

**24 Attachment R - Cost Allocation and Measurement and Verification Methodologies for Demand Reductions ~~by Arising Under the Incentivized Day Ahead Economic Load Curtailment Program~~ Distributed Energy Resources in a DER Aggregation**

~~Under the Incentivized Day Ahead Economic Load Curtailment Program—also referred to in the ISO Tariffs and ISO Procedures as the Day Ahead Demand Response Program (“Program” or “DADRP”), costs incurred by the ISO in covering Demand Reduction Providers’ Curtailment Initiation Costs and making Demand Reduction Incentive Payments for scheduled and verified Demand Reductions are to be recovered under Schedule 1. Measurement and verification of actual Demand Reductions scheduled under the Program shall be conducted in accordance with subsections 24.2, 24.3, and 24.4.~~

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**24.1 Cost Allocation Methodology for ~~Payments Demand Reductions to Demand Reduction Providers under the Program~~ 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 ~~scheduled and~~ 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 ~~Generator Bus Transmission Node that was~~ used to ~~b~~ Bid the associated Demand Reduction ~~associated with them~~ is located.

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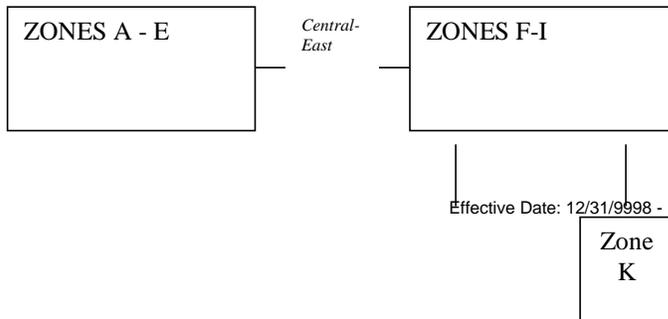
- b) In determining whether and how Transmission Customers located in particular Load Zones, or Composite Load Zones, have benefited from the Energy provided by Demand Reduction, and how much they shall be required to pay a share of the associated Schedule 1 Program Costs, the ISO shall account for the 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 ~~at~~ 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 ~~at~~ 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 ~~curtailment pursuant to the Program~~Energy provided by Demand Reduction occurred upstream, and (iii) the Composite Load Zone was downstream of a constraint and ~~curtailment pursuant to the Program~~Energy provided by Demand Reduction occurred downstream.

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

- d) The three ~~most frequently constrained~~ interfaces that will be used for this cost allocation are ~~currently~~ 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**

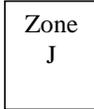


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*Sprainbrook -  
Dunwoodie*

*Con Ed – Long Island*



Based on these factors, Schedule 1 Program Costs shall be allocated to Transmission

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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
- $cost_{A...K}$  = revenue deficiencies due to DADRPDER Aggregation Demand Reductions in Load Zones A...K, calculated on a hourly basis
- $load_m$  = real-time Load for Transmission Customer m, calculated on an hourly basis
- $load_{A...K}$  = 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 Scheduled in the Program**

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 supplied by an Demand Reduction Provider individual Distributed Energy Resource within a DER Aggregation which is dispatched for Energy with no Regulation Service under the Program shall be the greater of: (i) difference between the Distributed Energy Demand Reduction Provider Resource's baseline load adjusted

Economic Customer Baseline Load (“ECBL”) for each ~~five-minute~~scheduled interval~~hour~~, which shall be calculated in accordance with section 24.2.1 and ISO Procedures, ~~and minus~~ the actual metered ~~hourly~~-load for each ~~6-second~~scheduled interval~~hour~~ 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 values 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 these DER Aggregation Demand Reductions to the ISO for each 6-second interval using real-time telemetry in accordance with Services Tariff section 13 and the ISO Procedures. Aggregators shall provide the DER Aggregation Actual Demand Reductions, determined based on revenue-quality meter data, to the ISO 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~~Scheduled to Reduce Load Under the Program~~**

The ISO shall employ two different calculation methodologies of the Economic Customer Baseline Load (“ECBL”) for ~~scheduled~~-Demand Reductions, depending on whether the Demand Reduction is ~~scheduled~~-on a weekend or a weekday, during the intervals with no Regulation Service dispatch for the DER Aggregation.

### 24.2.1.1 Definitions

**Adjusted Weekday ECBL:** For each ~~five-minute interval~~hour of the scheduled Demand Reduction, the Adjusted Weekday ECBL shall be equal to the sum of the ECBL and multiplied by the ECBL In-Day Adjustment Factor~~calculated for the scheduled Demand Reduction period~~.

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**ECBL In-Day Adjustment Factor:** The ECBL In-Day Adjustment shall be an adjustment ~~factor~~ that is applied to the ECBL for each ~~hour~~five-minute interval of the scheduled Demand Reduction period.

