

APPENDIX 2 – DEMAND RESPONSE PROGRAMS

ISO New England Load Response Program

Manual

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ISO New England Load Response Program

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ISO New England Load Response Program

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Section 1: Program Summary

The ISO and the Market Participants are continuing the Load Response Program (LRP) with the goal of reducing peak electricity demand by large power users. The majority of the revisions to the program is scheduled to begin on the SMD Effective Date and will continue through May 31, 2010.

Through the LRP, Market Participants (with a settlement account in the Energy Market or Demand Response Providers (DRPs) enrolled directly with the ISO) can enter into agreements with retail customers to encourage them to reduce their electricity consumption during periods of peak demand. The ISO is offering four distinct programs:

- (1) Day-Ahead Load Response Program
- (2) Real-Time Demand Response Program
- (3) Real-Time Price Response Program
- (4) Real-Time Profiled Response Program

1.1 Day-Ahead Load Response Program

The Day-Ahead Load Response Program provides a Day-Ahead option to the Real-Time programs. The Day-Ahead Load Response Program allows Real-Time program participants to offer energy reductions (100 kW minimum) of curtailment concurrent with the Day-Ahead Energy Market. If the curtailment offer clears concurrent with the Day-Ahead Energy Market, the Demand Resource will be paid the applicable Day-Ahead Zonal Price. Differences between the actual curtailment (in Real-Time) and the cleared curtailment are settled at the appropriate Real-Time Zonal Price (except during OP4 events) as specified later in this Manual. Demand Resource offers will clear only if the offer, inclusive of Curtailment Initiation Price, is recovered in full. If a Demand Resource deviates in Real-Time from its cleared Day-Ahead offer, the deviation will not be eligible for NCPC Credits or responsible for NCPC Charges. The Real-Time deviation will be charged or credited at the Real-Time Zonal Price (except during OP4 events) as specified later in this Manual. NCPC Accounting is defined in Appendix F of Market Rule 1. Demand Resources participating in the Day-Ahead Load Response Program are eligible to qualify as an ICAP Resource only if the Demand Resource is either in the Real-Time Demand Response Program or the Real-Time Profiled Response Program. Demand Resources either in the Real-Time Demand Response Program or the Real-Time Profiled Response Program qualify as an ICAP Resource in accordance with *ISO New England Manual for Installed Capacity, M-20* and Section 4.5.2 in this Manual. The performance criteria and level of ICAP credit are specified in Section 7 of this Manual. Demand Resources participating in the Day-Ahead Load Response Program through the Real-Time Price Response Program are not eligible to qualify as an ICAP Resource.

Program participants will be notified that their Day-Ahead offer was accepted (“cleared”) and for which hours.

1.2 Real-Time Demand Response Program

The Real-Time Demand Response Program is made up of two sub-programs based upon response time. These are: the 30-Minute Demand Response Program and the 2-Hour Demand Response Program. The Real-Time Demand Response Program requires customers to commit to mandatory energy reductions (100 kW to ~5 MW) on either 30-minutes notice or 2-hours notice from the ISO. Demand Resources in the Real-Time Demand Response Program are eligible to qualify as ICAP Resources in accordance with *ISO New England Manual for Installed Capacity, M-20*. The performance criteria and level of ICAP credit are defined later in this Manual. These program participants receive a payment at the applicable Real-Time Zonal Price for the actual energy they interrupt.

For the Real-Time Demand Response Program, customers will be notified of mandatory interruptions when:

2-Hour Notice Demand Response will be activated during ISO New England Operating Procedure No. 4, Action During A Capacity Deficiency (OP4) when Actions 3, 4, 5, 7 and/or 8 are implemented. 30-Minute Notice Demand Response (not involving backup or emergency generation) will be activated at Action 9, and 30-Minute Notice Demand Response (involving backup or emergency generation) will be activated at Action 12 of OP4.

The duration of an interruption during times of capacity deficiency or system emergency may exceed the two-hour minimum guaranteed payment period. The ISO can call Real-Time Demand Response on either a zonal or system wide block basis. A block is a slice of the Demand Resources segregated by Load Response Program across the entire system approximately 200 MW (in each block of a Load Response Program) and representing similar percentages to the total amount of Real-Time Demand Response in these programs.

1.3 Real-Time Price Response Program

The Real-Time Price Response Program allows customers to voluntarily reduce energy consumption during certain periods as determined by the ISO. The Enrolling Participant in the Price Response Program only receives payments at the applicable Real-Time Zonal Price for the actual energy they curtail. The voluntary energy reduction must be between 100 kW and ~5 MW unless approved by the ISO.

For the Real-Time Price Response Program, voluntary reductions will be allowed when the forecasted hourly appropriate Zonal Price produced by the Day-Ahead Energy Market, the Resource Adequacy or any update of the Resource Adequacy where the Zonal Price is greater than or equal to \$100/MWh. The Real-Time Price Response Program will be implemented on a zonal basis.

1.4 Real-Time Profiled Response Program

The Real-Time Profiled Response Program requires the program participant to provide a statistically determined percentage of mandatory response that can be achieved upon demand by the ISO (200 kW minimum). This program is the only group that does not require Interval Metering, but an approved Measurement and Verification Plan (“M&V Plan”) in accordance with Appendix E of this manual is required. This group could include aggregated residential super-thermostat programs, pool pumps, and Distributed Generation. Demand Resources in the Real-Time Profiled Response Program are eligible to qualify as an ICAP Resource in accordance with *ISO New England Manual for Installed Capacity, M-20*. The performance criteria and the level of ICAP credit are defined later in this Manual. These Enrolling Participant receive payments at the applicable Real-Time Zonal Price for the actual energy they interrupt during events initiated by the ISO.

For the Real-Time Profiled Response Program, Participants will be notified of mandatory interruptions, during ISO New England Operating Procedure No. 4 (Action During A Capacity Deficiency OP4) when Action 3 is implemented.

The duration of an interruption during times of capacity deficiency or system emergency may exceed the two-hour minimum guaranteed payment period. The ISO will call Real-Time Profiled Response on a zonal or system wide block basis.

1.5 Internet-Based Communication System (IBCS)

The roles, responsibilities, and duties of the IBCS Open Solution and IBCS Providers are further defined in the document “Requirements for IBCS OS and IBCS Providers” posted on the ISO web site. This document also provides information on becoming a certified IBCS Provider.

During a Load Response Event, Real-Time Demand Response Program customers will be contacted through their IBCS Provider. Real-Time Price Response customers have the option of choosing notification through an IBCS Provider, or a lower technological option, which involves communication through an e-mail list server in conjunction with notice on the ISO web site. Enrolling Participants for the Real-Time Profiled Response Program will be notified of a Load Response Event by notifications transmitted by the IBCS Open Solution.

The first 1000 customers signed up for either the Real-Time Demand Response or the Real-Time Price Response Program (calculated from the June 1, 2000 initial commencement of the program) will be reimbursed for installation of the IBCS data collection equipment according to the following terms:

- (1) For customers enrolled in the Real-Time Demand Response Program, the Enrolling Participant will be reimbursed for 100% of installed hardware costs up to \$2,200 per customer installation, or \$22 per enrolled kW per customer installation, whichever is lower. For customer installations without customer-supplied LANs, the reimbursement rate will be capped at \$2,800 per customer installation or \$28 per enrolled kW per customer installation, whichever is lower. Customers qualifying for such payments must provide an interruption amount of at least 25 kW per customer installation. The reimbursement of installed hardware costs is limited to the first 1000 Real-Time Demand Response Program customer sites (including the former Type 6 Class 1). All payments will be made to the Enrolling Participants.
- (2) For customers enrolled in the Real-Time Price Response Program, the Enrolling Participant will be reimbursed for 50% of installed hardware costs up to \$1100 per customer installation, or \$11 per enrolled kW per customer installation, whichever is lower. For customer installations without customer-supplied LANs, the reimbursement rate will be capped at \$1400 per customer installation or \$14 per enrolled kW per customer installation, whichever is lower. Customers qualifying for such payments must provide an interruption amount of at least 25 kW per customer installation. The reimbursement of installed hardware costs is limited to the first 1000 Real-Time Price Response Program customer sites (including the former Type 6 Class 2). All payments will be made to the Enrolling Participants.

Real-Time Demand Response Program participants 300 kW or greater will be compensated a monthly IBCS Provider fee, not to exceed \$100. Customers must be signed up in only one of the programs; a single customer cannot be in more than one program for the same billing meter.

If an Enrolling Participant receives funds for the reimbursement of hardware costs, the customer to whom the equipment is installed must remain in its original program group for one year or until the expiration of the program, whichever occurs first. If a customer leaves its original program group before this time, the Enrolling Participant must replace the lost asset with a similar asset (without additional reimbursement for installation hardware costs) or pay back the reimbursement originally received.

Section 2: Eligibility Criteria

2.1 Effective Period of the Program

The majority of the LRP begins on the SMD Effective Date, and will continue through May 31, 2010. However, the Day-Ahead Load Response Program will commence as soon as practicable, after the SMD Effective Date. The effective date for the Day-Ahead Load Response Program will be at least two weeks after the ISO has given the Commission written notice that the System Rules and computer programs necessary to implement the Day-Ahead Load Response Program are fully in place and functional. The ISO shall post on its web site the specified date at the time that the ISO makes such notice to the Commission.

Potential customers wishing to participate, but not currently enrolled in the LRP should direct inquiries to the ISO's Market Support Services Group at (413) 540-4220 or custserv@iso-ne.com.

2.2 Who Can Participate?

Any Market Participant (with a settlement account) or any DRP, collectively known as Enrolling Participants, can subscribe either itself and/or an end-user to provide Load Reductions of not less than 100 Kilowatts (kW) and not more than 5 Megawatts (MW). Aggregation of load by the Enrolling Participant is allowed and can be used to reach or exceed the specific minimum requirement for a program. Reductions greater than 5 MW may be allowed at the discretion and approval of the ISO. Specific programs may have a minimum reduction requirement greater than 100 KW. Day-Ahead Load Response Program participants or any DRP must be at least 100 kW or aggregated by Load Zone to at least 100 kW. An Enrolling Participant can sign up any eligible load located within the New England Control Area.

All customers who participate in the LRP will be referred to as LRP customers. They are sub-divided into four major classes.

2.2.1 Day-Ahead Load Response Program

Enrolling Participants that sign up customers to participate in the Day-Ahead Load Response Program can offer curtailments concurrent with the Day-Ahead Energy Market. The submission of Day-Ahead Load Response offers is optional. These program participants agree that the customers in the Day-Ahead Load Response:

- (1) Must be willing and capable of interrupting load within the parameters of the offer.
- (2) Must be able to interrupt Monday-Friday, on non-Demand Response Holidays between 7:00 AM - 6:00 PM.
- (3) Must be participants in the Real-Time Demand Response Program, Real-Time Profiled Response Program or the Real-Time Price Response Program.

2.2.2 Real-Time Demand Response Program

Customers that participate in either of the Real-Time Demand Response Programs agree to a certain level of reduction at the discretion of the ISO. The difference between the two Real-Time Demand Response Programs is the notice period. These customers:

- (1) Must be willing and able to interrupt load within 30-minutes or within 2-hours (depending on which program they are in) after receiving the instruction from the ISO through their IBCS Provider.
- (2) Must be able to interrupt Monday-Friday, on non-Demand Response Holidays between 7:00 AM – 6:00 PM.
- (3) During OP4, when Actions 3, 4, 5, 7 and/or 8 is implemented (2 Hour Notice), or when Action 9 is implemented for 30-Minute Notice (not involving backup or emergency generation), or Action 12 for 30-Minute Notice Demand Response (involving backup or emergency generation), will be activated.
- (4) Duration of interruptions during times of capacity deficiency or system emergency may exceed the two-hour minimum guaranteed payment period.

Real-Time Demand Response Program customers are eligible to qualify as ICAP Resources in accordance with *ISO New England Manual for Installed Capacity, M-20*. The performance criteria and level of ICAP credit are defined later in this Manual. Enrolling Participants are paid for an actual interruption at the higher of:

- the appropriate Real-Time Zonal Price or;
- for the Real-Time 30 Minute Demand Response Program five hundred dollars per MWh (\$500/MWh) for a minimum of two hours; and for the Real-Time 2 Hour Demand Response Program three hundred and fifty dollars per MWh (\$350/MWh) for a minimum of two hours.

More detailed information on payments for this program is provided in Section 4.

2.2.3 Real-Time Price Response Program

Customers that participate in the Real-Time Price Response Program act on a strictly voluntary basis. These customers:

- (1) Utilize price signals to decide whether to voluntarily reduce load.
- (2) Will be notified when the forecast hourly Zonal Price is greater than or equal to \$100/MWh on a Monday-Friday, non-Demand Response Holidays between 7:00 AM – 6:00 PM.
- (3) Once notified, the window of availability for Real-Time Price Response can be as early as 7 AM and remain open until 6 PM (i.e., between the hour ending 0800 through the hour ending 1800).

Enrolling Participant will receive the higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a guaranteed minimum payment of \$100/MWh when the eligibility period is open. Real-Time Price Response Program Demand Resources that fail to respond when the ISO opens the window to curtail load are not subject to any penalties.

2.2.4 Real-Time Profiled Response Program

The Real-Time Profiled Response Program is for Enrolling Participants with loads that are capable of being interrupted on demand and within 2-hours, but may not have Interval Metering. These loads must be able to interrupt Monday-Friday, on non-Demand Response Holidays between 7:00 AM – 6:00 PM. Program participants are willing and capable of responding in Real-Time to ISO instructions to interrupt load within 2-hours once OP4 Action 3 has been implemented. The implementation of the interruption is under the direct control of the Enrolling Participant. However, the Enrolling Participant can activate these Demand Resources only when instructed to do so by the ISO. The Enrolling Participant will be instructed to activate these Demand Resources by a notice transmitted through the IBCS Open Solution. Demand Resources in this program could include aggregated residential super-thermostat programs, pool pumps and distributed generation. An Enrolling Participant aggregating Demand Resources for this program is required to provide a statistical response factor for the group. For example, an aggregated 10 MW Demand Resource having a 50% response rate would be credited for 5 MW of response when called.

Real-Time Profiled Response Program customers are eligible to qualify as an ICAP Resource in accordance with *ISO New England Manual for Installed Capacity, M-20*. The performance criteria and level of ICAP credit are defined later in this Manual.

Enrolling Participant will receive the higher of the applicable Real-Time Zonal Price or a minimum payment of \$100/MWh for the actual real-time statistically determined response quantity.

2.3 Minimum Qualifications for Load Response

To participate specifically in the LRP a Customer must:

- (1) Be a Market Participant (with a settlement account for the Energy Market or a DRP) or sign an agreement with such a Market Participant who will act as the Enrolling Participant, an intermediary between the ISO and the LRP Customer.
- (2) Interval meters for all Customers or an ISO approved M&V Plan are required for all programs.
- (3) The Real-Time Profiled Response Program requires a statistical representation of research meters, or equivalent technology acceptable to the ISO, to determine the response. The Real-Time Profiled Response Program also may use an approved M&V Plans. The M&V Plan must be approved by the ISO.
- (4) For each interval meter or approved M&V Plan, be able to provide a minimum 100 kW curtailment or aggregate interval meters to obtain a minimum 100 kW curtailment commitment per Zone during Load Response Events. For the Day-Ahead Load Response Program, the minimum size is 100 kW and customers may be aggregated (by Zone) to reach or exceed the minimum of 100 kW. For the Real-Time Profiled Response Program, the minimum size is 200 kW and any aggregation of customers to reach or exceed the minimum must be on Zonal basis.
- (5) Meet the metering requirements set forth in Section 4 of this Manual.
- (6) Real-Time Demand Response Customer must be able to connect to the IBCS.
- (7) Real-Time Demand Response Customer must be able to curtail its load within 30 minutes or within 2-hours of notification from the ISO determined by the program in which the Real-Time Demand Response Customer is enrolled. The Real-Time Demand Response Customer shall adhere to the requested interruption period for a specific Load Response Event for as long as practically possible.
- (8) Enrolling Participants in the Real-Time Profiled Response Program must be capable of receiving activation instructions through the IBCS Open Solution.
- (9) Must be able to submit required meter reading data to the ISO by 1300 on the third business day after the Operating Day. Revised metering data may be submitted up to 90 days following the dispatch day for inclusion in the following month's bill (see Section 4.8 of this Manual for the Settlement Timeline).

2.4 Load Aggregation

Load aggregation is permitted for all programs in order to reach or exceed the minimum level for the specific program, but the aggregated Demand Resources must be in the same Load Zone. For a Demand Resource that is able to reduce to the minimum for a given program at each site but are interested in participating in a program, an Enrolling Participant can aggregate these customers using the systems, software, and hardware that the specific Load Response Program requires. The aggregated amount must exceed 100 kW, or 200 kW, as applicable, per Load Zone. Aggregated loads must be located in the same Load Zone. The customers must be aggregated by Load Zone and by program and notice requirement (as applicable). For simplicity and ease of identification, the ISO suggests that aggregated groups are categorized as follows:

- "Participant - 1" 30-Minute Demand Maine
- "Participant - 1" Price Response Maine
- "Participant - 2" 2-Hour Demand NH
- "Participant - 2" Price Response NH

The ISO will expect to see each aggregated group as a single entity. The Enrolling Participants that desire to aggregate these customers using an IBCS will need to confirm with their IBCS Providers that they can and will aggregate the loads into a single control point. If Real-Time Price Response customers are to be aggregated, and the IBCS reporting option will not be used, then the Enrolling Participant is responsible for providing the aggregated data to the ISO.

2.5 Restrictions

A metered Load cannot be subscribed to more than one of the Programs. A meter can only participate in one of these programs. The Demand Resource may not participate in any of the load response programs if it is modeled in the Energy Management System (EMS). Selection of a specific program must remain in affect through the end of the calendar month. Notification to the ISO's Market Support Services Group must be made no later than seven business days prior to the start of the requested month. The Demand Resource must remain in the selected Program for one year.

2.6 Requirements for Customers with On-Site Generation

Owners of on-site and emergency generators including but not limited to hospitals, data centers, office buildings, warehouses, and industrial locations are eligible to participate in the LRP. On-site generation can serve all or part of what otherwise would be the ISO load, thereby reducing the total ISO load during a Load Response Event. The requirements for participation are as follows:

- (1) The owner of the generator must satisfactorily complete the information required on its associated NX-11C form.
- (2) The generator must be capable of responding within 30 minutes notice or within 2-hours notice of a request to reduce load for a Real-Time Demand Response customer depending upon which of these programs they are committed to.
- (3) For participation in any of the programs, except the Real-Time Profiled Response Program, the end-user must have an Interval Meter as described in Section 4.1, Telemetering Requirements, or an approved M&V Plan.
- (4) Real-Time Demand Response customers must be capable of receiving notification through the IBCS.
- (5) The customer must provide assurance that the same Metered Load is not subscribed with more than one Enrolling Participant or included in more than one program.
- (6) If applicable, comply with (at a cost to the generator owner) all state and federal air emissions regulations.

2.7 Responsibilities of Enrolling Participants

Each Enrolling Participant is expected to act as a liaison between the ISO and Enrolling Participant's customers. Enrolling Participants have the following responsibilities:

- (1) Sign up, set up, and train customers at cost to Enrolling Participant.
- (2) Allocate appropriate Demand Resources to ensure appropriate hardware and software installation.
- (3) Notify customer of curtailment schedules resulting from cleared offers in the Day-Ahead Load Response Program.
- (4) Arrange for customer notification of Real-Time events that require the customer's response.
- (5) Ensuring meter readings are submitted to the ISO in accordance with the program requirements for assets not having an IBCS installed.
- (6) Consult with the customers to improve performance during Load Response Events.
- (7) Assist the customers in the development of Load Curtailment strategies, and determine amount of curtailment possible at different price levels (as applicable).
- (8) Field questions about notices, baselines, and reports.
- (9) Enrolling Participant must provide self-certification of the customer's Load Response capability and verification that the ICAP Credit is a realistic estimate of the actual response.
- (10) Notify the customers of program availability and opportunity. The Enrolling Participant will:
 - (a) Obtain the necessary information from the customer required to complete the submission of administrative form (NX-11C) for signup to the LRP.
 - (b) Assure the NX-11C is complete and accurate.
 - (c) If necessary coordinate/ schedule site installation between their IBCS Provider and the customer.
 - (d) For the Real-Time Profiled Response Program, the Market Participant must obtain approval of its M&V Plan and must provide sufficient research meters or equivalent technology acceptable to the ISO, within the group to provide appropriate statistical confidence for the response in accordance with the approved M&V Plan.
 - (e) Settle with the customers, based on contract terms, for payments received under the program that the customer is enrolled in.
 - (f) Submit Meter data by 1300 hours on the third business day after the Operating Day.
 - (g) Meter data must be submitted for all non-Demand Response Holiday weekdays.
 - (h) Customers using the Low-Tech reporting options for the Real-Time Price Response Program must submit all meter data, including the 5 days of data that is needed for the Customer Baseline calculations, prior to the 90-day resettlement period.

Section 3: Operating Mechanism/Implementation

3.1 Event Initiation and Termination

3.1.1 Day-Ahead Load Response Program

The Enrolling Participant will be notified of the Demand Resource's cleared offer and resulting curtailment schedule in the same manner as the Day-Ahead Energy Market schedules are provided. It is the responsibility of the Enrolling Participant to notify the customer to interrupt consistent with the cleared offer.

3.1.2 Real-Time Demand Response Program

ISO Control Room operating personnel will be able to assess the Contracted MW amount and MW available for each program in the Real-Time Demand Response Program on a display provided by the IBCS Open Solution. This monitoring capability will be available at a minimum on weekdays, non-Demand Response Holidays and Sundays. The displays will allow the ISO Control Room to view possible curtailment MW amounts on a zonal or system wide basis. Real-Time Demand Response Program customers will only be notified when the following occurs:

During OP4 when Actions 3, 4, 5, 7 and/or 8 are implemented (2 Hour Notice), when Action 9 is implemented (30-Minute Notice not involving backup or emergency generation) or Action 12 is implemented for 30-Minute Notice Demand Response (involving backup or emergency generation).

The Operations Shift Supervisor or Senior System Operator will initiate a Load Response Event for the Real-Time Demand Response Program using the IBCS Open Solution. The Operations Shift Supervisor will select the appropriate Real-Time Demand Response Program, Zone or Block, enter a Start Date/Time, and enter an ESTIMATED End Date/Time. Prior to sending the notification, the Operations Shift Supervisor will be prompted by a confirmation message, which will be answered YES or NO. The curtailment message sent will be as follows:

This is ISO-NE, Curtail (**PROGRAM NAME**) loads in (**ZONE) or (**BLOCK) at (**TIME) on (**DATE). Estimated restore time is (**TIME) on (**DATE), do not reconnect loads without official notice from ISO-NE. ”

Separate notifications will be sent to customers in the 30-Minute Demand Response and the 2-Hour Demand Response in accordance with the specific Actions in OP4. The field Program Name will be filled in with one of the following: “30 Minute RT – Action 12”, “30 Minute RT – Action 9”, “2 Hr RT Demand”, or “RT Profiled Response”. The notice period

for any program begins at the time specified for the event start time in the message, and not the time stamp on the message itself.

Once a Real-Time Demand Response Program Notification has been issued by the ISO, the ISO Control Room operating personnel will be able to assess the MW contracted amount and MW available for interruption on a monitoring display. This monitoring capability will be available at all times. The Real-Time Demand Response Program customer will be monitored by the Control Room operating personnel to provide system load assessment. The displays will allow the Control Room to view curtailment MW amounts on a zonal or system wide basis.

When the following conditions occur, the Real-Time Demand Response Program customers will be notified to be restored:

- (1) 2 hour notice Demand Resources will be restored with the cancellation of OP4 Actions 3,4,5, 7 and/or 8 are cancelled.
- (2) 30 minute notice when Action 9 is cancelled (30-Minute Notice not involving backup or emergency generation) or Action 12 is cancelled for 30-Minute Notice Demand Response (involving backup or emergency generation).

To restore Real-Time Demand Response Program customers, the Operations Shift Supervisor will:

- Select the Real-Time Demand Response Program Restoration Program;
- Select the specific Load Response Event to restore;
- Enter the Restoration Time to end the curtailment.

The notification will be sent as follows:

"This is ISO-NE, Restore (**PROGRAM NAME**) loads in (**Zone) or (**Block) at (**TIME) on (**DATE)."

Again, separate notifications will be sent for the 30-Minute Demand Response and the 2-Hour Demand Response customers.

3.1.3 Real-Time Price Response Program

The results of the Day-Ahead Energy Market will be posted on the ISO external web site (www.iso-ne.com) at approximately 1600 each day. Updates of the system conditions will occur regularly. When either the results of the Day-Ahead Energy Market or a forecast Real-Time Zonal Price is greater than or equal to \$100/MWh during the program hours, The ISO will initiate a notification opening the Interruption Period by the following methods.

3.1.3.1 IBCS OPTION

- (1) Select the Price Response - Forecast \geq \$100 Zonal Price notification
- (2) Select the Price Response - Voluntary Program for the appropriate Load Zone

The notification to be sent to the appropriate Load Zone (s) is as follows:

“ISO-NE is opening the interruption period for RT Price Response loads in (**ZONE) at (**TIME) on (**DATE) and ending on 1800 on (**DATE).”

The Zone, Time and Date fields are populated with the correct times and the message is ready for delivery. Prior to sending notification, the ISO verifies that the Zonal Price \geq \$100 and between the hour ending 0800 through hour ending 1800; the forecast Zonal Price is for a weekday (Monday through Friday); and the forecast Zonal Price is not on a Demand Response Holiday. The IBCS Open Solution will relay the notification to provide Enrolling Participants and customers with notification that the “window is open.”

3.1.3.2 LOW TECH OPTION

The ISO will notify the ISO’s Market Support Services Group to place notification on the ISO external web site as follows

“ISO-NE is opening the interruption period for RT Price Response loads in (**ZONE) at (**TIME) on (**DATE) and ending on 1800 on (**DATE).”

The ISO will also notify Enrolling Participants and customers that are subscribed to the ISO’s list server via email that a Zonal Price greater than or equal to \$100/MWh has been forecast.

Real-Time Price Response customers may curtail at their choosing during the specified Date and Time.

Once a Price Response Program notification has been issued by the ISO, the ISO’s Control Room operating personnel will only be able to assess the response using the information provided through the IBCS Open Solution. This monitoring capability will be available at a minimum on weekdays, non-Demand Response Holidays and Sundays. The Control Room operating personnel will only monitor Price Response Program loads using the IBCS to provide information on the system response and assessment. The information will assist the Control Room to view possible curtailment MW amounts on a zonal or system wide basis. The MW contracted amount and the MW availability from those using the Low Tech Option will not be monitored by the Control Room. Real-Time Price Response Program customers shall provide their load reduction amounts to the ISO within 60 hours. Program participants using the "Super" Low Tech option for data reporting (where the Interval Meter is not read daily nor is the meter reading supplied to the ISO within the following 60 hours) must provide their load reduction amounts before the 90-day resettlement. Program participants electing this treatment will not be compensated until four months after the dispatch period as outlined in the 90-day resettlement process. (See Settlement Timeline in Section 4.8 of this Manual for further details.) Data will not be accepted after the 90-day resettlement window. If data is received passed this deadline no LRP credit will be given. Curtailment of loads will be solely based upon the willingness of the load to curtail based on acceptable price signals. It is the obligation of the Enrolling Participant to insure that all necessary

meter data is provided to the ISO in time for the 90-day resettlement. Enrolling Participants using the “Super” Low Tech option specifically waive the right to any resettlement with respect to settlement of customers using this option.

3.1.4 Real-Time Profiled Response Program

The ISO’s Control Room operating personnel will not be able to assess the Contracted MW amount and MW available for the program. Enrolling Participants of Real-Time Profiled Response Program customers will only be notified to interrupt these Demand Resources when the following occurs:

OP4 when Action 3 is implemented.

The Operations Shift Supervisor or Senior System Operator will initiate a Load Response Event for the Real-Time Profiled Response Program using the IBCS Open Solution. The Operations Shift Supervisor will select the appropriate Real-Time Profiled Response Load Zones or Blocks, enter a Start Date/Time, and enter an ESTIMATED End Date/Time. The curtailment message sent will be as follows:

“ This is ISO-NE, Curtail RT Profiled Response loads in (**ZONE) or (**BLOCK) at (**TIME) on (**DATE). Estimated restore time is (**TIME) on (**DATE), do not reconnect loads without official notice from ISO-NE. ”

Once a Real-Time Profile Response Program Notification has been issued by the ISO, the ISO’s Control Room operating personnel are not able to directly assess the MW amount of interruption in real-time.

When the following condition occurs, the Enrolling Participants of Real-Time Profiled Response Program customers will be notified that the load can be restored:

Termination of OP4 Action 3.

To restore Real-Time Profiled Response Program Customers, the Operations Shift Supervisor will:

- (1) Select the Real-Time Profiled Response Program Restoration Program;
- (2) Select the specific Load Response Event to restore;
- (3) Enter the Restoration Time to end the curtailment.

The notification will be sent as follows:

3.2 Procedures for Contacting Program Participants

Table 3.1 below, provides a summary of event notification and load restoration communication, the entity that is contacted, and the method of contact.

<u>Program</u>	<u>Contact</u>	<u>Contact Method</u>
Day-Ahead Load Response Program	Enrolling Participant	eMkt (same as Day-Ahead Energy Market)
Real-Time Demand Response Program	Enrolling Participant Customer	IBCS Provider
Real-Time Profiled Response Program	Enrolling Participant	IBCS OS
Real-Time Price Response Program	Enrolling Participant Customer	IBCS Provider or Low Tech Option (e-mail from list server and the ISO web-site)

Table 3.1 – Event Notification and Load Restoration Message Communication

3.3 Response Times

For the Day-Ahead Load Response Program, the Demand Resource is expected to curtail in accordance with the cleared offer.

After Real-Time Demand Response customers are notified by the ISO, the ISO expects curtailment of contracted load within 30 minutes or within 2-hours depending on the enrolled program. After the Enrolling Participants of Real-time Profiled Response customers are notified by the ISO, the ISO expects curtailment of contracted load within 2-hours. After Real-Time Price Response customers are notified by the ISO, they may voluntarily curtail load at their discretion during the designated Interruption Period.

Section 4: Telemetry, Verification, Billing and Settlement

4.1 Telemetry Requirements

The term Interval Meter as used throughout this manual refers to a meter that records energy consumption (or generation) on at least a fifteen (15) minute basis and may store energy consumption (or generation) to a finer granularity. For the purposes of the Demand Response Programs, an Interval Meter will include meters that meet either requirement provided below. Typically, the Interval Meter will be the meter used by the distribution company for billing purposes and will be revenue quality meter. Generally, the accuracy on a revenue quality meter is $\pm 0.5\%$. In the case where Interval Metering is installed specifically for the Demand Response Programs and will not be used for other billing purposes, the meter installation for program purposes can either be a revenue quality meter as described above or a non-revenue quality meter described as follows. A Demand Response asset may use non-revenue Interval Metering devices with an overall accuracy of $\pm 2.0\%$ as the source of the performance data. For each non-revenue Interval Meter design used, the Enrolling Participant will submit certification from the meter manufacturer that the model in question meets the $\pm 2.0\%$ accuracy threshold, recognizing errors in:

- Current measurement
- Voltage measurement
- A/D conversion
- Calibration

Such meters shall be periodically tested and calibrated in accordance with the standards for revenue quality metering.

An Enrolling Participant can submit an M&V Plan to the ISO for approval in place of Interval Metering.

4.1.1 Day-Ahead Load Response Program Metering Device Requirements

Demand Resources participating in the Day-Ahead Load Response Program, must meet the metering requirements of their associated Real-Time Load Response Program.

4.1.2 Real-Time Demand Response Metering Device Requirements

Per ISO New England OP14, metering devices shall meet the following requirements:

- (1) Real-Time telemetry per OP18 is not required for these customers; Interval Metering or an approved M&V Plan is required. However, the interconnection agreement with the local utility may require such telemetry.
- (2) IBCS through an ISO-approved provider is required.

4.1.3 Real-Time Price Response Metering Device Requirements

- (1) Real-Time telemetering per OP18 is not required for these customers; Interval Metering or an approved M&V Plan is required. However, the interconnection agreement with the local utility may require such telemetering.

4.1.4 Real-Time Profiled Response Metering Device Requirements

- (1) Real-Time telemetering per OP18 is not required for these customers; Interval Metering is not required. However, sufficient research meters, or equivalent technology acceptable to the ISO, shall be used to provide statistical confidence regarding the Amount Interrupted. Information on the customer's specific metering must be provided at time of registration. An approved M&V Plan is required.

4.1.5 Telemetering Configuration Requirements

Premises participating in the LRP shall subscribe under one of three physical configurations: On-Site Generation only, load only, or On-Site Generation and load. Integrated hourly metering devices shall be required (except for the Real-Time Profiled Response) as follows:

- (1) When a premise subscribes only the On-Site Generation, the Interval Meter may be installed to directly measure the generator's output (or as in (3) below);
- (2) When a premise subscribes only the load, the Interval Meter shall be installed to meter the entire facility; for totalized load, an Interval Meter is required for each participating load;
- (3) When a premise subscribes both the On-Site Generation and load, both the On-Site Generation and the load may be metered separately or jointly. Metering of the load can be configured so as to measure only the load, or combined load and generation.

When an approved M&V Plan is used, the measurement of load and curtailment shall be in accordance with the approved M&V Plan.

4.2 Calculation of Customer Baseline

4.2.1 Baseline Calculation Method

The Customer Baseline (CB) is the average hourly load, rounded to the nearest kWh, for each of the 24 hours in a day. The CB calculation process does not begin until the registration process and meter data reporting requirements are complete. There will be no retroactive CB calculations performed. The CB used for computing performance for the LRP shall consist of eligible weekdays (weekdays that are non-Demand Response Holidays and non-interruption days). The CB calculation for a Demand Resource participating in the Day-Ahead Load Response Program will exclude any day in which the Demand Resource had a cleared Day-Ahead offer. A CB is required for the LRP whenever load is participating in the program. However, there is no CB for Profiled Response or when an approved M&V Plan is used. For On-Site Generation or for an approved M&V Plan, where the actual generator output is metered, the metered output or the calculation in accordance with the M&V Plan will be used for the performance measurement.

The CB for the LRP shall be calculated as the simple average for each hour as defined below:

For a New Asset (an asset with no previously computed baseline):

The CB is the simple average and will be calculated for each hour in day based on meter data from the initial 5 business days after the asset is approved and hourly meter data begins to be recorded. Missing data during these initial 5 days will be assigned the value of zero and used in the computation of the CB. Since the asset is not available to interrupt for a Load Response Event during this 5-day period, Load Response Event days are included in the calculation of the CB for a new asset. Once the CB can be computed, the asset is ready to interrupt. Therefore, the CB for any hour of the first day that an asset is ready to interrupt (day 6) is:

$$CB_6 = (\text{Sum MeterReading}_{\text{for the hour}}) / 5 \quad [\text{day 6 CB calculation}]$$

From this point forward, the CB is calculated the same as any other asset that is ready to respond.

For Existing Assets (an asset that is ready to respond):

For each program day (weekdays and non-Demand Response Holidays), the CB is calculated starting from the previous day's CB. If the present day is a Load Response Event day, the CB for the present day is equal to the CB for the previous program day. If the present day is not a Load Response Event day, then the CB for the present day is calculated solely for the purpose of determining the CB for the next day. The CB for a non-Load Response Event program day is calculated starting from the previous day's CB and then applying the hourly data from the present day.

If the present day is a Load Response Event day, Demand Response Holiday or weekend, the CB is not computed. The CB is only calculated for non-Load Response Event program days. The CB for a Load Response Event day, a Demand Response Holiday or weekend, is equal to the CB for the previous program day. If the present day is a non-Load Response Event program day, the present day's CB is computed using the weighted average of the previous day's CB and the meter data for the present program day. The weighting for this calculation are 0.9 applied to the previous day's CB and 0.1 applied to the meter data. The computed CB becomes the CB for the next program day. Since Load Response Event days are excluded from the computation of the CB, if there are multiple, consecutive Load Response Event days, the CB calculated from the last non-Load Response Event day will be the CB for the consecutive event days as well. The computation is performed separately for all 24 hours of the day.

Continuing with the formula from day 6 above, if day 7 is a Load Response Event day (for the specific program) then the CB for day 7 is the CB from day 6 (the previous day). If day 7 is not a Load Response Event day, then the CB for day 7 is calculated solely for determining of the CB for day 8. The CB for each hour of day 7 is calculated using the following formula:

If day 7 is a Load Response Event day then:

$$CB_7 = CB_6 \quad \text{[day 7 CB if event day]}$$

If day 7 is not a Load Response Event day then:

$$CB_7 = 0.9 * CB_6 + 0.1 * \text{MeterReading}_7 \quad \text{[day 7 CB calculation]}$$

The CB distributed by the IBCS OS to the IBCS Providers each program day will be based upon the assumption that today will be a Load Response Event day.

When computing the CB as described above, no data will be excluded from the computation. Missing data will be assigned the value of zero.

In determining the actual interruption provided, the CB is subject to adjustment to reflect the actual usage for the two hours preceding the interruption. If the adjustment results in a reduction in the CB (the adjustment would lower the CB), then no adjustment is applied to the CB and the CB as originally computed is used to determine the amount of interruption. If there are multiple, consecutive Load Response Event days, the CB will be the CB from the last non-Load Response Event day. The adjustment to the CB to reflect the actual usage for the two hours preceding the interruption will be calculated separately for each Load Response Event day, and the adjustment for consecutive days will be the higher of the previous Load Response Event day's adjustment or the present day's adjustment. However, the CB adjustment to reflect actual usage for the two hours preceding the interruption is subject to the limitation described above.

Example 1: The Customer Baseline is 330 kWh for hour-beginning 10 AM, the time at which an interruption is due to start, and the customer's actual usage from hour-

beginning 8 AM to 10 AM is 20 kWh below the CB. The calculated adjustment would be down 20 kWh in each hour to reflect the actual load prior to the start of the event. However, since this adjustment would reduce the CB, the adjustment is not applied and the CB as originally computed for that day is used to determine the amount of interruption.

