

## **24 Attachment R - Cost Allocation and Measurement and Verification Methodologies for Demand Reductions by Distributed Energy Resources in a DER Aggregation**

### **24.1 Cost Allocation Methodology for Demand Reductions Recovered Pursuant to Schedule 1**

The “Schedule 1 Program Costs” for verified Actual Demand Reductions by DER Aggregations participating in the Energy and Ancillary Services Markets shall be equal to the Supplier payments for Demand Reductions calculated in accordance with ISO Services Tariff Section 4.5.2.

The “Schedule 1 Program Costs” for verified Demand Reductions by DER Aggregations participating in the Energy and Ancillary Services Markets shall be allocated to Transmission Customers, pursuant to the methodology set forth below, on the basis of their Load Ratio Shares and in proportion to the probability, given historical transmission congestion patterns, that a particular Demand Reduction will benefit them by reducing Energy costs in their Load Zones or “Composite Load Zones” (see below).

More specifically, Schedule 1 Program Costs shall be allocated to Transmission Customers each Billing Period as follows:

- a) Schedule 1 Program Costs shall initially be attributed to the Load Zone where the Transmission Node used to Bid the associated Demand Reduction is located.
- b) In determining whether and how Transmission Customers located in particular Load Zones, or Composite Load Zones, have benefited from the Energy provided by Demand Reduction, and how much they shall be required to pay a share of the associated Schedule 1 Program Costs, the ISO shall account for the effects of congestion at the most frequently constrained NYCA interfaces. When none of these interfaces are constrained Transmission Customers in all Load Zones shall

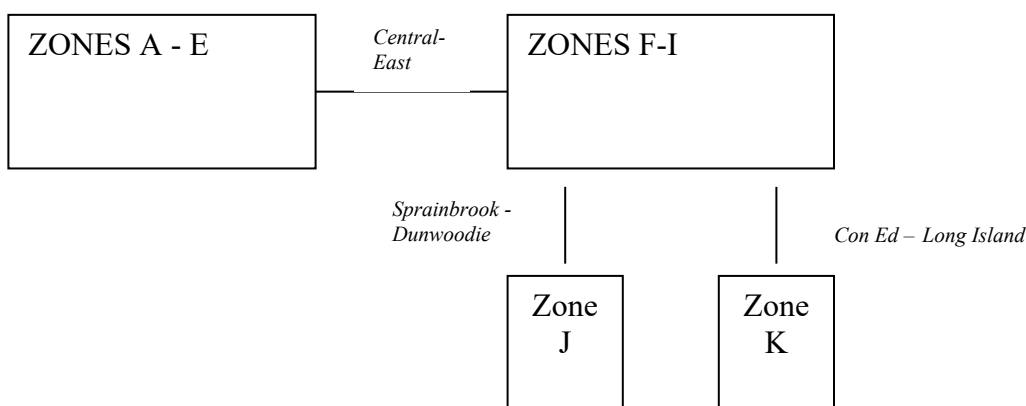
be deemed to have benefited from the Energy provided by Demand Reduction and shall pay a share of the associated Schedule 1 Program Costs. When one or more of the most frequently constrained NYCA interfaces is constrained, then Transmission Customers located in a Load Zone, or Composite Load Zone, that is upstream of the constrained interface, shall be deemed to have benefited from the upstream Energy provided by Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. Similarly, when one or more of the interfaces is congested, Transmission Customers located in a Load Zone, or Composite Load Zone, that is downstream of a constrained interface, shall be deemed to have benefited from the downstream Energy Provided by Demand Reduction and shall be required to pay a share of the associated Schedule 1 Program Costs. By contrast, Transmission Customers that are “separated” from the Energy provided by Demand Reduction by a constrained interface shall be deemed not to have benefited from it and shall not be required to pay a share of the associated Schedule 1 Program Costs.