- a) Calculate the ECBL In-Day Adjustment by ~~dividing subtracting~~ the average of the ECBL over the three five-minute intervals of the ECBL In-Day Adjustment Period from the average of the metered load for the ~~two hours~~same three five-minute intervals, provided that the DER Aggregation was not dispatched for Energy and/or Regulation Service, in any of the three five-minute intervals of the ECBL In-Day Adjustment Period~~on the day of the scheduled Demand Reduction by the average of the ECBL for the same two hours~~.
- 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, calculate the ECBL In-Day Adjustment by replacing the metered loads in step (a) above by the Proxy Load values 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 ~~Factor~~ shall be limited to ± 20% of the ECBL value for the five-minute interval it is applied to, a minimum of 0.8 and a maximum of 1.2.

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**ECBL In-Day Adjustment Period:** The ECBL Adjustment Period is the time prior to the

~~scheduled~~-Demand Reduction period that is used to determine the ECBL In-Day Adjustment.

The ~~intervals~~~~hours~~ to be used in the ECBL Adjustment Period shall be the ~~two~~~~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, hours that occur four hours prior to the first hour of the scheduled Demand Reduction period, provided that the hours are part of the same calendar day.~~

~~To determine the two hours of the ECBL In-Day Adjustment Period:~~

- ~~b) The fourth hour before the first hour of the scheduled Demand Reduction period shall be the first hour of the ECBL In-Day Adjustment Period, except when the fourth hour before first hour of the scheduled Demand Reduction period occurs on the previous day.~~
- ~~a) The third hour before the first hour of the scheduled Demand Reduction period shall be the second hour of the ECBL In-Day Adjustment Period, except when the third hour before the first hour of the scheduled Demand Reduction period occurs on the previous day.~~
- ~~b) When the third and/or fourth hour of the ECBL In-Day Adjustment Period occurs on the previous day, the ISO shall use as a substitute the hour beginning midnight on the day of the scheduled Demand Reduction. Both hours of the ECBL In-Day~~

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~~Adjustment Period may equal the hour beginning midnight on the day of the scheduled Demand Reduction.~~

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

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

**Proxy Load:** The Proxy Load for a five-minute interval is the adjusted ECBL for that interval calculated as per the instructions in Section 24.2.1.2 or 24.2.1.3. ~~**Weekday Proxy:** The~~

~~Weekday Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekday Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekday Window for that hour consisting of the corresponding hours in the ten weekdays preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.~~

~~Weekend Proxy: The Weekend Proxy is a value that is substituted for the metered load for any hour in any ECBL Weekend Window in which a Demand Reduction was scheduled. It shall be determined by (1) establishing a new ECBL Weekend Window for that hour consisting of the corresponding hours in the three weekends preceding the day the Demand Reduction occurred, and (2) repeating the steps described at section 24.2.1.2 b, c, d, and e.~~

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

e) To determine the ECBL for a ~~an~~ five-minute interval ~~hour of scheduled Demand~~

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~~Reduction~~ (a “Target HourInterval”) that occurs on a weekday:

a) Select the ~~hours~~ five-minute intervals that comprise the ECBL Weekday Window for that Target HourInterval.

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b) Select the metered load value for each hour five-minute interval in the ECBL Weekday Window where ~~no scheduled Demand Reduction occurred pursuant to this Program the DER Aggregation was not dispatched for Energy and/or Regulation Service.~~

c) For each hour five-minute interval of the ECBL Weekday Window where ~~the DER Aggregation was dispatched for Energy and/or Regulation Service a scheduled Demand Reduction occurred~~, select the Proxy Load values ~~Weekday Proxy~~ for that hour five-minute interval and day in place of the actual metered load for that hour interval.

d) Rank in descending order the metered load and ~~Weekday~~ 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 HourInterval.

e) Apply the ECBL In-Day Adjustment ~~Factor~~ to the ECBL to determine the Adjusted Weekday ECBL for the Target ~~Hour~~Interval.

#### 24.2.1.3 Methodology for the Calculating the Economic Customer Baseline Load for a Resource's Demand Reduction ~~Scheduled Under the Program on a Weekend~~

f) To determine the ECBL for a Target ~~Hour~~Interval that occurs on a weekend:

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a) Select the ~~hours~~five-minute intervals that comprise the ECBL Weekend Window for the Target ~~Hour~~Interval.

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b) Select the metered load value for each ~~hour~~interval in the ECBL Weekend Window where ~~no scheduled Demand Reduction occurred pursuant to this Program~~ the DER Aggregation was not dispatched for Energy and/or Regulation Service.

c) For each ~~hour~~five-minute interval of the ECBL Weekend Window where ~~a Scheduled Demand Reduction occurred~~ the DER Aggregation was dispatched for Energy and/or Regulation Service, select the ~~ECBL Weekend Proxy Load Value~~ for that hour and day in place of the actual metered load for the ~~hour~~interval.

~~Rank in descending order the metered load and ECBL Weekend Proxy values determined in steps b and c.~~

d) Calculate the average of the metered load and ECBL Proxy Load values. The value so calculated is the ECBL for the Target ~~Hour~~Interval.

e) Apply the ECBL In-Day Adjustment Factor to the ECBL to calculate the Adjusted Weekend ECBL for the Target ~~Hour~~Interval.