Example 2: The Customer Baseline is 330 kWh for hour-beginning 10 AM, the time at which an interruption is due to start, and the customer's actual usage from hour-beginning 8 AM to 10 AM is 20 kWh above the CB. The calculated adjustment would be an increase of 20 kWh in each hour to reflect the actual load prior to the start of the Load Response Event. Since this adjustment would increase the CB, the adjustment is applied and the adjusted CB is used to determine the amount of interruption.

The IBCS OS will calculate the Customer Baseline on a daily basis for Real-Time Demand Response Program customers. For all Real-Time Price Response Program customers, the ISO's Settlement department will calculate the baseline. The Enrolling Participants in the Real-Time Price Response Program may have their IBCS Provider calculate an "estimated" CB for the customer's benefit. However, the customer must be informed that this CB may not be exactly the same as the CB calculated by the ISO and used in the settlement process. The IBCS Provider or the Meter Reader (in the case of the Low Tech and "Super" Low Tech options) of Real-Time Price Response Program customers are required to provide the ISO with hourly meter data in an ISO specified format by 1300 on the third business day after the Operating Day. Meter Readers using the "Super" Low Tech reporting option must provide hourly-integrated values to the ISO in an ISO specified file format before the 90 day resettlement is performed. Enrolling Participants that choose this option waive their ability to request resettlement with respect to billing for these Demand Resources.

For settlement of the Real-time Price Response Program, the Customer Baseline is calculated by the ISO. The CB depicted by the IBCS Provider is for informational purposes only and will not be used in the LRP settlement.

The following graphic shows the CB load profile, adjusted profile, and actual load based on metered data described in example 2.

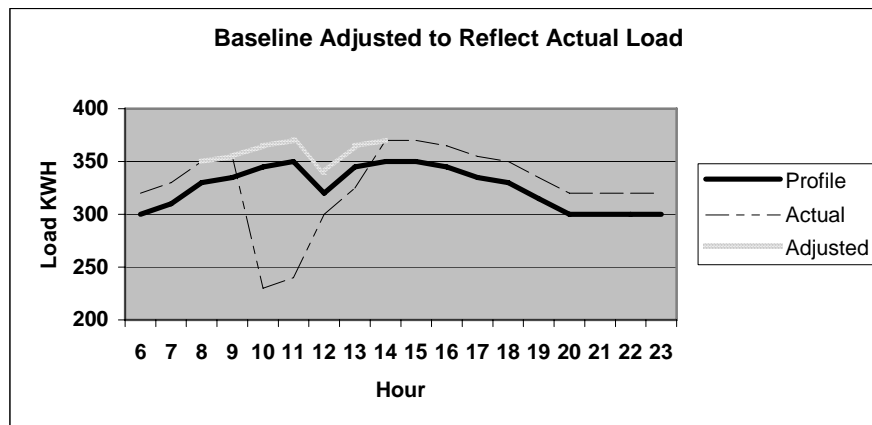


Figure 4.1 – Baseline Adjustment to Reflect Actual Load

4.2.2 Exclusion Provisions

Three types of exclusions are required when computing the Customer Baseline: Demand Response Holidays, Load Response Event days with events in a given Load Zone, and days that contain a cleared Day-Ahead offer period for a Demand Resource as defined below:

- (1) Demand Response Holidays are listed in OP14, Appendix C.
- (2) Load Response Event days (for a given Load Zone) are excluded from the CB calculation for the appropriate Load Response Program and therefore do not result in a recalculation of the CB. The CB for a Load Response Event day is equal to the CB calculated for the last non-event day. For assets that are building their 5-day historical data, Load Response Event days are not excluded from the CB calculation, because the asset is not Ready to Respond to a Load Response Event until a CB can be calculated.
- (3) Days that a Demand Resource's offer clears concurrent with the Day-Ahead Energy Market will be treated as a Load Response Event day and excluded from the CB calculation for that Demand Resource. The CB for a day containing a cleared Day-Ahead offer is equal to the CB calculated for the last non-cleared or non-Load Response Event day.

4.3 Performance Measurements and Compliance

4.3.1 Performance

Performance for metering configurations that include load reduction is measured as the difference between the CB (adjusted) and the actual metered usage by hour during the event. The CB shall be shifted (adjusted) to align the CB with the actual metered usage for two hours preceding the interruption for the LRP event. For a Day-Ahead Load Response Program cleared offer, the shift (adjustment) to align the CB with the actual meter usage will use the two hours immediately preceding the first hour of the Demand Resource's cleared Day-Ahead offer. However, if there are consecutive Load Response Event days or days containing a cleared Day-Ahead offer, the CB adjustment used on the first day will be compared to the CB adjustment for each consecutive Load Response Event day or day containing a cleared Day-Ahead offer, and the greater adjustment will be applied to the CB for the second and subsequent consecutive days. For On-Site Generation, either the generator output as metered or a combined measurement of the site load and On-Site Generation as metered (at the option of the Enrolling Participant) will be used for performance as defined below.

4.3.1.1 LOAD ONLY CONFIGURATION

For premises subscribing only the load, performance for each hour shall be calculated as:

$$P_h = CB_h - AL$$

Where: P_h = performance for the hour
 CB_h = Customer Baseline for the hour as calculated using the simple average method described above in section 4.2.
 AL = actual load for the hour

4.3.1.2 ON-SITE GENERATION ONLY CONFIGURATION

For premises subscribing for only On-Site Generation and metered at the generator, performance for each hour shall be calculated as:

$$P_h = OG_h$$

Where: P_h = performance for the hour
 OG_h = Metered on-site generator output for the hour

For premises subscribing for only On-Site Generation and metered such that only the net load reduction value is available, performance for each hour shall be calculated as:

$$P_h = CB_h - AL$$

Where: P_h = performance for the hour

CB_h = Customer Baseline for the hour as calculated using the simple average method described above in section 4.2.

AL = actual load for the hour

4.3.1.3 LOAD AND ON-SITE GENERATION CONFIGURATION

For premises subscribing both the On-Site Generation and the load and participating in the same LRP, performance for each hour shall be the net of On-Site Generation and load as defined below:

Where On-Site Generation and load are metered separately:

$$P_h = OG_h + [CB_h - AL]$$

Where On-Site Generation and load are metered such that only the net load reduction value is available, performance for each hour shall be calculated as:

$$P_h = CB_h - AL$$

Where: P_h = performance for the hour

OG_h = Metered on-site generator output for the hour

CB_h = Customer Baseline for the hour as calculated using the simple average method described above in section 4.2.

AL = actual load for the hour

4.3.2 Compliance Period

The Compliance Period includes every hour in the LRP event in which performance was greater than zero, beginning with the initial hour and ending with the end of the Load Response Event.

The Compliance Period for the Day-Ahead Load Response Program is the hours of the cleared Day-Ahead offer.

4.6 Failure to Respond in Real-Time

Demand Resources that fail to respond in Real-Time to a cleared Day-Ahead offer or a Load Response Event will result in the following settlement treatment.

4.6.1 Day-Ahead Load Response Program

For a Day-Ahead offer that clears concurrent with the Day-Ahead Energy market, the Enrolling Participant is financially bound to respond in Real-Time by curtailing load. Failure to interrupt in Real-Time up to the MW value of the cleared Day-Ahead offer will result in a LR deviation which may result in a charge or credit in Real-Time, which will be determined by the level of Day-Ahead and Real-Time LMPs as described in Section 4.5.1.1 of this Manual.

4.6.2 Real-Time Demand Response Program

4.6.2.1 CASE ONE – FAILURE TO REDUCE DEMAND

A Demand Resource in the Real-Time Demand Response Program that does not reduce demand during a Load Response Event will be subject to financial charges or credits, as outlined in Section 4.5 of this Manual, and will cause its Adjusted Capability to be reduced to zero on a going forward basis, effective for the next eligible ICAP Obligation Month. However, if that Demand Resource is able to fully comply with a subsequent Load Response Event, the Adjusted Capability will be reinstated for the following eligible ICAP Obligation Month.

4.6.2.2 CASE TWO – PARTIAL REDUCTION IN CURTAILMENT OBLIGATION

A Demand Resource in the Real-Time Demand Response Program that partially reduces during a Load Response Event will be subject to financial charges or credits, as outlined in Section 4.5 of this Manual. This action will cause its Adjusted Capability to be reduced to the level of its performance on a going forward basis, effective for the next eligible ICAP Obligation Month. For example, if a Real-Time Demand Response Program Demand Resource has agreed to a 5 MW curtailment but is able to reduce its demand by only 4 MW during a Load Response Event, that Demand Resource's Adjusted Capability will be reduced to 4 MW on a going forward basis.

4.6.3 Real-Time Profiled Response Program

4.6.3.1 CASE ONE – FAILURE TO REDUCE DEMAND

A Real-Time Profiled Response Program Demand Resource that does not reduce demand during a Load Response Event will be subject to financial charges or credits, as outlined in Section 4.5, and will cause its Adjusted Capability to be reduced to zero on a going forward basis, effective for the next eligible ICAP Obligation Month. However, if the Demand

Resource is able to fully comply with a subsequent Load Response Event, the Adjusted Capability will be reinstated to the statistically determined level for the following eligible ICAP Obligation Month.

4.6.3.2 CASE TWO – PARTIAL REDUCTION IN CURTAILMENT OBLIGATION

The response of a Real-Time Profiled Response Program Demand Resource is statistically determined for each event. As a result, differences in response can occur between each Load Response Event. These differences will be treated as if that Demand Resource is able to partially reduce demand during a Load Response Event, but is unable to reduce the full amount of its reduction. As a result, the Demand Resource's Adjusted Capability will be reduced to the amount of the measured statistical performance, to be effective for the next eligible ICAP Obligation Month.. For example, if a Real-Time Profiled Response Program Demand Resource is statistically expected to provide a 5 MW curtailment but the statistically calculated response for a specific Load Response Event is only 4 MW, that Demand Resource's Adjusted Capability will be reduced to 4 MW, effective for the next eligible ICAP Obligation Month.

Appendix E: Developing a Measurement and Verification Plan

8E.1 Introduction

The guidelines in this Appendix E provide an opportunity for Enrolling Participants with customers without facility-wide interval metering to participate in ISO New England Load Response Programs. Enrolling Participants must have the ability to cause their customers' electrical loads to be curtailed upon receipt of an event notification and report back their customers' aggregated or calculated energy usage or load curtailment. Examples of potential load curtailment strategies could include:

- Traditional direct load control, such as air-conditioner and electric hot water heater cycling and pool pump curtailments
- Permission-based control of thermostat set-points
- Control of lighting circuits and dimmable ballasts
- Compressor controls on vending machines and refrigeration
- Distributed generation dispatch

Enrolling Participants have several options for measuring and submitting energy usage or load curtailment data. Depending on the Load Response Program, the Enrolling Participant will submit to the ISO:

- **Energy Usage Data** for their customers that the ISO will use to calculate the customers' load curtailment following the methodology described in Section 5.2 of this manual, or
- **Load Curtailment Data** for their customers based on an approved methodology for measurement and verification described in the Enrolling Participant's M&V Plan.

8E.2 Developing an Acceptable M&V Plan

The objective of the Enrolling Participant's M&V Plan is to describe both the data acquisition procedure and the analysis methodology that will be used by the Enrolling Participant to determine their customers' aggregate energy usage or load curtailment by Load Zone and reporting interval for each Load Response Event. While unique issues may require attention on a case-by-case basis, all M&V Plans should address the following general issues.¹

8E.2.1 Description of the load curtailment measures

The M&V Plan should describe the nature of the load curtailment measures, including the type of end-use equipment involved and the manner in which load will be controlled by the Enrolling Participant. It should also characterize the nature of the loads under control, with respect to factors such as whether the loads are constant, staged, or continuously variable; are weather or time-dependent; or have interactive effects on other loads. To verify the

¹ Participants may wish to consult resources available on standard M&V practice for energy efficiency projects, such as the International Performance Measurement and Verification Protocol (IPMVP).

nature of load characteristics, some short-term monitoring may be necessary and the data included with the submittal of the M&V Plan.

- A **constant load** device is one that operates at the same demand (kW) whenever it is on, such as a bank of fluorescent lights controlled by a single switch or a single-speed compressor in a packaged air conditioner unit. Since demand is rarely perfectly constant, a load can be considered as constant if it varies by no more than 5-10% from its average value during operation.
- A **staged load** is one that can operate at several fixed demand levels, such as a two-speed compressor in a packaged air conditioning unit.
- A **continuously variable** load can operate at any demand within some range – for example, a fan or pump motor with flow controls or a variable speed drive.

The M&V Plan should identify the specifications for each piece of end-use equipment affected by the load curtailment strategy at each customer site. Relevant information may include the equipment capacity (kW, tons, horsepower, full-load amps, power factor, etc.), operating schedule, and customer controls (manual operation, energy management system, etc.).

8E.2.2 Measurement and monitoring strategy

The measurement and monitoring activities proposed for calculating energy usage or load curtailment are a central component of the M&V Plan, and the following set of issues should be addressed.

(1) *Monitored Parameter(s)*. At least three general options can be considered:

- (a) **Facility-wide metering of demand (kW)**. This is the traditional approach allowed in all Load Response Programs in which load curtailments are estimated based on the whole-premise interval meters. This approach is preferred if whole-premise interval metering already exists at a facility. However, this approach may not be appropriate if the curtailed loads are small relative to the total facility load due to the small “signal-to-noise ratio” or if installing whole-premise interval metering is not economic relative to other monitoring methods.
- (b) **End-use interval metering of demand (kW)**. This approach may be more appropriate than Option (a) if curtailed loads are small relative to the building load, a facility does not currently have whole-premise interval metering or if end-use demand (kW) data can be readily obtained from a building energy management or control’s system. However, consideration must be given to the possibility of interactive effects that may significantly alter loads on other end-use equipment. For example, control of dimmable ballasts may lead to higher use of task lighting. Therefore, M&V plans that propose end-use metering must describe why whole-premise interval metering is either not cost-effective or inappropriate.

(c) **End-use interval metering of a proxy variable for demand.** This method may include measuring something other than demand (kW) such as current (amperage) and voltage or equipment status (on/off, operating time). This approach is characterized by similar attributes as Option (b), but also requires that a correlation be established between the monitored proxy variable and demand (kW). These correlations may be established by conducting short-term monitoring or a series of spot measurements of both parameters, and correlating the data sets (e.g., by performing a regression analysis) to estimate the functional relationship between the two parameters. Alternatively, engineering estimates of this relationship or use of equipment manufacturer's data may be appropriate in some circumstances. For example, current and voltage measurements together with a power factor estimate an end-use's demand (kW). Similar to (b) above, M&V Plans that propose end-use metering of a proxy variable must describe why whole-premise interval metering is either not cost effective or inappropriate.

(d) **Other M&V Methodologies** such as calibrated building simulation may be proposed, however some may not be economically practicable or appropriate for load curtailment measures.

(2) *Monitoring Interval and Period.* The M&V Plan should specify the period over which monitoring will be conducted and the interval over which monitored values will be averaged, recorded and reported to the ISO. The recording and reporting interval must be consistent with those required by the specific Load Response Program as described in this manual. For example, the Real-Time Demand Response Program requires energy usage data to be recorded and reported every five minutes during events. The Real-Time Price Response Program requires energy usage data to be recorded every hour and reported either on a daily basis or within 90 days of the price event.

(3) *Instrumentation.* The M&V Plan should identify the type of monitoring and data logging equipment (i.e. manufacturer and model number) to be used, and its accuracy, as indicated by calibration or manufacturer's data. The preferred method for measuring demand (kW) is to use a true RMS measurement device with an accuracy of at least $\pm 2\%$.²

If alternative methods of measuring demand are proposed (i.e. proxy variables, voltage, current, etc.) the *calculated* demand (kW) values from the monitoring data should achieve an accuracy of $\pm 2\%$ on the *calculated* demand (kW).

If the proposed methods rely on the measured current (amps) and the nominal voltage, the power factor of the end-uses must be included in the demand (kW) calculations. Furthermore, demand measurements for three-phase devices should be conducted on all phases in order to account for any phase imbalance.

² This recommendation for meter accuracy follows the performance requirements for solid-state electrical metering devices set by the American National Standard Institute, ANSI C12.16-1991. Additionally, for power measurements on circuits with significant harmonics, IEEE Standard 519 recommends a digital sampling rate of at least 3 kHz.

If a facility's energy management system (EMS) will be used to record pulse output from a power transducer, the processing accuracy of the EMS must be verified.

- (4) *Sampling*. If sampling will be conducted, the M&V Plan should define each population to be sampled, the sample size, and the target level of precision and confidence. The M&V Plan should include all calculations conducted for determining the sample size and describe how the sample points will be selected. For additional information on sampling, refer to the section below titled "Sampling."

8E.3 Load reduction calculation methodology

The M&V Plan must describe how the Enrolling Participant will calculate their aggregate energy usage or load curtailments on a zonal basis from the monitored data of individual end-use devices or customers. The methodology will vary by program, as follows:

Real-Time Demand Response and Real-Time Price Response Programs:

The Enrolling Participant must submit their customer(s) actual aggregated and/or calculated energy usage in the frequency, format and method of data transmittal consistent with the requirements of each program. The actual aggregated and/or calculated demand (kW) data will be used to calculate the Enrolling Participant's customers' baseline and load curtailment for each event by Load Zone.

The ISO will use the customer baseline and load curtailment methodology for the Real-Time Demand Response and Real-Time Price Response Programs as described in Section 5.2 of the Program Manual.

Real-Time Profiled Response Program:

- (1) The actual load or value of a monitored proxy variable (e.g., duty cycle) during each hour of the load curtailment event, and
- (2) The baseline load or value of a monitored proxy variable during each hour of the event.

The baseline represents the value that would have been expected of the device or customer absent any load curtailment event. For constant load equipment that operates with a constant schedule and/or duty cycle, the baseline is a fixed quantity. However, for load curtailment measures involving variable load equipment or equipment whose operation is time-dependent or weather-dependent, the baseline must be calculated for each hour of each load curtailment event. The M&V Plan should explain how the actual and baseline loads will be calculated, identifying the period that will be used to calculate the baseline load (e.g., the prior ten similar days), and how any adjustments (e.g., for temperature or time of day) will be made. Program participants may wish to refer to the general ISO methodology for calculating customer baseline loads, as described in Section 5.2 of the Program Manual.

8E.3.1 Calculating load reductions from a sample

If energy usage or load curtailments will be measured for the entire population of controlled loads or customers, then the Enrolling Participant's aggregated energy usage or load curtailment in each measurement interval and zone will be calculated as the sum of all individual measured energy usage or load curtailments. However, if sampling will be conducted, the Enrolling Participant's aggregated energy usage or load curtailment in each measurement interval and zone must be calculated from the monitoring data of the sample, and the M&V Plan should describe how this calculation will be performed.

The calculation methodology will take one of two general forms:

- (1) Energy usage or load curtailments will be determined for each member of the sample and extrapolated to the population in terms of some average normalized value, such as the average kW reduction per unit, per ton of cooling capacity, per kW of connected load, or some other analogous unit.
- (2) A proxy variable for energy usage or load curtailment (e.g., change in duty cycle) is determined for each member of the sample, and the energy usage or load curtailment for the entire population is calculated based on the average measured value of the proxy variable and additional stipulated or measured input parameters for each member of the population (e.g., connected load).

A variety of other critical issues that relate to calculating energy usage or load curtailments from a sample may also arise and should be addressed in the M&V Plan, including equipment failure and customer over-rides. For control technologies that allow the Enrolling Participant to determine over-ride rates and signal failures, better accuracy is possible using these known rates and applying them to the savings for those with successful signal and no over-ride. For example, some thermostat control technologies allow the Enrolling Participant to know the signal failure and override for all members of the population. In this case, by separating out all members of the sample with signal failures or overrides, the variation in measured load reduction for the remaining sample points will be generally smaller than it would if the load reduction were calculated for the entire sample. The average load reduction for this subset of the sample can then be extrapolated to the portion of the population that had no signal failure or customer override.

8E.4 Sampling

If sampling will be conducted, the M&V Plan must define each population to be sampled, the sample size, and the target level of precision and confidence. The M&V Plan must include all calculations conducted for determining the sample size and describe how the sample points will be selected.

Enrolling Participants using a Sampling Plan are likely to employ load curtailment strategies that involve curtailing similar types of small loads dispersed across a large number of customer sites (e.g., cycling of residential air conditioners) or within a single customer facility (e.g., lighting circuits or vending machines). In some cases, it may not be feasible for the Enrolling Participant to individually monitor each piece of equipment, and it may be

appropriate to monitor a representative sample. To do so, the Enrolling Participant must first identify the relevant populations and then determine the appropriate sample size for each population. After monitoring has been conducted, the Enrolling Participant must evaluate the distribution of their sample in order to recalculate their sample size for the following year.

8E.4.1 Identifying the Relevant Populations

To monitor a sample of end points, the Enrolling Participant must first identify populations whose members (e.g., end-use devices, customers, lighting circuits) would be expected to have similar values for the monitored parameter. If the populations are defined too broadly, the sample will be unlikely to provide statistically significant results. Populations should consist of members that are similar with respect to:

- (1) Type and size of equipment affected by the load curtailment strategy;
- (2) Usage patterns (e.g., residential vs. commercial; coastal vs. inland weather zones); and
- (3) Load control strategy (e.g., duty cycle control vs. thermostat set point control).

8E.4.2 Determining the Appropriate Sample Size

The appropriate sample size depends on the target level of precision at some specified confidence interval. For all programs, the default statistical target is 90/10 (10% precision at a one-tailed 90% confidence level) in the load curtailment (kW) amount.³

A generally accepted methodology for calculating the appropriate sample size is to conduct simple random sampling for *each* population. To follow this approach, first calculate the sample size corresponding to an infinite population (n'), according to Equation (1):

$$n' = \left(\frac{z \times c.v.}{p} \right)^2 \quad (1)$$

where z is the z-factor for a given confidence interval ($z = 1.282$ for a one-tailed 90% confidence interval); p is the precision ($p = 0.1$ for 10% precision); and $c.v.$ is the coefficient of variation, which is equal to the ratio of the standard deviation of the sampled variable to its average value. In general, the greater the expected variation in the variable from one device to the next – e.g., due to operational patterns or equipment size – the greater the value of $c.v.$ that should be used to calculate the sample size. If monitoring has already been conducted, the $c.v.$ should be based on the monitored data. Otherwise, a default initial value of $c.v. = 0.5$ should be used. For loads curtailments that are likely to have significant variations from one device to the next, a larger $c.v.$ may be necessary.

The sample size (n) for the finite population (N) can then be calculated according to Equation (2):

³ In other words, the sample size should be sufficiently large such that there is a 90% probability that the average value of the sample will not exceed the average value of the population by more than 10%.

$$n = \frac{n'}{1 + \frac{n'}{N}} \quad (2)$$

where n is rounded up to the nearest integer.

If an Enrolling Participant has multiple populations, as an alternative they may calculate sample sizes based on a stratified sampling approach, applied across all of the populations. This technique involves more complex sample size calculations, but will generally yield a smaller total number of sample points.

If the Enrolling Participant believes that the sample sizes corresponding to a 90/10 statistical target would result in onerous M&V costs relative to project benefits, they may propose a reduction in sample sizes. However, the ISO will then de-rate the Enrolling Participant's load curtailments. To determine the level of de-rating, first calculate the precision at 90% confidence associated with the reduced sample size, according to Equation (3):

$$p = z \times c.v. \times \sqrt{\frac{N/n - 1}{N}} \quad (3)$$

The de-rating of load curtailments is based on the difference between this precision and the target level of 10%. For example, if the precision associated with a reduced sample size is 15%, load curtailments will be de-rated by 15%-10% = 5%.

For any sample calculation methodology, it is advisable that the Enrolling Participants over-sample (e.g., by 10%) to compensate for potential data loss due to failures in monitoring equipment or other factors. Also, as described above, the ISO may call a curtailment event in a subset of pricing zones, rather than system-wide. If only a sub-set of customers are called to curtail during such situations, the statistical accuracy of the sample will likely be reduced. To guard against such events, the program participant may wish to over-sample in some number of zones. Once the total sample size has been calculated for each population, the specific sample points should be selected at random from the members of each population.

8E.4.3 Evaluating the Sample Distribution Based on Monitoring Data

During the first year of participation a default value for the coefficient of variation ($c.v.$) will be set to 0.5. However, after curtailment events have been called, the Enrolling Participant can more accurately estimate the $c.v.$ of the population, based on the monitoring data for these events. For simple random sampling, the procedure for evaluating the $c.v.$ of each population is as follows:

- (1) For each hour of each load curtailment event, calculate the mean value and standard deviation of the sampling variable (e.g., kW reduction per unit).

- (2) Based on the hourly standard deviation and mean values, calculate hourly values for the *c.v.*, equal to the ratio of the standard deviation to the mean.
- (3) Calculate the average of the hourly *c.v.* values for all curtailment events during the calendar year.

Based on these calculated *c.v.* values, the Enrolling Participant can re-calculate the appropriate sample size for the following program year, using Equations (1) and (2). If the calculated *c.v.* values are significantly larger than 0.5, this could indicate either that the population has a wide distribution with respect to the sampling variable, or that the population is composed of two or more distinct groups that should be disaggregated into separate populations. In the latter case, the Enrolling Participant should re-calculate the *c.v.* values for each separate population, based on the existing sample data from each of these groups.

8E.5 Submitting energy usage or load curtailment data to the ISO

Energy usage or load curtailment data must be submitted in the format, frequency and method of transmittal consistent with each of the Load Response Programs as described in the Program Manual.

8E.6 M&V Plan Checklist

Enrolling Participants may wish to consult the following checklist to ensure that their M&V Plan addresses the necessary issues and contains adequate detail.

(1) The M&V Plan describes the load curtailment strategy and related end-use devices, identifying:

- ☐ The type, quantity, and location of end-use devices that will be controlled
- ☐ The manner in which end-use devices will be controlled
- ☐ The general characteristics of the end-use devices, with respect to factors such as load variability, time- or weather-dependence, and interactive effects on other end-use equipment
- ☐ Detailed specifications, to the extent possible, for each end-use device to be controlled, including nameplate capacity, operating schedule, and customer controls

(2) The M&V Plan describes the measurements that will be conducted to calculate load reductions for each hour and zone during the ISO load curtailment events, identifying:

- ☐ The parameters that will be measured
- ☐ The duration over which monitoring will be conducted
- ☐ The interval over which monitoring data will be averaged and recorded
- ☐ The type of monitoring and data logging equipment to be used and their accuracy (include calibration data and/or manufacturer's spec sheets to verify instrumentation accuracy)
- ☐ If applicable, the populations to be sampled, the target level of precision and confidence, and the sample sizes (include all calculations used to determine sample size)

(3) The M&V Plan describes the methodology by which aggregate load reductions for each hour and zone will be calculated from the monitoring data, identifying:

- ☐ How the actual load will be calculated, for M&V strategies that involve the measurement of proxy variables
- ☐ How the baseline load will be calculated, including the period used to calculate baseline loads and adjustments that will be made to account for weather or time of day
- ☐ If sampling will be conducted, the calculation method by which monitored results from the sample will be applied to the entire population, including (if applicable) the effect of customer over-rides and signal or equipment failure
- ☐ Any alternative calculation methods that will be employed specifically in cases that the ISO calls for load reductions in only a sub-set of pricing zones

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1. Total forecasted maximum generating Capacity in the Control Area c during month m (without any adjustments for External firm Capacity purchases, or sales, outages and maintenance) (CAP_{cm});
2. External forecasted firm Capacity purchases by Control Area c , other than purchases from Resources in the NYCA during month m (EP_{cm});
3. The forecasted amount of load management (i.e., interruptible load) in Control Area c during month m (LM_{cm});
4. Forecasted peak Load for Control Area c during month m , including system losses (PL_{cm});
5. Forecasted external firm Capacity sales by Control Area c during month m , other than firm Capacity sales to the NYCA (ES_{cm});
6. Forecasted losses, up to the border of the NYCA that would be incurred on transactions corresponding to sales of Unforced Capacity by that Control Area System Resource outside the Control Area (LS_{cm});
7. The amount of generating capacity that is forecasted to be unavailable in Control Area c due to planned maintenance during month m (PM_{cm}); and
8. Planning reserve requirements during month m for the Control Area c corresponding to reserve requirements necessary for this Control Area c to meet NERC Resource Adequacy and applicable reliability council criteria, taking into account all sales of Capacity from this Control Area c (PR_{cm}).

In cases in which any of the above data items is forecasted to vary from hour to hour within a month, the forecasted monthly value submitted for that data item should be the forecasted value of that data item during the peak load hour for that month for Control Area c .

To calculate the Net Projected Capacity of each Control Area System Resource for a specific month, the NYISO shall use the following formula: $NPC_{cm} = CAP_{cm} + EP_{cm} + LM_{cm} - PL_{cm} - ES_{cm} - LS_{cm} - PM_{cm} - PR_{cm}$.

Net Projected Capacity shall be used to determine the amount of Unforced Capacity a Control Area System Resource can provide using the equations in [Attachment J](#) to this Manual, Section 3.4.

4.11 [This Section intentionally left blank]

4.12 Special Case Resources

Special Case Resources are Loads capable of being interrupted upon demand, and distributed generators, rated 100 kW or higher, that are not visible to the ISO's Market Information System. The Unforced Capacity of a Special Case Resource corresponds to its pledged amount of Load

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reduction as adjusted by historical performance factors and as increased by the Transmission District loss factor. The calculation of this amount shall be made in accordance with Section 3.3 of [Attachment J](#) to this Manual.

4.12.1 Claiming of Unforced Capacity and RIPs

The Unforced Capacity of a Special Case Resource may be freely sold in Bilateral Transactions. However, such Unforced Capacity may not be claimed by an LSE towards satisfaction of its own LSE Unforced Capacity Obligation or be offered into an auction administered by the NYISO unless there is a Responsible Interface Party (RIP)) with respect to such Special Case Resource. RIPs are Market Participants that agree to be bound by the notification and other requirements applicable to RIPs under this Section 4.12. Responsible Interface Parties shall be responsible for all forms of communication to and from the NYISO for purposes of Minimum Payment Nomination, notification, dispatch, validation, and verification of Special Case Resources and the Unforced Capacity associated with Special Case Resources.

4.12.2 General Requirements

Every Special Case Resource must submit a Special Case Resource registration in accordance with the SCR Workbook located on the NYISO website at <http://www.nyiso.com/public/products/icap/auctions.jsp>. The most recent version of the SCR Workbook is located on this web page for the applicable Capability Period. In addition, each Special Case Resource must be accepted by the NYISO as an Installed Capacity Supplier before its Unforced Capacity may be claimed by an LSE towards its LSE Unforced Capacity Obligation or be offered in an auction administered by the NYISO. Every Special Case Resource must submit a Special Case Resource registration to the NYISO in accordance with the schedule and requirements of Section 4.2. Special Case Resources must also submit a notification letter identifying the RIP that they authorize to transact on their behalf and must obtain an identification number from the NYISO.

Interval billing meters are required of all Special Case Resources. Such metering must satisfy all requirements of Section 6 of the Emergency Demand Response Program (EDRP) Manual.

A Special Case Resource that supplies Load reductions solely through the use of a distributed generator (whether or not operated in parallel with the NYCA) and that elects to measure such Load reductions by metering the output of such distributed generator in accordance with Section 3.3(b) of [Attachment J](#) hereto shall provide to the NYISO DMNC test data as part of its Special Case Resource registration. A Special Case Resource that supplies Load reductions solely through the use of a distributed generator and that elects to measure such Load reductions by metering the output of such distributed generator in accordance with Section 3.3(b) of [Attachment J](#) must deduct from the output of such generator: (i) any auxiliary Load consumed by the generator and

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supplied from an external source; and (ii) any Load from a load bank used in conjunction with the generator when responding to NYISO dispatch under Section 4.12.3.

A Special Case Resource may specify generation in excess of its facility load, provided that it has installed metering capability satisfactory to the NYISO in order to quantify the net load change during a curtailment. Such resources must certify to the NYISO that they have obtained all necessary regulatory approvals to sell energy at wholesale and meet applicable utility interconnection and delivery (including metering) requirements. Energy payment rates for such generation in excess of load shall not exceed the applicable real-time LBMP.

Special Case Resources must meet the qualifications and comply with the procedures described below. A RIP claiming Unforced Capacity from Special Case Resources must comply with the requirements and procedures set forth below.

The Unforced Capacity of Special Case Resources may only be offered in auctions administered by the NYISO or be claimed by an LSE towards its LSE Unforced Capacity Obligation in even increments of 100 kW (e.g. 590 kW of Unforced Capacity would be rounded down to 500 kW). However, Special Case Resources may be aggregated to minimize the effect of this requirement, provided that each such aggregation is identified as a single block of Unforced Capacity. Aggregations of this type may only be used to meet the 100 kW block requirement but cannot be used to allow over-performance by one Special Case Resource to compensate for under-performance by another Special Case Resource. The performances of each Special Case Resource shall be reported individually using the Special Case Resource Workbook and shall be tracked in accordance with the procedures contained in this Section 4.12. Performance measurements will be calculated in accordance with Section 3.3 of Attachment J to this Manual.

RIP performance will be based on the performance of its overall portfolio of Special Case Resources. A RIP will not be charged with a deficiency penalty if the total performance of its individual Special Case Resources meets or exceeds the total capacity it is committed to supply from all of its individual Special Case Resources. If the RIP's portfolio of Special Case Resources does not meet its full commitment, the RIP will be subject to deficiency penalties as applicable to any Installed Capacity Resource.

The NYISO will also allow participation by aggregations of small customers using alternative metering and performance measurement subject to the procedures and limitations set forth in Section 3.8 of the [*NYISO Emergency Demand Response Program Manual*](#), except that the total of all such aggregations for Special Case Resources shall not exceed 100 MW.

4.12.3 Minimum Payment Nomination Requirements

For each month in which a Special Case Resource supplies Unforced Capacity to the NYCA, the RIP, or its assignee, must submit a Minimum Payment Nomination to the NYISO that will reflect the minimum guarantee price the Special Case Resource will be

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paid if called upon to reduce Load equal to the Installed Capacity Equivalent of the amount of Unforced Capacity it has supplied. There is no minimum Minimum Payment Nomination and a Special Case Resource's Minimum Payment Nomination cannot exceed \$500/MWh. This Minimum Payment Nomination, or Energy curtailment payment designation, associated with a Special Case Resource's Unforced Capacity will not be entered in the Day-Ahead Market, but instead will serve as a strike price that the NYISO can use to prioritize which Special Case Resources to call. Unlike a Generator or other Resource's Bid to supply Energy associated with Unforced Capacity, a Special Case Resource's Minimum Payment Nomination cannot be revised prior to Settlement in the Day-Ahead Market. A Special Case Resource's Minimum Payment Nomination is set for the entire month.

Special Case Resource Minimum Payment Nominations to perform at a minimum payment for Load reduction must be submitted at the same time all Installed Capacity Suppliers are required to submit their monthly Installed Capacity Supplier certification forms. See Section 4.7 of this Manual. Special Case Resource Minimum Payment Nominations must be submitted to the NYISO using the SCR Workbook located on the NYISO website at <http://www.nyiso.com/public/products/icap/auctions.jsp>. Responsible Interface Parties must submit Minimum Payment Nominations for all qualified Special Case Resources, regardless of whether, at the time of the submission, a qualified Special Case Resource has committed to supply Unforced Capacity in the NYCA market during the upcoming month. Once submitted, a Special Case Resource's Minimum Payment Nomination will remain in effect for the life of the Special Case Resource unless superseded by a successive Minimum Payment Nomination.

Special Case Resource Minimum Payment Nominations will be entered in a separate database and used only when the NYISO Operations department determines the need to call on these Resources in accordance with the NYISO Emergency Operations Manual. In the event the NYISO Operations department makes such a determination, the Minimum Payment Nominations placed for each Special Case Resource will allow the NYISO to call for Load reduction based on Special Case Resource zone location and price. As a result, the NYISO will be able to call less than the total pool of Special Case Resources in the NYCA and in each NYCA zone.

As an example, the NYISO may determine that it needs a Demand Reduction response of 25 MW in Zone J. A total of 50 MW of Special Case Resources located in Zone J is supplying Unforced Capacity. For this example, assume that each MW of Special Case Resource Capacity entered a different Minimum Payment Nomination, from \$0/MWh to \$500/MWh. In order to fulfill its need for 25 additional MW of reserves, the NYISO will call the 25 MWs of Special Case Resources in economic order based on their submitted Minimum Payment Nominations starting with the lowest values. See Section 4.12.8 for situations where multiple Special Case Resources have placed the same top Minimum Payment Nomination called upon by the NYISO and the total MW offered at that price exceed the ISO's needs.

4.12.4 Performance

A Special Case Resource must make Energy available, for a minimum four (4) hour block (except where environmental constraints that have been previously considered and approved by the NYISO require a shorter block), in amounts that correspond to the Installed Capacity Equivalent of the amount of Unforced Capacity it supplies to the NYCA, by reducing Load or by transferring Load to a distributed generator. The obligation to reduce Load or to transfer Load to a distributed generator shall commence at the top of the hour after the NYISO has provided the following notices:

- (a) on the day before the Special Case Resource's performance may be required, the NYISO shall provide twenty-one (21) hour notice to the RIP, so long as notification is provided by 3:00 PM ET. If notice is provided to the RIP after 3:00 PM ET on the day before the Special Case Resource's performance may be required, then the NYISO shall instead provide twenty-four (24) hours notice;
- (b) following the advance notice described in (a) above, on the operating day the NYISO shall provide at least two (2) hours notice to the RIP that the Special Case Resource's performance will be required. The Special Case Resource shall reduce its Load or to transfer Load to a distributed generator (as appropriate) commencing at the top of the hour immediately after the two-hour notice period has expired. In the alternative, the NYISO may specify the hour at which the Special Case Resource shall commence performance of its obligation by reducing its Load or to transferring Load to a distributed generator (as appropriate), so long as the start hour specified by the NYISO is at least two hours in the future.

