Market Manual

Market Manual 3: Metering

Part 0.3.7: Totalization Table Registration

Issue 1.0
April 4, 2025

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

MAN-151

Disclaimer

The posting of documents on this Web site is done for the convenience of *market participants* and other interested visitors to the *IESO* Web site. Please be advised that, while the *IESO* attempts to have all posted documents conform to the original, changes can result from the original, including changes resulting from the programs used to format the documents for posting on the Web site as well as from the programs used by the viewer to download and read the documents. The *IESO* makes no representation or warranty, express or implied, that the documents on this Web site are exact reproductions of the original documents listed. In addition, the documents and information posted on this Web site are subject to change. The *IESO* may revise, withdraw or make final these materials at any time at its sole discretion without further notice. It is solely your responsibility to ensure that you are using up-to-date documents and information.

This *market manual* may contain a summary of a particular *market rule*. Where provided, the summary has been used because of the length of the *market rule* itself. The reader should be aware, however, that where a *market rule* is applicable, the obligation that needs to be met is as stated in the *market rules*. To the extent of any discrepancy or inconsistency between the provisions of a particular *market rule* and the summary, the provision of the *market rule* shall govern.

Document Change History

Issue	Reason for Issue	Date
Refer to Issue 23.0 (IMP-PRO-0047) for changes prior to Market Transition.		
1.0	Market transition	April 4, 2025

Related Documents

Document ID	Document Title
MAN-145	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

Table of Contents

List of Figures

List of Tables

Table of Changes

Reference (Section and Paragraph)	Description of Change
Throughout	Added reference to electricity storage participation where required.

Market Transition

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

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

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

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

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

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

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

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

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

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

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

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

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

Market Manuals

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

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

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:

a. "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".

b. "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 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

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:

   o totalization tables for Network DPs; and

   o 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
***Station Service* Factor**	**21 kW**

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,   embedded generation facility,* or *embedded electricity storage 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:

   o 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;

   o Method #2: coefficient "k_1" must be multiplied by the inverse ratio of breakers, 10/3, while coefficient "k_3" must be multiplied by the ratio, 3/10; coefficient "k_2" 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*.

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

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*.

$$\text{ratio}_{\text{MMPi}} = \frac{1}{\sum_{i}^{n} \text{MMP}_{i}}$$

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.

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

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

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):

$$SF_{in} = \frac{4 \times (\text{\# of elements} \times a \times Vassumed^2)}{20}$$

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:

	Σ *energy* = 0	Σ *energy* <> 0
Σ **volts = 0**	NLL not applied	NLL applied
Σ **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 RTSC 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 6th 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 6th 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 6th 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 RTSC 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 6th 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 6th 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 6th 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.

1   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.

2   Channel Summary for THE summary meter

   ● the makeup 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.

3   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.

4   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

Legend	Description
Oval	An event that triggers task or that completes task. Trigger events and completion events are numbered sequentially within procedure (01 to 99).
Task Box	Shows reference number, party responsible for performing task (if "other party"), and task name or brief summary of task. Reference number (e.g. 1A.02) indicates procedure number within current *market manual* (1), sub-procedure identifier, if applicable, (A), and task number (02).
Solid horizontal line	Shows information flow between the *IESO* 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.

IESO	TRANSMITTER	MSP	MMP

01
Notification of MP accepted into Compliance Aggregation/Meter Disaggregation Program

7.01
Develop Compliance Aggregation/Meter Disaggregation Model and send to MMP

7.04
Receive IESO-FORM-1660/1665

7.12
Receive/review info submitted; resolve deficiencies with the MSP

7.13
Process/enter totalization table data into Metering Registry

7.14
Update Compliance Aggregation/Meter Disaggregation Model

7.15
Generate Site Registration Report for all delivery points affected

7.16
Upload to Online IESO the Site Registration Report for relevant delivery point(s) and finalized Compliance Aggregation/Meter Disaggregation Model to the MSPs; make adjustments upon MSP request

7.19
Receive signed Site Registration Report

06
End of Totalization Table Registration Return to the procedure for Creation and Maintenance of Delivery Point Relationships

7.10
Review and approve IMO-FORM-1310 for transmission tariff delivery point.

7.18
Approve Site Registration Report for transmission tariff delivery point via Online IESO

02
From the process of Meter Point Registration or upon receipt of Compliance Aggregation/Meter Disaggregation Model

7.06
Download IMO-FORM-1310: Totalization Table Form from IESO Web site

7.07
Enter information for the relevant delivery point(s) on IMO-FORM-1310

7.08
Submit to the IESO the completed IMO-FORM-1310. Resolve any deficiencies with the IESO

7.09
Submit IMO-FORM-1310 to transmitter for transmission tariff delivery point.

7.011
Submit approved IMO-FORM-1310 to IESO

7.17
- Review and approve Site Registration Report; resolve any deficiencies with the IESO
- Receive finalized Compliance Aggregation/Meter Disaggregation Model and advise MMP

If affected delivery point   Link 1

7.02
Receive and review Compliance Aggregation/Meter Disaggregation Model. Resolve any deficiencies with the IESO

7.03
Download IESO-FORM-1660: Acceptance of Compliance Aggregation Model or IESO-FORM-1665: Acceptance of Meter Disaggregation Model; complete and submit it to IESO

7.05
Submit Compliance Aggregation/Meter Disaggregation Model to MSP

04
Receive finalized Compliance Aggregation/Meter Disaggregation Model

05
Receive signed SRR

Link 1

Figure 3−1: Work flow for Totalization Table Registration

IESO	TRANSMITTER	MSP	MMP

Link
1

Only if affected

7.20

If an affected MSP:

Request own MMP to advise affected MMP that affected IMO-FORM-1310: Totalization Table Form must be re-submitted

7.21 Own MMP

- Receive notification and advise affected MMP to notify affected MSP to re-submit IMO-FORM-1310 to IESO
- Receive newly created Totalization Table Form from own MSP send it to affected MMP

07
Affected Transmitter
Review and approve IMO-FORM-1310 for the relevant transmission tariff delivery point as in Step 7.10

7.23 Affected MSP

If an affected MSP:

- provide a copy of the newly created IMO-FORM-1310 to both affected MMP and affected Transmitter, if required

7.22 Affected MMP

- Receive notification and request affected MSP to re-submit IMO-FORM-1310 to IESO
- Attach newly created IMO-FORM-1310

08
Affected MSP
Submit a revised IMO-FORM-1310 for the relevant delivery point by following the current procedure

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

– End of Section –

Appendix A: Forms

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). 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[1]:** 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)

---

[1] Required only when loss coefficients "a" and "b" and/or "e" and "f" are used.

- - b (I^2)

Radial line:

- - e (V^2)

- - f (I^2)

- **Coefficents 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_1

  - - k_2

  - - k_3

  Radial line:

  - - k_1

  - - k_2

  - - k_3

- **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;

- **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* and *embedded electricity storage facilities* 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 –

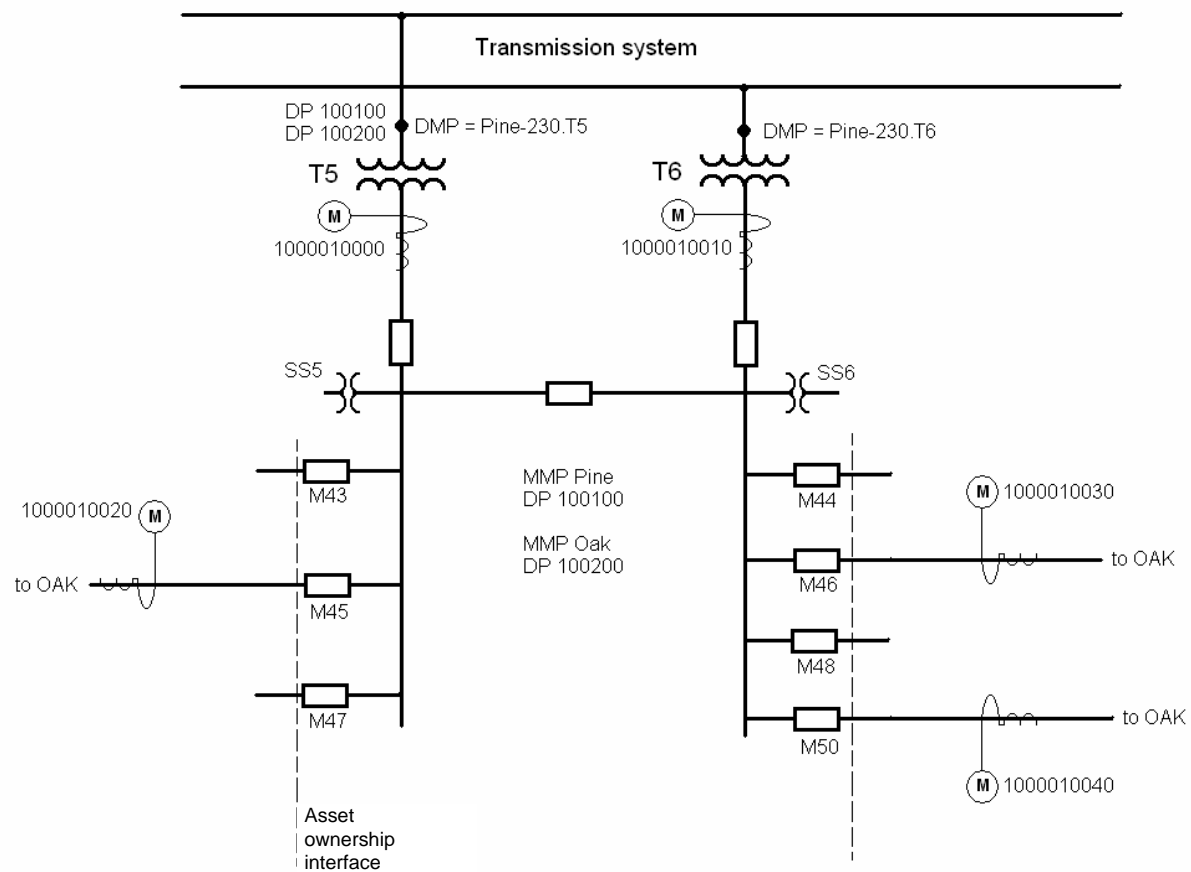# Appendix C: Example of Totalization

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

Table C–1: Totalization Table Form

TOTALIZATION TABLE FORM

ieso Power to Ontario. On Demand.

