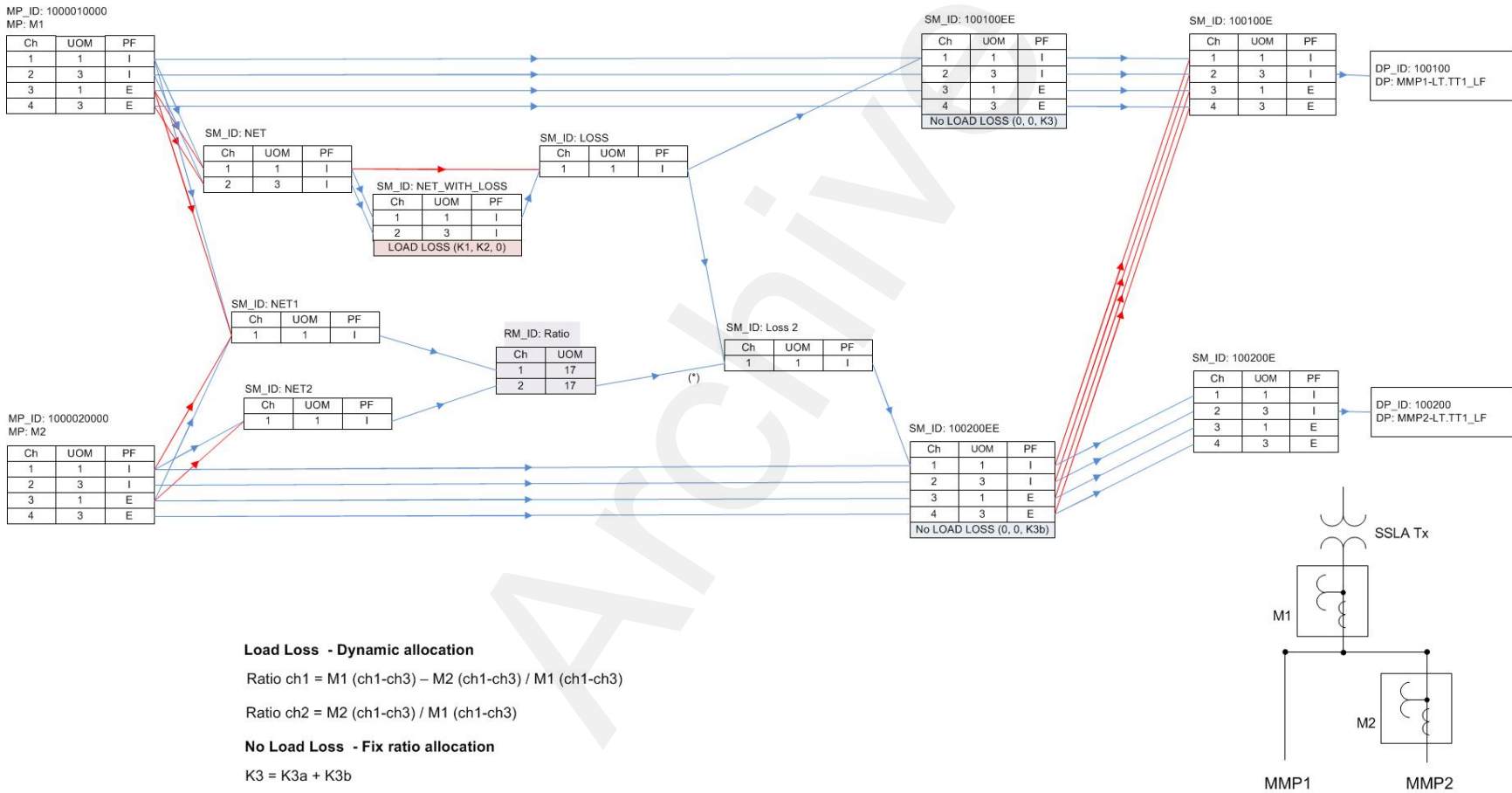
**A. ENERGY MARKET**

MMP #	DPID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	LORM	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation		Radial Line		TLF										
																	a(V <sup>2</sup> )	b(f <sup>2</sup> )	e(V <sup>2</sup> )	f(f <sup>2</sup> )		k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>				
1	100100	100100E		1000010000	1	+	1	del	M1		0.0	120	0.95	WYE	80	140			0	0.1463	T1Dynamic	T1Dynamic	37.5766								
					2	+	3	del																							
					3	+	1	rec																							
					4	+	3	rec																							
2	100200	100200E		1000020000	1	+	1	del	M2		0.0										T1Dynamic	T1Dynamic	75.1533								
					2	+	3	del																							
					3	+	1	rec																							
					4	+	1	rec																							
				1000030000	1	+	1	del	M3		0.0										T1Dynamic	T1Dynamic	75.1533								
					2	+	3	del																							