If the Special Case Resource is unable to provide full output within two (2) hours due to operational constraints, the RIP may petition the NYISO for permission to provide maximum output from the Special Case Resource within a longer period. The ISO's permission will not be unreasonably withheld. In granting permission, the NYISO will calculate the appropriate de-rating factor for use in determining the amount of Unforced Capacity that such Special Case Resource can provide in the future.

The NYISO will use the average of the one-hour peak Loads during the noon to 8 PM time period during the four (4) middle months in each Capability Period to create a Special Case Resource Average Peak Monthly Demand ("APMD") baseline. The NYISO will use the Summer 2006 Capability Period performance to calculate the baseline and this APMD methodology will be applied to all curtailable Load Special Case Resources beginning with the Summer 2007 Capability Period.

If a new resource has no interval billing meter data from the prior like Capability Period, its Installed Capacity value may be provisionally based on billing demand data. Such declarations will be subject to actual in-period verification using actual interval billing meter data for the applicable Capability Period and the resource's performance during an event or audits that rely on estimated data shall be subject to all the same deficiency payments and forward deratings as apply to all other Special Case Resources.

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In the case where a Special Case Resource is using a distributed generator for demand reduction, the Installed Capacity value of that Special Case Resource is based on the net contribution to reducing the NYCA peak Load in the prior Capability Year. Beginning with the Summer 2007 Capability Period,¹ the normal production level of the distributed generator does not qualify as Special Case Resource capacity except as provided below. For example, a back-up generator that was not operating during the prior year NYCA peak would qualify for full output value less associated parasitic consumption, auxiliary and load bank Load, if any. A generator that was operating during the prior NYCA peak would only get Capacity credit for the net increase over its contribution to the prior year's NYCA peak Load.

An exception is made when the LSE, Transmission District and NYCA peak Load upon which Installed Capacity requirements were based are grossed up to account for the Special Case Resource's operation. Under these circumstances the Special Case Resource would be treated as a back-up generator that was not operating during the prior year NYCA peak. Special Case Resources that use a distributed generator for demand reduction during the NYCA peak Load period and that desire to qualify this demand reduction as Installed Capacity must authorize the RIP to request such treatment of the NYISO. The RIP must, in turn, notify the NYISO of the Special Case Resource's authorization to treat the Special Case Resource generator's production as Installed Capacity. The NYISO will then assume responsibility for notifying the Transmission Owner in whose Transmission District the Special Case Resource generator exists and ensure that the generator demand reduction is properly accounted for in the relevant Transmission District Load forecast. The SCR Workbook used to register and report performance in accordance with these procedures, along with detailed instructions on its use, is located on the NYISO website at

<http://www.nyiso.com/public/products/icap/auctions.jsp>.

Small customer aggregations as described in Section 4.12.2 of this Manual will use the CBL as defined in Section 3.8 of the [**NYISO Emergency Demand Response Program Manual**](#) to establish their Installed Capacity baseline.

A Special Case Resource may be required by the NYISO to demonstrate its pledged Load reduction capability once in every Capability Period for a period not to exceed one clock hour if it has not otherwise already been called by the NYISO to reduce Load in such period. There will be no Energy payments for these one hour audits. Audits will be conducted only during DMNC Test Periods. The NYISO will not ordinarily require a Special Case Resource to demonstrate its pledged Load reduction capability via an audit until such time as it appears unlikely that a Special Case Resource event will be called in the relevant Capability Period.

For purposes of determining deficiencies, Special Case Resources must demonstrate their pledged load reduction for a minimum of one hour each Capability Period. This

¹ NYISO note: To the extent the addition of this deferral to the beginning of the Summer 2007 Capability Period conflicts with the requirements of §5.12.11(a) of the Services Tariff, the NYISO and the Market Participants are obligated to comply with the tariff.

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demonstration must be during an actual called Special Case Resource event. If there are no such Special Case Resource events, one-hour audit results will be used. If a Special Case Resource does not meet its pledged Load reduction during an event, or if there is no event and the audit result is applied, the Special Case Resource will be subject to derating for the next like Capability Period and the RIP will be subject to deficiency penalties if the overall performance of all Special Case Resources in the RIP portfolio is less than that committed and certified in accordance with the applicable calculations in Section 3.3 of Attachment J to this Manual. This methodology will be implemented commencing with the Summer 2006 Capability Period.

UCAP values will be calculated for each Special Case Resource in accordance with Section 3.3 of Attachment J to this Manual. Performance will be based on all reported hours during all called Special Case Resource events in a Capability Period and will apply to the next like Capability Period. If results are reported for any audits during a Capability Period, they will also count toward determining the UCAP value for each Special Case Resource. For example, if there are no Special Case Resource events, then audit results will apply. If an audit is conducted in August and there are subsequent Special Case Resource events, all event hours will apply plus the audit hour.

In the event that a Special Case Resource located at a retail customer was in operation (in the case of a distributed generator) or providing Load reduction (in the case of interruptible Load), at the time of the system or Transmission District peak upon which the Minimum Unforced Capacity Requirement of the LSE serving that customer is based, the LSE's Minimum Unforced Capacity Requirement shall be increased by the amount of Load that was served or interrupted by the Special Case Resource.

4.12.5 NYISO Notification Procedures

The NYISO will provide twenty-one (21) hour-ahead notification if notification is provided by 3:00 PM ET, or twenty-four (24) hour notice otherwise, and two (2) hour notice, as required by this Manual (and described in Section 4.12.4, above), to the RIP. The former notification will be provided after 11 am, day-ahead, when the Day-Ahead Market closes. The NYISO commits not to use the day-ahead notification of potential need to operate indiscriminately but rather only when the Day-Ahead Market indicates potential serious shortages of supply for the next day in accordance with the Emergency Operations Manual. The day-ahead notice may occur on a weekend day or a holiday, as needed.

The NYISO shall provide notice no less than two (2) hours ahead of required operation or interruption, in the manner described in Section 4.12.4, above. Requested hours of operation within the two hour notification window and/or beyond the maximum 4 hours obligation will be considered voluntary for purposes of performance measurement. Notifications will normally be specified from, and to, specific clock hours, on-the hour. Performance calculations and energy payments will only be calculated for energy reductions for whole clock hours; i.e. from 13:00 to 14:00, 14:00 to 15:00, etc.

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Responsible Interface Parties shall contact their Special Case Resources through whatever communication protocols are agreed to between the Special Case Resources and the RIPs. Communication from the RIP to the Special Case Resource is the responsibility of the RIP. Such communication is subject to review by the NYISO. Any misrepresentation of the NYISO program in such notifications is subject to sanction by the NYISO, up to and including disqualification as a RIP.

Responsible Interface Parties claiming Special Case Resource Unforced Capacity shall provide the NYISO with their phone and Internet contact information that allows for notification by the NYISO at any time. Responsible Interface Parties shall confirm receipt of both instances of notification (day-ahead and two (2) hour) within 1 hour by Internet or telephone reply to the NYISO. Such reply must confirm the relay of proper notification by the RIPs to their Special Case Resource clients, where applicable.

4.12.6 Capacity Adjustment Procedures

Seasonal performance factors will be calculated in accordance with Attachment J of this Manual. Existing Special Case Resources that have a performance record from the prior like Capability Period will have initial Unforced Capacity values determined based on this calculation. New Special Case Resources will be assigned Unforced Capacity values based on the ratio of the sum of all Unforced Capacity values to the sum of all Installed Capacity values of all Special Case Resources in the associated RIP's portfolio of resources in accordance with calculations set forth in Section 3.3 of Attachment J. Necessary metrics will be collected beginning with the Summer 2006 Capability Period. This methodology will apply beginning with the Summer 2007 Capability Period.

A Special Case Resource that fails to respond to RIP notification by reaching pledged Load reduction capability or maximum pledged generator output within two (2) hours following notice from the NYISO to the RIP, or that fails to provide output for the period required by the NYISO or four (4) hours, whichever is less, will be considered forced out (for unperformed hours) for purposes of calculating the Unforced Capacity value of the Special Case Resource for future Obligation Procurement Periods. See [Attachment J](#) of this Manual for further explanation of a Special Case Resource's Unforced Capacity value.

A Special Case Resource that has successfully petitioned the NYISO for permission to reach pledged Load reduction or maximum output in more than two (2) hours will be considered forced out in the amount of Unforced Capacity not backed by Energy for the period starting two (2) hours following the notice from the NYISO to the RIP until the Special Case Resource attains pledged Load reduction or maximum output.

A Special Case Resource (SCR) that cannot operate for the full four (4) hours when called for by the ISO, due to environmental permit limits or otherwise, shall be considered forced out for the hours it is unable to operate or is operated at reduced output.

4.12.7 RIP Requirements

In addition to other requirements under this Section 4.12, a RIP claiming Unforced Capacity from a Special Case Resource for sale into a NYISO-administered auction or for its own requirements (in the case of a RIP, which is an LSE) shall fulfill the following obligations:

- Submit to the NYISO a letter from each Special Case Resource authorizing the RIP to act on behalf of the Special Case Resource during each Capability Period. The letter must specify that the RIP has authority to sell the Special Case Resource's Unforced Capacity, act as the organization of record for all financial transactions, and should be signed by an authorized representative of the Special Case Resource.
- Notify the NYISO in advance, as provided in Section 4.3.3, whenever the Special Case Resource is unavailable to provide its pledged Load reduction.
- Report operating data to the NYISO as required in Section 4.4.7 using the SCR Workbook located on the NYISO website at <http://www.nyiso.com/public/products/icap/auctions.jsp>
- Make certifications to the NYISO each month as provided in Section 4.7.
- Document reductions in Load with interval billing meter readings on customer Load (or with readings on the distributed generator(s) in the case of a Special Case Resource whose performance is calculated under Section 3.3 of [Attachment J](#)) for the four (4) hour period following the two (2) hour NYISO notice under Section 4.12.4. See Section 6 of the Emergency Demand Response Program Manual for metering requirements. In the event that Energy made available from Special Case Resource Unforced Capacity is a small percentage of the total metered Load at the location of the Special Case Resource, such that it may not be clearly reflected by meter reads alone, the NYISO will also accept operations logs to augment metered output to ensure accurate verification.
- The RIP (including a Transmission Owner that is a RIP) shall retain all interval meter readings upon which it bases its certification of compliance, for a period of three (3) years.

4.12.8 Special Case Resource Demand Response Payments

Except in the case of an audit test, which may require performance for up to one hour in each Capability Period, each time a Special Case Resource is called upon to perform, it will receive an Energy payment for the amount of Load reduction resulting from its performance, measured in terms of the Energy supplied during each clock hour of its performance using the Energy calculation methodology specified in the EDRP Manual. If the NYISO requests performance by Special Case Resources for more than four (4) hours, each Special Case Resource shall be paid for the duration of the event in accordance with this Section 4.12.8, starting with the hour specified by the NYISO as

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the starting time of the activation, or, in the event that the NYISO specified that the Demand Reduction begin as soon as possible, starting with the next whole clock-hour at which the Special Case Resource began its response. Each Special Case Resource shall be paid the zonal Real-Time LBMP per MWh of Energy reduced for the duration of the event. Payment for Special Case Resource Load reductions are conditioned upon verification of performance for the time period requested by the NYISO.

If the NYISO requests performance by Special Case Resources for four (4) hours or less, each Special Case Resource shall be paid as if it had been activated for four (4) hours. Each Special Case Resource that reduces demand shall receive a payment consistent with the scarcity pricing rules, in accordance with this Section 4.12.8, for the duration of the NYISO request or for two (2) hours, whichever is greater, starting with the hour specified by the NYISO as the starting time of the event, or, if the NYISO specified that the Demand Reduction begin as soon as possible, starting with the hour that the Special Case Resource began to perform. Each Special Case Resource shall be paid the zonal Real-Time LBMP per MWh of Load reduced for the four-hour minimum payment period. Payment for Special Case Resource Load reductions is conditioned upon verification of performance for the time period requested by the NYISO.

Special Case Resource Minimum Payment Nominations would be eligible to participate in the LBMP price setting under the scarcity pricing rules, which permit Bids, or in this case Minimum Payment Nominations, to set prices if at least one (1) MW of Special Case Resource Capacity is needed to satisfy the total reserve requirement, following performance and verification. In the event that a Special Case Resource's Minimum Payment Nomination total for the number of hours of requested performance exceeds the LBMP revenue that Special Case Resource receives, that Special Case Resource will be eligible for a Bid Production Cost Guarantee to make up the difference.

When more than one Special Case Resource has submitted the highest Minimum Payment Nomination selected by the NYISO to perform during an event, the NYISO will specify the number of MWs of the amount of Special Case Resources that must perform during that event such that all such resources are selected in the same zone provided that single source resources shall be taken without being called upon for partial performance.

To continue the example listed in Section 4.12.3, each Special Case Resource that was called to perform in Zone J would be paid the greater of its Minimum Payment Nomination or the applicable LBMP per MW per hour of requested performance following verification of performance of Demand Reduction. When at least one (1) MW of Special Case Resource Capacity is needed to satisfy the total reserve requirement, the Minimum Payment Nominations submitted by these Resources may be considered when determining the LBMP.

Emergency Demand Response Program Manual

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Disclaimer

The information contained within this manual, along with the other NYISO manuals, is intended to be used for informational purposes and is subject to change. The NYISO is not responsible for the user's reliance on these publications or for any erroneous or misleading material.

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1. Definitions and Acronyms

Capability Period - Six (6) month periods that are established as follows: (1) from May 1 through October 31 of each year (“Summer Capability Period”); and (2) from November 1 of each year through April 30 of the following year (“Winter Capability Period”).

Curtailment Customer Aggregator (or Aggregator) – An organization qualified as a CSP that enters into contracts with Demand Side Resources to either interrupt load or start up Local Generation under the EDRP.

Curtailment Program End Use Customer (EUC) – A retail end-user that qualified as a CSP and can either interrupt load or start up Local Generation under the EDRP.

Curtailment Services Provider (CSP) – A qualified provider that can produce real-time verified reductions in NYCA Load of at least 100 kW, pursuant to the Emergency Demand Response Program (“EDRP”) and related ISO procedures. Curtailment Service Providers can be either a LSE, a Direct Customer, a Curtailment Customer Aggregator, or a Curtailment Program End Use Customer.

Customer Base Load (CBL) – Average hourly energy consumption as calculated in Section 6, used to determine the level of load curtailment provided.

Day-Ahead Zonal LBMP – The price (in \$/MWh) for combined energy, losses, and transmission congestion determined on an hourly basis in the day-ahead electricity market.

Demand Side Resources - Resources that result in the reduction of a Load in a responsive and measurable manner and within time limits established in the ISO Procedures.

EDRP – Emergency Demand Response Program, described in this manual.

EDRP Loads – Retail end-users that provide load reduction and have been registered through a CSP to participate in the Emergency Demand Response Program.

Emergency Condition - Any abnormal system condition as specified by the ISO that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of the electric system.

Emergency Generation - An electrical generator installed to handle emergency outages at a facility, for short periods of time.

In-Day Peak Hour Forecast – Forecasted morning and evening peak loads as determined by the NYISO Shift Supervisor or his assignee, used to evaluate total operating capacity.

Installed Capacity (ICAP) - A Generator or Load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the New York Control Area for the purpose of ensuring that sufficient energy and capacity are available to meet reliability rules. The Installed Capacity requirements, established by the New York State Reliability Council, include a margin of reserve in accordance with the Reliability Rules.

Interval Metering – An approved metering device, which records electricity usage for each fifteen-minute period during a billing period.

Load Bank - An electric resistance coil or similar device that creates an electric load which is used for testing generators under load.

Load Curtailment (or Reduction) - A reduction in energy usage at a retail end user's facility that is the result of the retail end user either reducing the energy consumed or operating an on-site generator.

Load Serving Entity (LSE) – Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail end users located within the NYCA, including NYISO Direct Customers.

Local Generator - A generator operated by or on behalf of loads offering load reductions pursuant to the Emergency Demand Response Program. Such generators are not synchronized to a utility's local distribution system or, if synchronized to the local distribution system, must certify to the NYISO that they have obtained all necessary regulatory approvals to sell energy at wholesale and meet applicable utility parallel interconnection requirements. On-site generators that are base-loaded do not qualify for the EDRP.

Locational Based Marginal Price (LBMP) - The price of energy bought or sold in the LBMP Markets at a specific location or zone.

Meter Service Provider (MSP) - An entity that provides meter services, consisting of the installation, maintenance, testing and removal of meters and related equipment.

Meter Data Service Provider (MDSP) – An entity providing meter data services, consisting of meter reading, meter data translation and customer association, validation, editing and estimation.

New York Independent System Operator (NYISO) - Not for profit organization created to supply New York's electric power needs and to facilitate the power market equitably.

New York Control Area (NYCA) –The Control Area that is under the control of the NYISO which includes transmission facilities listed in the ISO/TO Agreement Appendices A-1 and A-2, as amended from time-to-time, and Generation located outside the NYS Power System that is subject to protocols which allow the ISO and other Control Area operator(s) to treat some or all of that Generation as though it were part of the NYS Power System.

NYISO Customer – An entity which has complied with the requirements contained in the ISO Services Tariff, including having signed a Service Agreement, and is qualified to utilize the Market Services and the Control Area Services provided by the NYISO under the ISO Services Tariff; provided, however, that a party taking services under the Tariff pursuant to an unsigned Service Agreement filed with the Commission by the NYISO shall be deemed a Customer.

NYISO Direct Customer – An entity, which takes or provides service directly from or to the NYISO, and is responsible for bidding, scheduling, and billing functions for their facilities.

NYISO Limited Customer – An entity that joins the NYISO to participate in the EDRP; registration requirements are the same as for a NYISO Customer except that a Limited Customer:

- Is not required to satisfy the financial assurance obligations imposed on Customers,
- Their status as a Limited Customer expires at the end of the EDRP program, and
- Voting privileges are waived with respect to the governance process.

All NYISO Customers meeting the eligibility criteria set forth in Section 3 qualify as Limited Customers, and may participate in the EDRP subject to the registration procedures defined in Section 4.

NYISO Services Tariff – The document that sets forth the provisions applicable to the services provided by the ISO related to its administration of competitive markets for the sale and purchase of Energy and Capacity and for the payments to Suppliers who provide Ancillary Services to the ISO in the ISO Administered Markets and provision of Control Area Services, including services related to ensuring the reliable operation of the NYS Power System.

NYS DEC – New York State Department of Environmental Conservation

Operating Reserve Shortage – Failure to maintain the Minimum Operating Reserve Requirement as defined in Section 4.1.1 of the NYISO System Operating Procedures.

Real-Time Zonal LBMP – The price (in \$/MWh) for combined energy, losses, and transmission congestion determined on a roughly five-minute basis in the real-time electricity market.

Remote Metering - Metering equipment, which allows for remote collection of metering data.

Special Case Resource - Loads capable of being interrupted upon demand, and distributed generators, rated 100 kW or higher, that are subject to special rules set forth in the NYISO Services Tariff, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers.

Zone - One of eleven geographical areas located within the NYCA that is bounded by one or more of the fourteen New York State Interfaces. During the implementation of the LBMP Markets, all Loads located within the same Load Zone pay the same Day-Ahead LBMP and the same Real-Time LBMP for Energy purchased in those markets.

2. Program Summary

The Emergency Demand Response Program (EDRP) provides a mechanism for load reduction during emergency conditions, more specifically defined in this document, thereby facilitating the reliability of the New York State bulk power system.

Retail end users who agree to participate in the EDRP can be accommodated through one of four types of Curtailment Service Providers (CSPs):

- Load Serving Entities (LSEs), either that currently serving the load or another LSE
- Through NYISO-approved Curtailment Customer Aggregators
- As a Direct Customer of the NYISO
- As a NYISO-approved Curtailment Program End Use Customer

Curtailment Customer Aggregators and Curtailment Program End Use Customers must register with the NYISO as Limited Customers as defined in Section 4.0.

Curtailment Service Providers should be able to provide load reduction of at least 100 kW per Zone and be able to respond within two hours of emergency notification.

Participation in the EDRP is voluntary and no penalties attach if a CSP fails to respond to a NYISO notice to reduce load.

Retail end users participating in the EDRP cannot participate in the NYISO's Special Case Resources Program. Special Case Resources that have registered with the NYISO but not sold their capacity will be added to the list of EDRP participants for that period of time when their capacity is unsold, and will be called with EDRP participants if an EDRP event is activated.

The NYISO will allow participation by aggregations of smaller customers, the curtailed usage of which will be determined by using an alternative to the basic provisions regarding the metering and measurement of performance. Direct-generation and self-generation resources are not eligible. Direct serve customers are also prohibited from operating under alternative performance measures. Section 3.8 describes the details of this program option.

Curtailment Service Providers will be given notice no less than two hours in advance of the time specified to reduce load, pursuant to NYISO emergency operations procedures. If the ISO activates the Emergency Demand Response Program for more than four hours, each CSP shall be paid the higher of \$500/MWh, or the zonal Real-Time LBMP per MWh of demand reduced, starting with the hour specified by the ISO as the starting time of the activation, or, in the event that the ISO specified that the demand reduction begin as soon as possible, starting with the hour that the CSP began its response.

If the ISO activates the EDRP for four hours or less, each CSP shall be paid as if the EDRP had been activated for four hours. Each CSP that reduces demand shall be paid the higher of \$500/MWh or the zonal Real-Time LBMP per MWh of demand reduced, for the duration of the ISO activation of the EDRP or for two hours whichever is greater, starting with the hour specified by the ISO as the starting time of the activation, or, in the event that the ISO specified that the demand reduction

begin as soon as possible, starting with the hour that the CSP began its response. Each CSP shall be paid the zonal Real-Time LBMP per MWh of demand reduced for the remainder of the four-hour minimum payment period, provided that a verified demand reduction was effectuated by the time specified in the ISO's notice.

A detailed explanation of payments can be found in Section 6.

The program will be effective May 1, 2001 and will continue through October 31, 2005. At the end of each Capability Period, the program will be evaluated and changes recommended as necessary.

3. Eligibility Criteria / Participant Qualification

3.1. Effective Period of the Program

The program begins on May 1, 2001, and will continue through October 31, 2005. At the end of each Capability Period (May-October and November-April), program performance will be evaluated to see if any rules and procedures need to be modified.

Entities wishing to participate may apply for entry into the program at any time.

3.2. Who Can Participate?

The EDRP allows wholesale electricity market participants to subscribe retail end users able to provide Load Reduction (Demand Side Resources) when called upon during emergency conditions. Wholesale market participants are grouped into four broad classes of Curtailment Service Providers (CSPs):

- Load-Serving Entities (LSEs) as defined in [\[2\]](#) that currently serve retail end users capable of load reduction or an LSE that subscribes another LSE's load solely for the purpose of participating in the NYISO EDRP. LSEs may claim load reductions from their retail end users or the retail end users of another LSE. Load curtailment programs currently in place or under implementation may directly qualify for the EDRP (see 3.4 Restrictions below).
- Direct Customers of the NYISO as defined in [\[2\]](#) may claim their own load reductions.
- NYISO-approved Curtailment Customer Aggregators (Aggregators) of retail end users capable of load reduction. Aggregators may claim load reductions from Demand Side Resources with which they have a contractual arrangement. An Aggregator is required to join the NYISO as a NYISO Limited Customer.
- NYISO-approved Curtailment Program End Use Customers (EUC), end-use customers whose load is normally served by an LSE but who wish to participate directly with the NYISO solely for purposes of the EDRP. Curtailment Program End Use Customer's (EUCs) must be capable of reducing at least 100 kW of load. An EUC is required to join the NYISO as a NYISO Limited Customer.

Participation in the EDRP is voluntary; no penalties are imposed upon CSPs or Demand Side Resources for not responding to load reduction requests.

3.3. Minimum Qualifications for CSPs

To serve as a CSP, you must:

1. Be a NYISO Customer (in the case of LSEs and Direct Customers) or a NYISO Limited Customer (in the case of Aggregators and EUCs) of the NYISO and be able to pledge Load Reduction in the NYCA.
2. Be able to completely disconnect from the local distribution system and supply required load via local generators¹ or to reduce a measurable and verifiable portion of the load.
3. Be capable of reducing at least 100 kW of load per Zone.
4. Be capable of responding within two hours of notice from the NYISO.
5. Follow the registration procedures defined in Section 4 of this manual.
6. CSPs are required to provide hourly interval metering data to validate performance; specific metering requirements are given in Section 6 of this manual.

3.4. Restrictions

An individual Demand Side Resource can subscribe to either EDRP or the ICAP SCR program, but not both. Special Case Resources (SCRs) that have registered with the NYISO but not sold their capacity will be added to the list of EDRP participants for that period of time when their capacity is unsold, and will be called with EDRP participants if an EDRP event is activated.

To participate in the program, an individual Demand Side Resource cannot subscribe the same metered load with more than one CSP.

Retail end users under a contract that prevents them from curtailing energy are prohibited from participating in the program. The NYISO will consult with the appropriate LSE and Electric Distribution Company to verify that the load to be reduced is not under any other specific contractual obligation that would prevent participation in the EDRP.

3.5. Requirements for Curtailment Customers with Local Generation

Owners of on-site and emergency generators including, but not limited to hospitals, data centers, office buildings, warehouses and industrial locations are eligible to participate in the EDRP. Local Generation will serve all or part of what otherwise would be NYISO load (i.e., the retail end user's specific load delivered from their LSE), thereby reducing the total NYISO load during declared emergencies. The requirements for participation are as follows:

1. Be capable of responding within 2 hours of a request to reduce load.
2. Must have an integrated hourly or permanent recording meter as described in Section 6.1, Metering Requirements.
3. Be capable of receiving notification from a Curtailment Service Provider (CSP).

¹ These generators can be either non-synchronized to the grid or synchronized to the grid.

4. Demand Side Resources that will use on-site generators to reduce load and that have Load Banks for testing purposes must ensure that the Load Bank is not operating during the hours required by the EDRP.

Nothing in the EDRP expands or reduces the rights or obligations a Local Generator may have to buy or sell energy into the wholesale market.

3.6. Compatibility with ICAP Special Case Resources

The EDRP pays for energy during times of emergency, but does not pay for capacity. The NYISO has a separate program called Special Case Resources (SCR) within the Installed Capacity (ICAP) market that pays for capacity and energy. SCR is available to generators and load reduction providers that meet testing, metering and other requirements. While there are no penalties for non-performance as an EDRP provider, the SCR program will reduce future capacity payments if the NYISO calls for operation and the SCR does not perform. In the event that the NYISO activates SCR to reduce their consumption of energy in accordance with the criteria set forth in Section 5, the NYISO may activate the EDRP. SCRs that have registered with the NYISO but not sold their capacity will be added to the list of EDRP participants for that period of time when their capacity is unsold, and will be called with EDRP participants if an EDRP event is activated. See the ICAP Manual located at www.nyiso.com/public/products/icap/index.jsp for more details on SCR.

3.7. Compatibility with LSE-Sponsored Curtailment Programs

There are curtailment programs in New York State both currently in place and under development that are designed to help the local utility with distribution load management. Each program is aimed at enhancing the reliability of the local electric system during time of high usage or outages. The EDRP is designed to be compatible with these programs.

Demand Side Resources may participate in both the EDRP and the Day-Ahead Demand Reduction Program (DADRP) offered by the NYISO. If an EDRP event is called and a Demand Side Resource is participating in both programs, payments will be made as follows:

1. If the Demand Side Resource has not had a demand reduction bid accepted in the Day-Ahead Market for the day of the EDRP event, demand reduction provided as a result of the EDRP event call will be paid in accordance with the rules set forth in this manual.
2. If the Demand Side Resource is responding to the schedule determined from the bid accepted in the Day-Ahead Market, payments will be made in accordance with the DADRP rules up to the demand reduction scheduled in the Day-Ahead Market. Additional verified demand reduction above that scheduled in the Day-Ahead Market will be paid in accordance with the rules set forth in this manual.

3.8.Small Customer Aggregation

1. Aggregations must be at least 0.5 MW for EDRP. The NYISO will establish an up-front means of certifying that the aggregation has an expectation of meeting this requirement. This will be established as part of the approval of the verification methodology; the sampling plan or other measurement methodology will assign an initial (a priori deemed) estimate of the response per site in order to drive the sample size. The aggregation can be comprised of two or more different sampling methods, provided that such a super aggregation was allowed by the NYISO. The MW limit can also be met by combining participants enrolled by different brokers (CSP or LSE) provided that the brokers agree to submit all participants under a single program entity.
2. Aggregations receive an initial settlement of 75% of the deemed response. For any event that results in payments to participants of an aggregation, the NYISO will pay out 75% of the amount determined by applying the curtailment payment rates to the a priori deemed performance level as defined in (1) above in the normal course of settlements for PRL program participants. At the end of the contract term under which the aggregation was approved, and after all required analyses have been conducted, the NYISO will perform a final settlement assessment and pay out or demand payment of the amount determined by that settlement assessment process.
3. Aggregators must accept full responsibility for payments to and penalties levied against the members of the aggregation. The NYISO will require that each member of the aggregation execute an agreement to participate indicating that it accepts the provisions of the ISO program and authorizes the LSE/CSP to act as its broker for the purposes of participation
4. Proposals for measuring aggregation performance can involve one of several methods:
 - a) The deployment of approved whole-premise kW metering devices on a sample of participants
 - b) The deployment of approved end-use device or process kW metering devices on a sample of participants that elect to limit PRL program participation to specified end-use devices or processes.
 - c) Provision for supplying verifiable behavioral actions, equipment operating logs, or other data that is deemed to be sufficiently indicate the load level the customer otherwise would have consumed, but for the PRL program event participation
 - d) Other measurement systems that indicate the load level the customer otherwise would have consumed, but for the PRL program event participation
5. Promulgate provisions that govern applications. A process and procedures will be drawn to govern how applications are made, processed and ruled upon, and to set limits to aggregation projects by zone, provider, program, or any other category. The number of aggregations allowed needs to accommodate all of the utilities plus a reasonable number of CSPs and LSEs. Each proposal for small customer aggregation will be reviewed by the NYISO staff and the Price Responsive Load Working Group, and must be approved by a

majority of the Chairs and Vice-Chairs of the Management Committee and Business Issues Committee and the Chairman of the Price Responsive Load Working Group.

6. The Aggregation broker is responsible for all costs associated with developing and administering the alternative performance methodology. Applications for approval of alternative methodologies must include a explicit description of the methodology and how it would be tracked and administered, accompanied by the specific administration processes required. The NYISO in approving an application will specify the costs associated with administration that the applicant must bear. The aggregation applicant must agree to be responsible for all such costs, including costs incurred by the ISO for developing and administering the alternative methodology. The ISO may, at its discretion, require that some or all of such cost be reimbursed by the applicant upon approval of the methodology, or deduct all costs from payments for curtailments by participants, or a combination of the two methods of cost recovery.
7. One method per end-use premise. End-use electricity customers may subscribe load at a given premise to PRL programs only under a single performance methodology, either the standard method or an approved alternative methodology.
8. Failure to comply with aggregation procedures. The NYISO may, at any time, terminate its agreement with an aggregation broker if it determines that the broker is not fulfilling its obligation under the aggregation agreement. Customers belonging to such aggregation may henceforth participate by signing up under any approved means of participation.

3.9.EDRP Program Evaluation

Curtailment Service Providers must participate in any NYISO sponsored EDRP program evaluations.

4. CSP Registration Procedures

To qualify as a Curtailment Service Provider (CSP) you must be an LSE, Direct Customer, Curtailment Customer Aggregator or Curtailment Program End Use Customer. The registration form is posted on the NYISO web site (www.nyiso.com) and included in Attachment A to this manual. The general requirements for each CSP class are as follows:

4.1. Load Serving Entities (LSE)

For LSE's that are enrolling a retail end user whose load is served by the LSE:

1. Complete Attachment A of this manual. An electronic version of Attachment A is available on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_a2003.doc
2. Register each Demand Side Resource with the NYISO after signing a contract using the EDRP Certification form provided in Attachment B of this manual. Any information on the identity of a Demand Side Resource that is provided to the NYISO will be treated as confidential, and will not be disclosed to third parties without the express permission of the end-use customer, unless aggregated or otherwise presented in such a way as to preserve confidentiality. An electronic version of Attachment B is available on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_b2004.doc
3. By submitting the EDRP Certification Form, the LSE confirms that the load to be reduced is not under any specific contractual obligation that would prevent participation in the EDRP.
4. The EDRP participant registration is deemed approved 30 calendar days after LSE submission of Attachment B for each retail end user unless the NYISO contacts the LSE via phone or e-mail to the contrary.

For LSE's that are enrolling a retail end user whose load is served by a different LSE:

1. Complete Attachment A of this manual.
2. Register each Demand Side Resource with the NYISO after signing a contract using the EDRP Certification form provided in Attachment B of this manual. Any information on the identity of a Demand Side Resource that is provided to the NYISO will be treated as confidential, and will not be disclosed to third parties without the express permission of the end-use customer, unless aggregated or otherwise presented in such a way as to preserve confidentiality.

3. After receipt of the EDRP Certification Form, the NYISO will forward the registration to the appropriate LSE and Electric Distribution Company to confirm that the load to be reduced is not under any specific contractual obligation that would prevent participation in the EDRP.
4. The EDRP participant registration is deemed approved in 30 calendar days after notification is provided to the LSE unless the NYISO contacts the LSE via phone or e-mail to the contrary.

4.2. Direct Customers

Direct Customers of the NYISO should fill out Attachment A and one copy of Attachment B. An electronic version of Attachment A is available on the NYISO website at:

http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_a2003.doc

An electronic version of Attachment B is available on the NYISO website at:

http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_b2004.doc

4.3. Curtailment Customer Aggregators

Curtailment Customer Aggregators are companies that work with owners of generation and load reduction to make it easier to participate in the NYISO Emergency Demand Response program. To register as a Curtailment Customer Aggregator, you must become at least a NYISO Limited Customer. If you are applying for NYISO Limited Customer status as a Curtailment Customer Aggregator and will only be a seller to the NYISO:

1. Complete Attachment A of this manual. An electronic version of Attachment A is available on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_a2003.doc
2. Complete Sections A, B, F, G, H, J and K of the NYISO Registration Packet, available at the NYISO website.
3. Sign the Market Services Tariff.
4. Register each Demand Side Resource with the NYISO after signing a contract using the EDRP Certification form provided in Attachment B of this manual. Any information on the identity of a Demand Side Resource that is provided to the NYISO will be treated as confidential, and will not be disclosed to third parties without the express permission of the end-use customer, unless aggregated or otherwise presented in such a way as to preserve confidentiality. An electronic version of Attachment B is available on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_b2004.doc

5. After receipt of the EDRP Certification Form, the NYISO will forward the registration to the appropriate LSE and Electric Distribution Company to confirm that the load to be reduced is not under any specific contractual obligation that would prevent participation in the EDRP.
6. The EDRP participant registration is deemed approved in 30 calendar days after notification is provided to the LSE unless the NYISO contacts the Curtailment Customer Aggregator via phone or e-mail to the contrary.

The application process can take up to 30 days.

4.4.Curtailment Program End Use Customer (EUC)

An EUC is any Local Generation owner or retail end user capable of interrupting load that can reduce at least 100kW in a zone and wants to participate in the EDRP directly with the NYISO.

If you are applying for NYISO Limited Customer status as an EUC and will only be a seller to the NYISO:

1. Complete Attachment A of this manual. An electronic version of Attachment A is available on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_a2003.doc
2. Complete Sections A, B, F, G, H, J and K of the NYISO Registration Packet, available at the NYISO website.
3. Sign the Market Services Tariff.
4. Register each Demand Side Resource with the NYISO after signing a contract using the EDRP Certification form provided in Attachment B of this manual. An electronic version of Attachment B is available on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/edrp_att_b2004.doc
5. After receipt of the EDRP Certification Form, the NYISO will forward the registration to the appropriate LSE and Electric Distribution Company to confirm that the load to be reduced is not under any specific contractual obligation that would prevent participation in the EDRP.
6. The EDRP participant registration is deemed approved in 30 calendar days after notification is provided to the LSE unless the NYISO contacts the EUC via phone or e-mail to the contrary.

The application process can take up to 30 days.

5. Operating Mechanism / Implementation

5.1. When Will the Program be Called?

The EDRP is limited to when called by the NYISO as a part of the In-day Peak Hour Forecast response to an Operating Reserve Peak Forecast Shortage as defined in [3]. The EDRP may be called in conjunction with Special Case Resources.

The NYISO will invoke the EDRP as one of its emergency procedures in conjunction with the In-day Peak Hour Forecast response to an Operating Reserve Peak Forecast Shortage, as defined in [3], or in response to the Major Emergency state as defined in [4]. Day-ahead notice of a potential operating reserve shortage shall be provided to CSPs when possible. The program is intended to support the New York State power system during emergency periods and the NYISO reserves the right to use its discretion in calling upon EDRP resources to relieve system or zonal emergencies.

The NYISO will declare an Alert State, or Major Emergency for real-time shortage of Operating Reserve, and activate all available in-state generating resources to re-establish the Operating Reserve. If required levels of real-time Operating Reserves cannot be re-established, the NYISO will utilize the EDRP to re-establish real-time Operating Reserves.

5.2. NYISO Protocol for Local Generator Participation

This section describes the circumstances under which state agencies, state authorities, regulated utilities, and non-regulated CSPs may contract with customers who agree to reduce demand on the electricity grid by offloading all or a portion of their own power needs through the operation of emergency generators.

This protocol was agreed upon by the New York Public Service Commission (PSC), New York Department of Environmental Conservation (DEC), New York Energy Research and Development Agency (NYSERDA), New York Power Authority (NYPA), Long Island Power Authority (LIPA), and the NYISO.

The terms and conditions contained in this protocol are intended to be incorporated into utility demand reduction programs regulated by the PSC and are to be made preconditions to participation in the Emergency Demand Response Program (EDRP) by the NYISO.

5.2.1. Program Limitations

Self-generation customers participating in the program will be activated only by the NYISO emergency demand response program, or the transmission owner (TO) in the event of a localized distribution emergency.

Self generation operated in response to either an EDRP or a TO call shall be limited to no more than 200 hours annually. Program participants, not the NYISO, are responsible for

ensuring compliance with the 200 hour maximum operation requirement and will report to the NYISO all instances in which self generation is activated in response to a TO call and the duration of such activations.