- c) The ISO shall determine the extent of congestion at the most frequently constrained interfaces using a series of equations that calculate the static probability that: (i) no constraints existed in the transmission system serving the Load Zone or Composite Load Zone; (ii) the Composite Load Zone was upstream of a constraint and Energy provided by Demand Reduction occurred upstream, and (iii) the Composite Load Zone was downstream of a constraint and Energy provided by Demand Reduction occurred downstream.

Costs shall be allocated to each Transmission Customer that is deemed to have benefited from the verified Demand Reduction on a Load Ratio Share basis, using Real-Time metered hourly Load data.

- d) The three interfaces that will be used for this cost allocation are the “Central-East” interface, which divides western from eastern New York State, the Sprainbrook-Dunwoodie interface, which divides New York City and Long Island from the rest of New York State, and the Consolidated Edison Company (“ConEd”) - Long Island interface (including the Y49/Y50 lines), which divides New York City from Long Island. Given these limiting interfaces, four Composite Load Zones currently exist, *i.e.*, West of Central-East (Load Zones A, B, C, D, E), East Upstate Excluding New York City and Long Island (Load Zones F, G, H, I), New York City (Load Zone J), and Long Island (Load Zone K). The geographic configuration of these Composite Load Zones is depicted in the illustration below.

#### Relationship Between Frequently Constrained Interfaces and Composite Load Zones



Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission Customers as follows:

For Transmission Customer m in Load Zones A-E:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E) +$	'Central East const
$a_3 * (cost_A + \dots + cost_I + cost_K) * load_m / (load_A + \dots + load_I + load_K) +$	'NYC constraint
$a_4 * (cost_A + \dots + cost_J) * load_m / (load_A + \dots + load_J) +$	'LI constraint
$a_5 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E) +$	'Cent East + NYC
$a_6 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E) +$	'Cent East + LI
$a_7 * (cost_A + \dots + cost_I) * load_m / (load_A + \dots + load_I) +$	'NYC + LI
$a_8 * (cost_A + \dots + cost_E) * load_m / (load_A + \dots + load_E)$	'Cent East + NYC + LI

For Transmission Customer m in Load Zones F-I:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_F + \dots + cost_K) * load_m / (load_F + \dots + load_K) +$	'Central East const
$a_3 * (cost_A + \dots + cost_I + cost_K) * load_m / (load_A + \dots + load_I + load_K) +$	'NYC constraint
$a_4 * (cost_A + \dots + cost_J) * load_m / (load_A + \dots + load_J) +$	'LI constraint
$a_5 * (cost_F + \dots + cost_I + cost_K) * load_m / (load_F + \dots + load_I + load_K) +$	'Cent East + NYC
$a_6 * (cost_F + \dots + cost_J) * load_m / (load_F + \dots + load_J) +$	'Cent East + LI
$a_7 * (cost_A + \dots + cost_I) * load_m / (load_A + \dots + load_I) +$	'NYC + LI
$a_8 * (cost_F + \dots + cost_I) * load_m / (load_F + \dots + load_I)$	'Cent East + NYC + LI

For Transmission Customer m in Load Zone J:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_F + \dots + cost_K) * load_m / (load_F + \dots + load_K) +$	'Central East const
$a_3 * cost_J * load_m / load_J +$	'NYC constraint
$a_4 * (cost_A + \dots + cost_J) * load_m / (load_A + \dots + load_J) +$	'LI constraint
$a_5 * cost_J * load_m / load_J +$	'Cent East + NYC
$a_6 * (cost_F + \dots + cost_J) * load_m / (load_F + \dots + load_J) +$	'Cent East + LI
$a_7 * cost_J * load_m / load_J +$	'NYC + LI
$a_8 * cost_J * load_m / load_J$	'Cent East + NYC + LI

For Transmission Customer m in Load Zone K:

$a_1 * (cost_A + \dots + cost_K) * load_m / (load_A + \dots + load_K) +$	'no constraints
$a_2 * (cost_F + \dots + cost_K) * load_m / (load_F + \dots + load_K) +$	'Central East const
$a_3 * (cost_A + \dots + cost_I + cost_K) * load_m / (load_A + \dots + load_I + load_K) +$	'NYC constraint
$a_4 * cost_K * load_m / load_K +$	'LI constraint
$a_5 * (cost_F + \dots + cost_I + cost_K) * load_m / (load_F + \dots + load_I + load_K) +$	'Cent East + NYC
$a_6 * cost_K * load_m / load_K +$	'Cent East + LI
$a_7 * cost_K * load_m / load_K +$	'NYC + LI
$a_8 * cost_K * load_m / load_K$	'Cent East + LI + NYC

In all cases, the variables are:

- $a_1$  = fraction of time when no constraints exist
- $a_2$  = fraction of time when Central East interface alone is constraining
- $a_3$  = fraction of time when Sprainbrook-Dunwoodie interface alone is constraining
- $a_4$  = fraction of time when Con Ed-Long Island (including the Y49/Y50 lines) interfaces are constraining, but Central East and Sprainbrook-Dunwoodie

- interfaces are not constraining
- $a_5$  = fraction of time when Central East and Sprainbrook-Dunwoodie interfaces are constraining but Con Ed-Long Island (including the Y49 and Y50 lines) interfaces are not constraining
- $a_6$  = fraction of time when Central East, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining but the Sprainbrook-Dunwoodie interface is not constraining
- $a_7$  = fraction of time when Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining but the Central East interface is not constraining
- $a_8$  = fraction of time when Central East, Sprainbrook-Dunwoodie, Con Ed-Long Island interfaces (including the Y49/Y50 lines) are constraining
- $\text{cost}_{A...K}$  = revenue deficiencies due to DER Aggregation Demand Reductions in Load Zones A...K, calculated on a hourly basis
- $\text{load}_m$  = real-time Load for Transmission Customer m, calculated on an hourly basis
- $\text{load}_{A...K}$  = real-time Loads for all Transmission Customers in Load Zones A...K, calculated on an hourly basis

## 24.2 Measurement of Actual Demand Reduction of Individual Distributed Energy Resources within a DER Aggregation

For the purposes of Demand Reduction calculations described in this Section, the metered load values of Distributed Energy Resources shall be zero or greater. The measured amount of Demand Reduction for each 6-second interval by an individual Distributed Energy Resource within a DER Aggregation which is dispatched for Energy with no Regulation Service shall be the greater of: (i) the Distributed Energy Resource's adjusted Economic Customer Baseline Load ("ECBL") for each five-minute interval, which shall be calculated in accordance with section 24.2.1 and ISO Procedures, minus the telemetered load for each 6-second interval and (ii) zero.

The measured amount of Demand Reduction for each 6-second interval by an individual Distributed Energy Resource within a DER Aggregation which is dispatched for Regulation Service shall be the greater of: (i) the Distributed Energy Resource's Baseline Load for each 6-second interval of Regulation Service, which shall be calculated in accordance with section

24.2.2 and ISO Procedures, minus the Distributed Energy Resource's telemetered load for each 6-second interval and (ii) zero.

The amount of Demand Reduction supplied by a DER Aggregation shall be the sum of Demand Reductions from each individual Distributed Energy Resource within the DER Aggregation. Aggregators shall provide to the ISO DER Aggregation Demand Reductions for (i) each 6-second interval using real-time telemetry in accordance with Services Tariff Section 13 and the ISO Procedures, and (ii) each hour using revenue-quality meter data pursuant to this section 24.2, and in accordance with the ISO Procedures.

**24.2.1 Methodology for the Calculating the Economic Customer Baseline Load for a Distributed Energy Resource within a DER Aggregation during Intervals with no Regulation Service Dispatch**

The ISO shall employ two different calculation methodologies of the Economic Customer Baseline Load ("ECBL") for Demand Reductions, depending on whether the Demand Reduction is on a weekend or a weekday, during the intervals with no Regulation Service dispatch for the DER Aggregation. A Demand Side Resource's six-second telemetry data, normalized into five-minute intervals, shall be used in each ECBL calculation methodology.