	T__		T__		T__	
Breaker Ratio	MMP Feeders	Total Feeders T5/T6	MMP Feeders	Total Feeders	MMP Feeders	Total Feeders
MMP Name						
MMP1: Pine	4	7				
MMP2: Oak	3	7				

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

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

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

A. ENERGY MARKET

MMP #	DP ID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	UoM	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation a(V²)	Transformation b(I²)	Radial Line e(V²)	Radial Line f(I²)	Transformation k₁	Transformation k₂	Transformation k₃	Radial Line k₁	Radial Line k₂	Radial Line k₃	TLF
				100001000	1	+	kWh	del	T5												0.0192	-0.173	104.410				
			100100C99	100001000	2	+	kVARh	del	T5																		
				100001000	3	+	kWh	rec	T5																		
				100001000	4	+	kVARh	rec	T5																		
				1000010010	1	+	kWh	del	T6												0.0192	-0.173	104.410				
				1000010010	2	+	kVARh	del	T6																		
				1000010010	3	+	kWh	rec	T6																		
				1000010010	4	+	kVARh	rec	T6																		
				1000010020	1	-	kWh	del	M 45												0.0448	-0.173	44.747				
				1000010020	2	-	kVARh	del	M 45																		
1	100100	100100EE	100200E	1000010020	3	-	kWh	rec	M 45																		
				1000010020	4	-	kVARh	rec	M 45																		
				1000010030	1	-	kWh	del	M46												0.0448	-0.173	44.747				
				1000010030	2	-	kVARh	del	M46																		
				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)

			100200C99	1000010020	1	+	kWh	del	M 45										0.0448	-0.173	44.747				
				1000010020	2	+	kVARh	del	M 45																
				1000010020	3	+	kWh	rec	M 45																
				1000010020	4	+	kVARh	rec	M 45																
				1000010030	1	+	kWh	del	M46										0.0448	-0.173	44.747				
				1000010030	2	+	kVARh	del	M46																
2	100200	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	Channel No.	Operator (+ or -)	UoM	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation a(V²)	b(I²)	Radial Line e(V²)	f(I²)	Transformation k₁	k₂	k₃	Radial Line k₁	k₂	k₃	TLF
1	100101	100101N	100100EE	100001000	1	+	kWh	del	T5																		
				100001000	3	+	kWh	rec	T5																		
				1000010010	1	+	kWh	del	T6																		
				1000010010	3	+	kWh	rec	T6																		
				1000010020	1	-	kWh	del	M 45																		
				1000010020	3	-	kWh	rec	M 45																		
				1000000030	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	100102C	100100EE	100001000	1	+	kWh	del	T5																		
				100001000	3	+	kWh	rec	T5																		
				1000010010	1	+	kWh	del	T6																		
				1000010010	3	+	kWh	rec	T6																		
				1000010020	1	-	kWh	del	M 45																		
				1000010020	3	-	kWh	rec	M 45																		
				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	100201N	100200E	1000010020	1	+	kWh	del	M 45																		
				1000010020	3	+	kWh	rec	M 45																		
				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																		
	100202	100202C	100200E	1000010020	1	+	kWh	del	M 45																		
				1000010020	3	+	kWh	rec	M 45																		
				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																		

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

– End of Section –

# Appendix D: Metering - Settlement Principles

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 m*etering 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, electricity storage participants* 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
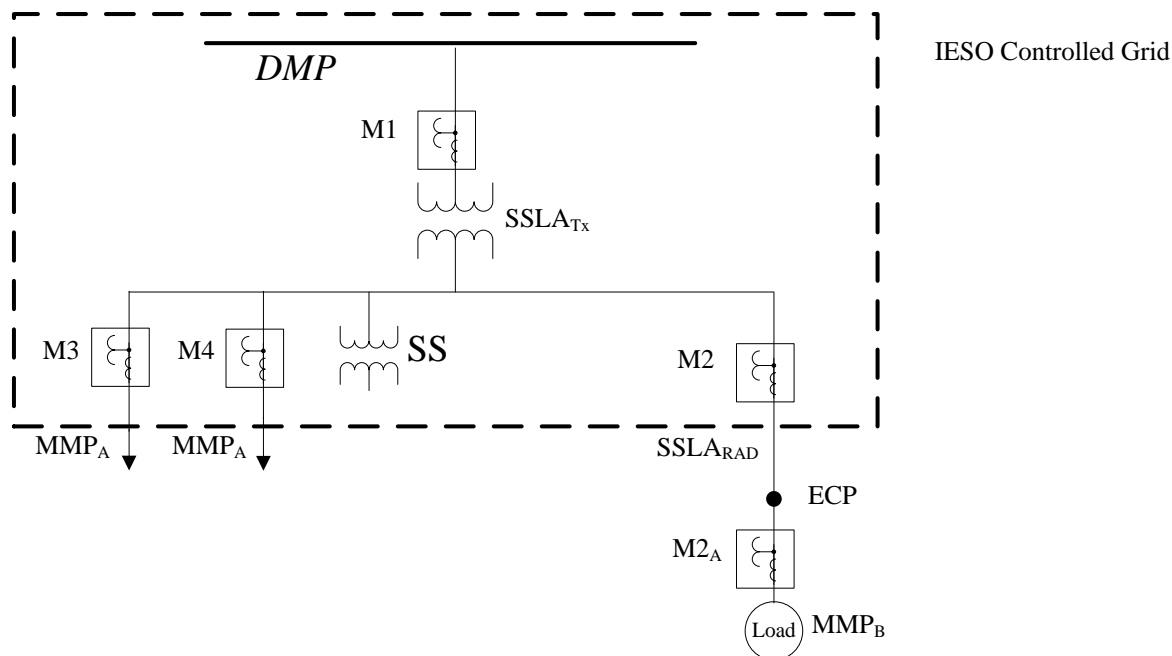
Definitions

M1 – *Primary RWM*

$M2_A$ – *Embedded RWM*

M2, M3 & M4 – RWM

SS - *station service* (note location may vary)

$SSLA_{TX}$ - site specific loss adjustment in kWh – transformer

$SSLA_{RAD}$ - site specific loss adjustment in kWh - radial line loss

Where there is sharing of losses and *station service*, MMPA share Y, MMPB 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 $SSLA_{TX}$ and SS allocation agreement between *Metered Market Participants*

No agreement - means Market Rules Ch 9 default values for $SSLA_{TX}$ 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. $SSLA_Y$ and $SSLA_Z$ 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_Y and SS_Z is the application of the ratios of Y and Z to the total *station service* load, also in kWh.
3. The *embedded connection point* is equivalent to the *defined meter point* 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 measurement error corrections 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
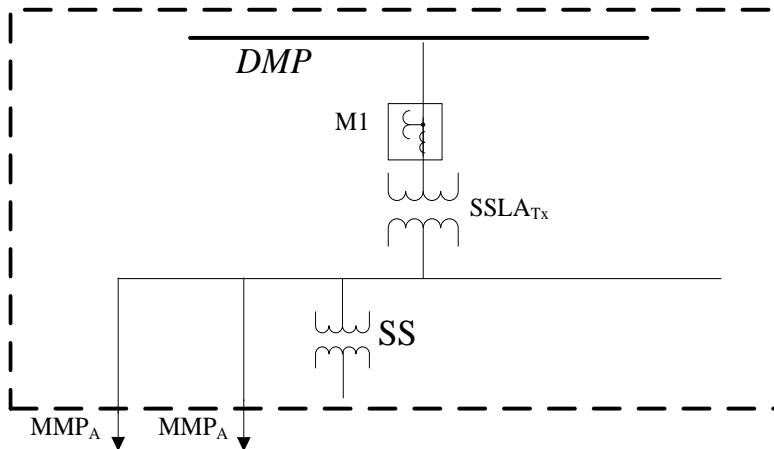
Total Energy	=	M1	M1 captures all losses and *station service*
MMP_A Energy	=	M1	
MMP_A TT	=	M1	

2a. High Side Meter + MMP$_B$ Directly Connected to the TS bus with the feeder meter
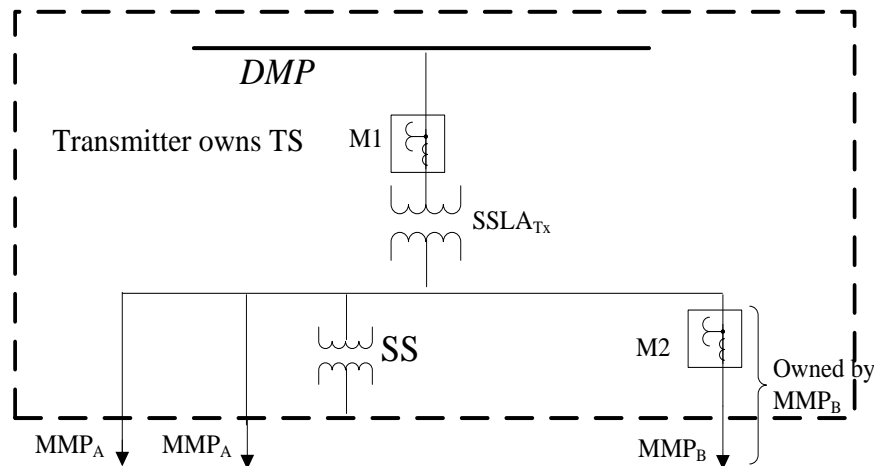
MMP_A and MMP_B are directly connected to the TS bus inside the fence
MMP_A and MMP_B are *transmission customers*

2a.1. <u>Agreement on Losses</u>

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

MMP$_B$ Energy	=	M2+SS$_Z$+SSLA$_Z$
MMP$_B$ TT	=	M2+SS$_Z$+SSLA$_Z$

2a.2 No Agreement on Losses (MMPB gets zero losses)

SS$_Z$ = 0, SSLA$_Z$ = 0

MMP$_A$ Energy	=	M1-M2
MMP$_A$ TT =	M1-M2	
MMP$_B$ Energy	=	M2
MMP$_B$ TT =	M2	

Note:

1. MMP$_B$ provides the loss calculation

2b. Bus Meter + MMP$_B$ Directly Connected to the TS bus with feeder meter
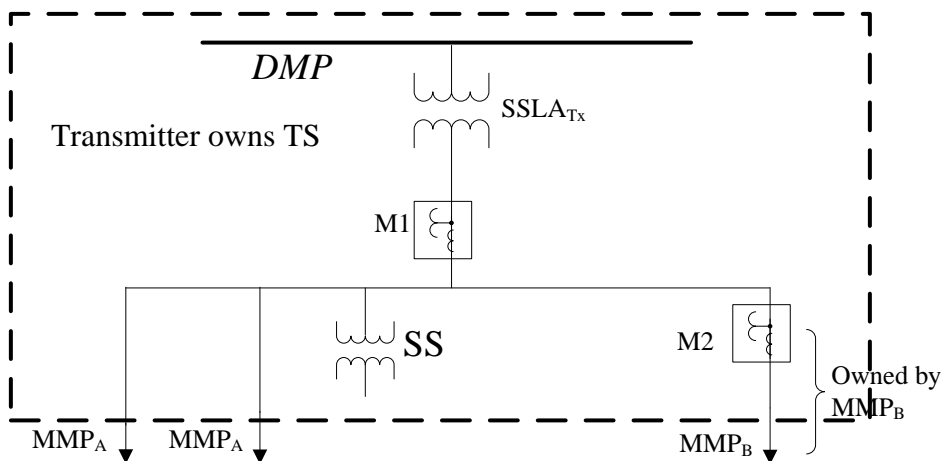
- MMP$_A$ and MMP$_B$ are directly connected to the TS bus inside the fence
- MMP$_A$ and MMP$_B$ are *transmission customers*

2b.1 Agreement on Losses

MMP$_A$ Energy	=	M1+ SSLA$_{TX}$ - (M2+SS$_Z$+SSLA$_Z$)
MMP$_A$ TT	=	M1+ SSLA$_{TX}$ - (M2+SS$_Z$+SSLA$_Z$)
MMP$_B$ Energy	=	M2+ SS$_Z$ + SSLA$_Z$
MMP$_B$ TT	=	M2+ SS$_Z$ + SSLA$_Z$

2b.2 No Agreement on Losses (MMP$_B$ gets zero losses)

SS$_Z$ = 0, SSLA$_Z$ = 0

MMP$_A$ Energy	=	M1 + SSLA$_{TX}$ -M2
MMP$_A$ TT	=	M1 + SSLA$_{TX}$ -M2
MMP$_B$ Energy	=	M2
MMP$_B$ TT	=	M2

Notes:

1. MMP_A provides the loss calculation.

3. Feeder Meters – MMPA and MMPB Directly Connected to TS Bus
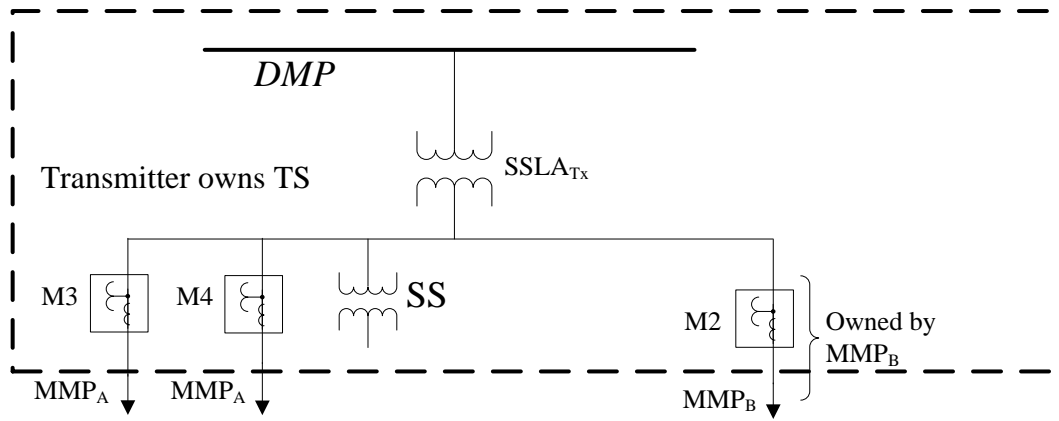
- MMP_A and MMP_B are directly connected to the TS bus inside the fence
- MMP_A and MMP_B are *transmission customers*

3.1 Agreement on Losses

MMP_A Energy	=	$M3+M4+SS_Y+SSLA_Y$
MMP_A TT	=	$M3+M4+SS_Y+SSLA_Y$
MMP_B Energy	=	$M2+SS_Z+SSLA_Z$
MMP_B TT	=	$M2+SS_Z+SSLA_Z$

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$_B$ embedded in MMP$_A$ Feeder
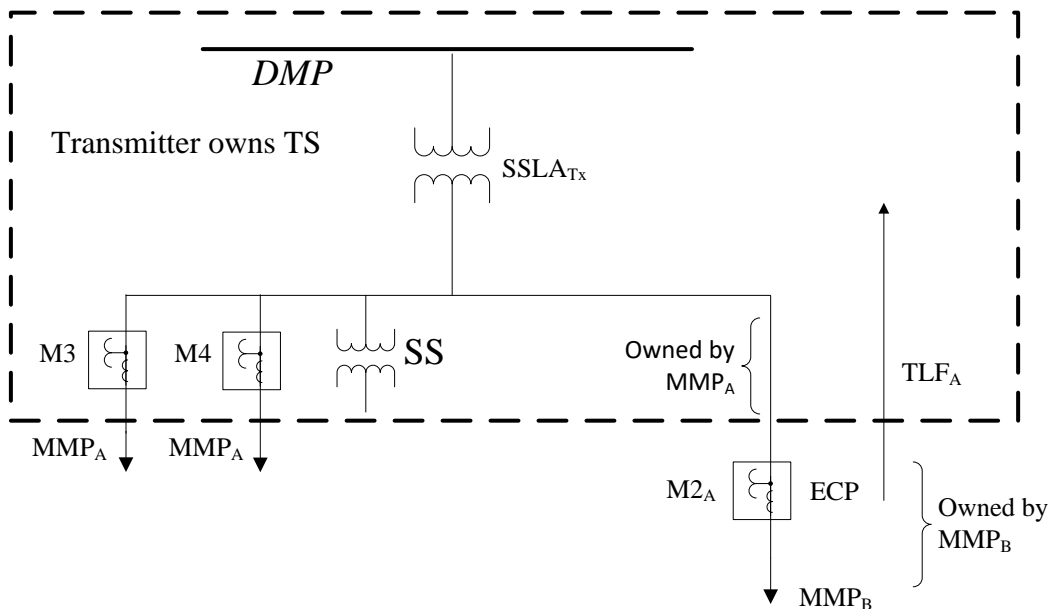
- MMP$_A$ is the *transmission customer*
- MMP$_B$ is embedded in MMP$_A$ feeder

4.1 <u>No Agreement on Losses is required</u>

MMP$_A$ Energy	=	M3+M4+SS$_Y$+SSLA$_Y$
MMP$_A$ TT	=	M3+M4+SS$_Y$+SSLA$_Y$+M2$_A$.TLF$_A$
MMP$_B$ Energy	=	M2$_A$.TLF$_A$ per *OEB*

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. MMPA provides the loss calculation.
3. Share Y = 2/3 based on breaker count used by MMP$_A$

5. MMP$_A$ and MMP$_B$ Directly Connected, MMP$_C$ Embedded in MMP$_B$
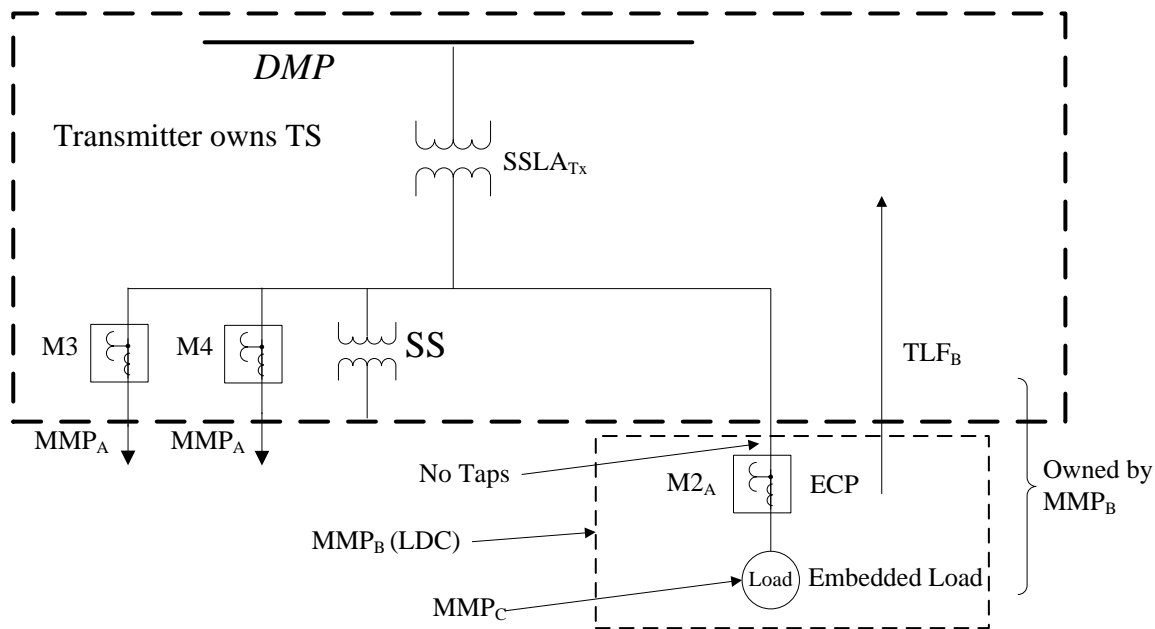
- MMP$_A$ and MMP$_B$ are directly connected to the TS bus inside the fence
- MMP$_A$ and MMP$_B$ are *transmission customers*

5.1 <u>No Agreement on Losses is required</u>

MMP$_A$ Energy	=	M3+M4+SSY+SSLAY
MMP$_A$ TT	=	M3+M4+SSY+SSLAY
MMP$_B$ TT	=	M2$_A$.TLF$_B$
MMP$_C$ Energy	=	M2$_A$.TLF$_B$ per *OEB*

Notes:

1. MMP$_B$ provides the loss calculation.
2. Loss share Y=2/3 based on breaker count used by MMP$_A$

6a. MMPA and MMPB Directly Connected, MMPC Embedded in MMPB − Feeder Meters
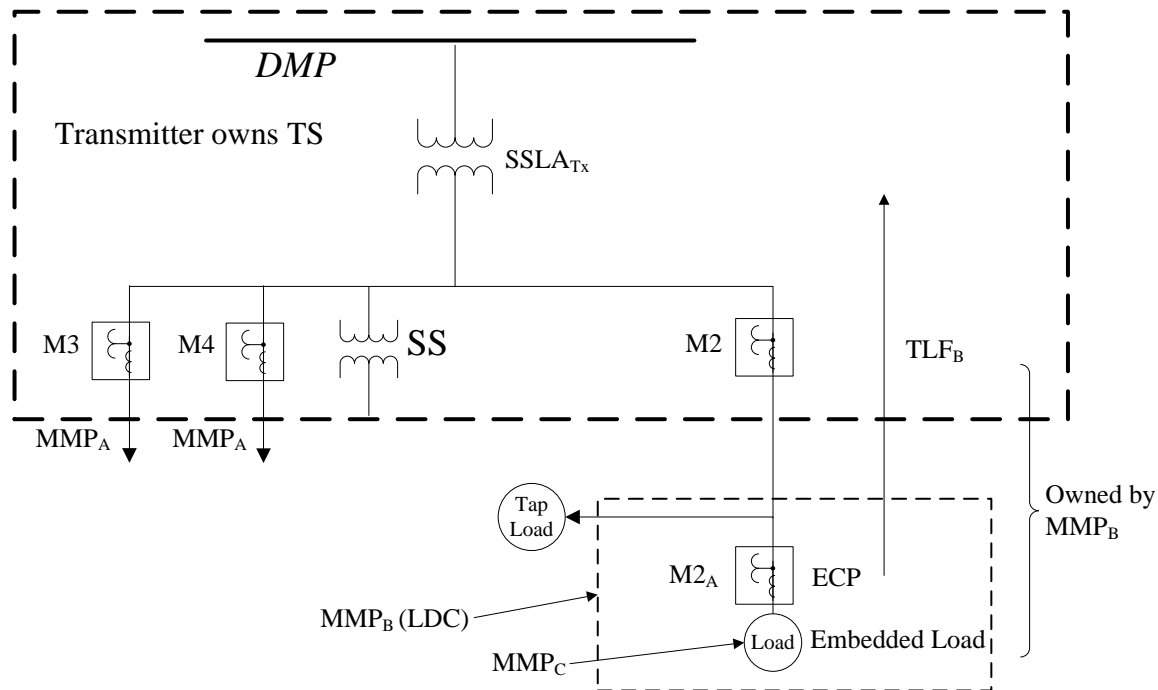
- MMP$_A$ and MMP$_B$ are directly connected to the TS bus inside the fence
- MMP$_A$ and MMP$_B$ are *transmission customers*
- MMP$_A$ and MMP$_B$ are the two parties that have to agree on losses

6a.1 Agreement on Losses

MMP$_A$ Energy	=	M3+M4+SS$_Y$+SSLA$_Y$
MMP$_A$ TT	=	M3+M4+SS$_Y$+SSLA$_Y$
MMP$_B$ Energy	=	M2+SS$_Z$+SSLA$_Z$-M2$_A$.TLF$_B$
MMP$_B$ TT	=	M2+SS$_Z$+SSLA$_Z$
MMP$_C$ Energy	=	M2$_A$.TLF$_B$ per *OEB*

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$_A$ provides the loss calculation.

6b. MMP$_B$ and MMP$_C$ Embedded
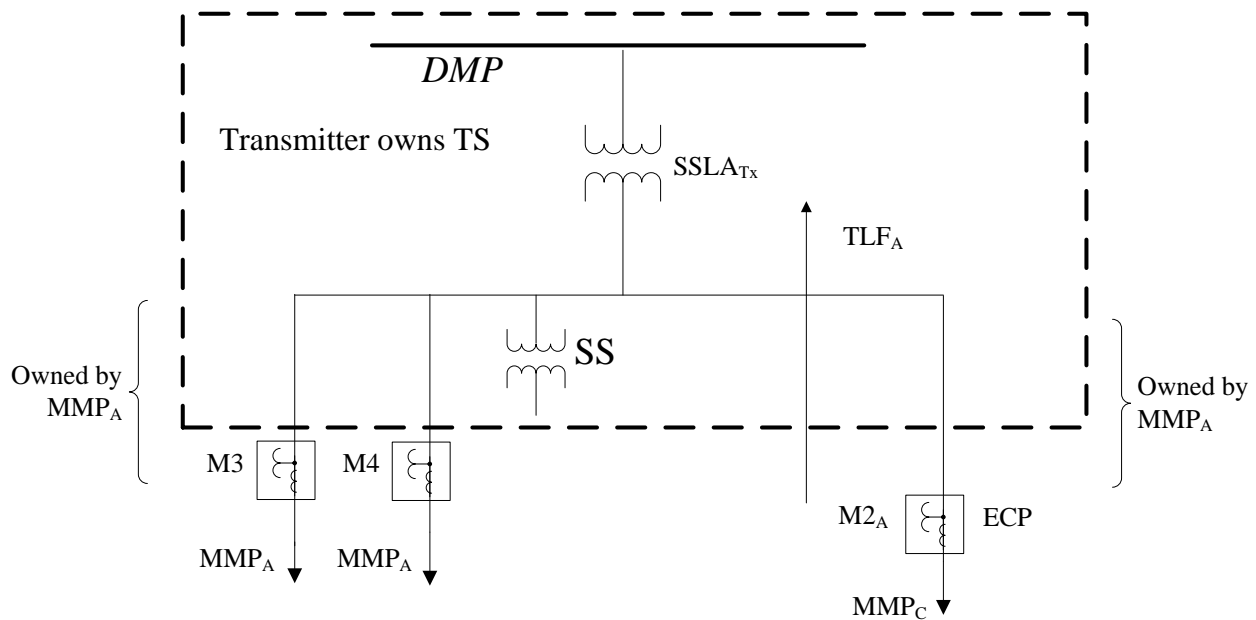
- MMP$_B$ and MMP$_C$ have moved outside the fence
- MMP$_B$ and MMP$_C$ are both embedded in MMP$_A$ feeders
- MMP$_A$ is the *transmission customer*

6b.1 <u>Agreement on Losses</u>

MMP$_A$ TT	=	M3.TLF$_A$ + M4.TLF$_A$ + M2$_A$.TLF$_A$
MMP$_B$ Energy	=	M3.TLF$_A$ + M4.TLF$_A$ per *OEB*
MMP$_C$ Energy	=	M2A.TLF$_A$ per *OEB*

Notes:

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

7a. Multiple Embedded Distributors with Taps
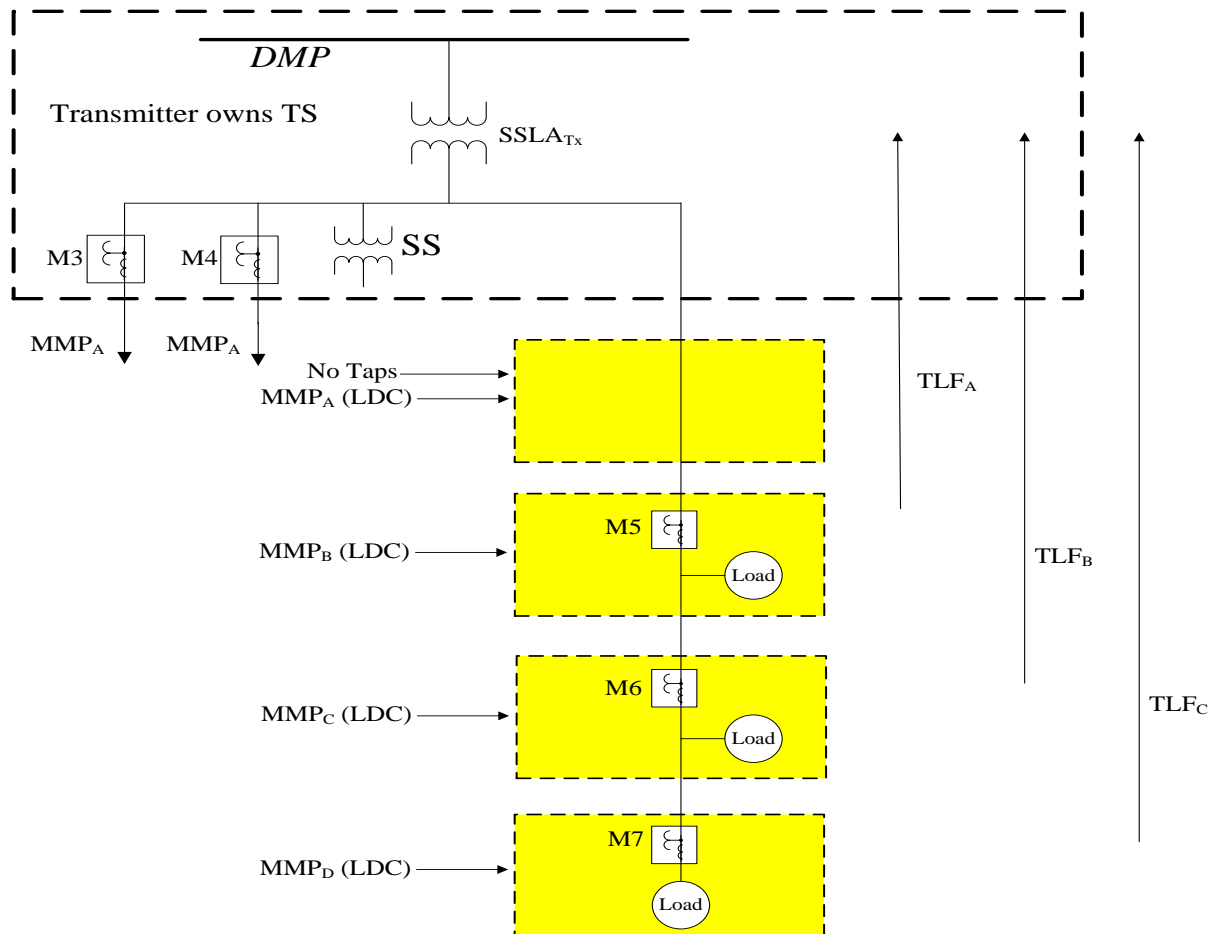
- MMP$_A$ is directly connected to the bus inside the fence
- MMP$_B$, MMP$_C$ and MMP$_D$ are embedded
- MMP$_A$ is a *transmission customer*

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 *OEB*
MMP$_C$ Energy	=	M6.TLF$_B$ - M7.TLF$_C$ per *OEB*
MMP$_D$ Energy	=	M7.TLF$_C$ per *OEB*

Notes:

1. MMP$_A$ provides the loss calculation.

7b. Embedded Distributors in Parallel
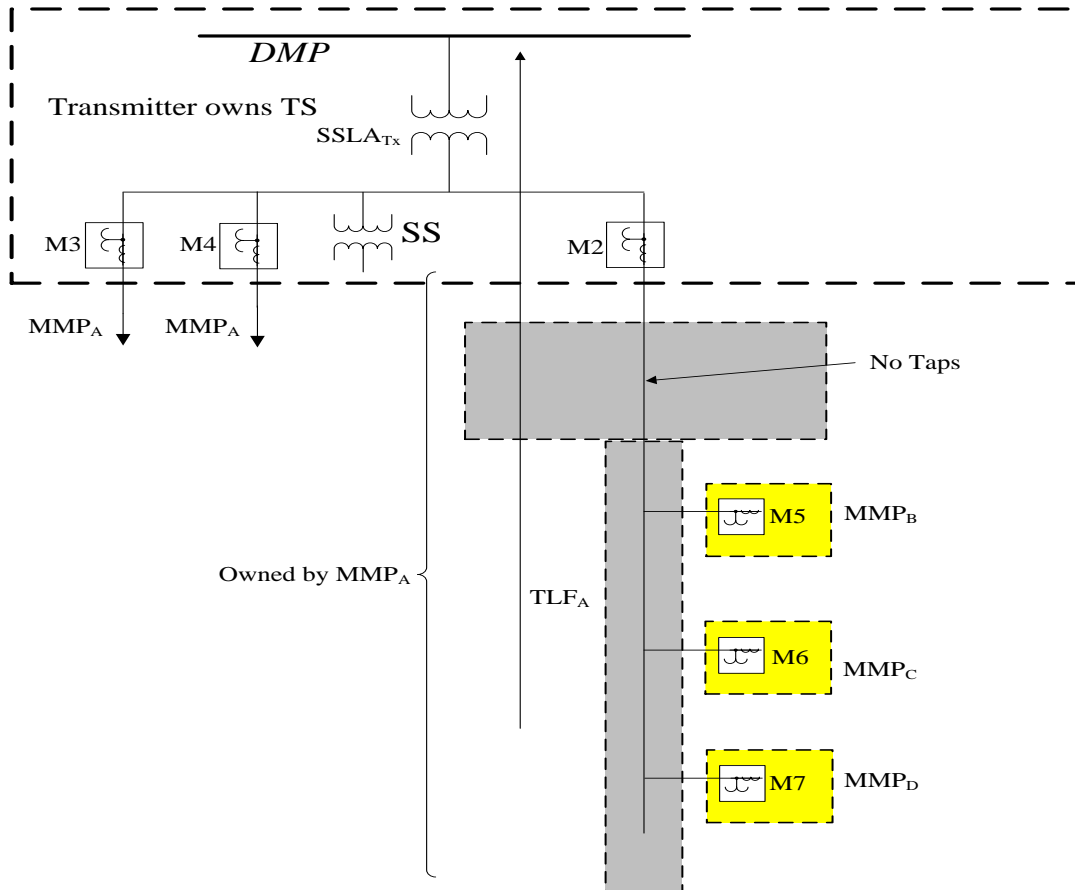
- MMP$_A$ is directly connected
- MMP$_A$ is a *transmission customer*
- MMP$_B$, MMP$_C$ and MMP$_D$ are embedded

7b.1 <u>No Agreement on Losses is required</u>

MMP$_A$ Energy =	M3+M4+M2+SS+SSLA$_{TX}$ - M5.TLF$_A$ - M6.TLF$_A$ - M7.TLF$_A$
MMP$_A$ TT =	M3+M4+M2+SS+SSLA$_{TX}$
MMP$_B$ Energy =	M5.TLF$_A$ per *OEB*
MMP$_C$ Energy =	M6.TLF$_A$ per *OEB*
MMP$_D$ Energy =	M7.TLF$_A$ per *OEB*

Notes:

1. MMP$_A$ provides the loss calculation.

7c. Embedded Distributors in Parallel (Meters Located Between LDC Taps)
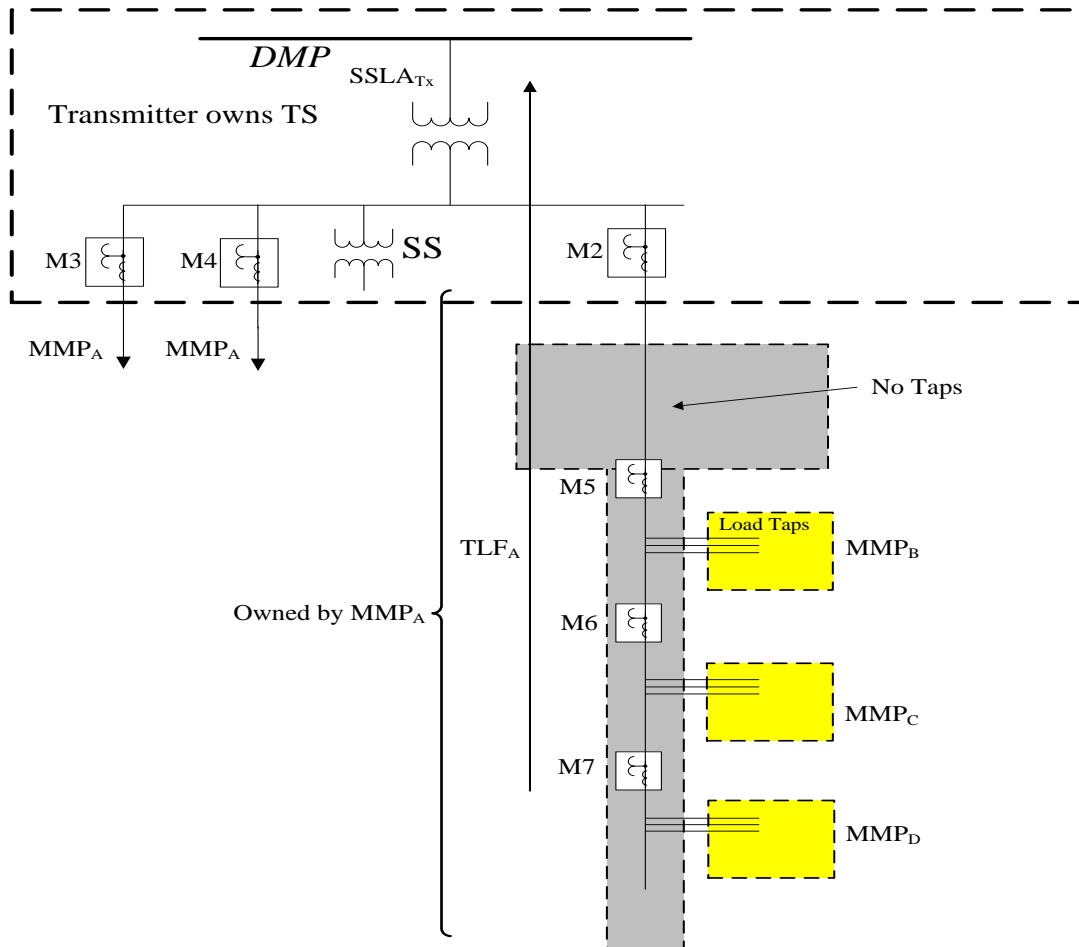
- MMP$_A$ is directly connected
- MMP$_A$ is a *transmission customer*
- MMP$_B$, MMP$_C$ and MMP$_D$ are embedded

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 *OEB*
MMP$_C$ Energy	=	M6.TLF$_A$ − M7.TLF$_A$ per *OEB*
MMP$_D$ Energy	=	M7.TLF$_A$ per *OEB*

Notes:

1. MMP$_A$ provides the loss calculation.

8a. Embedded Generator (G) or Embedded Electricity Storage (ES) in an Embedded Distributor – Feeder Meters
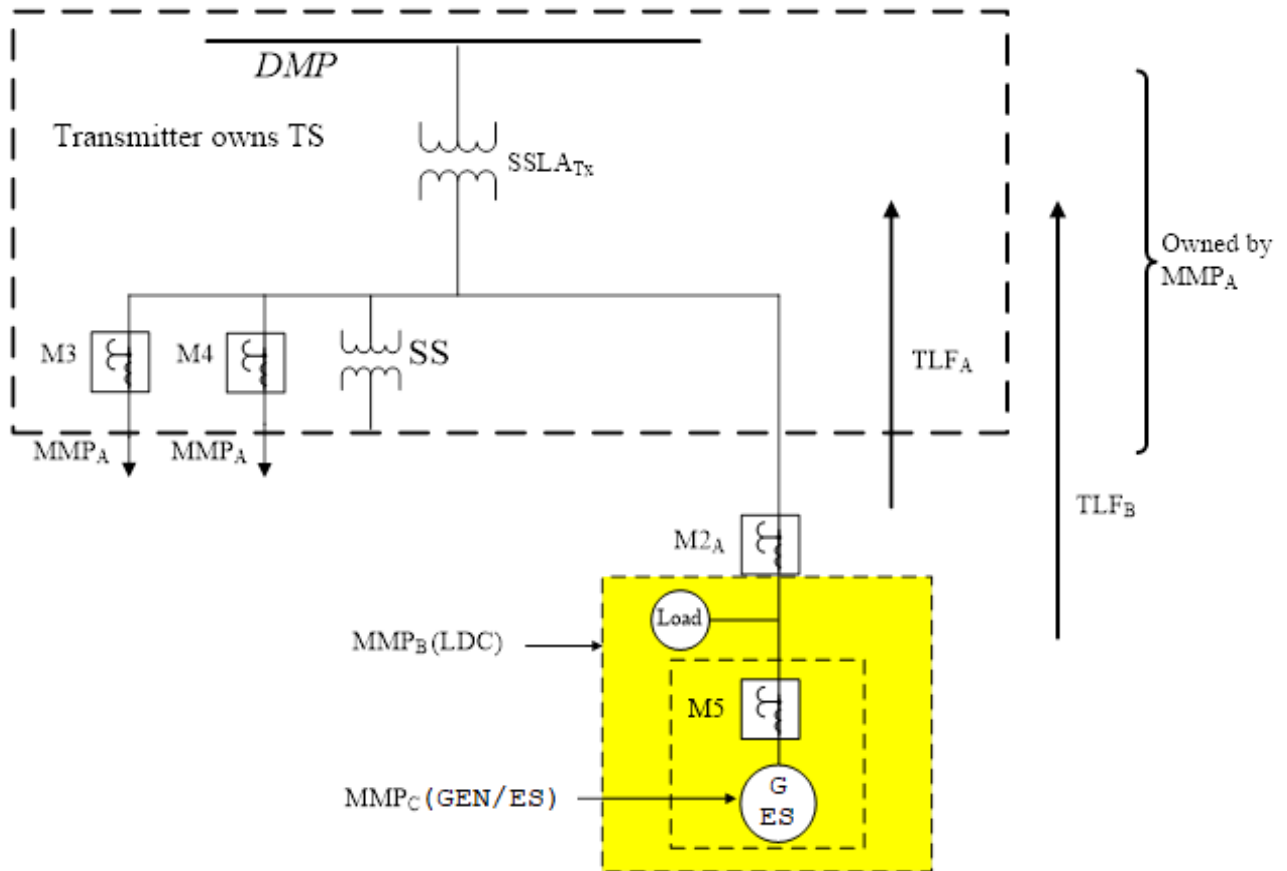
- MMP$_A$ is directly connected
- MMP$_A$ is a *transmission customer*
- MMP$_B$ and MMP$_C$ are embedded