Wherever supplies are available for delivery, program participants utilizing diesel fueled emergency generators will use ultra-low sulfur diesel fuel in generators that will be activated in response to a call, as well as for testing purposes. Program participants, not the NYISO, are responsible for ensuring compliance with the ultra-low sulfur fuel requirement. This fuel requirement applies to all tank fills made during the calendar year in which the customer has contracted to participate in the program. NYSERDA will make the determination as to when supplies are available for purposes of this guideline.

Where a supply of ultra-low sulfur fuel is not available for delivery and a state agency is the project sponsor, the participating state agency will mitigate the use of regular diesel fuel by purchasing ultra-low sulfur fuel for displacement of regular diesel fuel at a level that is no less than three times the amount of regular diesel fuel that would be expected to have been consumed by generators participating in its emergency self-generation program.

In addition to the above mitigation measures, the program will be limited to the following:

- a) Model year 1995 or newer generators; or
- b) Model 1994 and older generators must demonstrate, either by generator-specific manufacturer's data or through emissions testing, that NO_x emissions do not exceed 35 pounds per megawatt-hour (lb/MWh). Emissions testing methods for "test and tune" purposes should be conducted consistent with industry-established protocols (such as the American Society of Testing and Materials [ASTM] D6522-00) and applicable DEC regulations.

Program participants, not the NYISO, are responsible for ensuring compliance with the emissions testing requirements for model 1994 and older generators.

5.2.2. Reimbursement of Expenses

NYSERDA will reimburse System Benefits Charge (SBC) eligible customers within the Consolidated Edison service territory a portion of the qualifying costs for expenses involved in preparing for participation in the program. For all non-SBC eligible customers, expenses will be reimbursed by the participating state agency or authority as provided for in the respective demand reduction program.

Eligible expenses include; testing and tuning of emergency generators, advanced metering, communications and control devices, rewiring circuits, installation of transfer switchgear, environmental permitting, selective catalytic reduction technologies, stack modification, operational improvements, cost differential (if any) for use of ultra-low sulfur fuel, and implementation of advanced dual-fuel options.

5.3.Notification Procedures

When the NYISO activates the Emergency Demand Response Program (EDRP), a specific set of messages will be sent to Curtailment Service Providers (CSPs). A CSP will be asked to take certain actions in response to NYISO notification. This section describes the contact procedures and actions that will be requested of CSPs.

The time frame for advisory and activation notices will be a function of the degree of warning the NYISO has in identifying and responding to operating reserve shortages / major emergencies.

Notification from the NYISO will always take place via two communications media:

- Burst e-mail messages to all listed CSP email addresses.
- Automated phone call to each CSP's main contact phone number.

After receiving an EDRP notification, the CSP should take the following steps:

1. The CSP should assess whether or not he/she has resources that can respond, and the MW level of response by zone.
2. Click on the web link within the notification email that was sent. This will provide a response page. Once the available MW by zone information is entered and submitted, it will automatically be tallied at the NYISO with other CSP responses.
3. If for some reason this link is unavailable, the CSP should contact NYISO Market Services at 518-356-6060 with the information.

If the NYISO does not receive the automated response in a reasonable amount of time, they will call additional CSP cell phone and pager numbers in an attempt to make a connection. In this case, NYISO staff will identify themselves by name and indicate that the NYISO has activated the EDRP program, followed by the specific requests below.

5.3.1. Day-Ahead Advisory

EDRP resources may be needed tomorrow between the hours hh:mm and hh:mm. Zones included in this notification are: A,B,C,D,E,F,G,H,I,J,K,. Please reply within one hour indicating:

- If you expect to have resources participating,
- and MWs expected.

Day-ahead notice does not constitute activation of the EDRP program, and is only meant to be advisory.

5.3.2. In-Day Advisory

EDRP resources may be needed later today between the hours hh:mm and hh:mm. Zones included in this notification are: A,B,C,D,E,F,G,H,I,J,K . Please reply within one hour indicating:

- If you expect to have resources participating,
- and MWs expected.

In-day notice does not constitute activation of the EDRP program, and is only meant to be advisory.

5.3.3. Activating EDRP – 2-Hour Notification

EDRP resources are needed from hh:mm and hh:mm. Zones included in this notification are: A,B,C,D,E,F,G,H,I,J,K

5.3.4. Activating EDRP – Immediate Notice

EDRP resources that can respond immediately are needed from hh:mm and hh:mm. Zones included in this notification are: A,B,C,D,E,F,G,H,I,J,K

5.3.5. Extending an EDRP Event

The call for EDRP resources will be extended until hh:mm. Zones included in this notification are: A,B,C,D,E,F,G,H,I,J,K

5.3.6. Terminating an EDRP Event

As of hh:mm EDRP resources are no longer needed to respond. Zones included in this notification are: A,B,C,D,E,F,G,H,I,J,K

6. Metering, Verification, Billing and Settlement

6.1. Metering Requirements

CSPs must use certified Meter Service Providers (MSP) or Transmission Owners to install and Meter Data Service Providers (MDSP) to read revenue-grade interval meters. Installation of any devices directly connected to the revenue meter, such as totalizers, must be performed by certified MSPs. Non-revenue-grade meters meeting the 2% accuracy requirement as defined in Section 6.1.1 may be installed by CSPs as long as they are certified by a Professional Engineer as meeting ANSI C12 standards and are periodically tested and calibrated in accordance with the standards applicable to MSPs. CSPs must use a certified MDSP to read such meters. Transmission Owner or MDSP certification is required to read the revenue grade meter on load. Acceptable interval metering for Demand Side Resources for load reduction or local generation is described below in Section 6.1.1.

6.1.1. Metering Device Requirements

Meters installed under the 2001 EDRP rules prior to March 20, 2002 can be used as the source of EDRP event reporting data.

Hourly interval metering data is required to validate performance. Demand Side Resources may use non-revenue interval metering devices with an overall accuracy of $\pm 2\%$ as the source of performance data. For each non-revenue interval meter design used, the CSP will submit certification from the meter manufacturer that the model in question meets the $\pm 2\%$ accuracy threshold, recognizing errors in:

- Current measurement
- Voltage measurement
- A/D conversion
- Calibration

Such meters would be periodically tested and calibrated in accordance with the standards applicable to MSPs and MDSPs.

Where a revenue meter exists, losses in secondary/service circuits between the revenue meter and the non-revenue interval meter may be compensated for so as to bring the reading within $\pm 2\%$ of the revenue meter. The CSP must demonstrate compliance through comparison of the revenue and non-revenue meters, or show calculation of losses between the revenue and non-revenue meters.

6.1.2. Metering Configuration Requirements

Premises participating in the EDRP shall subscribe under one of three configurations: Local Generation only, load only, or local generation and load. Integrated hourly metering devices shall be required as follows:

1. When a premise subscribes only the Local Generation, an hourly interval meter can be installed to measure the generator's output, or interval metering of the total net load can be used.
2. When a premise subscribes only the load, the hourly interval meter shall be installed to meter the entire facility or for totalized load, an hourly interval meter is required for each participating load.
3. When a premise subscribes both the Local Generation and load, metering can be configured so as to measure only the load or combined load and generation.

Figure 6.1 illustrates examples of acceptable configurations.

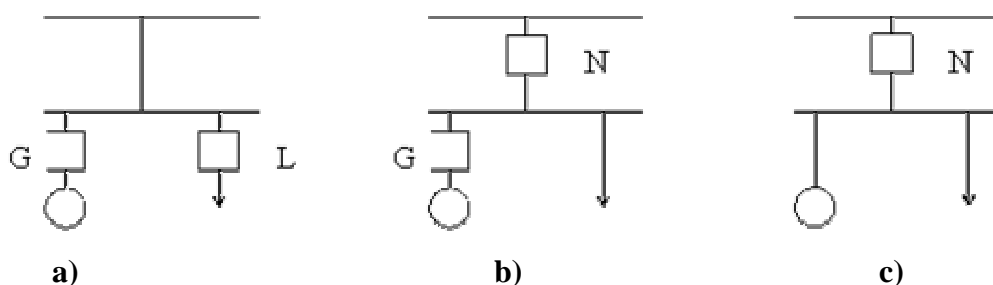


Figure 6.1 – Metering Configurations

6.2. Calculation of Customer Baseline

6.2.1. Historical Operating Data

CSPs shall be required to provide historical operating data for each load or on-site generator upon registration for participation in the EDRP. It is the responsibility of the CSP to provide the CBL calculation to the NYISO and ensure that calculations are complete and accurate. These requirements may be met by:

1. For Local Generation that is participating in the EDRP the generator meter ID and MSP ID certifying meter installation must be supplied on the End-Use registration form in Attachment B;
2. For loads with existing interval meters

Provide a minimum of 1 complete billing period of hourly interval data immediately preceding the first Capability Period the load will participate in; or

3. For totalized loads with existing interval meters

For totalized loads, provide hourly interval data for a minimum of 1 complete billing period of hourly interval data for all participating loads at the premise; or

4. For newly installed load interval meters

For newly installed interval meters, provide the prior three months summary of monthly MWh consumption and demand values, if available.

6.2.2. Baseline Calculation Method (Interruptible Load or Both Local Generation and Interruptible Load)

I. The Average Day CBL

A. Average Day CBLs for Weekdays

Step 1. Establish the CBL Window. Establish a set of days that will serve as representative of participant's typical usage.

A.1.a Determine the participant's peak hourly load over the past 30 days or the period covered by the load data file, whichever is smaller. This value becomes the initial seed value for the average event period usage level.

A.1.b Beginning with the weekday that is two days prior to the event:

A.1.b.1 Eliminate any holidays as specified by the NYISO.

A.1.b.2 Eliminate any days where the NYISO declared an EDRP event for which the participant was eligible for payment for a curtailment.

A.1.b.3 Eliminate any days in which the participant's DADRP curtailment bid was accepted in the DAM, whether or not the participant actually curtailed.

A.1.b.4 Create the average daily event period usage for that day, defined as the simple average of the participant's actual usage over the hours that define the event for which the CBL is being developed.

A.1.b.5 Eliminate low usage days. If the average daily event period usage is less than 25% of the average event period usage level, eliminate that day.

A.1.b.6 If the day has not been eliminated, update the average event period usage level by including the average daily event period usage for this day. If this is the first day added to the CBL Window, replace the average event period usage level (which was the initial seed value) with the average daily event period usage. Add this day to the CBL Window.

A.1.c Move back one day and loop to step A.1.b.1

A.1.d Final Weekday CBL Window must contain 10 weekdays days.

Step 2. Establish the CBL Basis. Identify the five days from the 10-day CBL Window to be used to develop CBL values for each hour of the event.

A.2.a Order the 10 days in the CBL Window according to their average daily event period usage level, and eliminate the five days with the lowest average daily event period usage.

A.2.b The remaining five days constitute the CBL Basis.

Step 3. Calculate Average Day CBL values for the event.

A.3.a For each hour of the event, the CBL is the average of the usage in that hour in the five days that comprise the CBL basis.

B. Average Day CBL for Weekends

Step 1. Establish the CBL Window

B.1.a The CBL Window is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for Holidays or event days.

Step 2. Establish the CBL Basis.

B.2.a Calculate the average daily event period usage value for each of the three days in the CBL Window.

B.2.b Order the three days according to their average daily event period usage level.

B.2.c Eliminate the day with the lowest average value

B.2.d The Weekend CBL Basis contains 2 days.

Step 3. Calculate Weekend Average Day CBL values for the event.

B.3.a For each hour of the event, the CBL value is average of usage in that hour in the two days that comprise the CBL basis.

II. Elective Weather-Sensitive CBL formulation

Step 1. Calculate the Average Day CBL values for each hour of the event period described in (I) above.

Step 2. Calculate the Event Final Adjustment Factor. This factor is applied to each of the individual hourly values of the Average Day CBL.

A. Calculate the Adjustment Basis Average CBL

2.A.1 Establish the adjustment period, the two-hour period beginning with the start of the hour that is four hours prior to the

commencement of the event through the end of the hour three hours prior to the event.

2.A.2 Calculate the Adjustment Basis Average CBL.

2.A.2.a Apply the Average Day CBL formula as described in I. Average Day CBL (page 2), to the adjustment period hours as though it were an event period two hours in duration, but using the five days selected for use in the Average CBL Basis (i.e., average the ten hours).

2.A.2.b Calculate the average of the two usage values derived in 2.A.2.a, which is the Adjustment Basis Average CBL.

B. Calculate the Adjustment Basis Average Usage

2.B.1 The adjustment basis average usage is the simple average of the participant's usage over the two-hour adjustment period on the event day.

C. Calculate the gross adjustment factor

2.C.1 The gross adjustment factor is equal to the Adjustment Basis Average Usage divided by the Adjustment Basis Average CBL

D. Determine the Final adjustment factor. The final adjustment factor is as follows:

2.D.1 If the gross adjustment factor is greater than 1.00, then the final adjustment factor is the smaller of the gross adjustment factor or 1.20

2.D.2 If the gross adjustment factor is less than 1.00, the final adjustment factors are the greater of the gross adjustment factor or .80.

2.D.3 If the gross adjustment factor is equal to 1.00, the final adjustment factor is equal to the gross adjustment factor.

Step 3. Calculate the Adjusted CBL values.

A. The Event Adjusted CBL value for each hour of an event is the product of the Final Adjustment Factor and the Average CBL value for that hour.

III. Selecting a CBL method

A.1 The participant selects the CBL formula when it registers, or is registered by its LSE or CSP, with the NYISO for program participation. The choice of CBL becomes effective when the NYISO accepts the registration.

A.2 At the initial registration to the PRL program, participants may elect either the Average Day CBL or the Adjusted CBL formula.

A.3 At the time that the new Adjustable CBL formulation becomes effective, registered participants in the PRL program may apply to change to the adjusted formula CBL method beginning thirty (30) days after such notification or to become effective May 1, 2002.

A.4 Participants may switch CBL methods by making application to the NYISO. For such a change applicable to the summer capability period (May 1 – October 31), the application must be submitted to NYISO by April 1. For a change applicable to the winter capability period (November 1 – April 30), the application must be submitted to NYISO by October 1. The change in the CBL formula becomes effective at the beginning of the next capability period after the NYISO accepts the application.

6.2.3. Example Customer Baseline Calculation

As an example, Assume a 4-hour EDRP event was called from 12 noon to 4 pm; notice was sent out at 10 a.m.. The past 10 days MWh consumption for similar hours, along with the four hours prior to event initiation, was:

Time	Day n-2	Day n-3	Day n-4	Day n-5	Day n-6	Day n-7	Day n-8	Day n-9	Day n-10	Day n-11
8-9	5	4	4	4	3	6	2	3	3	4
9-10	5	3	5	4	4	2	3	3	2	4
10-11	7	5	6	5	5	5	4	4	4	5
11-12	8	6	8	6	7	8	5	6	6	7
12-1	10	8	9	7	10	12	5	7	7	8
1-2	11	6	12	8	11	8	8	8	6	10
2-3	7	9	9	6	9	9	8	8	6	9
3-4	5	6	7	6	7	7	6	7	5	6

Steps 1 and 2: sum the MWh for the hours 12-4 each day and select the 5 highest totals:

	MWh n-2	MWh n-3	MWh n-4	MWh n-5	MWh n-6	MWh n-7	MWh n-8	MWh n-9	MWh n-10	MWh n-11
	33	29	37	27	37	36	27	30	24	33
Selected?	Y		Y		Y	Y				Y

Step 3: Calculate the CBL for each hour using the five highest days selected:

Time	Day n-2	Day n-4	Day n-6	Day n-7	Day n-11	CBL
12-1	10	9	10	12	8	9.8
1-2	11	12	11	8	10	10.4
2-3	7	9	9	9	9	8.6
3-4	5	7	7	7	6	6.4

The CBL in the right-hand column above would be the non-weather –adjusted value. If this customer was signed up with the weather-sensitive calculation option, the CBL would be adjusted upward or downward based on the actual usage in the two hours prior to event notification. In this example, the Adjustment Basis Average CBL will be the average of the MWh for hours beginning 8 and 9 over the five days chosen for the CBL:

Time	Day n-2	Day n-4	Day n-6	Day n-7	Day n-11	
8-9	5	4	3	6	4	
9-10	5	5	4	2	4	
Average						4.2

On the day of the event (day n), assume the actual metered load consumption is as shown in the following table:

Hour Beginning	8	9	10	11	12	1	2	3
MWh	4	5	4	3	2	3	3	4

In this case, the Adjustment Basis Average Usage is the average of the MWh in hours 8 and 9, or 4.5 MWh. The Gross Adjustment Factor is the ratio of the Adjustment Basis Average Usage to the Adjustment Basis Average CBL, 4.5/4.2 or 1.07. The CBL will therefore be adjusted upward by 1.07 – the following table shows the resulting new CBL and the computed load reduction for the four-hour event period.

Hour Beginning	12	1	2	3
Load (MWh)	2	3	3	4
CBL (MWh)	10.5	11.1	9.2	6.8
Load Reduction (MWh)	8.5	8.1	6.2	2.8

It is important to note that if the actual usage in the two hours prior to notification was *lower* than the Adjustment Basis Average CBL, the CBL curve would have been shifted *downward* and would result in load reduction performance that was lower than would have been determined using the Average Day CBL (without weather adjustment).

6.2.4. Baseline Calculation Method (Local Generation Only)

For Local Generation using separate metering, a similar CBL calculation is used to eliminate any base load portion of generation from the actual performance during the event.

1. Calculate the Local Generation during similar hours over the past 10 weekdays, beginning two days prior to the curtailment event and excluding days where curtailment due to participation in the EDRP or the Day-Ahead programs occurred.
2. $MWh(k) = \text{sum}(h(i) \dots h(j))$ for each day $k = d(n-2) \dots d(n-11)$
3. Select the 5 lowest values of $MWh(k)$ and use those days $d(l)$, $l = 1 \dots 5$ to calculate the CBL.

4. Calculate the CBL for each hour $h(i)$ as the average of the five $h(i)$ values for days $d(l)$, $l = 1 \dots 5$.

6.3. Performance Measurements and Compliance

6.3.1. Performance

Performance for metering configurations where load reduction is included is measured as the difference between the Customer Baseline and the actual metered usage by hour during the event. The Customer Baseline type used for computing performance shall be the same day-type as the day-type of the EDRP event. For Local Generation, the generator output as metered will be used for performance as defined below. The equations are given for the alternative metering configurations shown in Figure 6.1.

Load Only Configuration

For premises subscribing only the load, performance for each hour shall be calculated as:

$$P_h = (CB-xx)_h - AL_h \text{ (Meter configuration 6.1a)}$$

$$P_h = (CB-xx)_h - AN_h \text{ (Meter configuration 6.1b and 6.1c)}$$

Where P_h = performance for the hour

$CB-xx_h$ = Customer Baseline day-type (weekday – CB-WD, Saturday CB-SA, or Sunday-CB-SU) for the hour as calculated using the simple average method described above in Section 6.2.2

AL_h = actual load for the hour using meter L in configuration 6.1a

AN_h = actual load for the hour using meter N in configuration 6.1b and 6.1c

Local Generation Only Configuration

For premises subscribing only Local Generation, performance for each hour shall be calculated as:

$$P_h = OG_h - (GCB-xx)_h$$

Where P_h = performance for the hour

OG_h = Metered On-site generator output for the hour using meter G in either configuration 6.1a or 6.1b

$GCB-xx_h$ = Customer Baseline day-type (weekday – GCB-WD, Saturday – GCB-SA or Sunday GCB-SU) for the hour h as determined for Local Generation described in Section 6.2.3.

Load and Local Generation Configuration

For premises subscribing both the Local Generation and the load and participating in the same EDRP event, performance for each hour shall be the net of Local Generation and load as defined below:

$$P_h = [OG_h - (GCB-xx)_h] + [(CB-xx)_h - AL_h] \text{ (Meter configuration 6.1a)}$$

$$P_h = (CB-xx)_h - AN_h \text{ (Meter configuration 6.1b and 6.1c)}$$

Where P_h = performance for the hour

OG_h = Metered On-site generator output for the hour

$GCB-xx_h$ = Customer Baseline day-type (weekday – GCB-WD, Saturday – GCB-SA or Sunday GCB-SU) for the hour h as determined for Local Generation described in Section 6.2.3.

$CB-xx_h$ = Customer Baseline day-type (weekday – CB-WD, Saturday CB-SA, or Sunday-CB-SU) for the hour as calculated using the simple average method described above in Section 6.2.2

AL_h = actual load for the hour using meter L in configuration 6.1a

AN_h = actual load for the hour using meter N in configuration 6.1b and 6.1c

6.3.2. Compliance

Initial Compliance

Initial Compliance (IC) is measured as the first event hour in which performance in the hour is greater than zero (actual load is less than baseline).

Final Compliance (Restored Load)

Final Compliance (FC) is measured as the last hour in which performance is greater than zero, or the last hour of the EDRP event, whichever is earlier.

Compliance Period

The Compliance Period includes every hour in the EDRP event in which performance was greater than zero, beginning with the Initial Compliance hour and ending with the Final Compliance hour or the end of the EDRP event, whichever is earlier.

Table 6.3.2 illustrates examples of Initial Compliance and Final Compliance for an event starting at noon and lasting for five hours.

Table 6.3.2: Examples of Performance during an EDRP Event

			NYISO EDRP Event						
	10 - 11AM	11 - 12 AM	12 - 1 PM	1 - 2 PM	2 - 3 PM	3 - 4 PM	4 - 5 PM	5 - 6 PM	6 - 7 PM
Customer 1									
BL	125	125	125	125	150	150	150	150	125
AL	130	120	110	100	100	125	150	160	140
Performance		5	15	25	50	25	0		
			IC	P	P	FC			
Compliance Period									
Customer 2									
BL	200	200	250	250	250	200	200	200	200
AL	200	200	250	225	200	175	175	175	200
Performance			0	25	50	25	25	25	
				IC	P	P	FC		
Compliance Period									
Customer 3									
BL	300	300	350	350	350	300	300	300	300
AL	300	300	350	325	325	325	275	275	300
Performance			0	25	25	0	25	25	
				IC	P	P	FC		
Compliance Period									
Legend	BL = Baseline		IC = Initial Compliance				P = Performance		
	AL = Actual Load		FC = Final Compliance						

6.4. Settlement Procedures

CSPs shall provide verification of load reduced within 45 days of the emergency by providing interval billing meter data to the NYISO. Verification of load reduction not received by the NYISO within 45 days of the emergency may not be compensated pursuant to this program. All load reduction is subject to NYISO audit, and market monitoring unit review. The NYISO will be responsible for settlement payment.

6.4.1. Data Submission

A CSP will submit the response(s) of the Demand Side Resource(s) that participated in the emergency event to the NYISO within 45 days of the event being called. Failure to so provide such data will result in a CSP not receiving payment for its participation in the

EDRP. The ISO maintains the ability to subsequently review the data through the Market Monitoring Unit.

6.4.2. EDRP Reporting

In establishing the reporting requirements for this program, information regarding the identity of Demand Side Resources participating in this program shall be treated as confidential by the NYISO, and will not be shared with third parties.

The Event Participation Report (found in Attachment C) or the equivalent .csv file format described in Attachment D shall be required for reporting performance in an EDRP event. Either version is intended to be completed for each load or Local Generation resource participating in a CSP's EDRP program.

6.4.3. Demand Side Resource Reduction Data

A CSP will submit response(s) of the Demand Side Resource(s) or Local Generation that participated in the emergency event aggregated by hour and by zone.

- a) Where the CSP's Demand Side Resource response is based on individual end use loads alone or for premises with both participating load and Local Generation, the CSP is required to provide metered hourly interval data for each load and the Local Generation for the entire billing period in which the EDRP event occurred.
- b) Where the CSP's Demand Side Resource response is provided only from Local Generation, the CSP shall provide interval data for the 24-hour period ending midnight of the day of the EDRP event.
- c) If the EDRP event occurs less than 10 days into a billing period for any end-use load or premises with participating load and Local Generation, the prior month's bill period data must also be provided for that end-use load and Local Generation.

6.4.4. Data Format

Individual end-use or Local Generation hourly interval load data for the billing period in which an EDRP event occurred shall be submitted in electronic form to the NYISO in one of the following formats:

- a) Excel spreadsheet format (Event Participation Summary Report) as described in Attachment C. A template can be found on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/event_participation_form_050102.xls
- b) Comma-Separated Variable format as described in Attachment D. A template can be found on the NYISO website at:
http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response/end%20use.csv

CSPs should submit one file per day containing meter and CBL data for all participants.

Electronic data files may be submitted via one of the following methods:

- a) e-mail to: abreidenbaugh@nyiso.com or edrp-scr@nyiso.com;

b) CD-ROM or other electronic medium.

6.4.5. Calculation of Payments

For interruptible load resources and Local Generation resources whose MW performance in any hour is at or below the peak load consumption of the resource, the NYISO will calculate the payment to CSPs using the following formula:

If the Emergency is four hours or longer:

$$P_h * \max(\$500, \text{LBMP}_{\text{RT Zonal}, h}) \text{ for each hour } h \text{ of the emergency}$$

If the Emergency is less than four hours:

$$P_h * \max(\$500, \text{LBMP}_{\text{RT Zonal}, h}) \text{ for each of the first two hours } h \text{ of the emergency, or for the duration of the emergency, whichever is greater (a minimum two-hour payment for performance)}$$

+

$$P_h * \text{LBMP}_{\text{RT Zonal}, h} \text{ for the remainder of the four-hour period.}$$

P_h = performance during hour h as defined in Section 6.3.1

$\text{LBMP}_{\text{RT Zonal}, h}$ = Real-time zonal LBMP for hour h

For Local Generation Resources whose MW performance in any hour exceeds the peak load consumption of that resource, the NYISO will pay the resource for that portion of the energy produced above peak load consumption (G_h) as follows:

$$G_h * \text{LBMP}_{\text{RT Zonal}, h}$$

Where G_h is the performance of the Local Generation Resource in excess of the hourly peak load consumption.

In most cases, NYISO Operators will specify a start and end time for the curtailment event. This information will be provided at least two hours prior to the starting time. Demand Side Resources will be expected to begin curtailment at the specified starting time. Participants who respond to a notice will be paid for performance in accordance with the above formulas for either the length of the curtailment period or four hours, whichever

is greater. The four-hour minimum payment period will begin at the time when the NYISO directs the retail end user to reduce load or, if load reduction is requested as soon as possible, when the retail end user begins his load reduction response.

CSPs that fail to provide load reduction when requested by the NYISO incur no penalties for failure to respond to the EDRP.

6.4.6. Distribution of Payments

Payments will be made by the NYISO directly to the CSPs.

Payments will be made by the ISO as part of the monthly bill generated by the ISO. The bill will record the payment as an emergency energy payment and will break down the payment by total MWh by zone, hourly zonal price, and total payment. These payments will be made to the CSPs for all emergencies which have had data submitted and approved in accordance with the data policy prior to the end of the month.

6.4.7. Verification, Errors and Fraud

All load reduction data is subject to audit by the NYISO and its Market Monitoring unit. Disputes concerning erroneous payments shall be resolved through the ISO's Dispute Resolution Procedures.

If the ISO in its review of the CSP's account determines the CSP or one of its customers has committed fraud to extract EDRP payments from the ISO, the ISO will have the right to ban the CSP or the CSP's customer from the EDRP as well as pursue all of the ISO's legal rights, at its sole discretion.

6.5. Assessment of Program Charges

6.5.1. Objectives of Cost Allocation

The costs for the program will equal the sum of all payments to customers calculated and paid out under Section 6.4.5.

In general, cost allocations should be designed with fairness and market efficiency (i.e., sending the correct price signals) in mind. If it can be determined that some locations provoke the need for a service and/or benefit from that service, then it is proper (from both a fairness and market efficiency perspective) to charge loads in those locations for the service specifically.

In the case of the EDRP, the cost allocation method should be done on a Zonal rather than statewide (i.e., "all loads - every time") basis so that price signals will be produced that help encourage reliability improvements where reliability needs to be improved.

6.5.2. Causes for EDRP Being Invoked

EDRP will be invoked during situations in which one or both of the following actually occur or are predicted to occur within a specific Zone or set of Zones:

EDRP Condition 1

Internal Load **exceeds** Available (Internal) Generation plus Import Capability

Where Import Capability equals the lesser of Transmission Import Capability for that Zone (or set of Zones) **OR**

Supply Available for Import via that Transmission

EDRP Condition 2

Locational Operating Reserve Requirements **exceed** Available Operating Reserves.

6.5.3. EDRP Cost Allocation

Based upon the objectives for cost allocation and the causes for initiating the EDRP (i.e., Conditions 1 and 2 as defined above), the following cost allocation method will be used:

Costs associated with EDRP will be allocated to all Loads in Zones for which EDRP will directly help to alleviate Conditions 1 and or 2.

The above rule translates into the following table:

Table 6.5.3: Emergency Demand Reduction Program Cost Allocation

Location of Condition 1 and/or 2	EDR Cost Allocation
All or Part of One NYCA Zone (including relief for Local Reliability Rule problems within a Zone as requested by a TO)	All Loads in that Zone (L_z)
Two or More NYCA Zones	All Loads in those Zones (L_{zsum})
All Zones in NYCA	All Loads in NYCA (L_{system})
An External Control Area	The External Control Area ($L_{external}$)

6.5.4. Cost Allocation Formula

The monthly charge for EDRP payments will be recovered from all Transmission Customers, and will be calculated as the product of (A) payments made to Curtailment Service Providers and (B) the ratio of (i) the customer's billing units for the month to (ii) the sum of all billing units during that month.

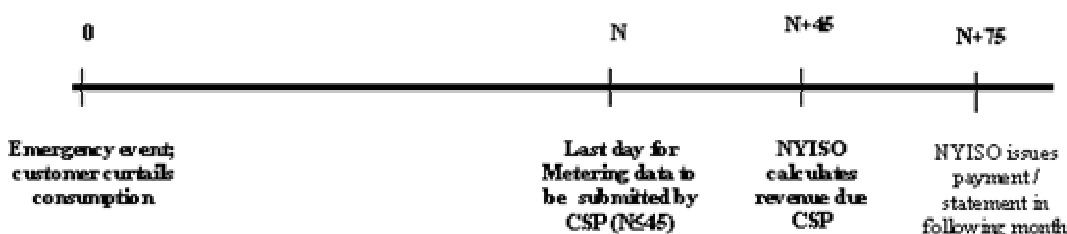
Billing units shall be based on the Actual Energy Withdrawals for all Transmission Service to supply Load in the NYCA, and hourly Energy schedules for all Wheels Throughs and Exports. To the extent that the ISO activates the Emergency Demand Response Program in response to an Emergency or a real-time locational Operating Reserves shortage or a peak forecast of an Operating Reserves shortage in a particular zone or zones, including relief to meet a Local Reliability Rule within a zone as requested by a Transmission Owner, the billing units for such charges will be based on the Actual Energy Withdrawals in the affected zone(s) during the hours in which the Emergency Demand Response Program was activated.

LSEs shall also be required to pay the monthly charges calculated above for Transmission Customers, which the LSE serves as retail access customers.

This charge will appear as a distinct line item on the customer bill. The NYISO will separately provide supporting material that will include the amount of load response for each hour of the emergency.

6.6. Timeline for Settlement

Figure 6.6: Days from Curtailment Event



For the month immediately following the calculation of revenues to be paid to the CSP:

- Approximately on 8th of following month NYISO bills are generated; costs and revenues will be posted to the CSP and LSE Billing Statements
- Approximately on 16th payments are due from the LSEs
- Approximately on 22nd revenues will be due from the ISO to the CSPs

7. References

- [1] Stage 2 ICAP Manual, Dec. 30, 2002 (available on NYISO website at http://www.nyiso.com/services/documents/manuals/pdf/planning_manuals/stage2_icap_manual_12_30_02.pdf)
- [2] Market Administration and Control Area Services Tariff (available on NYISO website at http://www.nyiso.com/public/documents/tariffs/market_services.jsp)
- [3] Section 4.4.1 of the NYISO Emergency Operations Manual (available on NYISO website at http://www.nyiso.com/public/webdocs/manuals/operations/em_op_mnl.pdf)
- [4] Section 3.2 of the NYISO Emergency Operations Manual (available on NYISO website at http://www.nyiso.com/public/webdocs/manuals/operations/em_op_mnl.pdf).

Day-Ahead Demand Response Program Manual

July 2003

1.0 Definitions and Acronyms

Bid - Offer to purchase and/or sell Energy, Demand Reductions, Transmission Congestion Contracts and/or Ancillary Services at a specified price that is duly submitted to the ISO pursuant to ISO Procedures.

Bid Price - The price at which the Supplier offering the Bid is prepared to provide the product or service, or the buyer offering the Bid is willing to pay to receive such product or service.

Bid Production Cost - Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost and Minimum Generation and Start-Up Bid).

Bidder - An entity that bids a Demand Reduction into the Day-Ahead market.

Curtailed Initiation Cost - The fixed payment, separate from a variable Demand Reduction Bid, required by a qualified Demand Reduction Provider in order to cover the cost of reducing demand.

Customer - An entity which has complied with the requirements contained in the ISO Services Tariff, including having signed a Service Agreement, and is qualified to utilize the Market Services and the Control Area Services provided by the ISO under the ISO Services Tariff; provided, however, that a party taking services under the Tariff pursuant to an unsigned Service Agreement filed with the Commission by the ISO shall be deemed a Customer.

Customer Base Load (CBL) – Average hourly energy consumption as calculated in Section 5, used to determine the level of load curtailment provided.

Day-Ahead - Nominally, the twenty-four (24) hour period directly preceding the Dispatch Day, except when this period may be extended by the ISO to accommodate weekends and holidays.

Day-Ahead Zonal LBMP – The price (in \$/MWh) for combined energy, losses, and transmission congestion determined on an hourly basis in the day-ahead electricity market.

Demand Reduction - A quantity of reduced electricity demand from a Demand Side Resource that is bid, produced, purchased and sold over a period of time and measured or calculated in Megawatt hours.

Demand Reduction Incentive Payment - A payment to Demand Reduction Providers that are scheduled to make Day-Ahead Demand Reductions. The payment shall be equal to the product of: (a) the Day-Ahead hourly LBMP at the applicable Demand Reduction bus; and (b) the lesser of the actual hourly Demand Reduction or the Day-Ahead scheduled hourly Demand Reduction in MW.

Demand Reduction Provider - An entity, qualified pursuant to ISO Procedures, that bids Demand Side Resources of at least 1 MW.

Demand Side Resources (DSR) - Resources located in the NYCA that are capable of reducing demand in a responsive, measurable and verifiable manner within time limits, and that are qualified to participate in competitive Energy markets pursuant to this Tariff and the ISO Procedures. Demand Side Resources may reduce demand only by curtailing NYCA Load.

EDRP – Emergency Demand Response Program.

Installed Capacity (ICAP) - A Generator or Load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the New York Control Area for the purpose of ensuring that sufficient energy and capacity are available to meet reliability rules. The Installed Capacity requirements, established by the New York State Reliability Council, include a margin of reserve in accordance with the Reliability Rules.

Load Serving Entity (LSE) – Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail end users located within the NYCA, including NYISO Direct Customers.

Locational Based Marginal Price (LBMP) - The price of energy bought or sold in the LBMP Markets at a specific location or zone.

Meter Service Provider (MSP) - An entity that provides meter services, consisting of the installation, maintenance, testing and removal of meters and related equipment.

Meter Data Service Provider (MDSP) – An entity providing meter data services, consisting of meter reading, meter data translation and customer association, validation, editing and estimation.

Real-Time Zonal LBMP – The price (in \$/MWh) for combined energy, losses, and transmission congestion determined on a roughly five-minute basis in the real-time electricity market.

Remote Metering - Metering equipment which allows for remote collection of metering data.

Special Case Resource - Loads capable of being interrupted upon demand, and distributed generators, rated 100 kW or higher, that are subject to special rules set forth in the NYISO Services Tariff, in order to facilitate their participation in the Installed Capacity market as Installed Capacity Suppliers.

Supplier - A Party that is supplying the Capacity, Demand Reduction, Energy and/or associated Ancillary Services to be made available under the ISO OATT or the ISO Services Tariff, including Generators and Demand Side Resources that satisfy all applicable ISO requirements.

Zone - One of eleven geographical areas located within the NYCA that is bounded by one or more of the fourteen New York State Interfaces. During the implementation of the LBMP Markets, all Loads located within the same Load Zone pay the same Day-Ahead LBMP and the same Real-Time LBMP for Energy purchased in those markets.

2.0 Day-Ahead Demand Reduction Program - Overview

2.1 Administration

Beginning July 1, 2003, DADRP will be open to both host Load Serving Entities (LSEs) and Demand Reduction Providers (DRPs) including non-host LSEs.

2.2 Bidding

The NYISO will accept Demand Reduction Bids wherein an LSE/DRP can bid on behalf of a Demand Side Resource for a specific MW curtailment (in minimum increments of 1 MW by Bus) in contiguous "strips" of one or more hours. A single bid will be limited to a strip of no more than eight hours. The Demand Reduction Bid would include the Day-Ahead LBMP above which the Load would not consume, and could also include a Curtailment Initiation Cost.

Bidders are required to submit an average energy bid of at least \$50/MWh to be eligible for scheduling in the Day-Ahead market. Bids submitted below the floor price will be rejected from the MIS.

2.3 SCUC Objective Function

The objective function for SCUC will be to eliminate Demand Reduction Bids from Day-Ahead Bid Load when the total Bid Production Cost over the 24 hour Dispatch Day will be reduced compared to serving that Load, including consideration of paying the Demand Reduction Bid and any bid Curtailment Initiation Costs. Thus, curtailments will not be scheduled unless they reduced total Day-Ahead production costs.

2.4 Setting LBMP

Demand Reduction Bids can set Day-Ahead LBMP just as a comparably bid Generator. If no Supply Bids remain and a Demand Reduction Bid is the last resource chosen, NYISO's Market Monitoring and Performance Unit will reserve the day-ahead price for those hours and subsequently determine if the LBMP as set by the Demand Side Resource is appropriate or if a supply-side resource should set LBMP.