					3	+	1	rec																							
					4	+	3	rec																							

- Note 1. Apportioning of T1 Transformation No Load Loss based on load serving breakers (1/3 th for MMP1 and 2/3 for MMP2).
- 2. Apportioning of T1 Transformation Load Loss based on dynamic allocation between MMP1 (MPID 1000010000) and MMP2 (MPID 1000020000 and MPID 1000030000).
- 3. Radial Line loss coefficients are applied to M1 meter.

**b. Bus and feeder meters**

**Dynamic Load Loss Allocation – bus and feeder meters**





**TOTALIZATION TABLE FORM**

Facility Name: Transformer TS  
 Effective Date: TBD  
 MSP ID:  
 Prepared By:

MMP Name	Breaker Ratio	
	MMP Feeders	Total Feeders
MMP1	1	2
MMP2	1	

Non-metered Station Service (kW) 0

Factor	k1	k2	k3
T1total	0.0373	0.0468	112.73
MMP1	Dynamic	Dynamic	56.3650
MMP2	Dynamic	Dynamic	56.3650

**A. ENERGY MARKET**

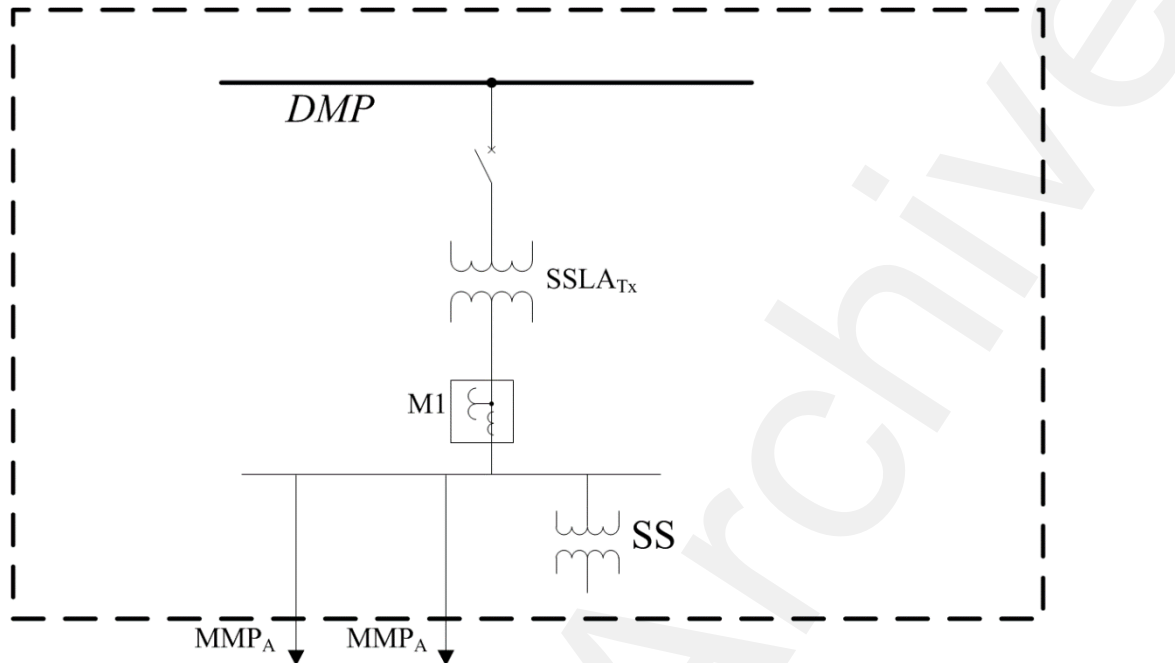
MMP #	DPID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	Uo/M	Energy Flow	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation		Radial Line		Transformation			Radial Line			TLF							
																	a(V <sup>2</sup> )	b(I <sup>2</sup> )	e(V <sup>2</sup> )	f(I <sup>2</sup> )	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>								
1	100100	100100EE	100100EE	1000010000	1	+	1	del	M1		0.0																							
					2	+	3	del																										
					3	+	1	rec																										
					4	+	3	rec																										
		100200EE	1000020000	1	-	1	del	M2		0.0																								
				2	-	3	del																											
				3	-	1	rec																											
				4	-	1	rec																											
2	100200	100200EE	10200EE	1000020000	1	+	1	del	M2		0.0																							
					2	+	3	del																										
					3	+	1	rec																										
					4	+	1	rec																										