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 *OEB*
		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* or *embedded electricity storage participant* 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 output is higher than MMP_B load, MMP_A should install feeder metering or agree with MMPB the loss factor (LF1) to be applied to $M2_AC_{34}$ (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 the Transmitter List
MMP_A TT network   = $M3+M4+SS_Y+SSLA_Y + M2_A.TLF_A$
MMP_A TT connection   = $M3+M4+SS_Y+SSLA_Y + M2A.TLF_A + M5C_{34}.LF$

8b. Embedded Generator (G) or Embedded Electricity Storage (ES) in an Embedded Distributor – Bus Meter
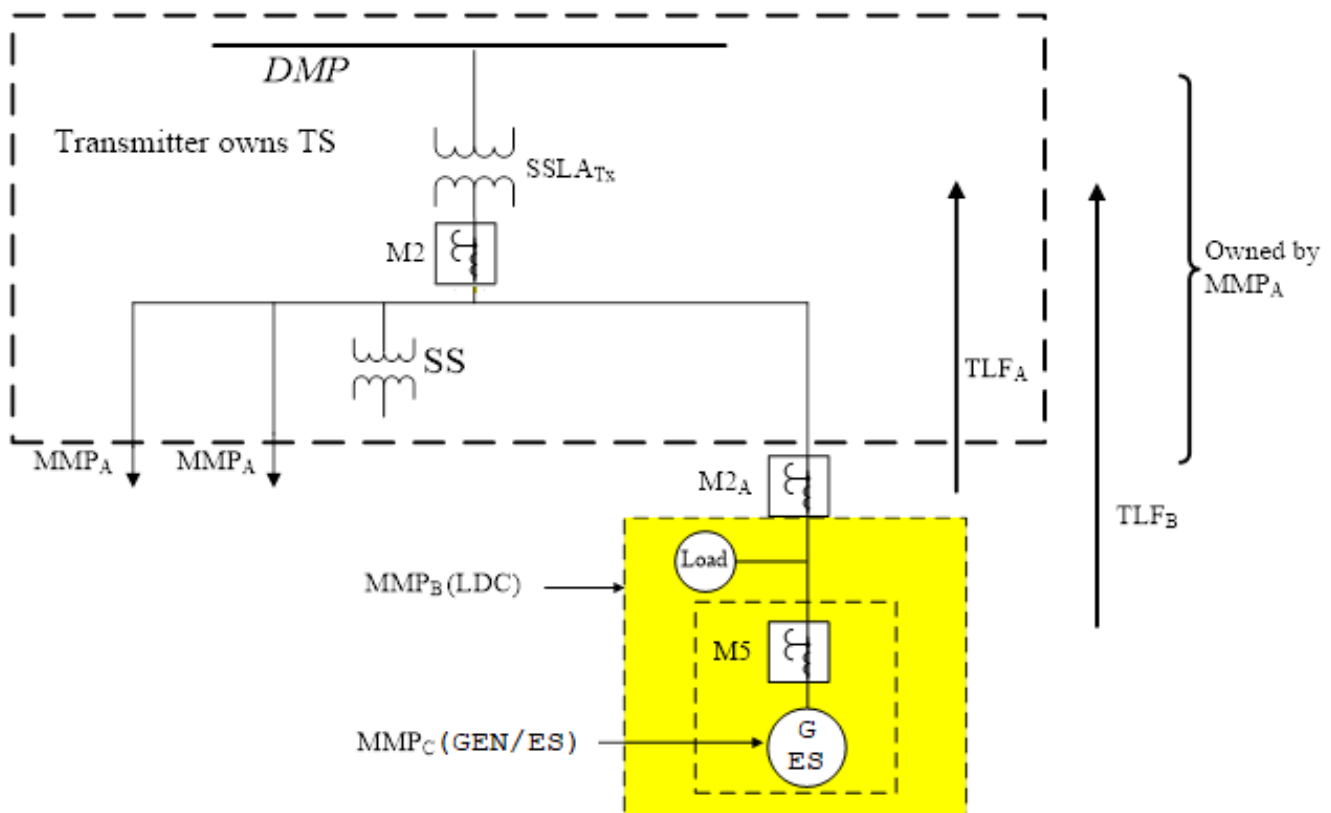
- MMP_A is directly connected

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

8b.1 <u>No Agreement between MMP_A and MMP_B is required if:</u>

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

$M2_A$ registers non-zero values on Ch # 1 and zero values on Ch # 3.

MMP_A Energy	=	$M2+SSL_A-M2_A.TLF_A$
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 4
MMP_C Energy	=	$M5_{12}.TLF_B$ (delivered channels 1 & 2) = $M5C_{12}.TLF_B$ per

OEB

$M5_{34}. LF$ (for received channels 3 & 4) = $M5C_{34}.LF$ =   see note 2

$M5C_{12}.TLF_B + M5C_{34}.LF$

8b.2 <u>An agreement between MMP_A and MMP_B is required if:</u>   see note 3

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

$M2_A$ registers zero values on Ch # 1 and non-zero values on Ch # 3.

MMP_A Energy = $M2+SSL_A - (M2_AC_{12}.TLF_A + M2_AC_{34}.LF1)$ see note 3

MMP_A TT   =   Check the appropriate transmission rate schedule for details

MMP_B Energy = $M2_{A12}.TLF_A$ (delivered channels 1 & 2) = $M2_AC_{12}.TLF_A$

$M2_{A34}. LF_1$ (for received channels 3 & 4) = $M2_AC_{34}.LF_1$ see note 3   = $(M2_AC_{12}.TLF_A + M2_AC_{34}.LF1) - (M5C_{12}.TLFB + M5C_{34}.LF)$ see note 4

MMP_C Energy = $M5_{12}.TLF_B$ (delivered channels 1 & 2) = $M5C12.TLF_B$ per

OEB

$M5_{34}. LF$ (received channels 3 & 4)   = $M5C_{34}.LF$ see note 2 & 4

= $M5C_{12}.TLF_B + M5C_{34}.LF$

Note:
1. The *embedded generator* or *embedded electricity storage participant* 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_1) is applied. If an agreement does not exist, $LF_1=TLF_A$ (Refer to example 8.a.1).
4. $M5C_{12}$ and $M5C_{34}$ are direction dependent (ch 1 & 2 delivered, ch 3 & 4 received).
5. MMP_A provides the loss calculations.
6. MMP_A responsible for *station service* metering

Example of *transmission tariff settlement*:

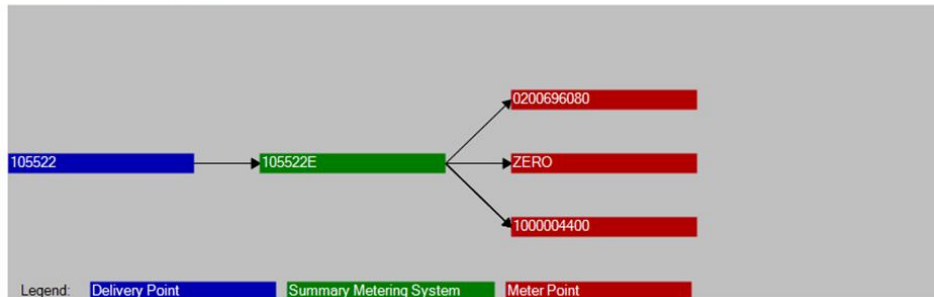Using Ontario Transmission Rate Schedules and the Transmitter List

MMP_A TT network $=M2+SSLA$

MMP_A TT connection $=M2+SSLA+ M5C_{34}.LF$

— End of Section —

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

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 VT: 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 VT: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
        CT: VT: 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 VT: 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 VT: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
        CT: VT: 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 VT: 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 VT: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
         CT: VT: 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 VT: 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 VT: 366 Service Type: D DateRange Wed Jun 25 09:18:00 EST 2003 - Sat Jan 31 23:59:59 EST 2015
         CT: VT: 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, TLF-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:

  o *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.