2.5 Customer Baseline Load

A Demand Side Resource's Customer Baseline Load (CBL) will provide a reference to verify its compliance with a scheduled curtailment. The CBL for DSRs bidding curtailable load is based upon the five highest energy consumption levels in comparable time periods over the past ten days, beginning two days prior to the day for which the load reduction is bid. More information can be found in Section 5, Calculating Customer Baseline Load for DADRP.

2.6 Determining the Amount of Load Reduction

For DSRs bidding curtailable load, the amount of actual Real-Time curtailment determined will be equal to its CBL less its actual Real-Time consumption during the specified curtailment.

2.7 Payments

1. An LSE/DRP with a Demand Side Resource that curtails Load (as scheduled Day-Ahead by the NYISO) will be charged for its full Demand Reduction Bid at Day-Ahead LBMP.
2. An LSE/DRP with a Demand Side Resource that curtails Load (as scheduled Day-Ahead by the NYISO) will be paid by the NYISO the Day-Ahead LBMP. If needed, a supplemental payment will be made to allow full recovery of the Curtailment Initiation Cost.
3. In addition, an LSE/DRP with a Demand Side Resource that curtails Load (as scheduled Day-Ahead by the NYISO) will receive a rebate from the NYISO as an Incentive for the curtailed amount of Load priced at Day-Ahead LBMP.

2.8 Payment Sharing

The payments under the Day-Ahead Demand Reduction Program will be made by the NYISO to the LSE/DRP. The portion that will be transferred from the LSE/DRP to the Demand Side Resource is outside the scope of the NYISO, and must be arranged between the LSP/DRP and the Demand Side Resource. Each Investor Owned Utility (IOU) Transmission Owner (excluding LIPA and NYPA) shall designate in its retail tariff the portion of the total payments that it will share with Demand Side Resources that curtail use under this program, and it will apply such portion in a non-discriminatory manner. LIPA and NYPA agree to implement the intent of the preceding sentence in a consistent manner.

2.9 Cost Allocation of Incentives and Uplift

The ISO shall recover supplemental payments to Demand Reduction Providers pursuant to Rate Schedule I of its Open Access Transmission Services Tariff. Cost recovery will be allocated to all Loads excluding exports and Wheels Through on a zonal basis in proportion to the benefits received after accounting for, pursuant to ISO Procedures, Demand Reduction imbalance charges paid by Demand Reduction Providers. Section 9, DADRP Cost Allocation, defines the cost allocation method to be used. Briefly, the approach:

- charges loads in all Zones when DADRP curtailment occurs and no NYCA constraints exist,
- charges loads in all Zones upstream of a constraint when DADRP curtailment occurs upstream of that constraint, and
- charges loads in all Zones downstream of a constraint when DADRP curtailment occurs downstream of that constraint.

Constraints at the three significant limiting NYCA Interfaces (Central East, Sprainbrook-Dunwoodie, and Con Ed – Long Island) will be modeled as static percentages; together with the unconstrained portion of time, these will sum to 100%.

2.10 End-User Requirements

Demand Side Resources will be required to have interval billing metering, and will be responsible for any incremental metering and billing system implementation and administration costs in accordance with applicable retail tariffs.

2.11 Small Generator Eligibility

Beginning in 2003, the program will be open only to resources that provide load reduction through interruptible load; load reduction through on-site generation will not be permitted.

2.12 Non-Performance Penalties

If an LSE/DRP has a Demand Side Resource scheduled for a curtailment that would have been eligible for the Incentive payment, but that subsequently fails to curtail, the LSE/DRP will be charged the higher of Day-Ahead or Real-Time LBMP for non-curtailed Load. The premium paid over Real-Time LBMP will be applied to reduce costs allocated to Loads for Incentive and supplemental payments (on the same Zonal basis).

2.13 ICAP Eligibility

Demand Side Resources that qualify as Special Case Resources will be treated identically as other Special Case Resources for purposes of ICAP payments.

2.14 Sunset Clause

The Incentive portion of the Day-Ahead Demand Reduction Program will expire on October 31, 2005 unless the NYISO Management Committee affirmatively extends the program. The program will be re-evaluated every year for potential modifications and improvements.

2.15 Conversion to Economic Day-Ahead Program

If the Incentive portion of the Program is not continued past October 31, 2005, it will convert at that time to an Economic Day-Ahead Load Curtailment Program retaining the same rules and features as the Incentivized Program with the exceptions that:

- The Incentive payment will no longer be made by the NYISO.
- The non-performance penalty will no longer apply (i.e., Loads that fail to curtail will be charged Real-Time LBMP).

Thus, if the Incentive portion of the Program is discontinued, an Economic Day-Ahead Load Curtailment Program will continue such that an LSE/DRP with a Demand Side Resource that curtails Load (as scheduled Day-Ahead by the NYISO) will continue to be paid by the NYISO the higher of the Demand Reduction Load Bid or Day-Ahead LBMP.

2.16 Small Customer Aggregation

1. Aggregations must be at least 2.0 MW for DADRP. The NYISO will establish an up-front means of certifying that the aggregation has an expectation of meeting this requirement. This will be established as part of the approval of the verification methodology; the sampling plan or other measurement methodology will assign an initial (a priori deemed) estimate of the response per site in order to drive the sample size. The aggregation can be comprised of two or more different sampling methods, provided that such a super aggregation was allowed by the NYISO. The MW limit can also be met by combining participants enrolled by different brokers (DRP or LSE) provided that the brokers agree to submit all participants under a single program entity.
2. Aggregators must accept full responsibility for payments to and penalties levied against the members of the aggregation. The NYISO will require that each member of the aggregation execute an agreement to participate indicating that it accepts the provisions of the ISO program and authorizes the LSE/DRP to act as its broker for the purposes of participation
3. Proposals for measuring aggregation performance can involve one of several methods:
 - a. The deployment of approved whole-premise kW metering devices on a sample of participants
 - b. The deployment of approved end-use device or process kW metering devices on a sample of participants that elect to limit PRL program participation to specified end-use devices or processes.
 - c. Provision for supplying verifiable behavioral actions, equipment operating logs, or other data that is deemed to be sufficiently indicate the load level the customer otherwise would have consumed, but for the PRL program event participation
 - d. Other measurement systems that indicate the load level the customer otherwise would have consumed, but for the PRL program event participation
4. Promulgate provisions that govern applications. A process and procedures will be drawn to govern how applications are made, processed and ruled upon, and to set limits to aggregation projects by zone, provider, program, or any other category. The number of aggregations allowed needs to accommodate all of the utilities plus a reasonable number of DRPs and LSEs. Each proposal for small customer aggregation will be reviewed by the NYISO staff and the Price Responsive Load Working Group, and must be approved by a majority of the Chairs and Vice-Chairs of the Management Committee and Business Issues Committee and the Chairman of the Price Responsive Load Working Group.
5. Aggregations may be declared as ICAP or UCAP, subject to the rules established in the applicable NYISO Procedures for ICAP/UCAP suppliers.
6. The Aggregation broker is responsible for all costs associated with developing and administering the alternative performance methodology. Applications for approval of alternative methodologies must include an explicit description of the methodology and how it would be tracked and administered, accompanied by the specific administration processes required. The NYISO in approving an application will specify the costs associated with administration that the applicant must bear. The aggregation applicant must agree to be responsible for all such costs, including costs incurred by the ISO for developing and administering the alternative methodology. The ISO may, at its discretion,

require that some or all of such cost be reimbursed by the applicant upon approval of the methodology, or deduct all costs from payments for curtailments by participants, or a combination of the two methods of cost recovery.

7. One method per end-use premise. End-use electricity customers may subscribe load at a given premise to PRL programs only under a single performance methodology, either the standard method or an approved alternative methodology.
8. Failure to comply with aggregation procedures. The NYISO may, at any time, terminate its agreement with an aggregation broker if it determines that the broker is not fulfilling its obligation under the aggregation agreement. Customers belonging to such aggregation may henceforth participate by signing up under any approved means of participation.

3.0 DADRP Registration Procedures

Registration material and a copy of this manual can be found on the NYISO website at:

http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response_prog.html

You can also access this information from the NYISO website front page by following the link to: The Markets > Demand Response Programs.

If you are an LSE or DRP currently registered as a Customer with the NYISO, please complete Attachment A, the LSE/DRP Registration Form. In addition, fill in one Demand Side Resource Registration Form (Attachment B) for each Demand Side Resource you will be sponsoring in the program.

The NYISO also needs to know specific information for modeling the Demand Side Resource bid. LSEs/DRPs must fill out Attachment C for each single or composite Demand Side Resource being modeled.

If you are not currently an LSE, or you are interested in acting as a DRP, you need to register as a Customer with the NYISO using the Market Relations Registration Packet found on the NYISO website at:

<http://www.nyiso.com/services/registration.html>

Specific instructions for registration are contained in the following sections.

3.1 Load Serving Entities

For LSEs who are enrolling a retail end user whose load is served by the LSE:

1. Complete Attachment A of this manual.
2. Register each Demand Side Resource with the NYISO after signing a contract with that resource, using the appropriate DADRP Certification form provided in Attachment B or C of this manual. Any information on the identity of a Demand Side Resource that is provided to the NYISO will be treated as confidential, and will not be disclosed to third parties without the express permission of the end-use customer, unless aggregated or otherwise presented in such a way as to preserve confidentiality.
3. By submitting the DADRP Certification Form, the LSE confirms that the load to be reduced is not under any specific contractual obligation that would prevent participation in the DADRP.
4. The DADRP participant registration is deemed approved for bidding after the Demand Side Resource has been assigned a generator bus and the billing relationship between the LSE and the Demand Side Resource has been set up. The NYISO will confirm approval via phone or e-mail to the LSE.

For LSEs who are enrolling a Demand Side Resource whose load is served by a different LSE (Commodity Provider):

1. Complete Attachment A of this manual.
2. Register each Demand Side Resource with the NYISO after signing a contract using the appropriate DADRP Certification form provided in Attachment B or C of this manual. Any information on the identity of a Demand Side Resource that is provided to the NYISO will be treated as confidential, and will not be disclosed to third parties without the express permission of the end-use customer, unless aggregated or otherwise presented in such a way as to preserve confidentiality.

3. Within two days after receipt of the DADRP Certification Form, the NYISO will forward the registration to the appropriate Commodity Provider to confirm that the load to be reduced is not under any specific contractual obligation that would prevent participation in the DADRP.
4. Unless otherwise prohibited by the Commodity Provider, the DADRP participant registration is deemed approved for bidding after the Demand Side Resource has been assigned a generator bus and the billing relationship between the LSE and the Demand Side Resource has been set up. The NYISO will confirm approval via phone or e-mail to the LSE.

3.2 Demand Response Providers

To register as a Demand Response Provider you must become a NYISO Customer. If you are applying for NYISO Customer status:

1. Complete Attachment A of this manual.
2. Complete Sections A, B, G, H, I, J, L, N and O of the NYISO Registration Packet, available at the NYISO Website.
3. Sign the Market Services Tariff.
4. Register each Demand Side Resource with the NYISO after signing a contract using the appropriate DADRP Certification form provided in Attachment B or C of this manual. Any information on the identity of a Demand Side Resource that is provided to the NYISO will be treated as confidential, and will not be disclosed to third parties without the express permission of the end-use customer, unless aggregated or otherwise presented in such a way as to preserve confidentiality.
5. Within 2 days after receipt of the DADRP Certification Form, the NYISO will forward the registration to the appropriate Commodity Provider to confirm that the load to be reduced is not under any specific contractual obligation that would prevent participation in the DADRP.
6. Unless otherwise prohibited by the Commodity Provider, the DADRP participant registration is deemed approved for bidding after the Demand Side Resource has been assigned a generator bus and the billing relationship between the LSE and the Demand Side Resource has been set up. The NYISO will confirm approval via phone or e-mail to the LSE.

3.3 Historical Operating Data

LSEs/DRPs shall be required to provide historical operating data for each Demand Side Resource upon acceptance for participation in the DADRP. These requirements may be met by:

For loads with existing interval meters:

- 1) Provide the most recent complete billing period of hourly interval data.

For totalized loads with existing interval meters:

- 2) For totalized loads, provide hourly interval data for one complete billing period of hourly interval data for all participating loads at the premise; or

For newly installed load interval meters:

- 3) For newly installed interval meters, provide the prior three month's summary of monthly MWh consumption and demand values, if available.

3.4 Credit Requirements for DADRP

Demand Response Providers will need to adhere to the following credit requirements if they intend to participate in the NYISO enhanced DADRP program. Collateral will need to be obtained by the DRP and presented to the NYISO before the DRP can participate in the DADRP program. Once participation is granted the NYISO credit department will monitor the activity of the DRP and will reserve the right to request additional collateral if conditions warrant. The collateral will stay in place for the duration of the DRP's participation in the DADRP program.

For those Market Participants who are required to post collateral, the collateral requirement will be calculated by the following formula:

Collateral Requirement: = (Average accepted MWh per month) * (Average Day-Ahead LBMP Price during the prior years summer capability period) * (20% Percentage Factor) * (4)

Where

Average accepted MWh per month =

- *For DRPs who are currently active in the DADRP program = The average will be determined by the historical number of accepted MWh made per month by the DRP, for the months associated with previous years summer capability period.*
- *For DRPs who are currently registered in the DADRP program, but have never been active or for new DRPs who are not currently registered in the DADRP program = Estimate of the average number of projected accepted MWh per month, for the months associated with the summer capability period.*

The estimated value will be determined during the registration process with input from both the DRP and NYISO staff. For estimates that are significantly higher than actual accepted MWh the NYISO will review the collateral requirement after four months of activity and may reduce the collateral requirement. If the estimated value is significantly lower than actual accepted MWh the NYISO, as stated above, does reserve the right to request additional collateral at any time during the program.

Average Day-Ahead LBMP Price during the prior years summer capability period = The average Day-Ahead LBMP at the NYISO reference bus for the previous summers capability period for hours in which the Day-Ahead price is greater than \$50.

20% Percentage Factor = The 20% percentage factor is based on a 3.7% penalty rate compared to total program payment plus a 5.5% historical difference between scheduled and actual curtailment.

The following example is based on the historical summer 2002 scheduled curtailment data for XYZ Company.

Inputs:

- Average accepted MWh per month = 200
- Average Day-Ahead LBMP price during the summer 2002 capability period = 64.91
- 20% percentage Factor

Collateral Requirement for 2003 = $(200) * (64.91) * (.2) * (4) = \$10,385.60$

4.0 DADRP Bidding Instructions

LSE Offers

When bidding as a Demand Reduction Provider the LSE must place two separate bids into the MIS System. The first bid is its normal load bid that it would submit regardless of whether or not the LSE is Demand Reduction Provider. In addition to its normal load bid the same LSE must also submit a generator bid for the amount that the LSE is willing to curtail.

DRP Offers

A DRP is not required to submit a load bid into the MIS – this is the responsibility of the LSE who serves the Demand Side Resource. The DRP must submit a generator bid for the amount of load curtailment desired to be scheduled in the DAM.

The curtailable load will be modeled as a generator in the ISO's unit commitment software, and uses a generator bid to make the curtailable MWs available to the ISO. The bidding instructions on the following pages track the payment examples in Section 8, and will demonstrate different ways to input bidding information into the MIS system.

To prevent situations where load bids an outage that would occur regardless of whether or not the bid was accepted during periods when load reduction is not needed, a floor bid price has been established for DADRP. A curtailment bid for an individual hour must have a bid price that is at or above \$50/MWh for every block of load offered for curtailment. The load- weighted average bid price for bids that include curtailment production cost guarantees or minimum run times must be equal to or greater than \$50/MWh. Bids submitted below the floor price will be rejected from the MIS.

5.0 Calculating Customer Baseline Load for DADRP

The calculation of Customer Baseline Load requires the Meter Data Service Provider (MDSP) to have two key pieces of data:

- 1) Net metered load for each Demand Side Resource/Aggregate
- 2) Demand Side Resource/Aggregate scheduled hours

The MDSP will receive hourly interval net metered load directly from the facilities. The MDSP should use the Day-Ahead Operating Plan information contained in the file named:

DAMGenScheduleCCYYMMMD.csv

posted on bdsftp1.nyiso.com each day to determine the scheduled hours for a Demand Side Resource/Aggregate. This data posting is described in Section 2.2 and Appendix 1 of the NYISO Communication Interface Manual.

5.1 Baseline Calculation Method (Interruptible Load)

I. The Average Day CBL

A. Average Day CBLs for Weekdays

Step 1. Establish the CBL Window. Establish a set of days that will serve as representative of participant's typical usage.

A.1.a Determine the participant's peak hourly load over the past 30 days or the period covered by the load data file, whichever is smaller. This value becomes the initial seed value for the *average event period usage level*.

A.1.b Beginning with the weekday that is two days prior to the event:

A.1.b.1 Eliminate any holidays as specified by the NYISO.

A.1.b.2 Eliminate any days where the NYISO declared an EDRP event for which the participant was eligible for payment for a curtailment.

A.1.b.3 Eliminate any days in which the participant's DADRP curtailment bid was accepted in the DAM, whether or not the participant actually curtailed.

A.1.b.4 Create the *average daily event period usage* for that day, defined as the simple average of the participant's actual usage over the hours that define the event for which the CBL is being developed.

A.1.b.5 Eliminate low usage days. If the average daily event period usage is less than 25% of the average event period usage level, eliminate that day.

A.1.b.6 If the day has not been eliminated, update the average event period usage level by including the average daily event period usage for this day. If this is the first day added to the CBL Window, replace the average event period usage level (which was the initial seed value) with the average daily event period usage. Add this day to the CBL Window.

A.1.c Move back one day and loop to step A.1.b.1

A.1.d Final Weekday CBL Window must contain 10 weekdays days.

Step 2. Establish the CBL Basis. Identify the five days from the 10-day CBL Window to be used to develop CBL values for each hour of the event.

A.2.a Order the 10 days in the CBL Window according to their average daily event period usage level, and eliminate the five days with the lowest average daily event period usage.

A.2.b The remaining five days constitute the CBL Basis.

Step 3. Calculate Average Day CBL values for the event.

A.3.a For each hour of the event, the CBL is the average of the usage in that hour in the five days that comprise the CBL basis.

B. Average Day CBL for Weekends

Step 1. Establish the CBL Window

B.1.a The CBL Window is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for Holidays or event days.

Step 2. Establish the CBL Basis.

B.2.a Calculate the average daily event period usage value for each of the three days in the CBL Window.

B.2.b Order the three days according to their average daily event period usage level.

B.2.c Eliminate the day with the lowest average value

B.2.d The Weekend CBL Basis contains 2 days.

Step 3. Calculate Weekend Average Day CBL values for the event.

B.3.a For each hour of the event, the CBL value is average of usage in that hour in the two days that comprise the CBL basis.

II. Elective Weather-Sensitive CBL formulation

Step 1. Calculate the Average Day CBL values for each hour of the event period described in (I) above.

Step 2. Calculate the Event Final Adjustment Factor. This factor is applied to each of the individual hourly values of the Average Day CBL.

A. Calculate the Adjustment Basis Average CBL

2.A.1 Establish the adjustment period, the two-hour period beginning with the start of the hour that is four hours prior to the commencement of the event through the end of the hour three hours prior to the event.

2.A.2 Calculate the Adjustment Basis Average CBL.

2.A.2.a Apply the Average Day CBL formula as described in I. Average Day CBL (page 2), to the adjustment period hours as though it were an event period two hours in duration, but using the five days selected for use in the Average CBL Basis (i.e., average the ten hours).

2.A.2.b Calculate the average of the two usage values derived in 2.A.2.a, which is the Adjustment Basis Average CBL.

B. Calculate the Adjustment Basis Average Usage

2.B.1 The adjustment basis average usage is the simple average of the participant's usage over the two-hour adjustment period on the event day.

C. Calculate the gross adjustment factor

2.C.1 The gross adjustment factor is equal to the Adjustment Basis Average Usage divided by the Adjustment Basis Average CBL

D. Determine the Final adjustment factor. The final adjustment factor is as follows:

2.D.1 If the gross adjustment factor is greater than 1.00, then the final adjustment factor is the smaller of the gross adjustment factor or 1.20

2.D.2 If the gross adjustment factor is less than 1.00, the final adjustment factors are the greater of the gross adjustment factor or .80.

2.D.3 If the gross adjustment factor is equal to 1.00, the final adjustment factor is equal to the gross adjustment factor.

Step 3. Calculate the Adjusted CBL values.

A. The Event Adjusted CBL value for each hour of an event is the product of the Final Adjustment Factor and the Average CBL value for that hour.

III. Selecting a CBL method

A.1 The participant selects the CBL formula when it registers, or is registered by its LSE or DRP, with the NYISO for program participation. The choice of CBL becomes effective when the NYISO accepts the registration.

A.2 At initial DADRP registration, participants may elect either the Average Day CBL or the Adjusted CBL formula.

A.3 At the time that the new Adjustable CBL formulation becomes effective, registered participants in DADRP may apply to change to the adjusted formula CBL method beginning thirty (30) days after such notification.

A.4 Participants may switch CBL methods by making application to the NYISO. For such a change applicable to the summer capability period (May 1 – October 31), the application must be submitted to NYISO by April 1. For a change applicable to the winter capability period (November 1 – April 30), the application must be submitted to NYISO by October 1. The change in the CBL formula becomes effective at the beginning of the next capability period after the NYISO accepts the application.

5.1.1. Example Customer Baseline Calculation

As an example, assume a 4-hour bid from 12 noon to 4 pm was accepted. The past 10 days MWh consumption for similar hours, along with the four hours prior to event initiation, was:

Time	Day n-2	Day n-3	Day n-4	Day n-5	Day n-6	Day n-7	Day n-8	Day n-9	Day n-10	Day n-11
8-9	5	4	4	4	3	6	2	3	3	4
9-10	5	3	5	4	4	2	3	3	2	4
10-11	7	5	6	5	5	5	4	4	4	5
11-12	8	6	8	6	7	8	5	6	6	7
12-1	10	8	9	7	10	12	5	7	7	8
1-2	11	6	12	8	11	8	8	8	6	10
2-3	7	9	9	6	9	9	8	8	6	9
3-4	5	6	7	6	7	7	6	7	5	6

Steps 1 and 2: sum the MWh for the hours 12-4 each day and select the 5 highest totals:

	MWh n-2	MWh n-3	MWh n-4	MWh n-5	MWh n-6	MWh n-7	MWh n-8	MWh n-9	MWh n-10	MWh n-11
	33	29	37	27	37	36	27	30	24	33
Selected?	Y		Y		Y	Y				Y

Step 3: Calculate the CBL for each hour using the five highest days selected:

Time	Day n-2	Day n-4	Day n-6	Day n-7	Day n-11	CBL
12-1	10	9	10	12	8	9.8
1-2	11	12	11	8	10	10.4

2-3	7	9	9	9	9	8.6
3-4	5	7	7	7	6	6.4

The CBL in the right-hand column above would be the non-weather –adjusted value. If this customer was signed up with the weather-sensitive calculation option, the CBL would be adjusted upward or downward based on the actual usage in the two hours prior to when the scheduled load reduction was to take place. In this example, the Adjustment Basis Average CBL will be the average of the MWh for hours beginning 8 and 9 over the five days chosen for the CBL:

Time	Day n-2	Day n-4	Day n-6	Day n-7	Day n-11	
8-9	5	4	3	6	4	
9-10	5	5	4	2	4	
Average						4.2

On the day of the event (day n), assume the actual metered load consumption is as shown in the following table:

Hour Beginning	8	9	10	11	12	1	2	3
MWh	4	5	4	3	2	3	3	4

In this case, the Adjustment Basis Average Usage is the average of the MWh in hours 8 and 9, or 4.5 MWh. The Gross Adjustment Factor is the ratio of the Adjustment Basis Average Usage to the Adjustment Basis Average CBL, 4.5/4.2 or 1.07. The CBL will therefore be adjusted upward by 1.07 – the following table shows the resulting new CBL and the computed load reduction for the four-hour event period.

Hour Beginning	12	1	2	3
Load (MWh)	2	3	3	4
CBL (MWh)	10.5	11.1	9.2	6.8
Load Reduction (MWh)	8.5	8.1	6.2	2.8

It is important to note that if the actual usage in the two hours prior to notification was *lower* than the Adjustment Basis Average CBL, the CBL curve would have been shifted *downward* and would result in load reduction performance that was lower than would have been determined using the Average Day CBL (without weather adjustment).

5.2 Calculating CBL for Aggregated Load Bids

For aggregated bids involving more than one Demand Side Resource as registered in Attachment C it is necessary to calculate a composite CBL for the bid. The composite CBL will be calculated as the sum of the non-coincident CBLs of the individual DSRs using the procedures defined in Section 5.1 above. The concept of non-coincident CBLs is illustrated with the following example.

Assume that two interruptible load Demand Side Resources have been aggregated into one bid. A one-hour bid is used, but the values in each cell could represent the sum of the MWh consumed over a multi-hour bid. The metered load for each DSR over the ten-day interval used by the CBL calculation is shown in table 5.1. The five days selected for the CBL calculation for each DSR are denoted by the shaded background.

Table 5.1 – Illustrating Non-Coincident CBL Calculation for Aggregated Resources

	Day(n-2)	Day(n-3)	Day(n-4)	Day(n-5)	Day(n-6)	Day(n-7)	Day(n-8)	Day(n-9)	Day(n-10)	Day(n-11)
DSR #1	3.2	4.5	3.3	4.2	1.1	1.3	4.5	3.6	3.2	2.3
DSR #2	7.2	7.2	4.5	7.3	7.3	4.9	4.9	6.2	6.3	6.7

The CBL for DSR #1 is given as $(4.5 + 3.3 + 4.2 + 4.5 + 3.6)/5 = 4.02$ MWh.

The CBL for DSR #2 is given as $(7.2 + 7.2 + 7.3 + 7.3 + 6.7)/5 = 7.14$ MWh.

The composite non-coincident CBL for the aggregated resources would be $4.02 + 7.14 = 11.16$ MWh.
The CBL is termed non-coincident because different days are used for each individual CBL calculation.

6.0 Reporting and Verifying Customer Baseline Load and Meter Data

6.1 Metering Requirements

LSEs are required to provide hourly interval metering data to validate performance. Demand Side Resources participating in the DADRP must have an integrated hourly metering device, installed to capture the facility's net load, certified by a Meter Service Provider that provides integrated hourly kWh values for market settlement purposes. DADRP participants must also contract with a Meter Data Service Provider for collection and reporting of DADRP data to the NYISO. If an LSE contracts with a non-TO MSP or MDSP, the metering and data reporting will be handled by the NYISO on a case-by-case basis.

When a Demand Side Resource registers for participation in the program, whether as a self-supply or interruptible load customer, an hourly interval meter shall be installed to meter the entire facility or for totalized load at each Demand Side Resource. An hourly interval meter is required for each participating load.

6.2 Historical Operating Data

LSEs shall be required to provide historical operating data for each load upon acceptance for participation in the DADRP. These requirements may be met by:

For loads with existing interval meters:

- 1) Provide a minimum of 1 complete billing period of hourly interval data immediately preceding the first Capability Period the load will participate in.

For totalized loads with existing interval meters:

- 2) For totalized loads, provide hourly interval data for a minimum of 1 complete billing period of hourly interval data for all participating loads at the premise; or

For newly installed load interval meters:

- 3) For newly installed interval meters, provide the prior three month's summary of monthly kWh consumption and demand values, if available.

6.3 Performance

Performance for interruptible loads is measured as the difference between the Customer Baseline and the actual metered usage by hour during the period when load reduction is scheduled. The Customer Baseline type used for computing performance shall be the same day-type as the day-type corresponding to the period when load reduction is scheduled, as described in Section 5 of this manual.

Performance for a interruptible load Demand Side Resource/Aggregate for each hour shall be calculated as:

$$PRL_{\text{meter } h} = (CBL-xx)_h - NML_h$$

Where $PRL_{\text{meter } h}$ = calculated actual performance (Demand Reduction) for the hour

$CBL-xx_h$ = Customer Baseline day-type (weekday – CB-WD, Saturday-CB-SA, or Sunday-CB-SU)



Working to Perfect the Flow of Energy

PJM Manual 11:

Scheduling Operations

Revision: 30

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Prepared by

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Demand Resource Energy Market Participation

Qualified Curtailment Service Providers may offer the load reductions of Demand Resources into the Day-Ahead Market pursuant to the following rules and requirements.

Day-Ahead Operations

- Demand Resources, except Demand Resources served under LMP-based contracts which provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, have the option to participate in the Day-Ahead Market. Participants in Economic Load Response Program may submit a bid to reduce the load they draw from the PJM system in advance of real-time operations. In the Day-Ahead Market, the participant may submit a Load Response Bid on behalf of a Demand Resource ("Load") for a specific KW curtailment (in minimum increments of .1 MW or 100 KW).
- Demand Resources that are served under LMP-based contracts which provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, do not have the option to participate in the Day-Ahead Market.
- Each Market Participant's profile (which is defined by PJM) shall specify the transmission zones or aggregates for which that Participant is eligible to submit load response bids.
- Load Response Bids are assumed to include losses (transmission zone losses and share of 500 kV losses).
- Load Response Bids shall specify for each Demand Resource:
 - KW quantity to be reduced
 - Location (transmission zone or aggregate)
 - Price, in \$/MW, at which the load shall be curtailed
 - The Load Response Bid could also include for each Demand Resource:
 - Shut down costs, for each period (When the Shut down costs entered in eMkt and Load Response Application are not the same, PJM will use the lower of the two values)
 - Minimum down times for which the load reduction must be committed
 - Shutdown costs and minimum down times are optional, and will default to zero (0) if not submitted.
- Shutdown cost will be expressed in dollars, and represents the fixed cost associated with committing a load response resource.
- Shutdown costs will be changeable only every six months, corresponding to the six-month periods during which price-based start-up costs may be changed for generators.
- The six month periods for shutdown costs are defined as follows: Period 1 is defined as April 1 - September 30 and Period 2 is defined as October 1 - March 30.

- Minimum down time will be expressed as a number of hours, and represents the minimum number of contiguous hours for which a load response bid must be committed in the Day-Ahead Market.
- If a Program Participant submits no day-ahead bid information, then a zero KW quantity is assumed.
- The list of transmission zones and aggregates for which Load Response Bids are accepted is defined by PJM.
- All day-ahead Load Response Bids will be submitted to the eMKT website by 1200 each day.
- The Day-Ahead Market closes at 1600 each day, and cleared Load Response Bids will be posted to eMKT.

Real-Time Operations

- Demand Resources including Demand Resources served under LMP-based contracts which provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, have the option to participate in the Real-Time Market. Curtailment Services Providers, representing Demand Resources participating as Economic Load Response resources, may choose to commit to a reduction of the load they draw from the PJM system during times of high prices. These Curtailment Service Providers are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise.
- Demand Resources served under LMP-based contracts which provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, have the option to participate in the Real-Time Market under the following circumstances. The Curtailment Service Provider shall provide PJM with a “strike” price for the Demand Resource’s zonal LMP at which the Demand Resource will reduce load, as well as any shutdown costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the load reduction must be committed.
- In cases where the zonal real-time LMP reaches the “strike” price and the load response is dispatched by PJM, PJM shall pay the CSP the difference between the actual savings achieved based on zonal LMP and the total value of the load response bid, if savings achieved by the load reduction are less than the total value of the load response bid. For purposes of this provision, the load response bid will be the sum of the “strike” price times the MW of reduction achieved during each hour of the time period the reduction was dispatched by PJM or minimum down-time whichever is greater, plus submitted shutdown costs.
- Each Curtailment Service Provider is responsible for maintaining the load reduction information associated with each Demand Resource registered via the eLoad Response application.

- At the time of registration, each Curtailment Service Provider shall specify for each Demand Resource ("Load") the following operational information:
 - KW quantity to be reduced.
 - Locational Marginal Price (LMP), in \$/MW, at which the load shall be reduced ("strike" price)
 - Pricing Zone (transmission zone or aggregate)
 - Load Reduction Method
 - Time, in minutes, to reduce
 - Indicate if a load reduction may be dispatchable in real-time operations
 - Indicate if the Demand Resource ("Load") is served under an LMP-based contract
 - Shut Down Costs for Period 1, April 1 - Sept 30. When the Shut Down Costs entered in eMkt and Load Response Application are not the same, PJM will use the lower of the two values
 - Shut Down Cost for Period 2, October 1 - March 30. When the Shut Down Cost entered in eMkt and Load Response Application are not the same, PJM will use the lower of the two values
 - Minimum Down Time, in hrs
- If a Load Response Bid for a Demand Resource is not accepted in the Day-Ahead Market and the CSP indicates that it wishes the Demand Resource to be dispatchable in real time, the PJM dispatcher will use operational information provided during registration to dispatch the Demand Resource in real time.
- Curtailment Service Providers shall provide PJM with Notification during the 60 minute period prior to the reduction. Notification must be given when the CSP will submit a settlement for an energy payment when the load reduction complies with a synchronized reserve event or a regulation assignment. Until June 1, 2006 the Notification may be sent to PJM at loadresponse@pjm.com. CSPs providing notification by email shall verify the Notification in eLoadResponse by the end of the day after the event day.
- Demand Resources will not be eligible to set real-time price on the PJM system unless metered directly by PJM.
- Curtailment Service Providers shall provide PJM with Notification during the 60 minute period following the end of the load reduction. Alternatively, CSPs may indicate the length of their reduction within the Notification specifying the beginning of their reduction.

Demand Resource Metering and Settlement Data Requirements

The settlements submitted to PJM by Curtailment Service Providers must conform to the following requirements for data, including metered data, and Customer Baseline Load (CBL) calculations.

Metered Data

- For load reduction that is not metered directly by PJM, Curtailment Service Providers are responsible for forwarding the appropriate meter data (as defined in this Manual) to PJM within 60 days of the reduction. Participants submitting a settlement for an energy payment when load reduction complies with a synchronized reserve event or regulation assignment must use data provided by the load meter. This data shall be forwarded through eLoadResponse.
- If the meter data files are not received within 60 days, no payment for participation is provided.
- Meter data must be provided for the hour prior to the reduction, as well as every hour during the reduction with the following exception. When on-site generation is deployed exclusively to support the load reduction, the CSP may provide qualified meter data from the on-site generation for each hour of the event day instead of actual load metered data. Provision of hourly meter data from the on-site generation will be deemed a certification by the CSP that the on-site generation was not used for any purpose other than to support the load reduction during the event day.
- Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM.
- Objection by the EDC or the LSE to the CBL, the Meter Data, or the retail rate shall be clearly set forth in the Comments related to the Settlement Data. The CSP shall correct and re-submit the Settlement Data within 2 business days. The objecting EDC and/or LSE shall have 5 business days to review the re-submitted Settlement Data or PJM will assume acceptance.
- All load reduction data are subject to PJM Market Monitoring Unit audit.

Customer Baseline Load (CBL)

- For those CSPs that wish to measure load reductions by comparing metered load against an estimate of what metered load would have been absent the reduction, a Customer Baseline Load (CBL) shall be calculated for each Demand Resource ("Load").
- A Customer Baseline Load cannot be calculated for the Demand Resources participating as Emergency Load Response resources.
- A Customer Baseline Load is calculated for two timeframes: an Average Day CBL for Weekdays and the Average Day CBL for Weekends/Holidays.
- At the time it enters the Load Response Program, the Demand Resource or its representative (CSP), shall specify whether it desires to apply a Weather Sensitivity Adjustment (WSA) for the summer period (May-October, inclusive) or the winter period (November-April) or both.
- The election to apply the WSA may be changed only annually.

- The WSA shall increase or decrease the CBL. The WSA shall be calculated for interval-metered Demand Resources using a simplified methodology, including a regression analysis and analysis method, as defined in the Program Documentation. This simplified methodology only will be applicable for reductions in real-time Economic Load Response during the summer months when the hourly temperature at the nearest major airport equals or exceeds 85 degrees during each hour of the load reduction event and the WSA would make more than a five percent difference in the CBL that is calculated.
- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.
- For Demand Resources without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100%. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted.
- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the Demand Resource's historical, seasonal, on-peak non-coincident peak load.
- Case-by-case suggestions for alternative WSA methods or adjustments to the Demand Resource's historical, seasonal, on-peak non-coincident peak load may be approved by PJM if negotiated in good faith and agreed to by all appropriate parties.
- Curtailment Service Providers are responsible for forwarding the appropriate CBL data (to PJM within 60 days of the reduction.
- If the CBL data files are not received within 60 days, no payment for participation is provided.
- CBL data must be provided for each contiguous hour during which load reduction was accomplished.
- PJM will forward Customer Baseline (CBL) and Weather-Sensitive Adjustment (WSA) calculations to the appropriate EDC and LSE for optional review.
- EDC and LSE will provide feedback to PJM within ten (10) business days of receipt of data.
- Objection by the EDC or the LSE to the CBL, the Meter Data, or the retail rate shall be clearly set forth in the Comments related to the Settlement Data. The Curtailment Service Provider shall correct and re-submit the Settlement Data within 2 business days. The objecting EDC and/or LSE shall have 5 business days to review the re-submitted Settlement Data or PJM will assume acceptance. This procedure does not affect the requirement for the CSP to submit the settlement to PJM within 60 days of the load reduction event.

- The Demand Resource shall inform PJM directly or inform its CSP, who shall inform PJM, of any significant change to the Demand Resource's operations that increases or decreases the Demand Resource's CBL.
- A significant incremental change is defined as any operational or physical change to the Demand Resource's facilities that will adjust more than half the hours in the Demand Resource's CBL by at least 20% for more than twenty consecutive days. PJM may require and approve such adjustments to the CBL as are necessary to reflect the significant incremental change.
- All CBL data are subject to PJM Market Monitoring Unit audit.