**24.2.1.1 Definitions**

**Adjusted Weekday ECBL:** For each five-minute interval, the Adjusted Weekday ECBL shall be equal to the sum of the ECBL and the ECBL In-Day Adjustment Factor.

**ECBL In-Day Adjustment Factor:** The ECBL In-Day Adjustment shall be an adjustment that is applied to the ECBL for each five-minute interval.

- a) Calculate the ECBL In-Day Adjustment by subtracting the average of the ECBL over the three five-minute intervals of the ECBL In-Day Adjustment Period from

the average of the telemetered load for the same three five-minute intervals, provided that (i) the DER Aggregation was not dispatched for Energy and/or Regulation Service during any of three five-minute intervals of the ECBL In-Day Adjustment Period, or (ii) the DER Aggregation was dispatched for Energy and/or Regulation Service during one or more of the three five-minute intervals of the ECBL In-Day Adjustment Period, but the LBMP for each of those intervals was less than the applicable Monthly Net Benefits Threshold.

- b) If the DER Aggregation was dispatched for Energy and/or Regulation Service during one or more of the three five-minute intervals of the ECBL In-Day Adjustment Period and the LBMP for the interval(s) was equal to or exceeded the applicable Monthly Net Benefits Threshold, calculate the ECBL In-Day Adjustment in step (a) above and add the measured Demand Reduction to the metered Load as the Proxy Load value for one or more of the three five-minute intervals of the ECBL In-Day Adjustment Period in which the DER Aggregation was dispatched for Energy and/or Regulation Service.
- c) The ECBL In-Day Adjustment shall be limited to  $\pm 20\%$  of the ECBL value for the five-minute interval it is applied to.

**ECBL In-Day Adjustment Period:** The ECBL Adjustment Period is the time prior to the Demand Reduction period that is used to determine the ECBL In-Day Adjustment. The intervals to be used in the ECBL Adjustment Period shall be the three consecutive five-minute intervals starting 60 minutes prior to the first operating interval of dispatch and ending 45 minutes prior to the operating interval of dispatch. All the subsequent intervals of uninterrupted dispatch following the first interval of dispatch shall use the same ECBL In-Day Adjustment Period. The

ECBL In-Day Adjustment Period shall be recalculated for every interval of dispatch which is preceded by an interval of non-dispatch.

**ECBL Weekday Window:** The ECBL Weekday Window is the time period reviewed in determining the ECBL for any five-minute interval that takes place on a weekday. It shall consist of the like-kind-five-minute intervals from the previous ten weekdays that correspond to each five-minute interval that is being calculated. Treatment of NERC holidays that occur on weekdays shall be equivalent to all intervals that take place on the weekend.

**ECBL Weekend Window:** The ECBL Weekend Window is the time period reviewed in determining the ECBL for any five-minute interval that takes place on a weekend. It shall consist of the like-kind intervals from the previous three weekend days of the same type (Saturday or Sunday) that correspond to each five-minute-interval. Treatment of NERC holidays that occur on weekend days shall be equivalent to all intervals that take place on the weekend.

**Proxy Load:** The Proxy Load for a five-minute interval is the telemetered Load plus measured Demand Reductions.

#### **24.2.1.2 Methodology for the Calculating the Economic Customer Baseline Load for Demand Reductions on a Weekday**

To determine the ECBL for a five-minute interval (a “Target Interval”) that occurs on a weekday:

- a) Select the five-minute intervals that comprise the ECBL Weekday Window for that Target Interval.
- b) Select the telemetered load value for each five-minute interval in the ECBL Weekday Window where the DER Aggregation was not dispatched for Energy and/or Regulation Service.