  o *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

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
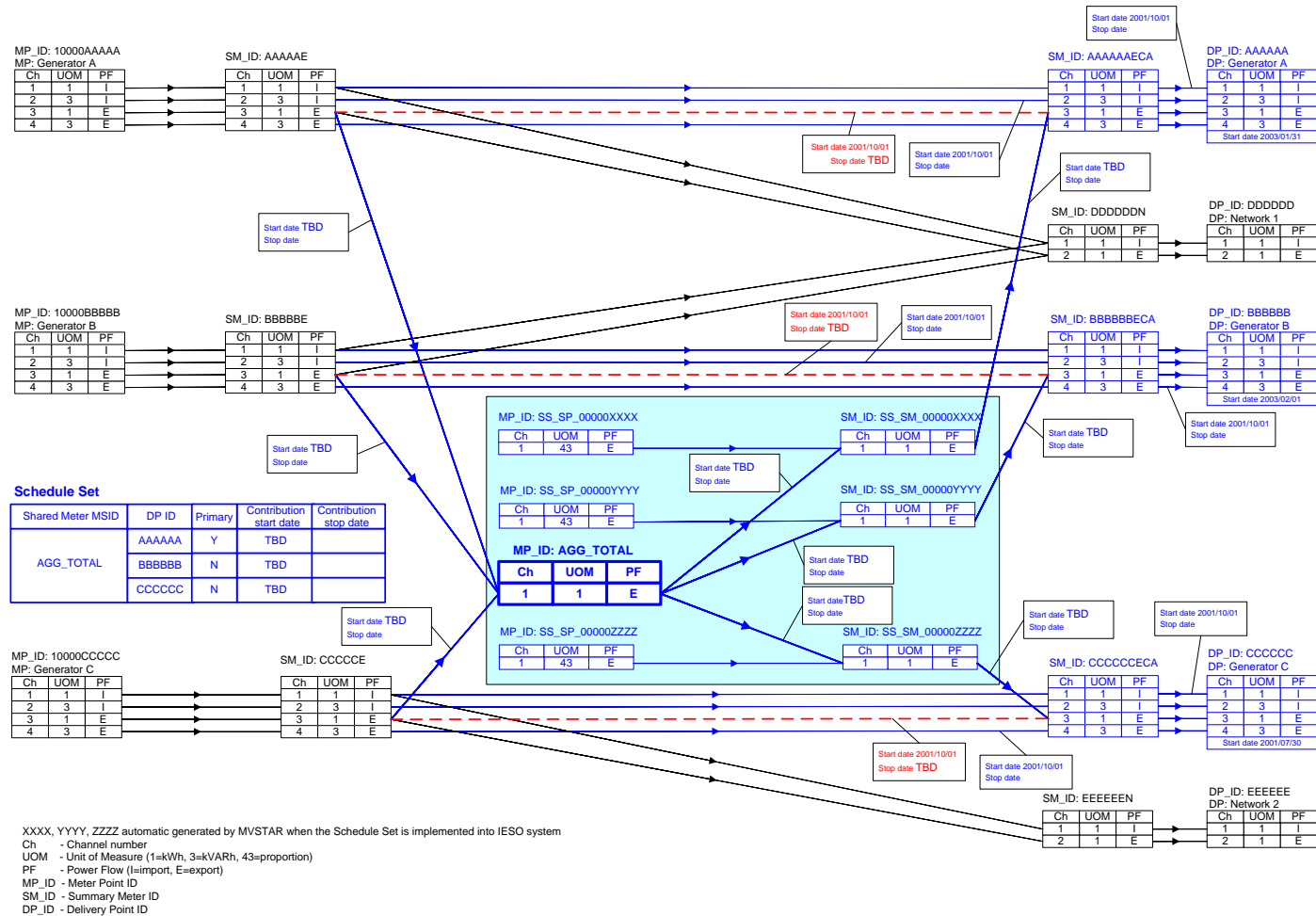
— End of Section —

Appendix G: Example of a Meter Disaggregation Model

MP_ID: 10000AAAA0
MP: DMP1

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

VC=10000AAAA0

SM_ID:DDDDDDN

Ch	UOM	PF
1	1	I
2	1	E

DP_ID: DDDDDD
DP: Network 1
Start Date: TBD

SM_ID: Total

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

(-)

(+)

MP_ID: SS_SP_00000XXXX
MP_ID:

Ch	UOM	PF
1	43	E

SM_ID: SS_SM_00000XXXX
SM_ID:

Ch	UOM	PF
1	1	E

DP_ID: AAAAAA
DP: Generator A
Start date: TBD

MP_ID: SS_SP_00000YYYY
MP_ID:

Ch	UOM	PF
1	43	E

SM_ID: SS_SM_00000YYYY
SM_ID:

Ch	UOM	PF
1	1	E

DP_ID: BBBBBB
DP: Generator B
Start date: TBD

MP_ID: DISAGG_TOTAL

Ch	UOM	PF
1	1	E

SM_ID: SS_SM_00000ZZZZ
SM_ID:

Ch	UOM	PF
1	1	E

DP_ID: CCCCCC
DP: Generator C
Start date: TBD

MP_ID: 10000BBBB0
MP: DPM2

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

VC=10000BBBB0

SM_ID: Net

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

MP_ID: SS_SP_00000ZZZZ
MP_ID:

Ch	UOM	PF
1	43	E

MP_ID: ZERO
MP: ZERO

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

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	

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

– End of Section –

Appendix H: Loss Dynamic Allocation - Models and Totalization Tables

a. Feeder meters

Dynamic Load Loss Allocation – feeder meters

TOTALIZATION TABLE FORM

ieso
Power to Ontario.
On Demand.

Facility Name	Transformer TS
Effective Date	TBD
MSP ID	
Prepared By	

Breaker Ratio		T1	
MMP Name		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 #	DP ID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	UofM	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation a(V²)	Transformation b(I²)	Radial Line e(V²)	Radial Line f(I²)	Transformation k₁	Transformation k₂	Transformation k₃	Radial Line k₁	Radial Line k₂	Radial Line k₃	TLF
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

Load Loss - Dynamic allocation

Ratio ch1 = M1 (ch1-ch3) – M2 (ch1-ch3) / M1 (ch1-ch3)

Ratio ch2 = M2 (ch1-ch3) / M1 (ch1-ch3)

No Load Loss - Fix ratio allocation

K3 = K3a + K3b

TOTALIZATION TABLE FORM

ieso Power to Ontario. On Demand.

Facility Name	Transformer TS
Effective Date	TBD
MSP ID	
Prepared By	

MMP Name	Breaker Ratio		T1	
			MMP Feeders	Total Feeders
MMP1			1	
MMP2			1	2

Non-metered Station Service (kW) _____ 0

Factor	k1	k2	k3
T1 total	0.0373	0.0468	112.73
MMP1	Dynamic	Dynamic	56.3650
MMP2	Dynamic	Dynamic	56.3650

A. ENERGY MARKET

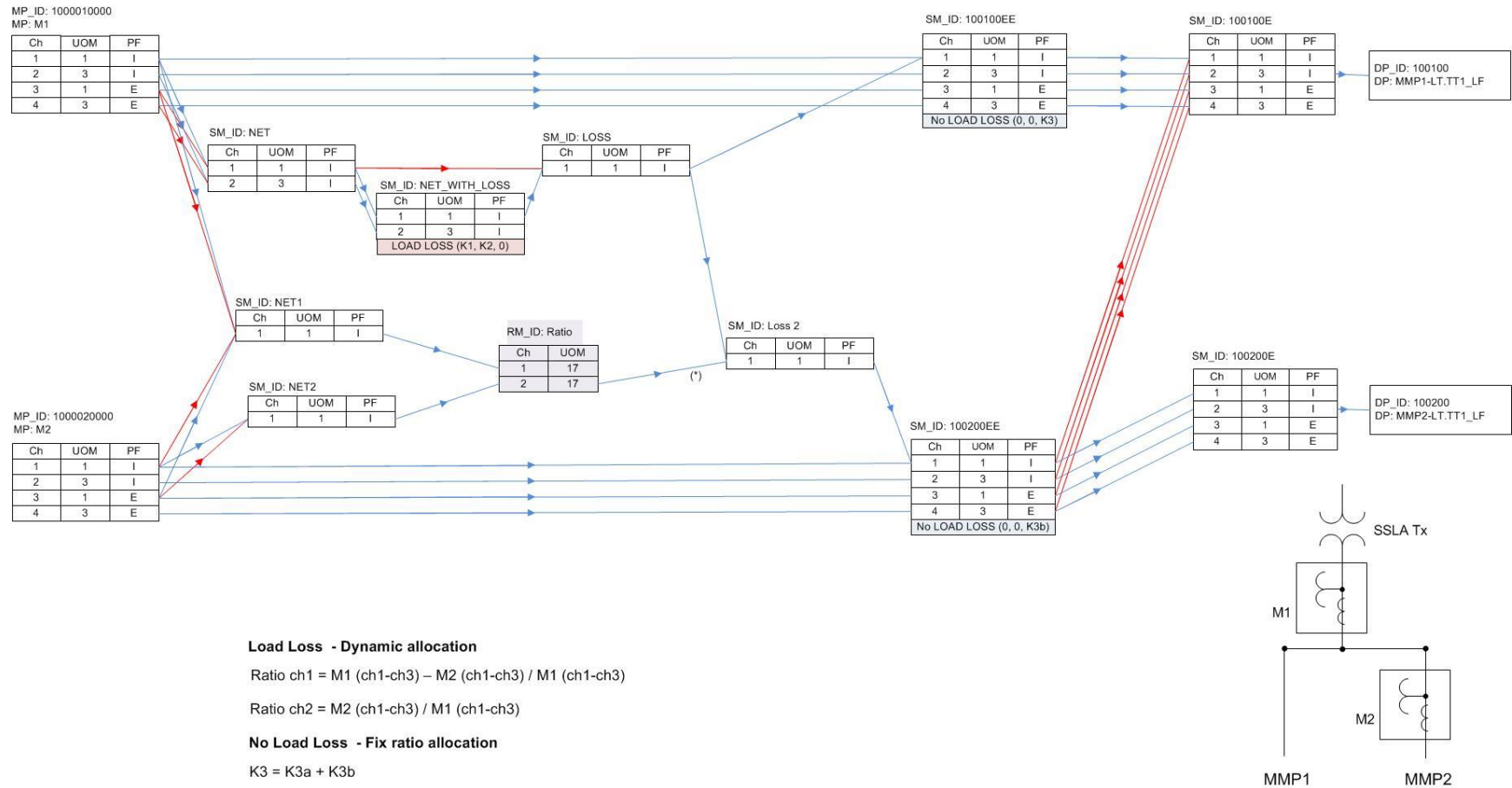| MMP #	DP ID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	UoM	Energy Flow	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation a(V²)	Transformation b(I²)	Radial Line e(V²)	Radial Line f(I²)	Transformation k₁	Transformation k₂	Transformation k₃	Radial Line k₁	Radial Line k₂	Radial Line k₃	TLF
			100100EE	1000010000	1	+	1	del	M1	0.0											0.0373	0.0468	112.7300				
		100100E			2	+	3	del																			
					3	+	1	rec																			
1	100100				4	+	3	rec																			
			100200EE	1000020000	1	-	1	del	M2	0.0											T1Dynamic	T1Dynamic	56.365				
					2	-	3	del																			
					3	-	1	rec																			
					4	-	1	rec																			
				1000020000	1	+	1	del	M2	0.0											T1Dynamic	T1Dynamic	56.3650				
2	100200	100200E	10200EE		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).