- Note 1. Apportioning of T1 Transformation No Load Loss based on load serving breakers (1/2 th for MMP1 and 1/2 for MMP2).
- Note 2. Apportioning of T1 Transformation Load Loss based on dynamic allocation between MMP1 (MPID 1000010000) and MMP2 (MPID 1000020000).

– End of Section –

## Appendix I: Dynamic No-Load Loss Application

### 1. Power System configuration example for the Dynamic No-Load Loss Application

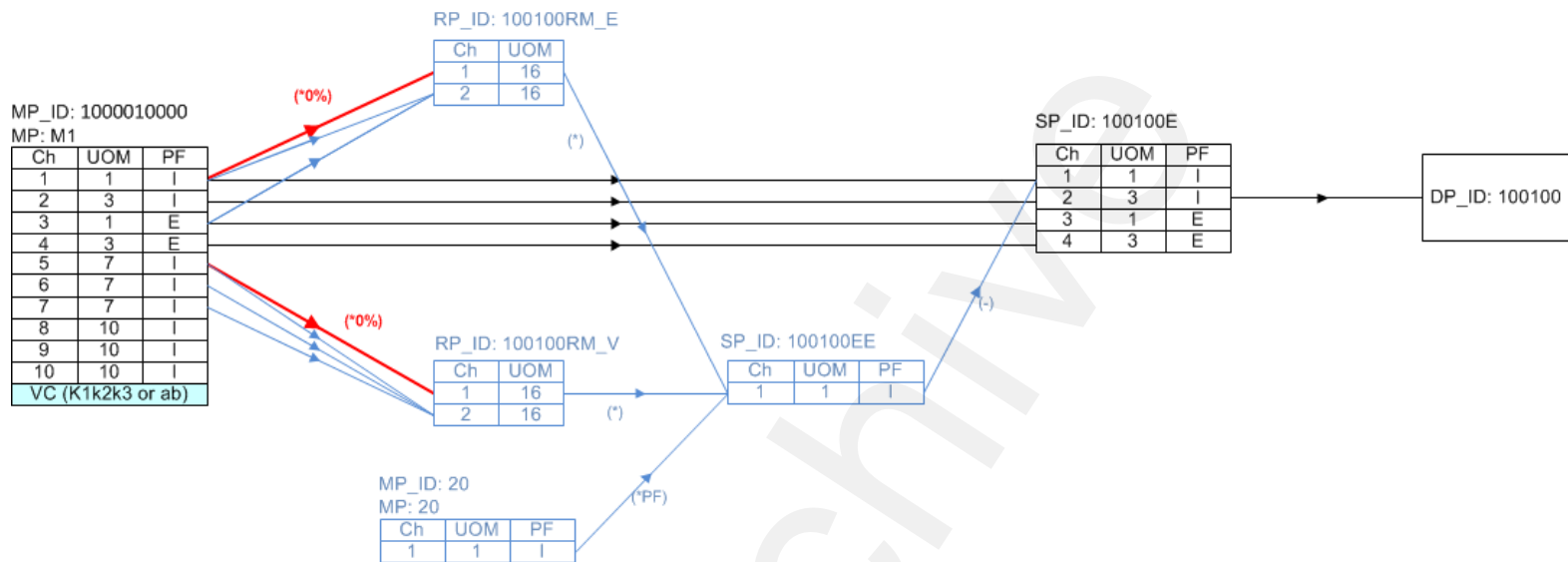


#### Requirements:

- $MMP_A$  is the only *market participant* accountable for the power component losses
- No *disconnect* equipment (e.g. breaker, switch) is installed between the power component and the M1 *metering installation*

Note: In cases where a *facility* is frequently disconnected from the source, the auxiliary power configuration of a *metering installation* must be such that both Main and Alternate meters are powered at all times (as per the Wholesale Revenue Metering Standard – Hardware).

## 2. Dynamic No-Load Loss Application Model



	RM_E Ch1=0 (½)	RM_E Ch1<>0 (0)
RM_V Ch1=0 (½)	1/4	0
RM_V Ch1<>0 (0)	0	0

The ratio meter RM\_V output will be as follows:  
 If  $\Sigma$  of all voltage channels is equal to zero; Ch1 (output) = 0.5  
 If  $\Sigma$  of all voltage channels is not equal to zero; Ch1 (output) = 0

The ratio meter RM\_E output will be as follows:  
 If  $\Sigma$  of all voltage channels is equal to zero; Ch1 (output) = 0.5  
 If  $\Sigma$  of all voltage channels is not equal to zero; Ch1 (output) = 0



### 3. Totalization Table Example for the Dynamic No-Load Loss Application



## TOTALIZATION TABLE FORM

Facility Name: Transformer Station TS

Effective Date: TBD

MSP ID:

Prepared By (MSP): MSP A

IESO Build By:

Breaker Ratio	T <sub>1</sub>		T <sub>2</sub>		T <sub>3</sub>	
	MMP Feeders	Total Feeders	MMP Feeders	Total Feeders	MMP Feeders	Total Feeders
MMP Name						
MMP1: MMP A	1					
		1				