- c) For each five-minute interval of the ECBL Weekday Window where (i) the DER Aggregation was dispatched for Energy and/or Regulation Service, and (ii) the LBMP for the five-minute interval was greater than or equal to the Monthly Net Benefits Threshold, select the Proxy Load values for that five-minute interval and day in place of the actual metered load for that interval.
- d) Rank in descending order the metered load and Proxy Load values determined in steps b and c.
- e) Calculate the average of the fifth and sixth ranked values. The value as so calculated shall be the ECBL for the Target Interval.
- f) Apply the ECBL In-Day Adjustment to the ECBL to determine the Adjusted Weekday ECBL for the Target Interval.

#### **24.2.1.3 Methodology for the Calculating the Economic Customer Baseline Load for a Resource's Demand Reduction on a Weekend**

To determine the ECBL for a Target Interval that occurs on a weekend:

- a) Select the five-minute intervals that comprise the ECBL Weekend Window for the Target Interval.
- b) Select the metered load value for each interval in the ECBL Weekend Window where the DER Aggregation was not dispatched for Energy and/or Regulation Service.
- c) For each five-minute interval of the ECBL Weekend Window where (i) the DER Aggregation was dispatched for Energy and/or Regulation Service, and (ii) the LBMP for the five-minute interval was greater than or equal to the Monthly Net Benefits Threshold, select the Proxy Load Value for that hour and day in place of the actual metered load for the interval.

- d) Calculate the average of the metered load and ECBL Proxy Load values. The value so calculated is the ECBL for the Target Interval.
- e) Apply the ECBL In-Day Adjustment Factor to the ECBL to calculate the Adjusted Weekend ECBL for the Target Interval.

#### **24.2.2 Methodology for Calculating the Baseline Load for a Distributed Energy Resource within a DER Aggregation during Intervals with Regulation Service Dispatch**

For each 6-second interval during which a DER Aggregation is dispatched to provide Regulation Service, the Aggregator shall calculate the individual Distributed Energy Resource's Baseline Load as the Distributed Energy Resource's 6-second telemetered Load prior to the start of dispatch for Regulation Service. If the Aggregation was dispatched to provide Energy and no Regulation Service in the interval prior to being dispatched for Regulation Service, the Aggregator shall use the Proxy Load value corresponding to the five-minute interval immediately preceding the dispatch instruction as the Distributed Energy Resource's Baseline Load.

#### **24.3 Verification of Actual Demand Reduction from DER Aggregations**

Demand Reduction calculated using the methodology described in Section 24.2 is subject to verification by the ISO. Aggregators shall report the data at the time and in the format required by the ISO pursuant to Section 24.4. If an Aggregator fails to report the required data to the ISO in accordance with Section 24.4, the Aggregator will be subject to penalties associated with a failure to supply the Demand Reductions and may lose its eligibility to participate in a DER Aggregation. All Demand Reduction data are subject to audit by the ISO. If the ISO determines that it has made an erroneous payment to an Aggregator, it shall have the right to recover it either by reducing other payments to that Aggregator or by any other lawful means.

## **24.4 Data Reporting Requirements for Aggregators**

Upon request, the Aggregator must submit to the ISO the information specified in this Section 24.4 for each Distributed Energy Resource in a DER Aggregation. The Aggregator must submit this information for the purpose of enrolling, registering, making settlements, and verifying the participation of each Distributed Energy Resource in the ISO's Energy market. If the Distributed Energy Resource has a Local Generator at its site, it must also have a meter, compliant with ISO standards and procedures, that measures the total output of the Local Generator, regardless of whether at initial enrollment the Local Generator is intended to be used to provide Demand Reduction in the DER Participation Model, provided that if the Local Generator is an Intermittent Power Resource, a meter that measures the total output of the Local Generator is not required..