Settlements Data Requirements

- Data required for emergency load response settlements :
 - Real-time LMP values by Zone or aggregate (including nodal) (PNODE)
 - Actual Metered Reduction (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
 - Actual Load (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
 - Market Participant acting as CSP (ParticipantName)
- Data required for day-ahead economic load response settlements :
 - Day-ahead LMP values by Zone or aggregate (including nodal) (PNODE)
 - Day-ahead load response scheduled MW quantities by Market Participant and by Zone or aggregate (including nodal) (PNODE)
 - Real-time LMP values by Zone or aggregate (including nodal) (PNODE)
 - Actual Metered Reduction (Hourly MW) by Market Participant and by Zone (PNODE)
 - Actual Load (Hourly MW) by Market Participant and by Zone (PNODE)
 - Load Serving Entity (LSEOrgId)
 - Market Participant acting as CSP (ParticipantName)
 - Loss Factor
 - Retail Rate (G & T)
- Data required for real-time economic load response settlements:
 - Real-time LMP values by Zone or aggregate (including nodal) (PNODE)
 - Actual Metered Reduction (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
 - Actual Load (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
 - CBL (Hourly MW)
 - Load Serving Entity (LSEOrgId)
 - Market Participant acting as CSP (ParticipantName)
 - Loss Factor
 - Retail Rate (G & T)
- There are two Operating Reserve calculations, which require the following information:



- Day-Ahead Operating Reserves
 - ShutDown Costs submitted biannually (When the ShutDown Costs entered in eMkt and eLoadResponse are not the same, PJM will use the lower of the two values)
- Balancing Operating Reserves
 - ShutDown Costs submitted biannually (When the ShutDown Costs entered in eMkt and eLoadResponse are not the same, PJM will use the lower of the two values)



Working to Perfect the Flow of Energy

PJM Manual 19:

Load Data Systems

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Prepared by

Capacity Adequacy Planning

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PJM Manual 19:

Load Data Systems

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Section 3: Load Management

Welcome to the *Load Management* section of the ***PJM Manual for Load Data Systems***. In this section you will find the following information:

- A description of the types of Load Management recognized by PJM (see “*Load Management Description*”).
- The requirements for qualifying and applying for Demand Resource (DR) or Interruptible Load for Reliability (ILR) status (see “*Certification Requirements*”).
- The compliance review process and method for determining penalties/rewards (see “*Compliance*”).

For information on how Load Management is operated, please refer to the [***PJM Manual for Emergency Operations \(M-13\)***](#).

Load Management Description

Demand Resource (DR) and Interruptible Load for Reliability (ILR) have the ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load Management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load Management rights or its agent (for Direct Load Control). DR and ILR receive payments as part of the Reliability Pricing Model (RPM).

The requirements for Load Management products to be qualified and the calculations involved in computing each resource provider’s LM value are described below.

Types of Load Management (LM)

PJM recognizes three types of LM:

Direct Load Control (DLC) – Load management that is initiated directly by the resource provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).

Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource provider's market operations center or its agent.

Guaranteed Load Drop (GLD) - Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of LM above, there can be two notification periods:

Step 1 (Short Lead Time) – LM which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.

Step 2 (Long Lead Time) – LM which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

Certification Requirements

Qualification as a LM Resource Provider

An LSE or Curtailment Service Provider (CSP) who wishes to utilize LM must provide (or contract with another LSE, CSP or EDC to provide) the following capability:

- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process.
- Supplemental Status Reports, detailing LM available, as requested by PJM.
- Entry of customer-specific LM certification information, for planning and verification purposes, into the PJM eLoadResponse® system.
- Customer-specific compliance and verification information for each PJM-initiated LM event, as well as aggregated LM resource provider load drop data for resource provider-initiated events, in accordance with established reporting guidelines.
- Load drop estimates for all LM events, as described in Attachment A.

LM Qualification

These requirements are described in terms of the customer response and qualifications. The specifics of the customer contract and tariffs are the responsibility of the LM resource provider and the regulatory process. PJM does not have direct involvement with customers.

The entity requesting LM must verify that each customer's load management meets the following criteria:

- Availability for up to the ten PJM-initiated interruptions at any time during the planning period.
- Interruptions of up to six consecutive hours duration between 12:00 PM (Noon) to 8:00 PM (Eastern Prevailing Time) for the months of May through September and 2:00 PM to 10:00 PM for the months of October through April on weekdays, other than PJM holidays.
- Load management must be able to be implemented within two hours of notification to the LM resource provider of a PJM-initiated load management event.
- Initiation of load interruptions upon request of PJM must be within the authority of the LM resource provider dispatcher without any additional approvals being required.

DLC programs are certified based on load research and customer subscription data. Load research guidelines are outlined in Attachment B.

Determination of Nominated Load Management Value

The determination of the value of the LM load reduction is consistent with the process for determination of the capacity obligation for the customer. Nominated load reductions are effective for an entire RPM Delivery Year.

The LM load reduction value for a Firm Service Level customer will be based on the Peak Load Contribution for the customer, as determined by the 5CP methodology.

The load management value for a Firm Service Level customer will be equal to the difference between its Peak Load Contribution and its pre-determined firm load adjusted for system losses

$$FSL = PLC - (FL - LossF)$$

Where: FSL =Load Management value;

PLC = the customer's EDC-assigned Peak Load Contribution;

FL = Firm Load level;

LossF = the customer's EDC-assigned loss factor.

The load management value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the LM Provider. The value nominated shall not exceed the customer's Peak Load Contribution.

The load management value for a Direct Load Control program will be based on load research and customer subscription. The value of the program is equal to the PJM-approved per-participant load reduction (evaluated at average peak day weather conditions and adjusted for the switch operability rate) multiplied by the number of active participants, adjusted for system losses

$$DLC = PPI * Cust * LossF)$$

Where: DLC =Load Management value;

PPI = the PJM-approved Per-Participant Impact;

Cust = the number of active participants;

LossF = the EDC-assigned loss factor.

The per-participant impact is to be estimated at long-term average local weather conditions at time of the RTO summer peak. Load research studies to support per-participant impacts must comply with the Guidelines for DLC load research studies presented in Attachment B.

Customer-specific LM information (EDC account number, peak load, notification period, etc.) will be entered into the PJM eLoadResponse® system to establish load management values. Additional data may be required, as defined in the Certification and Compliance descriptions.

Load Management Certification

LM Certification is the documentation of customer-specific data and LM credit information, used to verify the amount of load management available and set the allowable LM value.

Data is provided by both the zone EDC and the LM Provider, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution(5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Review data must be uploaded and approved prior to capacity obligations being locked for the effective date. LM Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the LM Provider. Guidelines for the estimation of load drops are detailed in Attachment A.

For Direct Load Control programs, the LM Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

PJM will provide templates to be used in supplying information for the LM Credit Review.

Each June, all LM values in the PJM LoadResponse® system will be reset to zero, necessitating the re-nomination of all LM.

Compliance

Compliance is the process utilized to review LM Provider performance during PJM-initiated Load Management events. The process establishes potential under/over compliance values for the LM Provider.

Compliance is event based (compliance is verified only if an event occurs between June and September).

PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews.

Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place.

LM Providers are responsible for the submittal of compliance information to PJM for each PJM initiated event during the compliance period.

Compliance for Direct Load Control programs will consider only the transmission of the control signal. LM Providers are required to report the time period (during the LM event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. LM Providers must submit actual customer load levels (for the event period) for the compliance report.

Compliance is checked on an individual customer basis for GLD, by comparing actual load dropped during the event to the nominated amount of load drop. LM Providers must submit actual loads and comparison loads for the compliance hours. Comparison loads must be developed from the guidelines included in Attachment A, and note which method was employed.

Compliance is averaged over the full hours of an LM event, for each customer or DLC program.

LM customers may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for the incremental load drop below zero.

For Interruptible Load for Reliability (ILR), compliance will be totaled over all FSL and GLD customers and DLC programs, by zone, to determine net ILR Provider compliance position(s) for the event.

For Demand Resource (DR), compliance will be totaled over all FSL and GLD customers and DLC programs, by the RPM auction into which it was entered, to determine net DR Provider compliance position(s) for the event.

DR and ILR compliance reviews are conducted separately.

For any LM event where the DR/ILR Provider's load management provided is less than the DR/ILR Provider's nominated value in the PJM eRPM system, a Compliance Deficiency Value will be equal to the DR/ILR deficiency for the event.

Penalties/Rewards

Penalties and rewards are assessed for PJM-initiated events on an event basis, following a compliance review.

A Load Management Compliance Penalty Charge is assessed to those Providers that under-complied during an event. The Load Management Compliance Penalty Charge is equal to the net zonal under-compliance MW times the Load Management Zonal Compliance Penalty Rate. The Load Management Zonal Compliance Penalty Rate per MW-event is one-fifth of the annual revenue rate (\$/MW-year) applicable to the Demand Resource or ILR resource.

The total Load Management Zonal Compliance Deficiency Penalties assessed to the Provider in a year is capped at the annual revenue rate the Demand Resource or ILR resource would receive.

The Load Management Compliance Penalty Charges collected from LM Providers are allocated the third billing month after the event occurs (e.g., June events will be included in the August bill, which is issued in September) on a pro-rata basis to those LM Providers that provided load reductions in excess of the amount obligated. The allocation to each over-performing Provider shall not exceed for each ILR resource or Demand Resource the volume of excess MWs provided by the resource during a single event times 1/5 of the annual revenue rate received by the ILR resource or Demand Resource.

Any Load Management Compliance Penalty Charges not allocated to over-performing Providers are instead allocated to all LSEs in the RTO based on the LSE's average Daily Unforced Capacity Obligation during the month the PJM-initiated Load Management event occurred

The Emergency Procedures Charges outlined in Schedule 14 of the Reliability Assurance Agreement for refusal to comply or failure to employ all reasonable efforts to comply will remain in effect, and will be assessed in addition to any penalty described here.

Attachment A: Load Drop Estimate Guidelines

General

LSEs receiving ALM credit, and Curtailment Service Providers offering load reduction into the Emergency option of the Demand-Side Response program are responsible for estimating hourly impacts from load management events, and for reporting them to PJM and the host EDC. Estimates must be produced and communicated for all events (whether PJM- or LSE-initiated), whenever they occur in the year. Estimates must be presented for each Contractually Interruptible customer and each Direct Load Control signal. Estimates must be communicated within forty-five days after the end of the month in which the event occurred.

EDCs are responsible for reporting the estimated impact of voltage reductions (optional) or significant losses of load on their systems.

Load drop estimates will be used to construct unrestricted loads used in the normalization of PJM seasonal peaks, and to calculate the unrestricted peak load contributions used in formulating capacity obligations.

Direct Load Control

The estimated load drop for a DLC program is based on the average impact per customer participating in the program (adjusted for losses), and the amount of time the transmission signal was sent. For each hour of an ALM event, the following calculation must be evaluated:

$$\text{DLC Load Drop} = \# \text{ of Active Customers} * \text{Per Participant Impact (MW)} * \text{Loss Factor} * \text{Transmission Signal Ratio}$$

where, # of Active Customers = the number of participants involved on the day of the interruption;

Per Participant Impact = the PJM-approved impact from a load research study;

Loss Factor = the applicable factor to equate the meter-level impact to a generator-level impact;

Transmission Signal Ratio = the percentage of the hour that the signal was operated (100%=1.0).

Contractually Interruptible

The estimated load drop for Firm Service Level and Guaranteed Load Drop customers is based on the comparison of the customer's metered load during the intervention versus an estimate of what the load would have been without an intervention, adjusted for losses. Alternately, generator data may be used, if the load drop was achieved via backup generation. For each hour of an ALM event, the following calculation must be evaluated:

$$CI \text{ Load Drop} = (\text{Comparison Load (MW)} - \text{Metered Load (MW)}) * \text{Loss Factor}$$

OR

$$CI \text{ Load Drop} = \text{Generation (MW)} * \text{Loss Factor}$$

where, Comparison Load = an estimate of the participant's load in absence of an interruption;

Metered Load = the participant's hourly integrated load;

Loss Factor = the applicable factor to equate the meter-level impact to a generator-level impact;

Generation = the hourly integrated output from a generator used to provide Guaranteed Load Drop.

Due to the differing nature of Firm Service Level and Guaranteed Load Drop programs, and the load profiles of customers involved, several options are available to estimate comparison loads:

Comparable Day: The customer's actual hourly loads on a non-interruption day judged to be similar in other respects to the interruption day. These loads may be adjusted for differences in weather conditions. Or, an average of the customer's actual hourly loads on peak days;

Same Day (Before/After Event): The customer's actual loads on the same day of the interruption, from the hours surrounding the event. This option is appropriate for high load factor customers with no weather sensitivity;

Load Profile: The Customer's estimated hourly load from an unrestricted load profile approved for use in retail balancing and settlements;

Customer Baseline: The Customer's baseline calculation used to calculate load drops for the PJM Demand Response program;

Regression Analysis: The customer's estimated hourly loads from a regression analysis of the customer's actual loads versus weather. This option is appropriate for customers with significant weather sensitivity.

Missing Data

If the methods outlined above for Contractually Interruptible customers can not be utilized due to missing hourly load data, estimates of actual loads during the ALM event may be substituted. Methods of estimation can vary, but the method chosen should be done as to provide the best approximation of actual loads. A possible estimation method is based upon previous performance: the customer's actual hourly loads or generation output on a previous ALM event day, judged to be similar in other respects to the event day for which load data is missing. These loads may be adjusted for differences in weather conditions.

Whenever missing data is estimated, a written explanation of which data is estimated and the method employed must accompany the load drop estimates.

Voltage Reduction

Whenever a part of the PJM system experiences a voltage reduction, whether it is PJM- or locally initiated, the distribution companies involved are to estimate its impact on hourly load levels. The estimated impact of a 5% voltage reduction will be 1.7% of the load in the affected area at the time of the voltage reduction. Variances from this guideline are acceptable in cases where a thorough analysis was performed. In such cases, a written explanation of the estimate must accompany the reported values.

Loss of Load

Whenever a part of the PJM system experiences a loss of load event (beyond the level of nominal localized outages), the Distribution Company involved is to estimate its impact on hourly load levels. The method used to estimate the impact of the loss of load event will vary by the circumstances involved, but the outcome of the estimation should represent the best approximation of the actual hourly loads that would have occurred if the loss of load event had not occurred. A written explanation of the loss of load event and how its impact was estimated is to accompany the report.

Attachment B: Direct Load Control Load Research Guidelines

The intention of these guidelines is to ensure that the estimated per-participant impacts of Direct Load Control program reliably represent the amount of load shed, on average, for active program participants.

Load Management Providers with Direct Load Control programs which employ a radio signal may elect to either submit a load research study supporting base per-participant impacts for their program, or utilize the base per-participant impacts contained in the “Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region” report. Providers utilizing other technology must submit a load research study. All Providers must submit switch operability studies once every five years.

Requirements for Provider-Submitted Studies

Study Design

DLC load research studies will be designed to achieve a minimum accuracy of 90% Confidence with 20% error.

Study Detail

Load research studies submitted must present estimated per-participant impacts in a matrix which details average impacts on non-holiday weekdays by hour, for the hours ending 13:00 through 20:00 (PJM Eastern Region) or 8:00 through 21:00 (PJM Western Region), and by weather condition (over a range of local conditions under which it can reasonably be expected that the program will be implemented). Separate matrices must be estimated:

By program (and/or cycling scheme);

By PJM zone.

Switch Operability Rate

In addition to base per-participant impacts, studies submitted to PJM must also include the average switch operability rate, reflecting the percentage of all active switches which both receive the control signal and operate. The switch operability rate must be supplied with the original base impact study, and then updated every five years. Any Provider with a switch operability study older than five years will be given a switch operability rate of 50%.

Utilizing the Deemed Savings Estimates

[Note: The “Deemed Savings Estimates” study report is available on the PJM.com website.]

Eligibility

Load Management Providers with Direct Load Control programs which employ a radio signal may elect to utilize the base per-participant impacts contained in the “Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in PJM Region” report.

Base Impact Value

Base impacts for air conditioning programs will be established utilizing the aggregate values detailed in Appendix F of the Deemed Savings Estimates report. The Provider must supply the applicable duty cycle strategy (percentage of each hour the unit is interrupted) and an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak). The Provider may opt to customize the base impact by supplying a research study which stratifies its program by A/C usage or connected A/C load. In this case, base impacts will be drawn from the aggregate results presented in Appendix G or H, as appropriate.

Base impacts for water heating programs will be established utilizing the aggregate values detailed in Appendix J. The Provider must supply an appropriate weather station or mix of weather stations. PJM will determine the WTHI standard value from average historical peak load weather conditions (coincident with the RTO peak)

EDCs with base impacts presented in the Deemed Savings report (BGE, JCPL, and PSEG) may elect to use those impacts.

Switch Operability Rate

All Providers utilizing the modeled base per-participant impacts must submit to PJM a switch operability rate study, reflecting the percentage of all active switches which both receive the control signal and operate. This study must be designed to achieve a minimum accuracy of 90% Confidence with 10% error. Any Provider without a switch operability study, or with one older than five years will be given a switch operability rate of 50%.

PJM Emergency Load Response Program

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Vice President, Governmental Policy
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EMERGENCY LOAD RESPONSE PROGRAM

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. There are two options for participation in the Emergency Load Response Program:

- ◆ **Full Program Option**
Participants in the Full Program Option receive an energy payment for load reductions during an emergency event and an Active Load Management (“ALM”) credit pursuant to Schedule 5.2 of the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the Reliability Assurance Agreement-South, as applicable.
- ◆ **Energy Only Option**
Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

PARTICIPANT QUALIFICATIONS

Two primary types of distributed resources are candidates to participate in either of the two options provided by the Emergency Load Response Program:

- ◆ **On-Site Generators**
These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.
- ◆ **Load Reduction**
A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

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PJM membership is required to participate in either of the two options provided by the Emergency Load Response Program. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C.*** However, for special members the \$5,000 annual membership fee, the \$1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

- Special Members are limited to be PJM market sellers;
- Voting privileges and sector designation are waived;
- Thirty day notice for waiting period is waived;
- Requirement for 24/7 control center coverage is waived;
- No PJM-supported user group capability is permitted.

To participate in either of the two options provided by the Emergency Load Response Program, the distributed resource must:

- Be capable of reducing at least 100 kW of load
- Be capable of receiving PJM notification to participate during emergency conditions.

To receive ALM Credits participants in the Full Program Option must satisfy the criteria set forth in Schedule 5.2 of the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and the Reliability Assurance Agreement-South, as applicable.

METERING REQUIREMENTS

The Load Response Program participants must have metering equipment that provides integrated hourly kWh values on an EDC account basis, that either meets the EDC requirements for accuracy or has a maximum error of two percent over the full range of the meter (including Potential Transformers and Current Transformers). The metering requirements can be met using either of the following two methods:

- Metering that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator).



Metering that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an EDC account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the CSP and verified by PJM with the EDC.

The installed meter must be one of the following:

- EDC-owned hourly meter,

- Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read electronically by PJM, or

- Customer-owned meter including one provided by an independent metering service provider or acquired from the CSP, approved by PJM, that is read by the customer (or the CSP), the readings from which are forwarded to PJM.

Nothing here changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

REGISTRATION

Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM web site (www.pjm.com). The following general steps will be followed:

1. The participant completes the Emergency Registration Form located on the PJM web site.

PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. PJM also confirms with the appropriate LSE and EDC whether the load reduction is under other contractual obligations. Other such obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. The EDC and LSE have ten (10) business days to respond or PJM assumes acceptance.

2. PJM informs the requesting participant of acceptance into the program and notifies the appropriate LSE and EDC of the participant's acceptance into the program.

Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

EMERGENCY OPERATIONS

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of ALM Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM web site, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price of a Full Program Option participant that reduces load may set the real time Locational Marginal Price ("LMP") provided that the participant's load reductions are needed to meet demand in the PJM Region. The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the Energy Only Option participant's resource satisfies PJM's telemetry requirements.



Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***



VERIFICATION

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for the hour prior to the event, as well as every hour during the event.

These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM. All load reduction data are subject to PJM Market Monitoring Unit audit.

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MARKET SETTLEMENTS

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The minimum duration of a load reduction request is two hours. The magnitude of relief provided by Full Program Option participants shall be the amount PJM dispatches up to the kW amount declared on the Emergency Registration Form. The magnitude of relief provided by Energy Only Option participants could be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form.

PJM pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP. If, however, the sum of the hourly payments (excluding any ALM Credits) to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (*i.e.* Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction when dispatched by PJM shall be assessed the ALM Deficiency Charge specified in Schedule 11 of the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, and Reliability Assurance Agreement-South, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases from the PJM energy market during the hour from day-ahead to real time.

Full Program Option participants that, prior to June 1, 2002, entered into contracts with LSEs or CSPs that enable participation in the Full Program Option, may participate in the Emergency Load Response program during ALM events as long as the customer's ALM contract explicitly excludes payment or credit for energy not consumed during ALM events.

If the LSE that submitted the Full Program Option participant for ALM credit indicates that such participant is not eligible for simultaneous credit under the Emergency Load Response program and ALM is called for concurrent with the Emergency Load Response program, then payments will be made to the participant according to the Emergency Load Response program only for the time during which ALM obligations were not in effect. Any response in excess of the contracted ALM amount will be compensated under the Emergency Load Response program for the entire duration of response.

In the event that a Full Program Option participant entered into an ALM contract with an LSE that enables participation in the Full Program Option after June 1, 2002, such participant shall be credited for load reductions pursuant to this Emergency Load Response Program, notwithstanding any terms or conditions contrary in the contract.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

REPORTING

Actual load reductions will be added back for the purpose of peak load calculations for capacity.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM web site.

On an annual basis PJM will prepare a report that summarizes the status of the program and will submit it to the PJM Board of Managers, the Members Committee, the Reliability Committee, the Energy Market Committee, and the Operating Committee for review.

NON-HOURLY METERED CUSTOMER PILOT

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.



Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

1.5 Market Sellers.

1.5.1 Qualification.

A Member that demonstrates to the Office of the Interconnection that the Member meets the standards for the issuance of an order mandating the provision of transmission service under section 211 of the Federal Power Act, as amended by the Energy Policy Act of 1992, may become a Market Seller upon execution of this Agreement and submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule. All Members that are Market Buyers shall become Market Sellers upon submission to the Office of the Interconnection of the applicable Offer Data in accordance with the provisions of this Schedule.

1.5.2 Withdrawal.

(a) A Market Seller may withdraw from this Agreement by giving written notice to the Office of the Interconnection specifying an effective date of withdrawal at least one day after the date of the notice; provided, however, that withdrawal shall not relieve a Market Seller of any obligation to deliver electric energy or related services to the PJM Interchange Energy Market pursuant to an offer made prior to such withdrawal, to pay its share of any fees and charges incurred or assessed by the Office of the Interconnection prior to the date of such withdrawal, or to fulfill any obligation to provide indemnification for the consequences of acts, omissions, or events occurring prior to such withdrawal; and provided, further, that withdrawal shall not relieve any entity that is a Market Seller and is also a Market Buyer of any obligations it may have as a Market Buyer under, or constitute withdrawal as a Market Buyer from, this Agreement or any other Related PJM Agreement.

(b) A Market Seller that has withdrawn from this Agreement may reapply to become a Market Seller at any time, provided it is not in default with respect to any obligation incurred under this Agreement.

1.5A Economic Load Response Participant.

1.5A.1 Qualification.

A Member or Special Member that is an end use customer, Load Serving Entity or Curtailment Service Provider that has the ability to cause a reduction in demand as metered on an electric distribution company account basis or has an On-Site Generator that enables demand reduction may become an Economic Load Response Participant by complying with the requirements of section 1.5A.

1.5A.2 Special Member.

Entities that are not Members and desire to participate solely in the Real-time Energy Market by reducing demand may become a Special Member by paying an annual membership fee of \$500 plus 10% of each payment owed by the Office of the Interconnection for a Load Reduction Event not to exceed \$5,000 in a calendar year. For entities that become Special Members pursuant to this section, the following obligations are waived: (i) the \$1,500 membership application fee set forth in section 1.4.3 of this Agreement; (ii) liability under section 15.2 of this Agreement for Member defaults; (iii) thirty days notice for waiting period; and (iv) the requirement for 24/7 control center coverage. In addition, such Members shall not have voting privileges in committees or sector designations, and shall not be permitted to form user groups. On January 1 of a calendar year, a Special Member under this section, at its sole election, may become a Member rather than a Special Member subject to all rules governing being a Member, including regular application and membership fee requirements.

1.5A.3 Registration.

Prior to participating in the PJM Interchange Energy Market, Economic Load Response Participants must complete the Economic Load Response Registration Form posted on the Office of the Interconnection's website and submit such form to the Office of the Interconnection for each end-use customer pursuant to the requirements set forth in the PJM Manuals. After confirming that an entity has met all of the qualifications to be an Economic Load Response Participant, the Office of the Interconnection shall notify the appropriate electric distribution company or Load Serving Entity of an Economic Load Response Participant's registration and request verification as to whether the load that may be reduced is subject to another contractual obligation and for confirmation of any associated transmission or distribution charges. The electric distribution company or Load Serving Entity shall have ten business days to respond. In the absence of a response, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations. In the event that the load is subject to another contractual obligation, special settlement terms may be employed to accommodate such contractual obligation. The Office of the Interconnection shall notify the end user or appropriate Curtailment Service Provider or Load Serving Entity that the Economic Load Response Participant has met the requirements of this section 1.5A. End-use customers that desire not to be simultaneously registered to reduce demand under the Emergency Load Response Program and under this section, upon one-day advance notice to the Office of the Interconnection, may switch its registration for reducing demand, if it has been registered to reduce load for 15 consecutive days under its current registration.

1.5A.4 Metering.

Economic Load Response Participants must have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis that either meets the electric distribution company requirements for accuracy or has a maximum error of two percent over the full range of the meter (including potential transformers and current transformers) and that meets the requirements set forth in the PJM Manuals. The Economic Load Response participant must meter reductions in demand either by recording integrated hourly values for On-Site Generators running to serve local load (net of output used by the On-Site Generator), by metering load on an electric distribution company account basis and comparing actual metered load to its Customer Baseline Load, calculated pursuant to section 3.3A of this Schedule, or on an alternative metering basis approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer. To qualify for compensation for such load reductions that are not metered directly by the Office of the Interconnection, data reflecting meter readings for each hour during in which the load reduction occurred must be submitted to the Office of the Interconnection in accordance with the PJM Manuals within 60 days of the load reduction.

1.5A.5 On-Site Generators.

An Economic Load Response Participant that intends to use an On-Site Generator for the purpose of reducing demand to participate in the PJM Interchange Energy Market shall represent to the Office of the Interconnection in writing that it holds all necessary environmental permits applicable to the operation of the On-Site Generator. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to enable participation in the PJM Interchange Energy Market and that the On-Site Generator is being operated in compliance with all applicable permits, including any emissions, run-time limits or other operational constraints that may be imposed by such permits.

1.5A.6 Active Load Management Participation.

An Active Load Management (“ALM”) customer may qualify to submit offers to reduce demand in the PJM Interchange Energy Market during Active Load Management events provided that, if the ALM customer entered into an ALM contract prior to June 1, 2002, such contract explicitly excludes payment or credit for energy not consumed during ALM events. In the event that the Load Serving Entity that is eligible to receive an ALM credit based on a contract with an ALM customer entered into prior to June 1, 2002 indicates that such contract does not permit the ALM customer to simultaneously participate in the PJM Interchange Energy Market pursuant to this section 1.5A.6, then such ALM customer may qualify to submit offers to reduce demand in the PJM Interchange Energy Market only for amounts in excess of its contractual obligations under its ALM contract. An ALM customer that has entered into an ALM

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contract on or after June 1, 2002 shall be eligible to submit offers to reduce demand in the Interchange Energy Market without limitation notwithstanding any terms or conditions to the contrary in its ALM contract.

1.5A.7 Non-Hourly Metered Customer Pilot.

Non-hourly metered customers may participate in the PJM Interchange Energy Market as Economic Load Response Participants on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period. Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering as set forth in Section 1.5A.4 of this Schedule, non-hourly metered customers that qualify as Economic Load Response Participants pursuant to this section 1.5A.7 shall be subject to the rules and procedures for participation by Economic Load Response Participants in the PJM Interchange Energy Market. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the PJM Interchange Energy Market.

1.5A.8 Batch Load Demand Resource Provision of Synchronized Reserve.

(a) A Batch Load Demand Resource may provide Synchronized Reserve in the PJM Interchange Energy Market provided it has pre-qualified by providing the Office of the Interconnection with documentation acceptable to the Office of the Interconnection that shows six months of one minute incremental load history of the Batch Load Demand Resource, or in the event such history is unavailable, other such information or data acceptable to the Office of the Interconnection to demonstrate that the resource meets the definition of "Batch Load Demand Resource" pursuant to section 1.3.1A.001 of this Schedule. This requirement is a one-time pre-qualification requirement for a Batch Load Demand Resource.

(b) Batch Load Demand Resources may provide up to 20 percent of the total system-wide PJM Synchronized Reserve requirement in any hour; provided, however, that in the event the Office of the Interconnection determines in its sole discretion that satisfying 20 percent of the total system-wide Synchronized Reserve requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, the Office of the Interconnection may reduce the percentage of the total system-wide PJM Synchronized Reserve

and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or

directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers, as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

1.8 Selection, Scheduling and Dispatch Procedure Adjustment Process.

1.8.1 PJM Dispute Resolution Agreement.

Subject to the condition specified below, any Member adversely affected by a decision of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market, including the qualification of an entity to participate in that market as a buyer or seller, may seek such relief as may be appropriate under the PJM Dispute Resolution Procedures on the grounds that such decision does not have an adequate basis in fact or does not conform to the requirements of this Agreement.

1.8.2 Market or Control Area Hourly Operational Disputes.

(a) Market Participants shall comply with all determinations of the Office of the Interconnection on the selection, scheduling or dispatch of resources in the PJM Interchange Energy Market, or to meet the operational requirements of the PJM Region. Complaints arising from or relating to such determinations shall be brought to the attention of the Office of the Interconnection not later than the end of the fifth business day after the end of the Operating Day to which the selection or scheduling relates, or in which the scheduling or dispatch took place, and shall include, if practicable, a proposed resolution of the complaint. Upon receiving

must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts; (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed.

3.3.6 Billing.

The Office of the Interconnection shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to Sections 3.3A.4 and/or 3.3A.5 of this Schedule set forth below, for demand reductions measured by comparing actual metered load to an end-use customer's Customer Baseline Load or other alternative metering basis as may be approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer.

3.3A.2 Customer Baseline Load.

(a) For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load, the Customer Baseline Load shall be determined using the following formula:

The Average Day Customer Baseline Load ("CBL")

Average Day CBL formula for weekdays

Step 1: Establish the CBL Basis: A set of days that will serve as representative of end-use customer's typical usage.

The Weekday *CBL Basis Window* is comprised of the 10 most recent days, beginning with the day two days prior to the event day for which the CBL is being calculated, excluding the following day-types.

1. NERC holidays
2. Weekend days
3. Event days, which are defined as days on which:
 - Office of the Interconnection declared a curtailment event for which the end-use customer was eligible, or
 - the end-use customer actually reduced demand and its measured reduction was submitted to the Office of the Interconnection for compensation.
4. Any day which the day's average daily event period usage is less than 75% of the average event period usage level.

To define the days that comprise the weekday CBL Basis Window:

Begin with the 10-day period defined by the weekday that is two days prior to the event through the weekday that is eleven days prior to the event day. This creates a 10-day window.

Eliminate any holidays, and replace them with days beginning with the 12th weekday day prior to the event day continuing until a non-holiday is encountered. This results in a 10-day window.

Eliminate any event days, replacing them with subsequent prior days, picking up with the first day not yet included in the window after completing the holiday replacement requirement.

The final weekday CBL Window must contain 10 weekdays.

Step 2: Establish the CBL basis. Identify the five days from the 10-day weekday CBL Basis Window to be used to develop CBL values for each hour of the event.

For each of the 10 days in the weekday CBL Basis window, create the *average daily event period usage* for that day, which is defined as the simple average of the participant's actual usage over the hours in the day that define the event for which the weekday CBL is being developed.

Create the *average event period usage level* for the 10 days in the weekday CBL Basis Window, which is defined as the simple average of the 10 average daily event period usage values.

Eliminate low usage days. For any day in the 10-day window for which the day's average daily event period usage is less than 75% of the average event period usage level, eliminate that day, then repeat Step 1 and 2 to replace the eliminated days and to create a new 10-day weekday CBL Basis Window.

Order the 10 days in the weekday CBL Basis Window according to their average daily event period usage level, and eliminate the five days with the lowest average daily event period usage.

The remaining five days constitute the weekday CBL Basis.

For each hour of the event, the weekday CBL is the average of the usage in that hour in the five days that comprise the weekday CBL Basis.

Average Day CBL formula for weekends and NERC holidays

Step 1: Establish the CBL Weekend/Holiday Basis Window.

The weekend/holiday CBL Basis Window is comprised of the most recent three like (Saturday or Sunday) weekend days. There are no exclusions for holidays or event days.

Step 2: Establish the Weekend/Holiday CBL Basis.

Calculate the average daily event period usage value for each of the three days in the weekend/ holiday CBL Basis Window.

Order the three days according to their average daily event period usage level.

Eliminate the day with the lowest average value.

The weekend/holiday CBL Basis contains 2 days.

Step 3: Calculate Weekend Average Day CBL values for the event.

For each hour of the event, the CBL value is the average of usage in that hour in the two days that comprise the weekend/holiday CBL Basis.

(b) In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.3 Weather-Sensitive Adjustment.

(a) Concurrent with submitting a Economic Load Response Registration Form to the Office of the Interconnection and annually thereafter, the Economic Load Response Participant shall notify the Office of the Interconnection whether it elects to apply the Weather-Sensitive Adjustment (or "WSA") for the summer period (May-October) or the winter period (November-April). The Weather-Sensitive Adjustment either will decrease or increase Customer Baseline Load values. The Weather-Sensitive Adjustment may apply to measure load reductions in both the Real-time Energy Market and Day-ahead Energy Market, except that the simplified analysis for the summer period cannot be used with regard to the Day-ahead Energy Market. Unless an alternative formula is approved by the Office of the Interconnection and agreed upon by all relevant parties, including any Curtailment Service Provider, Load Serving Entity and end-use customer, the Weather-Sensitive Adjustment shall be calculated using the following formula:

Regression Analysis (available for the summer and winter period.)

Step 1: Perform a regression analysis in Excel using the slope & intercept functions between the end-use customer's on-peak (8 AM to 8 PM), non-holiday, weekday hourly loads and the temperature-humidity index ("THI") on a seasonal basis for the period the WSA is being applied.

The Office of the Interconnection will post on the Office of the Interconnection website a spreadsheet of the THI values for all relevant weather stations located within the PJM region.

The regression analysis will produce a slope (m), expressing in kW/THI, and an intercept (b), expressed in kW, that describes the sensitivity of the end-use customer's load to weather.

Step 2: Determine the average THI for the on-peak hours for the five days used in the weekday CBL calculation.

Step 3: Determine the average THI for the on-peak hours of the event day.

Step 4: Calculate the WSA based on the following formula:

$$WSA = [(m \times THI_{EVENT DAY}) + b] / [(m \times THI_{CBL DAYS}) + b]$$

Simplified Analysis (available only for the summer period and for the Real-time Energy Market)

Step 1: Determine that the load is weather sensitive by agreement of the end-use customer, the Curtailment Service Provider, and the Load Serving Entity or by the Office of the Interconnection if there is no agreement. Weather adjustments could be negative or positive.

Step 2: Show that the hourly temperature reading at the nearest airport that provides weather information to the Office of the Interconnection equaled or exceeded 85 degrees Fahrenheit during each hour of the reduction event. The hourly temperature reading of another major airport nearby the end-use customer's location may be used if it can be shown that the temperature at the end-use customer's location correlates more closely.

Step 3: Calculate the average hourly load over two full hours beginning three hours prior to the Load Reduction Event.

Step 4: Calculate the average hourly load for the same hours using the values given by the CBL calculation.

Step 5: Compare the resulting average two hour loads from Steps 3 and 4.

Step 6: Determine if the difference from Step 5 expressed as a percentage is greater than 5 percent. If the difference is greater than 5 percent then the percentage will be the WSA for the reduction event.

Step 7: Submit an Excel spreadsheet to the Office of the Interconnection documenting the weather adjustment.

- The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.
- For end-use customers without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100 percent. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted in accordance with Steps 1-4 above.

- In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the end-use customer's historical, seasonal, on-peak non-coincident peak load.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide directly metered data and Customer Baseline Load and Weather-Sensitive Adjustment calculations to the appropriate electric distribution company or Load Serving Entity for optional review. The electric distribution company or Load Serving Entity will have ten business days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants participating in the Real-time Energy Market shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The Economic Load Response Participant that curtails or causes the curtailment of demand in real-time will be compensated by the Office of the Interconnection the real-time Locational Market Price less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction. In cases where the demand reduction is dispatched by the Office of the Interconnection, or the strike price of the end-use customer with a Locational Marginal Price based contract, as defined in Section 3.3A.4(d) below, is reached and such demand reduction is dispatched by the Office of the Interconnection, payment will not be less than the total value of the demand reduction bid, including any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed. Any shortfall will be made up through normal, real-time operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(b) An Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the corresponding hourly rate. In the event the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the corresponding hourly rate for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. However, in no event will the Economic Load Response Participant credit be reduced below zero on a daily basis.

(c) Economic Load Response Participants that have Locational Marginal Price based contracts pursuant to which they have agreed to pay their Load Serving

Entity for the physical delivery of energy according to the hour value of the real-time Locational Marginal Price as calculated by the Office of the Interconnection, may choose to reduce demand and be compensated for the reduction in the Real-time Energy Market under the following circumstances. The Economic Load Response Participant shall provide the Office of the Interconnection with a strike price for the end-use customer's zonal Locational Marginal Price at which the end-use customer will reduce demand, as well as any start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the demand reduction must be committed. In cases where the Economic Load Response Participant's zonal Locational Marginal Price reaches the strike price and the demand reduction is dispatched by the Office of the Interconnection, the Office of the Interconnection shall pay such Economic Load Response Participant the difference between the actual savings achieved based on zonal Locational Marginal Price and the total value of the end-use customer's demand reduction bid. For purposes of this provision the total value of the demand reduction bid will be the sum of the strike price times the MW of reduction achieved during each hour of the time period the demand reduction was dispatched by the Office of the Interconnection or the minimum down-time whichever is greater, plus the submitted start-up costs. Demand reductions hereunder will not be eligible to set real-time Locational Marginal Price.