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
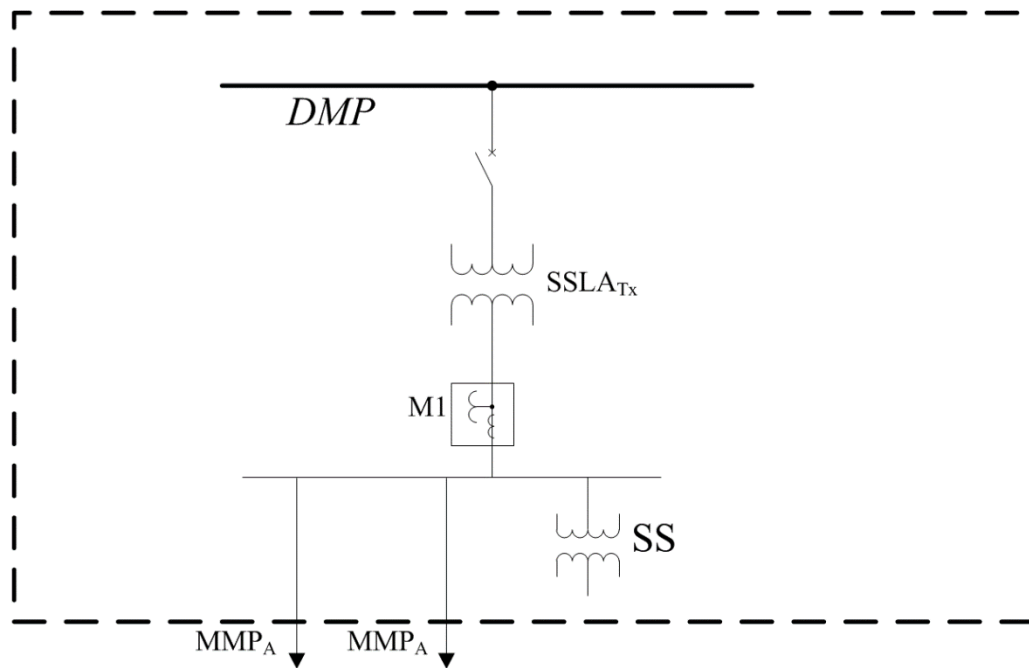
Requirements:

- 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*

<u>Note:</u> 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

RP_ID: 100100RM_E

Ch	UOM
1	16
2	16

(*0%)

MP_ID: 1000010000
MP: M1

Ch	UOM	PF
1	1	I
2	3	I
3	1	E
4	3	E
5	7	I
6	7	I
7	7	I
8	10	I
9	10	I
10	10	I
VC (K1k2k3 or ab)		

(*)

SP_ID: 100100E

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

DP_ID: 100100

(*0%)

RP_ID: 100100RM_V

Ch	UOM
1	16
2	16

(*)

SP_ID: 100100EE

Ch	UOM	PF
1	1	I

(-)

MP_ID: 20
MP: 20

Ch	UOM	PF
1	1	I

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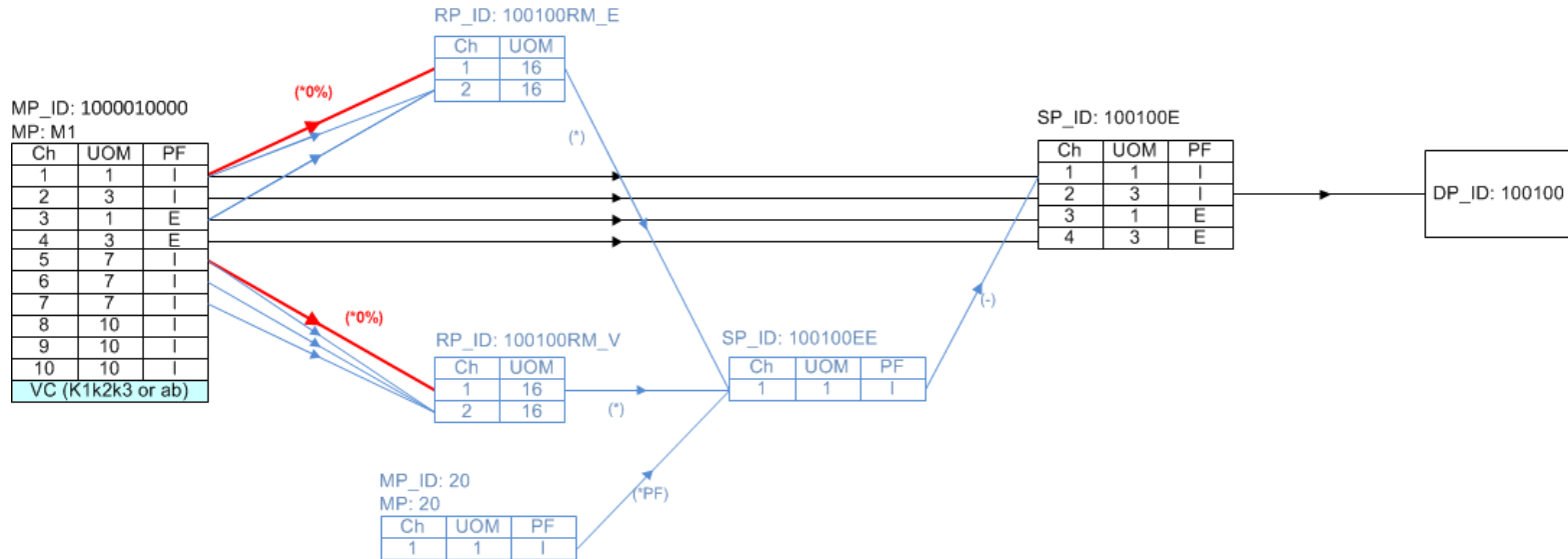
	RM_E Ch1=0 (½)	RM_E Ch1<>0 (0)
RM_V Ch1=0 (½)	1/4	0
RM_V Ch1<>0 (0)	0	0

The ratio meter RM_V output will be as follows:
   If Σ of all voltage channels is equal to zero; Ch1 (output) = 0.5
   If Σ of all voltage channels is not equal to zero; Ch1 (output) = 0

The ratio meter RM_E output will be as follows:
   If Σ of all voltage channels is equal to zero; Ch1 (output) = 0.5
   If Σ 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

ieso
Power to Ontario.
On Demand.

Facility Name	Transformer Station TS
Effective Date	TBD
MSP ID	
Prepared By (MSP)	MSP A
IESO Build By	

Breaker Ratio / MMP Name		T_		T_		T_		Non-metered Station Service (kW)
		MMP Feeders	Total Feeders	MMP Feeders	Total Feeders	MMP Feeders	Total Feeders	
MMP1: MMP A		1						
			1					

A. ENERGY MARKET

MMP #	DP ID	Summary 1	Summary 2	Meter Point ID	Channel No.	Operator (+ or -)	UofM	Energy Flow Direction	Description of Measured Circuit	Ratio (3 dec.)	MEC	Assumed Voltage	Assumed P.F.	Service Type	CT Ratio	PT Ratio	Transformation $a(V^2)$	$b(I^2)$	Radial Line $e(V^2)$	$f(I^2)$	Transformation k_1	k_2	k_3	Radial Line k_1	k_2	k_3	TLF
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
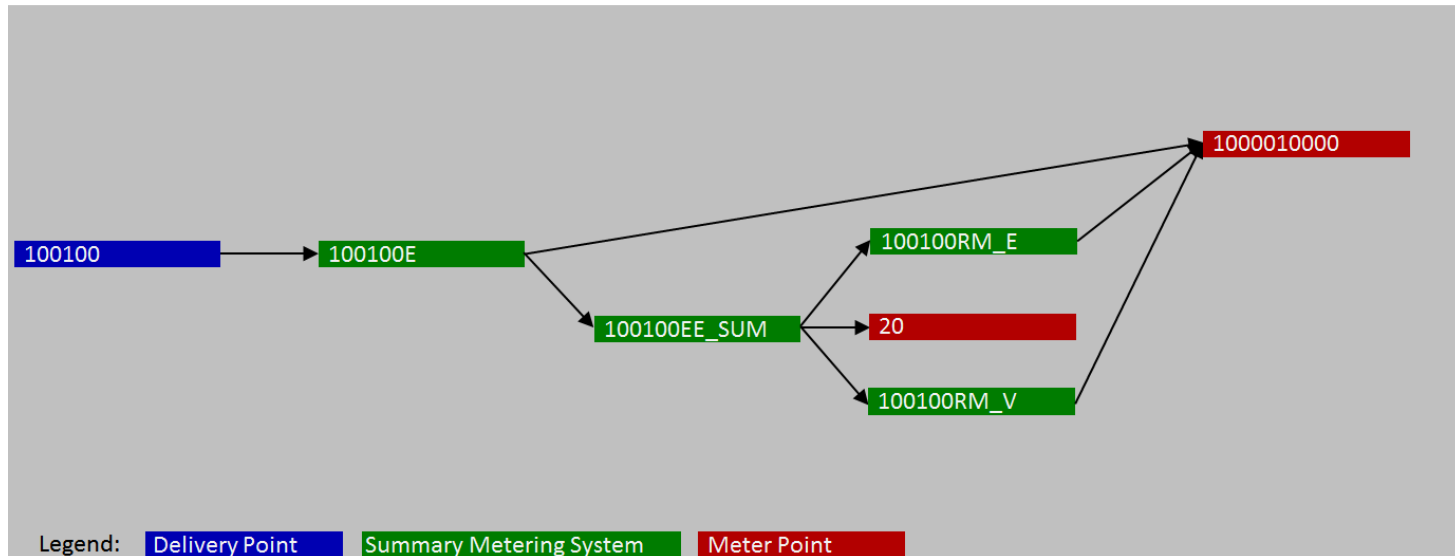
Delivery point 100100 is associated with 100100E from Fri Sep 30 00:00:00 EST 2018 to no end date

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
```

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
```

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

Document ID	Document Title
RUL-6 to RUL-24	Market Rules for the Ontario Electricity Market
MAN-132	Market Manual 2: Market Administration, Part 2.1:Dispute Resolution
MAN-145	Market Manual 3: Metering, Part 3.0: Metering Overview
MAN-147	Market Manual 3: Metering, Part 3.2: Meter Point Registration and Maintenance
MAN-148	Market Manual 3: Metering, Part 3.4: Measurement Error Correction
MAN-149	Market Manual 3: Metering, Part 3.5: Site-Specific Loss Adjustment
MAN-150	Market Manual 3: Metering, Part 3.6: Conceptual Drawing Review
MAN-152	Market Manual 3: Metering, Part 3.8: Creating and Maintaining Delivery Point Relationships
MAN-111	Market Manual 4: Market Operations, Part 4.3: Real-Time Scheduling of the Physical Markets

— End of Document —