### **24.4.1 Data Reporting Requirements for Enrollment of Distributed Energy Resources Participating within a DER Aggregation**

The Aggregator shall provide to the ISO the following information for each Distributed Energy Resource that is seeking to enroll, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation participating in the ISO's Energy market, which shall include providing information regarding each of the Distributed Energy Resource's interval meters required under Section 24.4:

- a. Meter test criteria, as described in the Services Tariff Section 13 and the ISO Procedures;
- b. Documentation to validate installation of interval meter equipment;
- c. Interval metering installation individual, company, and professional engineering license information;
- d. Make and model of installed interval metering device(s);

- e. Accuracy of installed interval metering device(s);
- f. Interval meter Current Transformer (CT) and Potential Transformer (PT) type designation, if applicable;
- g. CT Ratio, if applicable;
- h. Use of pulse data recorder as an interval metering device, if applicable;
- i. Pulse data recorder multiplier, if applicable;
- j. Any other type of meter multiplier used in the translation of data collected by the device for measuring demand, kWh, and/or MWh, if applicable;
- k. Its service address;
- l. Its Load Serving Entity;
- m. Its Transmission Owner;
- n. Its meter authority/Meter Services Entity;
- o. Distributed Energy Resource's maximum Winter and Summer reduction MW;
- p. Business classification of the Distributed Energy Resource (based on ISO-defined categories or national standards for business classification); and
- q. A description of any Local Generator at its site, including the Local Generator's system, its primary fuel type, the year in which it was built, the year of any retrofit, its nameplate capacity, and its horsepower, if applicable.

#### **24.4.2 Data Reporting Requirements for Verification of Demand Reductions of Distributed Energy Resources in the ISO's Energy and Ancillary Services Market**

The Aggregator shall retain for purposes of an audit, and provide the ISO with the following required data from each interval meter required under Section 24.4 for each Distributed Energy Resource that is registered, either individually or collectively with other

Distributed Energy Resources, as a DER Aggregation, to verify the calculated Demand

Reduction of a Distributed Energy Resource in the ISO's Energy and Ancillary Services market:

- a) Totalized net interval Demand Reduction data of the Distributed Energy Resource (*i.e.*, the net interval Demand Reduction data totalized across all Distributed Energy Resources that are registered, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation) for the period of the Demand Reduction of the Distributed Energy Resource in the format required for reporting to the ISO's Settlement Data Exchange application;
- b) Five-minute-interval metered Load data for each of the individual Distributed Energy Resources that is registered as part of a single DER Aggregation, for all intervals of Demand Reduction for the period for which it was enrolled; and
- c) Five-minute interval metered Load data for each of the individual Distributed Energy Resources that is registered as part of a single DER Aggregation, for all intervals of the period for which it was enrolled..

The Aggregator shall comply with the following when providing metering data to verify energy reductions of Distributed Energy Resources:

- a) Section 7.4.1 of the ISO Services Tariff;
- b) Section 13 of the ISO Services Tariff; and
- c) The ISO's Meter Data Management Protocols as provided on the ISO's website.

#### **24.4.3 Additional Data Required Upon Request**

To verify the participation of each Distributed Energy Resource that is enrolled, either individually or collectively with other Distributed Energy Resources, as a DER Aggregation in the ISO's Energy market, Aggregators and/or their meter authority/Meter Services Entity shall

provide the ISO upon the ISO's request such additional information that may be required, including, but not limited, to the following:

- a) Any data reporting requirements of Attachments H and O to the ISO Services Tariff;
- b) Any data reporting requirements of Section 3.4 of the ISO Services Tariff;
- c) Historical Load documentation;
- d) Load data history for Pre- and Post-Validation, Edit and Estimation (VEE);
- e) Up to three months of historical Load data when enrolling a Demand Side Resource to participate in the ISO's Energy market;
- f) New and existing metering documentation, including, but not limited to:
  - 1. Calibration records;
  - 2. Time check;
  - 3. Sum check;
  - 4. High/Low check; and
  - 5. Zero value check.