**24.2.2 Methodology for the 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.

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**24.3 Verification of Actual Demand Reduction ~~from Scheduled in the Program~~ DER Aggregations**

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

#### 24.4 Data Reporting Requirements for ~~Demand Reduction Providers~~ Aggregators

~~Upon request, (The Demand Reduction Provider~~ Aggregator must submit to the ISO the information specified in this Section 24.4 for each ~~Demand Side~~ Distributed Energy Resource ~~that it has enrolled either as in a DER Aggregation an individual DADRP resource or with other Demand Side Resources as part of a single, aggregated DADRP resource.~~ The ~~Demand Reduction Provider~~ Aggregator must submit this information for the purpose of enrolling, registering, making settlements, and verifying the participation of each ~~Demand Side~~ Distributed Energy Resource in the ISO's Energy market. ~~To enroll and participate in the DADRP, a Demand Side Resource must have NYPS approved, revenue quality, hourly interval meters sufficient to calculate its net Load.~~ If the ~~Demand Side~~ Distributed Energy Resource has a Local Generator at its site, it must also have ~~an hourly interval meter, compliant with ISO standards and procedures,~~ that measures the total output of the Local Generator ~~within a 2% accuracy threshold,~~ regardless of whether at initial enrollment the Local Generator is intended to be used to provide Demand Reduction in the ~~DER Participation Model, DADRP 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 ~~Demand Side~~ Distributed Energy Resources Participating ~~within a DER Aggregation as DADRP Resources~~

The ~~Demand Reduction Provider~~ Aggregator shall provide to the ISO the following information for each ~~Demand Side~~ Distributed Energy Resource that is seeking to enroll, either individually or collectively with other ~~Demand Side~~ Distributed Energy Resources, as a ~~DADRP resource~~ DER Aggregation participating in the ISO's Energy market, which shall include

providing information regarding each of the ~~Demand-Side~~Distributed Energy Resource's interval meters required under Section 24.4:

- a. ~~As left-M~~meter test criteria, ~~as prescribed in the New York Department of Public Service 16 NYCRR Part 92 Operating Procedure~~ 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-Data Services~~ Entity-Provider;
- o. ~~Demand~~Distributed Energy-Side Resource's maximum Winter and Summer reduction MW;

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- p. Business classification of the Distributed Energy Demand Side 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 Energy Demand Reductions of DADRP Distributed Energy Resources Scheduled in the ISO's Energy and Ancillary Services Market**

The ~~meter authority or Meter Data Service Provider of the Demand Reduction Provider~~ 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 Demand Side Distributed Energy Resource that is registered, either individually or collectively with other Distributed Energy Demand Side Resources, as a ~~DADRP~~ DER Aggregation resource, to verify the ~~scheduled~~ calculated Load Demand #Reduction of a ~~DADRP~~ Distributed Energy #Resource in the ISO's Energy and Ancillary Services market:

- a) Totalized net ~~hourly~~ interval Load Demand #Reduction data of the ~~DADRP Distributed Energy R~~esource (*i.e.*, the net ~~hourly~~ interval Demand Load #Reduction data totalized across all ~~Demand Side Distributed Energy~~ Resources that are registered, either individually or collectively with other ~~Demand Side Distributed Energy~~ Resources, as a ~~DADRP resource~~ DER Aggregation) for the period of the ~~scheduled~~ Load Demand #Reduction of the ~~DADRP Distributed Energy #R~~esource in the format required for reporting to the ISO's Settlement Data Exchange application;
- b) Hourly Five-minute-interval metered Load data for each of the individual ~~Demand~~

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~~Side~~Distributed Energy Resources that is registered as part of a single ~~DADRP~~DER Aggregation resource, for all ~~hours~~intervals of ~~the day on the days~~ of the scheduled Load Demand ~~r~~Reduction ~~for of the DADRP resource the period~~ for which it was enrolled; and

- c) ~~Hourly~~Five-minute-interval metered Load data for each of the individual ~~Distributed Energy~~Demand-Side Resources that is registered as part of a single ~~DADRP~~DER Aggregation resource, for all ~~hours~~intervals of ~~each of the thirty~~ days preceding the day in which the ~~DADRP~~ resource is scheduled ~~the period~~ for which it was enrolled.

The ~~meter authority or Meter Data Service Provider of the Demand Reduction Provider~~ Aggregator shall comply with the following when ~~reporting Demand Reduction providing~~ metering data to ~~verify energy reductions of Distributed Energy Resources~~the ISO:

- 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~~Demand-Side Resource that is enrolled, either individually or collectively with other ~~Distributed Energy~~Demand-Side Resources, as a ~~DADRP~~DER Aggregation resource in the ISO's Energy market, ~~Aggregators~~Demand Reduction Providers and/or their meter authority/~~Meter Data~~Services ~~Entity~~Provider shall provide the ISO upon the ISO's request such additional information that may be required, including, but not limited, to the following:

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- 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.

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