(d) The foregoing notwithstanding, until December 31, 2007 (unless extended by a two-thirds sector vote of the Members Committee), this Section 3.3A.4(d) shall apply. In the event the real-time Locational Marginal Price is greater than or equal to \$75/MWh, an Economic Load Response Participant that curtails or causes the reduction in demand in real-time will be paid the real-time Locational Marginal Price. In such event, an amount equal to the Economic Market Participant's generation and transmission charges, if any, will be recovered from all load within the zone in which the demand that was reduced is located. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction. If, in a calendar year, the total amount of recoverable charges reflecting generation and transmission related to demand reductions in the Real-time Energy Market and Day-ahead Energy Market combined exceeds \$17.5 million, for the remainder of the year, Economic Load Response Participants in the Real-time Energy Market shall receive for their demand load reductions the real-time Locational Marginal Price less an amount equal to the applicable generation and transmission charges regardless of the level of the Locational Marginal Price.

3.3A.5 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants participating in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection shall be paid the day-ahead Locational Marginal Price

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less an amount equal to the applicable generation and transmission charges. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction. Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids will not be less than the total value of the demand reduction bid, including any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall will be made up through normal, day-ahead operating reserves. In all cases, the applicable zonal or aggregate (including nodal) Locational Marginal Price is used as appropriate for the individual end-use customer.

(b) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that cannot demonstrate hourly performance in real-time equal to at least that of the day-ahead commitment will be charged real-time Locational Marginal Price for the amount of the shortfall, plus any associated balancing operating reserve charges. Load Serving Entities that otherwise would have load that was reduced shall receive any associated operating reserve credit plus, if the real-time Locational Marginal Price is higher than the day-ahead Locational Marginal Price during the shortfall, the difference between the day-ahead and the real-time Locational Marginal Price times the shortfall.

(c) Economic Load Response Participants that have real-time Locational Marginal Price-based contracts may not participate in the Day-ahead Energy Market.

(d) The foregoing notwithstanding, until December 31, 2007 (unless extended by a two-thirds sector vote of the Members Committee), this Section 3.3A.5(d) shall apply. In the event that an Economic Load Response Participant that submits a demand reduction bid in the Day-ahead Energy Market is accepted by the Office of the Interconnection when the day-ahead Locational Marginal Price is greater than or equal to \$75 MWh, the Economic Load Response Participant will be paid the day-ahead Locational Marginal Price. In such event, an amount equal to the Economic Market Participant's generation and transmission charges, if any, will be recovered from all load within the zone in which the demand that was reduced is located. The applicable generation and transmission charges are the charges the participant would have otherwise paid the Load Serving Entity absent the demand reduction. If, in a calendar year, the total amount of recoverable charges reflecting generation and transmission related to load reductions in the Real-time Energy Market and Day-ahead Energy Market combined exceeds \$17.5 million, for the remainder of the year, Economic Load Response Participants in the Day-ahead Energy Market shall receive the day-ahead Locational Marginal Price less an amount equal to the applicable generation and transmission charges regardless of the level of the Locational Marginal Price.



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Business Practices Manual

Energy and Operating Reserve Markets

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4.2 Resource Offer Requirements

Resource Offers are submitted by MPs at Resource CPNodes for the purpose of selling Energy and Operating Reserve into the Day-Ahead and Real-Time Energy and Operating Reserve Markets and can be submitted for all types of Resources. There are four types of Resources for which MPs may submit Offers: Generation Resources (including Jointly-Owned Generation Resources, Combined Cycle Resources, Cross Compound Resources, External Pseudo-Tied Generation Resources, Energy Limited Resources and Intermittent Resources), Demand Response Resources-Type I (DRR-Type I), Demand Response Resources-Type II (DRR-Type II) and External Asynchronous Resources. DRR-Type II Offer requirements are identical to Generation Resource Offer requirements and thus are combined under Section 4.2.2. Resource qualifications to provide Operating Reserve and Offer parameters are discussed for each Resource category (with Generation Resource and DRR-Type II combined) in the following Subsections.

4.2.1 Resource Qualifications and Eligibility to Provide Operating Reserve

The following subsections describe the requirements that must be met by any Resource in order to be qualified to submit Operating Reserve Offers for use in the Energy and Operating Reserve Markets. Exhibit 4-9 provides an Operating Reserve eligibility summary for Resources that are qualified to provide Operating Reserve.

Exhibit 4-9: Resource Eligibility Summary for Provision of Operating Reserve

Resource	Day-Ahead and Real-Time		
	Regulating Reserve	Spinning Reserve	Supplemental Reserve
Committed or on-line Generation Resources	✓	✓	✓
Committed or on-line Demand Response Resources - Type II	✓	✓	✓
Available External Asynchronous Resources	✓	✓	✓
Available off-line or uncommitted Quick-Start Resources			✓
Uncommitted Demand Response Resources - Type I		✓	✓

4.2.1.1 Regulation Qualified Resource Requirements

Any Resource that meets the following criteria will be considered a Regulation Qualified Resource and may submit Offers for Regulating Reserve for use in the Energy and Operating Reserve Markets. All Regulation Qualified Resources must:

- synchronized Generation Resources;
- uncommitted Demand Response Resources-Type I;
- synchronized Demand Response Resources-Type II; and
- available External Asynchronous Resources,

that have their hourly Supplemental Qualified Resource availability flags set to “True”.

4.2.2 Generation Resources and DRR-Type II Offer Requirements

The following Subsection describes the economic and operational Offer data for Generation Resources and Demand Response Resources-Type II and how these data are used in commitment and dispatch decisions.

4.2.2.1 Offer Information Summary

Generation Resource and DRR-Type II Offers consist of data submitted by MPs for consideration in commitment and dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Exhibits 4-10 and 4-10A identifies the data that may be included in a Generation Resource or DRR-Type II Offer and the markets in which they apply.

Exhibit 4-10: Generation Resource and DRR-Type II Economic Data Summary

Generation and DRR-Type II Offer Data	Units	Day-Ahead Offer	Real-Time Offer	Notes
Economic Offer Data				
Energy Offer Curve	MW, \$/MWh	Hourly	Hourly	
No-Load Offer	\$/hr	Hourly	Hourly	2
Regulating Reserve Offer	\$/MW	Hourly	Hourly	1
Spinning Reserve Offer	\$/MW	Hourly	Hourly	1
On-Line Supplemental Reserve Offer	\$/MW	Hourly	Hourly	1,3
Off-Line Supplemental Reserve Offer	\$/MW	Hourly	Hourly	4
Hot Start-Up Offer	\$	Daily	Daily	2
Intermediate Start-Up Offer	\$	Daily	Daily	2
Cold Start-Up Offer	\$	Daily	Daily	2
Self-Scheduled Regulation	MW	Hourly	Hourly	1
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly	1
Self-Scheduled On-Line Supplemental Reserve	MW	Hourly	Hourly	1,3
Self-Schedule Off-Line Supplemental Reserve	MW	Hourly	Hourly	4
Self-Scheduled Energy	MW	Hourly	Hourly	
Note 1: If qualified Note 2: Default Offers are also submitted by MPs to restrict the values submitted for Energy and Operating Reserve Markets, also used if no values are submitted for Energy and Operating Reserve Markets. Note 3: If not Spin Qualified Note 4: Quick-Start Resources only.				

Exhibit 4-10A: Generation Resource and DRR-Type II Operating Parameter Data Summary

Generation and DRR-Type II Offer Data	Units	Day-Ahead Offer	Real-Time Offer	Notes
Commitment and Dispatch Operating Parameter Offer Data				
Hot Notification Time	hh:mm	Daily	Daily	
Hot Start-Up Time	hh:mm	Daily	Daily	
Hot to Intermediate Time	hh:mm	Daily	Daily	
Intermediate Notification Time	hh:mm	Daily	Daily	
Intermediate Start-Up Time	hh:mm	Daily	Daily	
Hot to Cold Time	hh:mm	Daily	Daily	
Cold Notification Time	hh:mm	Daily	Daily	
Cold Start-Up Time	hh:mm	Daily	Daily	
Maximum Daily Starts	Integer	Daily	Daily	2
Maximum Weekly Starts	Integer	Daily	Daily	2
Minimum Run Time	hh:mm	Daily	Daily	2
Maximum Run Time	hh:mm	Daily	Daily	2
Minimum Down Time	hh:mm	Daily	Daily	2
Commitment Status	Select	Hourly	Hourly	2
Overall Economic Minimum Limit	MW	Hourly	Hourly	2
Overall Economic Maximum Limit	MW	Hourly	Hourly	2
Overall Regulation Minimum Limit	MW	Hourly	Hourly	2
Overall Regulation Maximum Limit	MW	Hourly	Hourly	2
Hourly Emergency Minimum Limit	MW	Hourly	Hourly	2
Hourly Emergency Maximum Limit	MW	Hourly	Hourly	2
Dispatch Band Economic Minimum Limit	MW	N/A	Hourly	
Dispatch Band Economic Maximum Limit	MW	N/A	Hourly	
Dispatch Band Regulation Minimum Limit	MW	N/A	Hourly	
Dispatch Band Regulation Maximum Limit	MW	N/A	Hourly	
Maximum Off-Line Response Limit	MW	Hourly	Hourly	2,6
Energy Dispatch Status	Select	Hourly	Hourly	2
Regulating Reserve Dispatch Status	Select	Hourly	Hourly	2
Spinning Reserve Dispatch Status	Select	Hourly	Hourly	2
On-line Supplemental Reserve Dispatch Status	Select	Hourly	Hourly	2
Off-line Supplemental Reserve Dispatch Status	Select	Hourly	Hourly	2,6
Single-Directional-Down Ramp Rate	MW/min	N/A	Hourly	2,4
Single-Directional-Up Ramp Rate	MW/min	N/A	Hourly	2,4
Bi-Directional Ramp Rate	MW/min	N/A	Hourly	2,4
Ramp Rate	MW/min	Hourly	Hourly	2,3,4
Single-Directional-Down Ramp Rate Curve	MW/min	N/A	Hourly	4,5
Single-Directional-Up Ramp Rate Curve	MW/min	N/A	Hourly	4,5
Bi-Directional Ramp Rate Curve	MW/min	N/A	Hourly	4,5
Market Availability Flag	Select	Hourly	Hourly	
Combined Cycle Status	Select	Daily	Daily	
Operating Reserve Qualification Flag	Select	Hourly	Hourly	7
<p>Note 2: Default Offers are also submitted by MPs to restrict the values submitted for Energy and Operating Reserve Markets, also used if no values are submitted for Energy and Operating Reserve Markets</p> <p>Note 3: Ramp Rate is used in Day-Ahead and RAC</p> <p>Note 4: Ramp Rates may be submitted by MPs at any time and remain fixed until changed by MPs</p> <p>Note 5: Not applicable if Dispatch Band model is selected</p> <p>Note 6: Only applicable to Quick-Start Resources</p> <p>Note 7: Status selections may be made to represent physical Resource limitations only.</p>				

The Midwest ISO maintains a Day-Ahead Offer¹⁰ and a Real-Time Offer¹¹ for each Generation Resource and DRR-Type II. These Offers are standing offers and maintained for each market independently of the

¹⁰ An Offer submitted for use in the Day-Ahead Energy and Operating Reserve Market clearing.

other. Updates to Generation Resource and DRR-Type II Offers may be designated as updating the Day-Ahead Offer only, the Real-Time Offer only, or both. If a submittal update is not received prior to the applicable Offer submittal timelines, the previous Offer data is in place and used unless otherwise removed or set to “Unavailable”.

Generation Resource and DRR-Type II Offer data may be returned to previously submitted values by submitting the value as null in the Real-Time Offer data or Day-Ahead Offer data respectively.

Offers for Generation Resources and DRRs-Type II that are not designated Network Resources (DNR) may be removed from either Energy and Operating Reserve Market by selecting a market available flag of “False” or by setting the Offer to “Unavailable” provided that the Resource has not been previously committed.

Offers for Generation Resources and DRRs-Type II that are designated Network Resources (DNR) may only be removed from the Real-Time Energy and Operating Reserve Market by selecting a market available flag of “False” if that Resource has not been committed in the Day-Ahead Energy and Operating Reserve Market or Day-Ahead RAC process. Additionally, for DNRs, Offers cannot be set to “Unavailable” Day-Ahead but may be set to “Unavailable” in Real-time provided that the Resource has not been previously committed.

The following two Subsections describe the Economic Offer Data and the Commitment and Dispatch Operating Data Offer Parameters specified in Exhibit 4-10 in more detail.

4.2.2.2 Economic Offer Data

The economic Offer data parameters for Generation Resources and DRR-Type II as identified in Exhibit 4-10 are described in more detail below.

4.2.2.2.1 Energy Offer Curves (MW/Price Pairs)

Energy Offer MW/Price pairs are submitted as part of the Day-Ahead Offer, Real-Time Offer, or both. Up to ten MW/Price pairs may be submitted for each hour of the day for the Day-Ahead Energy and Operating Reserve Market and for the Real-Time Energy and Operating Reserve Market. Exhibit 4-11 illustrates the Energy Offer options.

¹¹ An Offer submitted for use in any RAC process and for use in the Real-Time Energy Operating Reserve Market clearing within the Operating Hour.

- To submit a Self-Schedule for Spinning Reserve, the MP submits a Resource Self-Schedule MW value for Spinning Reserve and sets the Spinning Reserve Dispatch Status to Self-Schedule. Spinning Reserve will not be cleared above the Self-Scheduled Spinning Reserve MW amount.
- Self-Schedules for Supplemental Reserve can only be submitted for a Quick-Start Resource or an on-line Resource that is not a Spin Qualified Resource. To submit a Self-Schedule for Supplemental Reserve, the MP submits a Resource Self-Schedule MW value for Supplemental Reserve and sets the Supplemental Reserve Dispatch Status to Self-Schedule. Supplemental Reserve will not be cleared above the Self-Scheduled Supplemental Reserve MW amount.

In all cases, the minimum amount of Self-Schedule MW for Energy, Regulating Reserve, Spinning Reserve or Supplemental Reserve is equal to 1 MW.

Submitting a Self-Schedule value does not guarantee the unit is committed; the MP must designate the commitment status as “Must-Run” to achieve this result. A Self-Schedule is a price taker up to Self-Schedule MW level.

Submitted Self-Schedules may be rejected by the Midwest ISO if such schedules can not be physically implemented based upon submitted Resource limits and ramp rates.

4.2.3 Demand Response Resources-Type I (DRR-Type I) Offer Requirements

The following Subsection describes the economic and operational Offer data for Demand Response Resources-Type I and how these data are used in commitment and dispatch decisions.

4.2.3.1 Offer Information Summary

DRR-Type I Offers consist of data submitted by MPs for consideration in commitment and dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Exhibit 4-21 identifies the data that may be included in a DRR-Type I Offer and the markets in which they apply.

Exhibit 4-20: DRR-Type I Offer Data Summary

DRR-Type I Offer Data	Units	Day-Ahead Offer	Real-Time Offer	Notes
Economic Offer Data				
Hourly Curtailment Offer	\$/hr	Hourly	Hourly	2
Shut-Down Offer	\$	Daily	Daily	2
Spinning Reserve Offer	\$/MW	Hourly	Hourly	1
Supplemental Reserve Offer	\$/MW	Hourly	Hourly	1
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly	1
Self-Scheduled Supplemental Reserve	MW	Hourly	Hourly	1
Commitment and Dispatch Operating Parameter Offer Data				
Targeted Demand Reduction Level	MW	Hourly	Hourly	
Minimum Interruption Duration	hh:mm	Daily		
Maximum Interruption Duration	hh:mm	Daily		
Minimum Non-Interruption Interval	hh:mm	Daily		
Shut-Down Time	hh:mm	Daily		
Shut-Down Notification Time	hh:mm	Daily		
Commit Status	Select	Hourly	Hourly	2
Market Availability Flag	Select	Hourly	Hourly	
Contingency Reserve Qualification Flag	Select	Hourly	Hourly	3
Contingency Reserve Dispatch Status	Select	Hourly	Hourly	
Note 1: If qualified Note 2: Default Offers are also submitted by MPs to restrict the values submitted for Energy and Operating Reserve Markets, also used if no values are submitted for Energy and Operating Reserve Markets Note 3: Status selections may be made to represent physical Resource limitations only.				

The Midwest ISO maintains a Day-Ahead Energy and Operating Reserve Market Offer and a Real-Time Energy and Operating Reserve Market Resource Offer for each DRR-Type I. These Offers are standing offers and maintained for each market independently of the other. Updates to DRR-Type I Offers may be designated as updating the Day-Ahead Energy and Operating Reserve Market Offer only, the Real-Time Energy and Operating Reserve Market Offer only, or both. If a submittal update is not received prior to the applicable Offer submittal timelines, the previous Offer data is in place and used unless otherwise removed or set to “Unavailable”.

DRR-Type I Offer data may be returned to previously submitted values by submitting the value as null in the Real-Time Offer data or Day-Ahead Offer data respectively.

Offers for DRRs-Type I that are not designated Network Resources (DNR) may be removed from either Energy and Operating Reserve Market by selecting a market available flag of “False” or by setting the Offer to “Unavailable” provided that the Resource has not been previously committed.

Offers for DRRs-Type I that are designated Network Resources (DNR) may only be removed from the Real-Time Energy and Operating Reserve Market by selecting a market available flag of “False” if that Resource has not been committed in the Day-Ahead Energy and Operating Reserve Market or Day-Ahead

RAC process. Additionally, for DNRs, Offers cannot be set to “Unavailable” Day-Ahead but may be set to “Unavailable” in Real-time provided that the Resource has not been previously committed.

The following two Subsections describe the Economic Offer Data and the Commitment and Dispatch Operating Data Offer Parameters specified in Exhibit 4-20 in more detail.

4.2.3.2 Economic Offer Data

The economic Offer data parameters for a DRR-Type I as identified in Exhibit 4-20 are described in more detail below.

4.2.3.2.1 Energy Offer

Energy Offer price/MW pairs can not be submitted for a DRR-Type I because a DRR-Type I is not dispatchable on a 5-minute basis within the Operating Hour. As such, economic Offer data for a DRR-Type I is limited to a Shut-Down Offer and an Hourly Curtailment Offer. These two values are considered in the decision to commit a DRR-Type I to provide Energy. The Targeted Demand Reduction Level is the amount of Energy a DRR-Type I is committed to provide if committed based on economics.

The Shut-Down Offer may be submitted as part of the Default Offer or Daily Offer and the Hourly Curtailment Offer may be submitted as part of the Default Offer or Hourly Offer. The Real-Time Energy and Operating Reserve Market Shut-Down Offers and Hourly Curtailment Offers may be modified at any time prior to 1700 EST (OD-1) for consideration in the pre Day-Ahead RAC. The Shut-Down Offers may be only one value for the day whereas the Hourly Curtailment Offers may vary for each hour of the day. If a DRR-Type I was shut down more than once per day during the commitment, each shut down would be considered separately. Shut-Down time does not include any notification time.

4.2.3.2.2 Operating Reserve Offers

DRRs-Type I that are Spin Qualified Resources may submit Spinning Reserve Offers for use in the Energy and Operating Reserve Markets. DRRs-Type I that are Supplemental Qualified Resources but are not Spin Qualified Resources may submit Supplemental Reserve Offers for use in the Energy and Operating Reserve Markets. The allowed range for Contingency Reserve Offers is currently \$0.00 to \$100.00. If a DRR-Type I is committed for Energy, it can not provide Spinning Reserve or Supplemental Reserve.

4.2.3.3 Commitment and Dispatch Operating Parameter Offer Data

The Resource Offer parameters used in Day-Ahead Energy and Operating Reserve Market and RAC commitment and dispatch decisions are shown in Exhibit 4-21.

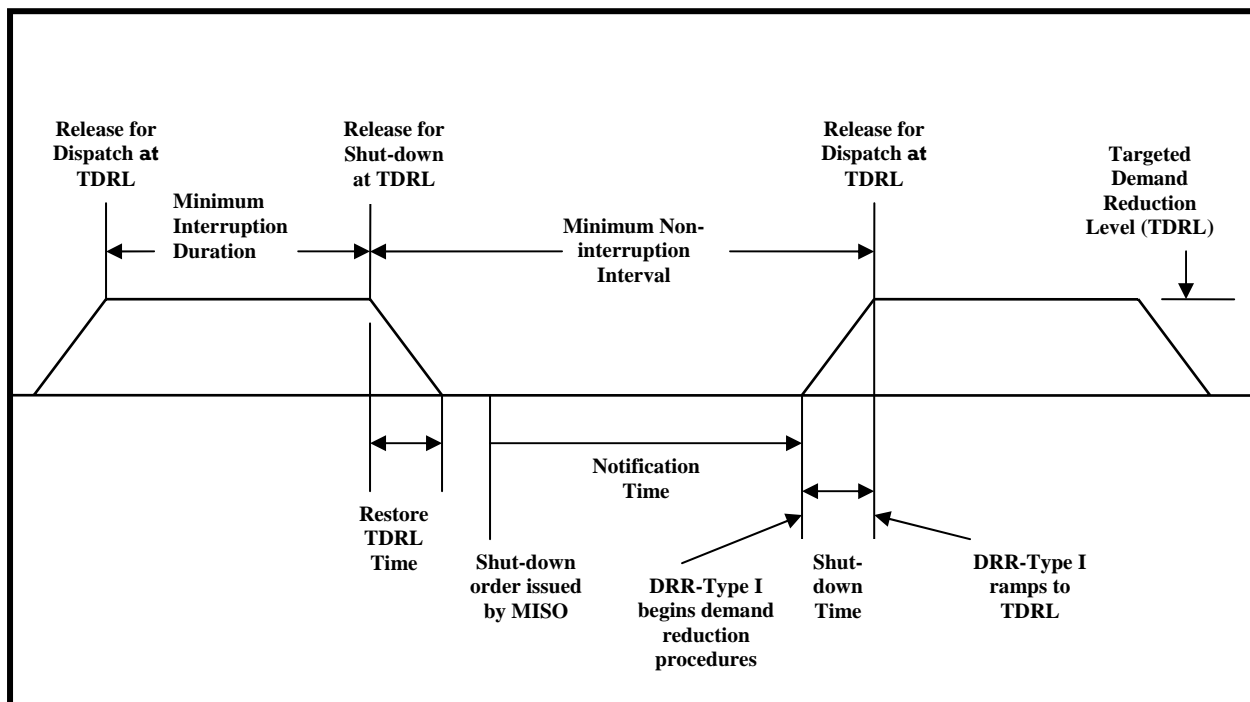
Exhibit 4-21: DRR-Type I Offer Parameters

Parameter	Validation	Use
<i>Notification Time</i>	The Shut-Down Notification Time parameter is submitted as part of the Daily Offer. These times are accepted in hh:mm format. The default value is 00:00.	The Shut-Down Notification Time is used in evaluating the commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, in conjunction with the associated Shut-Down Time, establishes the time required to shut down the Resource at the Targeted Demand Reduction Level.
<i>Shut-Down Time</i>	The Shut-Down Time parameter is submitted as part of the Daily Offer. This time is accepted in hh:mm format.	The Shut-Down Time is used in evaluating commitment in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market. This parameter, in conjunction with the associated Shut-Down Notification Time, establishes the time required to shut down the Resource at the Targeted Demand Reduction Level.
<i>Minimum Interruption Duration</i>	The Minimum Interruption Duration is submitted as part of the Daily Offer. This time is accepted in hh:mm format.	The Midwest ISO schedule commitments in the Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market are for at least as many consecutive hours as specified by Minimum Interruption Duration. Commitment times may be for greater than the Minimum Interruption Duration if a DRR-Type I is economic for additional hours.
<i>Minimum Non-Interruption Interval</i>	The Minimum Non-Interruption Interval is submitted as part of the Daily Offer. This time is accepted in hh:mm format. The default value is 00:00.	The Day-Ahead Energy and Operating Reserve Market and the Real-Time Energy and Operating Reserve Market commitments respect the Minimum Non-Interruption Interval in determining when a DRR-Type I is available for shut down.
<i>Maximum Interruption Duration</i>	The Maximum Interruption Duration can only be submitted as part of the Daily Offer. This time is accepted in hh:mm format. The default value is 99:99.	The Maximum Interruption Duration restricts the number of hours a DRR-Type I can be shut down during the Day-Ahead Energy and Operating Reserve Market or during a study period for the Real-Time Energy and Operating Reserve Market.

Further explanation of specific DRR-Type I parameters used for commitment purposes are provided below along with a graphical representation of how they tie together as depicted in Exhibit 4-22:

- ***Shut-Down Notification Time*** – The minimum time required from the time an order is received from the Midwest ISO to reduce consumption by an amount equal to the Targeted Demand Reduction Level to the time when the DRR-Type I begins demand reduction procedures.
- ***Shut-Down Time*** – The total time required from the time the DRR-Type I begins demand reduction procedures to the time the DRR-Type I has reduced demand equal to the Targeted Demand Reduction Level.

- ***Minimum Interruption Duration*** – The minimum number of hours at the Targeted Demand Reduction Level that the DRR-Type I owner requires the Midwest ISO recognize when committing the Resource or when deploying Contingency Reserve on that Resource. The Minimum Interruption Duration applies from the point where the DRR-Type I has reduced consumption by the Targeted Demand Reduction Level to the point where the Midwest ISO releases the DRR-Type I for de-commitment. Market Participants should exclude the Shut-Down Time and Start-Up Time (as defined in Exhibit 4-22) from the Minimum Interruption Duration to ensure the software recognizes the constraints described by all of the DRR-Type I parameters on cycling the Resource in the commitment process. DRR-Type I clearing in the DAM or committed in the RAC will have schedules for consecutive hours that are equal to or greater than the Minimum Interruption Duration.
- ***Minimum Non-Interruption Interval*** – The minimum number of hours that the DRR-Type I owner requires between the time the DRR-Type I is released to restore the Targeted Demand Reduction Level by the Midwest ISO and the time the DRR-Type I can reduce consumption equal to the Targeted Demand Reduction Level. Market Participants should include the Start-Up Time and the Shut-Down Time (as defined in Exhibit 4-23) in the Minimum Non-interruption Interval to ensure the software recognizes the constraints described by all of the DRR-Type I parameters on cycling the Resource in the commitment process. DRR-Type I clearing in the DAM or committed in the RAC will have schedules that do not violate the Minimum Non-Interruption Interval.

Exhibit 4-22: DRR-Type I Operation Timeline

4.2.3.3.1 DRR-Type I Commitment Status

Both a Day-Ahead Offer and Real-Time Offer have an associated DRR-Type I commitment status. The commitment status impacts the considerations made in unit commitment. The three commitment statuses are:

- **Unavailable** – designates the DRR-Type I is not available for Energy commitment in the Energy and Operating Reserve Markets.
- **Emergency** – designates the DRR-Type I is available for commitment for Energy in Emergency situations only.
- **Economic** – designates the DRR-Type I is available for commitment for Energy by the Midwest ISO. The default status for a DRR-Type I is the Economic status.

The single value commitment status submitted in the default Offer applies to the entire day. The commitment status can vary by hour in the Day-Ahead Offer or Real-Time Offer.

4.2.3.3.2 DRR-Type I Offer Dispatch Status

Dispatch Status for a DRR-Type I only applies to Contingency Reserve status. Contingency Reserve Dispatch Status selections made in combination with Commitment Status selections allow a DRR-Type I

to choose whether or not they are committed for Energy only or dispatched for Contingency Reserve only under both normal and Emergency conditions. Valid Contingency Reserve Dispatch Status selections for a DRR-Type I are: Economic, Self-Schedule, Emergency or Unavailable. Exhibit 4-23 shows the valid Dispatch Status and Commit Status selection combinations to achieve the desired results.

Exhibit 4-23: Valid DRR-Type I Commit and Dispatch Status Combinations

Commit Status	Contingency Reserve Dispatch Status	Normal			Emergency			Unavailable
		Energy Only	Contingency Reserve Only	Both	Energy Only	Contingency Reserve Only	Both	Both
Economic	Economic			√				
Economic	Unavailable	√						
Economic	Self-Schedule	Not Valid						
Economic	Emergency							
Unavailable	Economic		√					
Unavailable	Unavailable							√
Unavailable	Self-Schedule		√					
Unavailable	Emergency					√		
Emergency	Economic	Not Valid						
Emergency	Self-Schedule	Not Valid						
Emergency	Unavailable				√			
Emergency	Emergency						√	

4.2.3.3.3 DRR-Type I Self-Schedule

DRRs-Type I can only submit Self-Schedules for Spinning Reserve or Supplemental Reserve in amounts less than or equal to the Targeted Demand Reduction Level. Submitting a Self-Schedule for Spinning Reserve or Supplemental Reserve will guarantee that the DRR-Type I clears for Contingency Reserve to the extent that the Self-Scheduled MWs are needed to meet the Market-Wide or Zonal Contingency Reserve Requirements. Spinning Reserve or Supplemental Reserve will not be cleared above the Self-Scheduled amounts. A Self-Schedule is a price taker up to Self-Schedule MW level.

4.2.4 External Asynchronous Resources (EAR) Offer Requirements

The following Subsection describes the economic and operational Offer data for EARs and how these data are used in commitment and dispatch decisions.

- Limit updates for subsequent hours are accepted through the Market Portal without requiring a phone call.
- Dispatch Band selection may be submitted at any time via ICCP or via a phone call if ICCP is no functional.

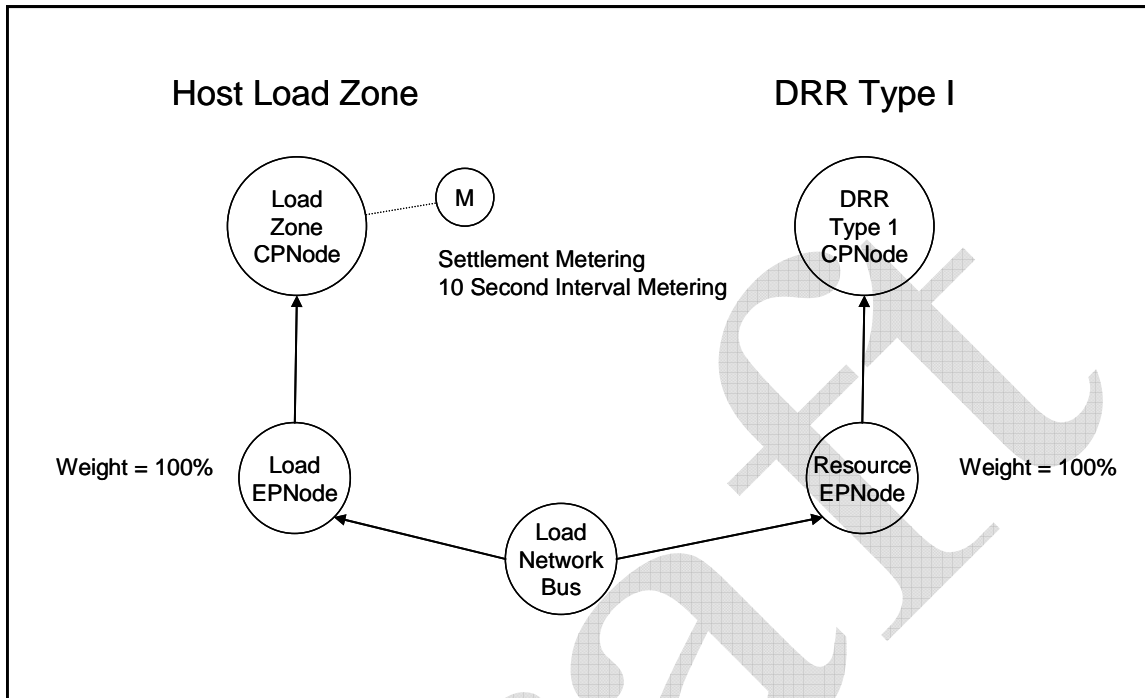
4.2.6 Resource Modeling

The following Subsection describe the special modeling requirements associated with Demand Response Resources-Type I, Demand Response Resources-Type II, External Asynchronous Resources, Jointly-Owned Generation Resources, Combined Cycle Resources, Cross Compound Resources, Energy Limited Resources, System Support Resources, Intermittent Resources and Resources under 5 MW.

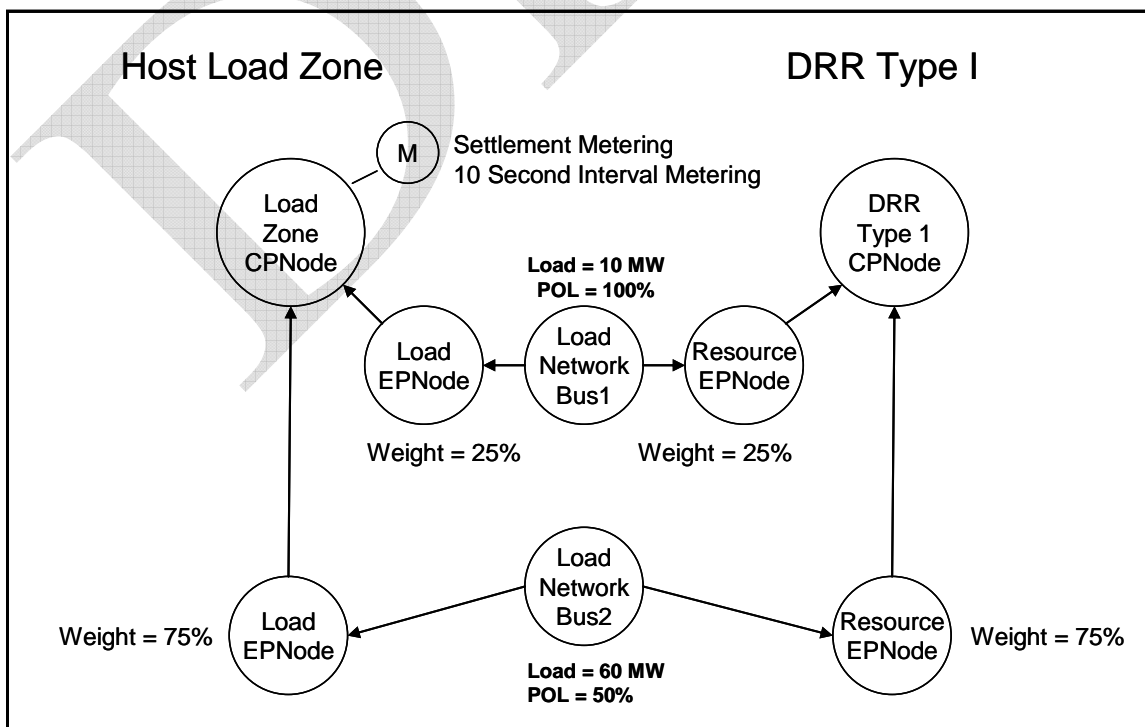
4.2.6.1 Demand Response Resources-Type I

A Demand Response Resource-Type I (DRR-Type I) is defined as any Resource hosted by an energy consumer or Load Serving Entity that is capable of supplying a specific amount of Energy or Contingency Reserve, at the choice of the Market Participant, to the Energy and Operating Reserve Markets through physical load interruption. This specific amount of Energy or Contingency Reserve is determined through the Targeted Demand Reduction Level Offer parameter.

No special modeling of a DRR-Type I is required in the Network Model, the Network model will continue to model the DRR-Type I as host Load only. However, for Commercial Modeling purposes, in order to model the DRR-Type I as a Resource, a special DRR-Type I CPNode is created and has the same definition as its associated host Load Zone CPNode. A DRR-Type I may be modeled based upon a single EPNode Load Zone or a multiple EPNode Load Zone depending upon the type of program being modeled. If the DRR-Type I is an interruptible load at a specific Bus the single EPNode modeling is used. To model load reductions within an existing multi-EPNode Load Zone relating to air-conditioning/hot water heater load reduction programs or other similar programs, the multi-EPNode is used. In either case, a separate Load Zone must be created to model the DRR-Type I load and separate Load Zone Settlement metering and 10 second interval metering must be submitted for the Host Load Zone. Exhibit 4-30 illustrates typical modeling for a single EPNode Load Zone DRR-Type I and Exhibit 4-31 illustrates typical modeling for a multiple EPNode aggregated DRR-Type I Load Zone

Exhibit 4-30: Single EPNODE DRR-Type I

In this Example, the Host Load Zone owns 100% of the load at the Bus, resulting in 100 % Load and Resource EPNODE weights.

Exhibit 4-31: Multiple EPNODE DRR-Type I

In this modeling example, the Host Load Zone owns 100 % of the Load at Bus 1 and 50% of the Load at Bus 2. The 10 MW load at Bus1 and the 60 MW Load at Bus2 represent the expected amount of load that can be reduced resulting from a DRR-Type I commitment for Energy. The Resource and Load EPNode weights are calculated based on the Host Load Bus Load ownership, 10 MW at Bus1 (100% * 10) and 30 MW at Bus 2 (50% * 60 MW): Bus1 Load and Resource EPNode weight = 10 MW/40 MW or 25%, Bus2 Load and Resource EP Node weight = 30 MW/40 MW = 75%. In this case, the DRR-Type I Targeted Demand Reduction Level would be 40 MW.

In either the single EPNode or multi-EPNode modeling, multiple DRR-Type I Resources can be associated with the same host CPNode as long as the host CPNode and all DRR-Type I CPNodes are owned by the same Asset Owner.

If the DRR-Type I is committed for Energy, the DRR-Type I output is set equal to the Targeted Demand Reduction Level. If the DRR-Type I is cleared for Contingency Reserve, amounts cleared can range from 1 MW up to the Targeted Demand Reduction Level, however, any Contingency Reserve Deployment Instructions issued to the DRR-Type I in Real-Time will be at the Targeted Demand Reduction Level.