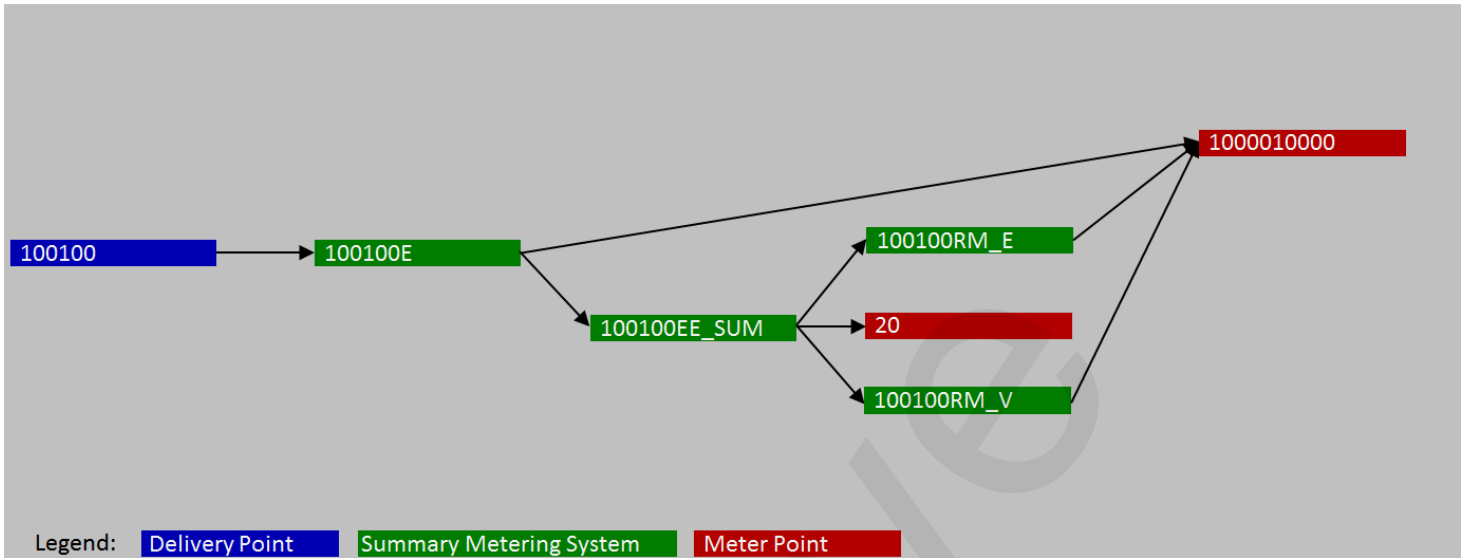
Non-metered Station Service (kW) \_\_\_\_\_

### A. ENERGY MARKET

MMP #	DP ID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+/-)	UoFM	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation		Radial Line		Transformation			Radial Line			TLF
																	a(V <sup>2</sup> )	b(I <sup>2</sup> )	e(V <sup>2</sup> )	f(I <sup>2</sup> )	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>	k <sub>1</sub>	k <sub>2</sub>	k <sub>3</sub>	
1	100100			1000010000	1	+	1	del	M1		0.0							0.025	-0.107	66.203							
					2	+	3	del																			
		100100E			3	+	1	rec																			
					4	+	3	rec																			

Note 1: IESO to implement the Dynamic No-Load loss application subject to the power transformer loading conditions.

#### 4. Site Registration Report (SRR) Example for the Dynamic No-Load Loss Application



Delivery point 100100 is associated with 100100E from Fri Sep 30 00:00:00 EST 2018 to no end date

##### Channel summary for 100100E

- 1) 5 minute, Summary channel, UOM 01, Power Flow DEL
- 2) 5 minute, Summary channel, UOM 03, Power Flow DEL
- 3) 5 minute, Summary channel, UOM 01, Power Flow REC
- 4) 5 minute, Summary channel, UOM 03, Power Flow REC

##### Detailed channel information for 100100

```

+ 100% of 100100E: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date
  5 minute, Summary channel, UOM 01, Power Flow DEL

+ 100% of 1000010000E: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date
  5 minute, Summary channel, UOM 01, Power Flow DEL
Losses:
  1000010000E DateRange Fri Sep 30 00:00:00 EST 2018 - No end date
Parameters:
  Assumed Voltage:120 Assumed PF:95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date
CT/PT/Service Type:
  CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date
  5 minute, M channel, UOM 01, Power Flow DEL
Parameters:
  Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date
CT/PT/Service Type:
  CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

- 100% of 100100EE_SUM: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date
  5 minute, Summary channel, UOM 01, Power Flow DEL

+ 2234.3040% of 20: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date
  15 minute, S channel, UOM 01, Power Flow DEL
Parameters:
  Assumed Voltage: Assumed PF: DateRange Fri Sep 30 00:00:00 EST 2018 - no end date
CT/PT/Service Type:
  CT: VT: Service Type: DateRange Fri Jul 20 08:31:00 EST 2001 - no end date
  
```

\* 100% of 100100RM\_V: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, Ratio channel, UOM 16, Power Flow DEL

\* 100% of 100100RM\_E: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, Ratio channel, UOM 16, Power Flow DEL

+ 100% of 100100E: Channel 2: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, Summary channel, UOM 03, Power Flow DEL

+ 100% of 1000010000E: Channel 2: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, Summary channel, UOM 03, Power Flow DEL

Losses:  
1000010000E DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

Parameters:  
Assumed Voltage:120 Assumed PF:95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:  
CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 2: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, M channel, UOM 03, Power Flow DEL

Parameters:  
Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:  
CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 100100E: Channel 3: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, Summary channel, UOM 01, Power Flow REC

+ 100% of 1000010000E: Channel 3: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, Summary channel, UOM 01, Power Flow REC

Losses:  
1000010000E DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

Parameters:  
Assumed Voltage:120 Assumed PF:95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:  
CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 3: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, M channel, UOM 01, Power Flow REC

Parameters:  
Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:  
CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 100100E: Channel 4: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, Summary channel, UOM 03, Power Flow REC

+ 100% of 1000010000E: Channel 4: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, Summary channel, UOM 03, Power Flow REC

Losses:  
1000010000E DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

Parameters:  
Assumed Voltage:120 Assumed PF:95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:  
CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 4: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - No end date  
5 minute, M channel, UOM 03, Power Flow REC

Parameters:  
Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:  
CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

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#### Loss code information

Loss Code 1000010000E  
Precedence 1, 1000010000E-E\_(1000010000E) (Equation Loss), Fri Sep 30 00:00:00 EST 2018 - No end date,  $0.025*(KVA2H) + 0.107*(KVAH) + 66.203$

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#### Ratio Point information

Ratio Point: 100100RM\_V  
1) 5 minute, Ratio channel, UOM 16, Power Flow DEL

2) 5 minute, Ratio channel, UOM 16, Power Flow DEL

CH 1 :

+ 0% of 1000010000: Channel 5: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 07, Power Flow DEL

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CH 2 :

+ 100% of 1000010000: Channel 5: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 07, Power Flow DEL

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 6: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 07, Power Flow DEL

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 7: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 07, Power Flow DEL

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

Ratio Point: 100100RM\_E

1) 5 minute, Ratio channel, UOM 16, Power Flow DEL

2) 5 minute, Ratio channel, UOM 16, Power Flow DEL

CH 1 :

+ 0% of 1000010000: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 01, Power Flow DEL

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CH 2 :

+ 100% of 1000010000: Channel 1: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 01, Power Flow DEL

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

+ 100% of 1000010000: Channel 3: Contribution DateRange Fri Sep 30 00:00:00 EST 2018 - no end date  
5 minute, M channel, UOM 01, Power Flow REC

Parameters:

Assumed Voltage:120 Assumed PF:0.95 DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

CT/PT/Service Type:

CT: 400 VT: 70 Service Type: W DateRange Fri Sep 30 00:00:00 EST 2018 - No end date

– End of Section –

## References

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<b>Document ID</b>	<b>Document Title</b>
MDP_RUL_0002	Market Rules for the Ontario Electricity Market
MDP_PRO_0016	Market Manual 1: Market Entry, Maintenance and Exit, Part 1.2: Facility Registration, Maintenance and De-Registration
MDP_PRO_0017	Market Manual 2: Market Administration, Part 2.1: Dispute Resolution
MDP_MAN_0003	Market Manual 3: Metering, Part 3.0: Metering Overview
MDP_PRO_0013	Market Manual 3: Metering, Part 3.2: Meter Point Registration and Maintenance
MDP_PRO_0010	Market Manual 3: Metering, Part 3.4: Measurement Error Correction
MDP_PRO_0011	Market Manual 3: Metering, Part 3.5: Site-Specific Loss Adjustment
MDP_PRO_0012	Market Manual 3: Metering, Part 3.6: Conceptual Drawing Review
IMP_PRO_0057	Market Manual 3: Metering, Part 3.8: Creating and Maintaining Delivery Point Relationships
IMP_PRO_0034	Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets

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