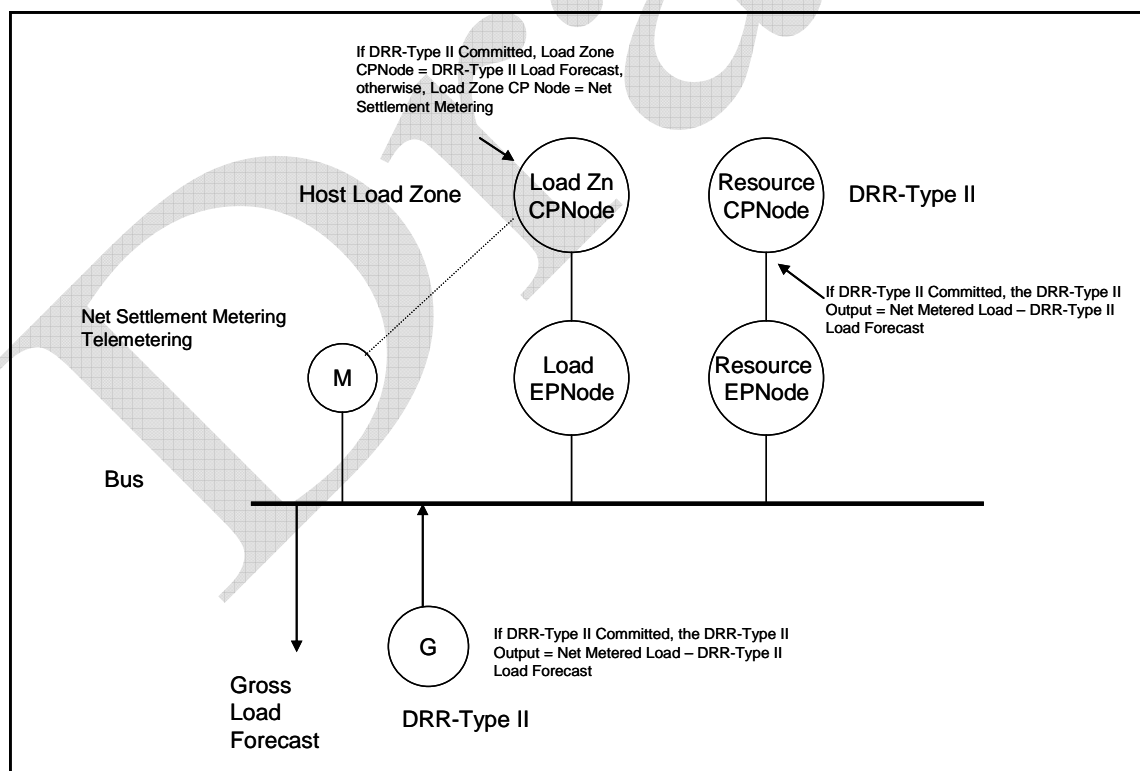
Each DRR-Type I must have interval metering installed that will capture demand consumption on a 4 to 10 second basis and such demand metering results must be submitted to the Midwest ISO at the same time that Metered data is submitted for Settlement purposes. The Midwest ISO analyzes the interval meter data to determine DRR-Type I compliance with commitment instructions to produce Energy or Contingency Reserve Deployment Instructions. If the DRR-Type I is committed to provide Energy, the data is used to verify that the DRR-Type I has reduced consumption in an amount equal to 75% of the Targeted Demand Reduction Level within the first 5 minutes of the Hour for which the DRR-Type I is committed. The DRR-Type I must meet this target in order to be eligible to receive Real-Time RSG credits. If the DRR-Type I is committed to provide Contingency Reserve and there is one or more Contingency Reserve Deployment Instructions issued to the DRR-Type I in an Hour, the submitted interval meter data is used by the Midwest ISO to determine compliance with the deployment instructions.

Hourly Energy Settlement relating to a DRR-Type I consists of two components: (1) Payment to the DRR-Type I at the CPNode LMP for the Targeted Demand Reduction Level in any Hour that the DRR-Type I is committed for Energy; and (2) charges to the Host Load Zone in any Hour the DRR-Type I is committed for Energy at the CPNode LMP for the submitted hourly Actual Energy Withdrawal minus the Targeted Demand Reduction Level (assuming injections are positive and withdrawals are negative). The adjustment to the Host Load CPNode Energy Settlement is required because we are modeling the demand reduction as a Resource output. A similar adjustment is applied in the Day-Ahead Energy and Operating Reserve Market by allowing the host CPNode demand to clear independently from the DRR-Type I CPNode.

4.2.6.2 Demand Response Resources-Type II

A Demand Response Resource-Type II is defined as any Resource hosted by an energy consumer or Load Serving Entity that is capable of supplying a range of Energy and/or Operating Reserve, at the choice of the Market Participant, to the Energy and Operating Reserve Markets through behind-the-meter generation and/or controllable load. Because a DRR-Type II may consist of both behind-the-meter generators and controllable load and we are modeling the DRR-Type II as a supply resource and revenue metering and telemetering are provided on a net basis at the Bus, special modeling is required in both the Network Model and the Commercial Model to account for the DRR-Type II properly as a Resource and to properly settle the associated host Load Zone demand when the DRR-Type II is committed. A DRR-Type II may only be modeled based upon a single EPNode to Load Zone CPNode representation. Additionally, to the extent behind-the-meter generation is currently modeled in the Network Model as a generator but settlement at the CPNode level is based off of a net metered load value, this type of behind-the-meter generation cannot be designated as a DRR-Type II and must be registered as a generation asset in order to participate directly in the Energy and Operating Reserve Markets. Exhibit 4-32 illustrates both Network Modeling and Commercial Modeling for a DRR-Type II.

Exhibit 4-32: DRR-Type II Modeling Example



In order to model the DRR-Type II as a Resource, a special DRR-Type II EPNode and CPNode is created in addition to the existing host Load Zone EPNode/CPNode representation. The DRR-Type II

telemetry combined with the DRR-Type II Load Forecast are used to calculate the DRR-Type II output at the DRR-Type II CPNode each Hour the DRR-Type II is committed. The DRR-Type II Load Forecast is provided to the Midwest ISO by the host LSE or energy consumer via ICCP every 5 minutes and reflects expected gross demand consumption by fixed and controllable load over the next 5-minute interval which does not include any expected load reductions resulting from DRR-Type II commitment. The calculated DRR-Type II output is compared to the DRR-Type II Dispatch Target for Energy for performance monitoring purposes. The DRR-Type II output is calculated for each 5-minute interval as follows, assuming injections are positive and withdrawals are negative:

$$\text{Calculated DRR-Type II Output} = \text{DRR-Type II telemetered amount} - \text{DRR-Type II Load Forecast}^{17}$$

Consider the following example. Assume the submitted DRR-Type II Hourly Economic Maximum Limit is 55 MW. For the next 5-minute interval, the DRR-Type II receives a Dispatch Target for Energy that averages 50 MW and the host LSE's or energy consumer's DRR-Type II Load Forecast for average consumption for that 5-minute interval of 70 MW. If the DRR-Type II performed perfectly and the DRR-Type II Load Forecast was exactly correct, we would expect to see an average DRR-Type II telemetered amount equal to negative 20 MW over the 5-minute interval (50 MW output – 70 MW demand). However, if we assume that the DRR-Type II telemetered amount is actually negative 25 MW, we need to calculate the actual DRR-Type II output which is equal to:

$$\text{Calculated DRR-Type II Output} = (-25 \text{ MW}) - (-70 \text{ MW}) = (+45 \text{ MW}).$$

Exhibit 4-34 provides some additional calculations for hourly DRR-Type II Energy Settlements for each 5-minute interval in an Hour.

¹⁷ For Energy Settlement purposes, the net telemetered values are adjusted based upon the end of month Metered values submitted for the Host CPNode.

Exhibit 4-33: DRR-Type II Hourly Settlement Calculations

Interval	Net Telemetered Value ¹⁸ (1)	DRR-Type II Load Forecast (2)	Average Dispatch Target	Calculated DRR-Type II Output (3) = (1) – (2)	Host CPNode (4) = (1) – (3)
1	-38	-70	30	32	-70
2	-40	-69	30	29	-69
3	-42	-70	30	28	-70
4	-33	-70	35	37	-70
5	-32	-68	35	36	-68
6	-30	-71	40	41	-71
7	-22	-70	45	48	-70
8	-24	-72	50	48	-72
9	-16	-70	55	54	-70
10	-25	-70	50	45	-70
11	-23	-70	45	47	-70
12	-30	-69	35	39	-69
Hourly Value	-29.58	-69.92	40.00	40.33	-69.92

The hourly values shown in green are used to calculate payments to the DRR-Type II Resource and charges from the Host Load Zone for the Hour. The adjustment to the host CPNode Energy Settlement is required because we are modeling the demand reduction as a Resource output. A similar adjustment is applied in the Day-Ahead Energy and Operating Reserve Market by allowing the host CPNode demand to clear independently from the DRR-Type II CPNode. If the DRR-Type II is not committed, the Host Load Zone settlement remains unchanged.

4.2.6.3 External Asynchronous Resources

An External Asynchronous Resource is defined as a DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is represented within the Midwest ISO Region through a Fixed Dynamic Interchange Schedule Import Schedule. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid. An EPNODE and CPNode are created for the EAR at the time of asset registration. Even though an EAR is modeled as a Resource internal to the Midwest ISO BA similar to a Pseudo-Tied External Resource, an EAR must have an associated Fixed Dynamic Interchange Schedule Import Schedule to participate in either the Day-Ahead and Real-Time Energy and Operating Reserve Markets or just the Real-Time Energy and Operating Reserve Market that is linked to the EAR CPNode. This Fixed Dynamic Interchange Schedule Import Schedule is used to ensure that the proper transmission reservation and corresponding estimated schedule has been made prior to accepting the EAR Offers for use in market

¹⁸ Adjusted for actual Hourly net Metered value.

LaaR Responsive Reserve Qualification

ERCOT Process For Qualification Testing Of High Set Interruptible Load In Accordance With ERCOT Protocols And Guides

Introduction

In ERCOT's evolving market model, interruptible load is a marketable product under the ERCOT Protocols. The four types of ancillary services that may be provided by Loads Acting as a Resources (LaaRs) are:

- Responsive Reserve Service
- Non Spinning Reserve Service
- Replacement Reserve Service
- Balancing Energy Service.

QSE's providing Ancillary Services shall meet qualification criteria and performance measures to operate satisfactorily within ERCOT. ERCOT shall develop an Ancillary Services qualification and testing program for all suppliers of Ancillary Services that is based on key factors needed for reliability.

Each type of service has its own requirements. This document provides for the initial qualification of load that is controlled by under-frequency relays and is capable of being manually interrupted within 10 minutes as is required to provide Responsive Reserve Service. Once a resource has qualified for Responsive Reserve Service the load may also be qualified to provide Non-Spinning Reserve Service, Replacement Reserve Service, and Balancing Energy Service. To accommodate ERCOT's system, loads qualified to provide Responsive Reserve Service shall be bid and scheduled as a UFR type resource.

SCOPE

This document defines procedures for the initial testing of loads desiring qualification to provide Responsive Reserve (RRS). Loads wanting to provide RRS can be qualified by performing a simulated test or by actually interrupting the load. The simulated test is designed to test the loads ability to be manually deployed by the QSE. It is not intended to test the under-frequency relay's ability to interrupt during an under-frequency condition. The protocols also allow loads to provide RRS provisionally until final testing can be successfully completed or the provisional qualification has expired. This document includes the requirements for provisional qualification. Performance monitoring and seasonal evaluations, which are required in the protocols, are addressed in the Operating Guides, and not within this document.

Provisional Qualification

All loads may be provisionally qualified for a period of ninety days as a Load acting as a Resource and may be eligible to participate as Resource

To request provisional qualification for RRS, the following is required:

- Resource Registration (complete, or update, Resource Registration form)
- Asset registration of LaaR (complete Resource: Loads acting as a Resource Registration form)
- Telemetry is in place and tested through the QSE to ERCOT showing:
 - ✓ load MW telemetry on each breaker of LAAR
[each registered LAAR may consist of load on multiple breakers;
for multiple loads less than 10 MW, then calculated MW is allowed]
 - ✓ breaker status [physical breaker status for load greater than 10MW;
for breaker load less than 10 MW, then calculated breaker status is allowed]
 - ✓ response MW telemetry (non-zero when supplying service)
 - ✓ the status of the high set under frequency relay.
 - ✓ verify LaaR response in QSE's schedule control error(SCE)
- Affidavit for provisional qualification of Loads to provide RRS is executed and provided to the ERCOT Demand Side Resource Coordinator

Qualification Requirements and Testing Procedure

Prior to being tested, each load requesting to be qualified to provide RRS shall have in place:

- Resource Registration (complete, or update, Resource Registration form)
- Asset registration of LaaR (complete Resource: Loads acting as a Resource Registration form)
- High Set under frequency relay set point documentation of the relay used to shed load at low frequency, the relay set point and typical loads to be shed is provided to the ERCOT customer representative and local TDSP. This documentation shall include the relay frequency setting as well as the operating time. (loads shall have their Under Frequency Relay tested to operate no lower than 59.7 Hz with a operating time of 20 cycles or less.)
- Provide simplified one-line diagram of LaaR facilities that include the underfrequency relay, control switches, operating devices, telemetry points, etc and label as Attachment A to this document
- Telemetry is in place and tested through the QSE to ERCOT showing:

- ✓ Load MW telemetry on each breaker of LAAR [each registered LAAR may consist of load on multiple breakers; for multiple loads less than 10 MW, then calculated MW is allowed]
 - ✓ Breaker status [physical breaker status for load greater than 10MW; for breaker load less than 10 MW, then calculated breaker status is allowed]
 - ✓ Response MW telemetry (non-zero when supplying service)
 - ✓ Status of the high set under frequency relay.
 - ✓ Verify LaaR response in QSE's schedule control error (SCE)
- Affidavit for Actual or Simulated Load Shedding Test executed and provided to the ERCOT Demand Side Resource Coordinator
 - Test date and deployment window is scheduled with ERCOT Demand Side Resource Coordinator and with the local TDSP representative. The TDSP is required only for simulated test. To schedule, complete the top portion of the RESULTS of RESPONSIVE RESERVE QUALIFICATION TESTING form and submit to the ERCOT Demand Side Resource Coordinator by either e-mail (mpatterson@ercot.com) or fax (attn: Mark Patterson; fax # 512-248-6560).

RRS Load Qualification Testing Procedure

QSE's wanting to qualify their Interruptible Load for the first time should propose a test date for tripping such loads or simulating such a trip with ERCOT. Each test shall be scheduled through the ERCOT Demand Side Resource Coordinator.

Testing may be accomplished by either actual load shedding, or simulation, at the requestor's option. If simulation is requested, the simulation must be witnessed and coordinated by a representative of the local TDSP.

Test procedure for actual load shedding follows:

On the date of the test the ERCOT Testing Operator shall call the QSE on a recorded phone line at a time left to ERCOT's discretion but within the agreed upon test window and order the interruptible load used as RRS to be removed from service.

At the direction of ERCOT, the QSE Operator shall initiate shedding of the load to be tested, recording the load prior to shedding, the name of the load shed (in the case of feeder loads the name of the substation and feeder line will suffice), the time of the shedding action, and any limiting factors.

During this test ERCOT will remain in telephone contact with the QSE shedding load. The ERCOT Testing Operator will announce immediately when he/she observes the load shed. The load shedding entity may immediately restore the shed load.

Test procedure for simulated load shedding follows:

Simulated load interruption will be accomplished with the local TDSP representative present as a witness. Scheduling testing with the local TDSP and fees associated with TDSP support will be the responsibility of the entity requesting qualification. With the TDSP representative present as a witness the following tests shall be

performed. Prior to beginning any testing the TDSP and QSE representatives will each communicate their readiness with the ERCOT Operations Supervisor at 512 248 3105.

Primary configuration to Simulate Load Shed

To simulate load shedding, the under-frequency relay is to be disconnected from the breaker and its outputs connected to a load simulating the breaker pickup coil impedance. The affidavit for actual or simulated load shed test is to be executed and provided to ERCOT acknowledging the test method is consistent with the method to be used during an actual manual deployment of the LaaR.

Alternate configuration to Simulate Load Shed

If the primary configuration does not accurately represent the configuration to be used during a manual deployment of the LaaR, an alternate configuration may be proposed by the requesting entity. Only proposals, which include a method where a TDSP witness can observe a simulated pickup of the breaker coil impedance, will be considered for the test. The affidavit for actual or simulated load shed test is to be executed and provided to ERCOT acknowledging the test method is consistent with the method to be used during an actual manual deployment of the LaaR.

To simulate ERCOT deployment of RRS, the TDSP representative will call ERCOT at 512 248-6821 and ask ERCOT to issue a manual deployment to the load being tested. ERCOT will issue a verbal manual deployment of RRS to the QSE specifying the specific LaaR resource to be shed (a sample script of the deployment instructed is provided at the end of this section). ERCOT will then communicate with the TDSP representative on site and confirm that a load disconnect instruction is received and deployed within 10 minutes of the deployment instruction to the QSE. ERCOT will confirm with the TDSP representative the MW amount of load shown on the point being tested.

The results of either test shall be provided verbally to the ERCOT Testing Operator immediately via telephone, and faxed to ERCOT at 512-248-6560 (attn: ERCOT Demand Side Resource Coordinator).

Upon conclusion of the test, the ERCOT testing operator shall document the success or failure of the test in the daily logs. In addition, an e-mail will be sent to the QSE documenting the results of the test. If qualification is successful, this e-mail will include an expected date that the LaaR will become available for participation in the Market. In most cases this date should be approximately 5 working days after the date of the test.

Sample script of the deployment instruction is as follows:

"This is _____ at ERCOT, the ERCOT Testing Operator. I will be conducting the qualification test for the LaaR to be tested to provide Responsive Reserve Service named _____. If you do not have any questions we will begin.

ERCOT is issuing a deployment instruction for the LaaR named _____ at this time. I will contact you again at the completion of this test."

Controllable Load Qualification

ERCOT Process For Qualification Testing Of Controllable Loads In Accordance With ERCOT Protocols And Guides

Introduction

In ERCOT's evolving market model, Controllable Loads (CLR) are a new type of Load Acting as a Resource (LaaR) that is capable of controllably reducing or increasing consumption under dispatch control (similar to AGC) and able to immediately respond proportionally to frequency changes (similar to generator governor action) to provide Ancillary Services. The types of Ancillary Services that may be provided by a (CLR) are:

- Up Regulation Service (URS)
- Down Regulation Service (DRS)
- Responsive Reserve Service (RRS)
- Non Spinning Reserve Service (NSRS)

LaaRs providing Ancillary Services shall meet qualification criteria and performance measures to operate satisfactorily within ERCOT. ERCOT shall develop an Ancillary Services qualification and testing procedure to be applied to all loads providing Ancillary Services that is based on key factors needed for reliability. This document provides for the initial qualification of loads wanting to participate in the ERCOT Ancillary Services Market as a Controllable Load. Due to the limitations within ERCOT's existing zonal market system a CLR qualified to provide the various Ancillary Services as defined in this document can only participate under the following conditions.

- ✓ Power flow at point of settlement meter must be net generation while providing services as a CLR
- ✓ A/S bids submitted on behalf of the CLR must be submitted as a "GEN" resource type
- ✓ Able to respond proportionately to frequency changes (similar to generator governor action)
- ✓ Capable of reducing or increasing consumption in response to dispatch instruction (similar to AGC)
- ✓ Due to net generation requirement, the Resource/QSE agrees to waive its right to any resource-specific premium payments that would result from a resource specific instruction (OOME) to the CLR

This document will be revised upon system changes that can accommodate controllable loads as a separate resource type.

SCOPE

This document defines procedures for the initial testing of loads desiring qualification as a CLR to provide URS, DRS, RRS, and NSRS. The qualification test for URS shall be a separate test than that for DRS. Due however to the similarity of the tests for RRS and NSRS a CLR who successfully completes the RRS qualification test will be qualified to provide not only for RRS but also qualified for NSRS without having to perform a separate test. Performance monitoring and seasonal evaluations, which are required in the protocols, are addressed in the Operating Guides, and not within this document.

Provisional Qualification

Provisional qualification is not available for a CLR.

Qualification Requirements and Testing Procedure

Prior to being tested, each CLR requesting to be qualified shall have in place:

- Resource Registration (complete, or update, Resource Registration form)
- Asset registration of CLR (complete Resource: Loads acting as a Resource Registration form)
- Provide simplified one-line diagram to the ERCOT Demand Side Resource Test Coordinator of the CLR facilities including settlement metering point, location of each telemetered point, any non-CLR loads and all generation behind the common settlement point.
- Telemetry is in place and tested through the QSE to ERCOT showing:
 - ✓ Load MW telemetry on each CLR load point. [For multiple loads less than 10 MW, an aggregated calculated MW value is allowed]
 - ✓ Response MW telemetry (non-zero when supplying service)
 - ✓ Verify CLR response in QSE's schedule control error (SCE)

Once all items noted above have been completed, the Resource/QSE entity is to schedule a testing date through their ERCOT Client Services Representative. To schedule, complete the top portion of Attachment I, II, or III, whichever applies based on the service to be tested and submit to your ERCOT Client Services Representative.

Controllable Load Qualification Testing Procedure for URS

The Up Regulation Service qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the Resource/QSE entity and ERCOT. For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Demand Side Resource Test Coordinator shall send a random sequence of raise, hold, and lower control signals to the QSE. To facilitate accurate measurements, each signal (raise, lower, or hold) shall remain unchanged for at least two (2) minutes. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have

only the CLR(s) assets being tested participating in regulation (i.e.; no non-CLR assets participating in regulation). The control signals shall not request CLR performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the CLR's ability to achieve the entire amount of Regulation Up requested for qualification during the period.

The CLR's average response to instruction for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any response is the result of the regulation requirement. The correlation coefficient between the expected average response from one minute to the next [limited to no more than the initial value + (request \times 1/2 \times stated ramp rate)], and the actual measured response during those minutes shall be statistically significant to two (2) positive standard deviations in order to pass the test.

On successful demonstration of all test criteria, ERCOT shall qualify the CLR to provide URS.

Controllable Load Qualification Testing Procedure for DRS

The Down Regulation Service qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the Resource/QSE and ERCOT. For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Demand Side Resource Test Coordinator shall send a random sequence of lower, hold, and raise control signals to the QSE. To facilitate accurate measurements, each signal (lower, hold, and raise) shall remain unchanged for at least two (2) minutes. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in regulation (i.e.; no non-CLR assets participating in regulation). The control signals shall not request CLR performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the CLR's ability to achieve the entire amount of Regulation Down requested for qualification during the period.

The CLR's average response to instruction for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any response is the result of the regulation requirement. The correlation coefficient between the expected average response from one minute to the next [limited to no more than the initial value + (request \times 1/2 \times stated ramp rate)], and the actual measured response during those minutes shall be statistically significant to two (2) positive standard deviations in order to pass the test.

On successful demonstration of all test criteria, ERCOT shall qualify the CLR to provide DRS.

Controllable Load Qualification Testing Procedure for RRS

The Responsive Reserve Service qualification test is performed during a continuous eight (8) hour window agreed on by the Resource/QSE and ERCOT. At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the Resource/QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in RRS (i.e.; no other resources automatically (AGC) dispatched participating in RRS). The QSE shall acknowledge the start of the test.

For the thirty (30) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for ten (10) minutes; and (iii) for each of the subsequent nineteen (19) clock-minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Responsive Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT. Satisfactory performance shall be deemed acceptable if ninety percent (90%) of each clock-minute measurement ten (10) minutes after notice through the balance of the test period is equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount expected.

On successful demonstration of all test criteria, ERCOT shall qualify that the CLR is capable of providing RRS. If this test is also being used to qualify the CLR to provide NSRS a communications test will be performed with the QSE to test their ability to receive the NSRS instruction.

Controllable Load Qualification Testing Procedure for NSRS

At any time during the window, selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Non-Spinning Reserve the QSE wishes to be qualified to. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in NSRS (i.e.; no non-CLR assets participating in NSRS). The QSE shall acknowledge the start of the test.

For the sixty (60) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for thirty (30)

minutes; and (iii) for each of the subsequent twenty-nine (29) clock minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT.

On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Non-Spinning Reserve and shall provide a copy of the certificate to the QSE.

ERCOT EILS Program Default Baseline Methodology

General Model Specification

ERCOT will endeavor to develop statistical models to estimate ESI ID level 15-minute interval load under “business as usual” conditions. If the statistical models thus developed in ERCOT’s judgment are deemed to be sufficiently accurate and reliable, the load estimates generated by these models for EILS event days shall be deemed to be the baseline loads for ESI IDs participating on the EILS program. These baseline loads shall then be compared against which the actual loads recorded on those days to assess performance by each ESI ID during the EILS event.

If accurate and reliable statistical models cannot be developed for a particular ESI ID, the Alternate Baseline methodology shall be applied in accordance with ERCOT Protocols.

In general, the default baseline model that will be used for ESI IDs can be written as follows:

$$kW_{d,h,int}^e = F(\text{Weather}_d, \text{Calendar}_d, \text{Daylight}_d)$$

where **e** is the ESI ID,

d is a specific day,

h is an hour on day **d**,

int is a 15-minute interval during hour **h**,

kW is the average load for an ESI ID in a specific 15-minute interval,

Weather represents weather conditions on the day and preceding days,

Calendar represents the type of day involved, and

Daylight represents solar data, such as the time of sunrise and sunset.

Within this general specification, there are an unlimited number of detailed specifications that involve different types of data (such as hourly versus daily weather variables) and different functional specifications that can be used to capture specific nonlinear relationships and variable interactions.

Note that interval load data values recorded during EECF events, during periods of notified unavailability of load for curtailment and apparent outlier load values will be excluded from the baseline model building process.

Model Decomposition

The model to be used is based on the following definitional decomposition.

$$kW_{d,h,int} = kWh_d \times \frac{kWh_{d,h}}{kWh_d} \times \frac{kW_{d,h,int}}{kWh_{d,h}}$$

$$= kWh_d \times Frac_{d,h} \times Mult_{d,h,int}$$

This decomposition allows analysis of three separate problems. The first is a model of daily energy (kWh_d). The second is a model of the fraction of daily energy that occurs in a specific hour ($Frac_{d,h}$). The third is a model of the load in an interval relative to the average load in the hour to which that interval belongs ($Mult_{d,h,int}$).

This breakdown allows development of a robust and relatively rich daily energy model that relies primarily on daily weather and calendar information. The hourly fraction models can then focus more on things that effect the distribution of loads through the day. The interval models can then be designed to distribute the loads within an hour to the 15-minute intervals in that hour.

As an example of how this works, suppose that the following conditions occur:

- Estimated energy for the day is 36.0 kWh.
- The fraction of daily energy that occurs in hour 17 is estimated to be 5.0%.
- The load in the first interval of this hour relative to the hourly load is 1.020.

Then the estimated load in kW for the interval from 4 p.m. to 4:15 p.m. is 1.836, computed as follows:

$$1.836\text{kW} = 36.0\text{kWh} \times .050\text{kW/kWh} \times 1.020$$

Daily Energy and Hourly Fraction Models

All three parts of each baseline model are estimated using multivariate regression. In their basic form, the daily energy and hourly fraction models are structured as follows:

$$Y = b_0 + b_1 \times X_1 + b_2 \times X_2 + \dots + e$$

where **Y** is the variable to be explained, the **X**'s are the explanatory variables, the **b**'s are the model parameters, and **e** is the statistical error term. For a baseline model, there is one equation of this form for daily energy and 24 equations for the hourly fractions. Although each equation is linear in the parameters, the equations may be highly nonlinear in the underlying variables, such as temperature. These nonlinearities are introduced in the definition of the X variables from the underlying weather and calendar factors.

Later sections provide discussions of weather variables, construction of model variables from the weather variables, and interactions between weather and calendar variables.

Business loads vary considerably across ESI IDs in terms of their weather sensitivity and, in general, are less weather sensitive than Residential loads. As a result, some of the baseline models will use a limited set of weather variables. Some ESI IDs will not have significant weather sensitivity on a daily basis, and, as a result, the models for such ESI IDs will be estimated using a simplified season/day-type specification that does not consider the influence of daily and hourly weather patterns.

Interval Multipliers

The translation from hourly results to 15-minute interval results is performed using multivariate regression of the following form:

$$kWh_{d,h,int} = (a_{int} \times kWh_{d,h-1} + b_{int} \times kWh_{d,h} + c_{int} \times kWh_{d,h+1})$$

And

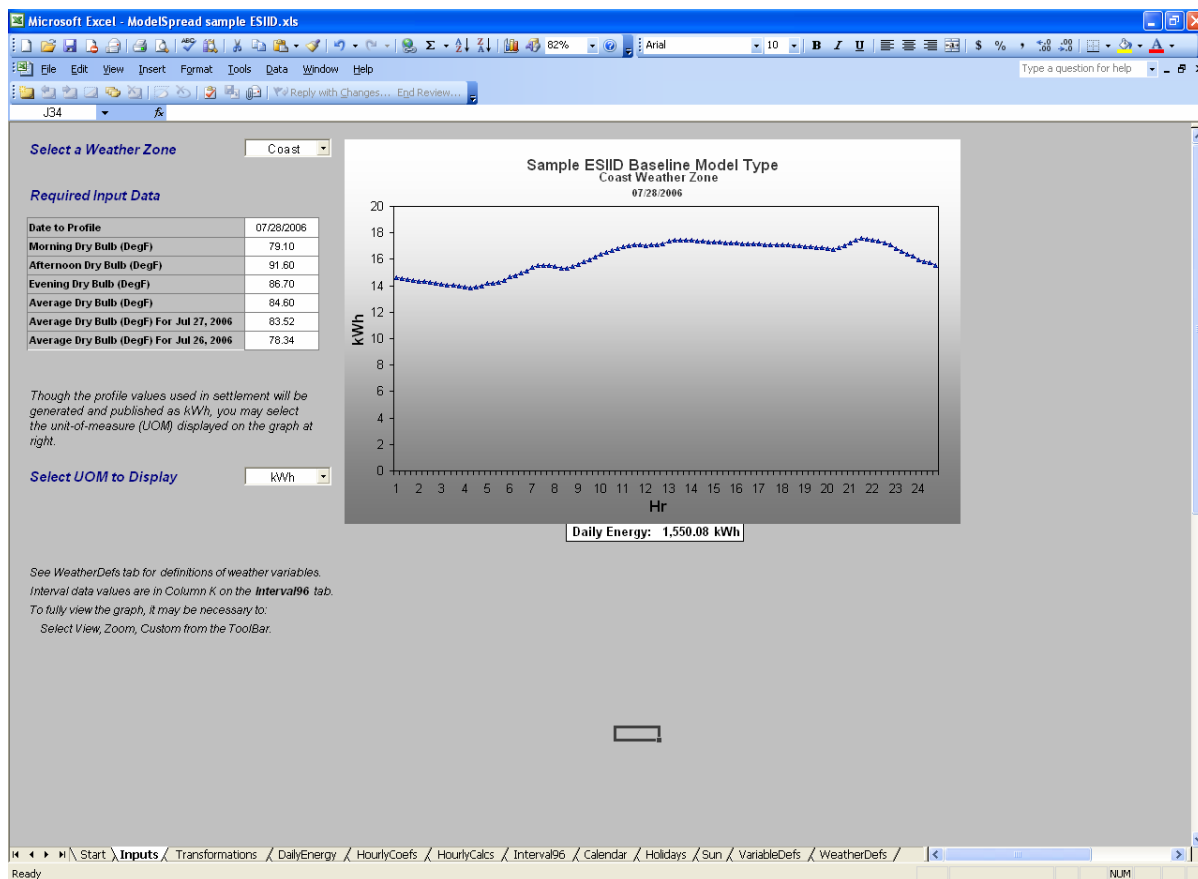
$$Mult_{d,h,int} = (kWh_{d,h,int} / kWh_{d,h})$$

Thus the load in a particular 15-minute interval is treated as a function of the hourly load estimate for the hour containing the interval and the hours immediately preceding and following that hour.

Baseline Model Spreadsheets

Details about the full set of estimated parameters for the baseline model for a specific ESI ID are documented in the baseline model spreadsheet developed for that ESI ID. Each spreadsheet has a worksheet named ***Inputs***, as shown in Figure 1.

Figure 1: Example of Baseline Model Spreadsheet



The **Inputs** sheet has a dropdown menu for selecting a weather zone, and a set of input boxes for entering dates and weather variables. This sheet also shows the 96-interval result graphically. Other sheets in the workbook are as follows:

- **Start.** This sheet contains text describing how to use the spreadsheet to calculate a baseline, how to examine the calculations, and how examine data inputs and transformations.
- **Transformations.** This sheet contains all transformations that are used to convert data from raw inputs into variables that appear in the daily and hourly model equations.
- **DailyEnergy.** This sheet contains the estimated coefficients for the daily energy equation. It also contains a column listing the values of all model variables given the user inputs. The final column presents the product of each coefficient and the corresponding variable value, giving the contribution of that variable to the predicted value for daily energy use.

- **HourlyCoef.** This sheet contains the full set of estimated coefficients for the hourly fraction models. Variable names are listed in the left-hand column, and there is one column for the coefficients for each hour.
- **HourlyCalcs.** This sheet shows all calculations required to compute hourly fractions. It also applies the predicted hourly fractions to the predicted value for daily energy use, giving the hourly energy estimates.
- **Interval96.** This sheet contains the parameters used to compute the interval multipliers. There is one row for each interval, and the parameters and calculations required to convert hourly values into 15-minute interval values are on this sheet. The final column presents the final 15-minute interval values.
- **Calendar.** This sheet contains all calendar inputs used in the model. Complete schedules are presented for all days from 2000 to 2010.
- **Holidays.** This sheet contains all holiday inputs used in the model. Complete holiday schedules are presented for all days from 2000 to 2010.
- **Sun.** This sheet contains sunrise and sunset data for all eight weather zones. These data extend from 2000 to 2010
- **VariableDefs.** This sheet presents definitions for all variables used in the model. They are presented in calculation order, so that all variables are defined before they are used to compute another variable.
- **WeatherDefs.** This sheet provides definitions for weather variables used in the models. It also provides a listing of the weather stations that are used and the weights that are used to combine weather stations in each zone.

By construction, these spreadsheets provide all data values (other than daily weather) required to implement the baseline models. They also provide the full set of parameters, transformations and detailed calculations that are made by the baseline models.

Discussion of Model Variables

The groups of variables that appear in these models are:

- Hourly and Interval Load Variables
- Calendar Variables
 - Day of the Week Variables
 - Holiday Variables
 - Weekday and Weekend Variables
 - Season Variables
 - Season/Day-Type Interaction Variables
- Weather Variables
 - Temperature Variables
 - Temperature Slopes
 - Constants and Temperature Slopes by Zone
 - Weather Based Day-Types
 - Heat Buildup Variables
 - Temperature Gain Variables
 - Time-of-Day Temperature Variables
- Daylight Variables
 - Daylight Saving
 - Time of Sunrise and Sunset
 - Fraction of dawn and dusk hours that is dark

In what follows, each of these groups of variables is discussed separately.

Hourly and Interval Load Variables

The load data that are used as the dependent variable in the baseline models are developed from 15-minute interval load data in kWh for the individual ESI IDs. Hourly interval load values are created by summing the corresponding 15-minute interval load values.

Calendar Variables

The main calendar variables include the day of the week, indicators of season, and holiday schedules.

Day of the Week Variables

The variables used in the models are:

Monday = 1 on Mondays, 0 otherwise.

TWT = 1 on Tuesdays, Wednesdays, and Thursdays, 0 otherwise.

Friday = 1 on Fridays, 0 otherwise.

Saturday = 1 on Saturdays, 0 otherwise.

Sunday = 1 on Sundays, 0 otherwise.

These variables are used in the daily energy and hourly fractional models. The following provides a discussion of the importance of these variables.

- **Saturday.** Commercial loads tend to be lower on Saturday than on weekdays, reflecting low levels of activity in office buildings and businesses that operate five days per week.
- **Sunday.** Commercial loads tend to be lower on Sunday than on weekdays, reflecting low levels of activity in office buildings and small retail and services businesses that are closed or that have abbreviated hours on Sunday.
- **Monday.** Monday loads tend to be slightly different than days in the middle of the week. This is especially true for manufacturing operations, where there is often no third shift on Sunday night and Monday morning.
- **Tuesday, Wednesday, and Thursday (TWT).** These days in the middle of the week tend to be highly similar for business loads.
- **Friday.** Friday loads tend to be slightly different than days in the middle of the week. Many businesses ramp down earlier on Friday.

Holiday Variables

In the daily energy models and the hourly fraction models, specific variables are introduced for each individual holiday. Weekday holidays have higher residential loads than typical weekdays and lower business loads. The exact affect on business loads depends on the holiday. For example on Thanksgiving, most commercial operations are closed. However on the day after Thanksgiving, office-type operations are usually closed but retail operations are open. All major national holidays fall on fixed days of the week with the exception of Christmas, July 4th, and New Year's day, making these three holidays the most difficult to model. The following is a list of all specific holidays that are included in the ERCOT models.

- NewYearsHoliday = Binary variable for New Year's Day holiday
- MartinLKing = Binary variable for Martin Luther King Day
- PresidentDay = Binary variable for Presidents' Day
- MemorialDay = Binary variable for Memorial Day
- July4thHol = Binary variable for Independence Day
- LaborDay = Binary variable for Labor Day
- Thanksgiving = Binary variable for Thanksgiving
- FridayAfterThanks = Binary variable for the Friday after Thanksgiving
- ChristmasHoliday = Binary variable for the Christmas Holiday
- XMasWkB4 = Binary variable for week before Christmas Holiday
- XMasAft = Binary variable for the week after Christmas Holiday

For NewYearsHoliday, ChristmasHoliday, and July4thHol, the holiday variables are set to 1 for the preceding Friday if the holiday date falls on a Saturday, and on the following Monday if the actual holiday date falls on a Sunday.

Major Holidays

In addition, to the individual holidays, a binary variable is constructed for major holidays (MajorHols). The MajorHols variable is defined as the sum of NewYearsHoliday, MemorialDay, LaborDay, Thanksgiving, FridayAfterThanks, and ChristmasHoliday. This variable is used in the definition of the WkDay and WkEnd variables.

Weekday and Weekend Variables

The WkDay variable is set to 1 on any weekdays that are not major holidays, and it is set to 0 on any Saturdays, Sundays, or days that are major holidays. The WkEnd variable is defined to be the complement of the WkDay variable. It is 1 on any Saturday, Sunday, or day that is a major holiday, and is 0 otherwise. Formally,

$$\begin{aligned}\text{WkDay} &= \text{Monday} + \text{Tuesday} + \text{Wednesday} + \text{Thursday} + \text{Friday} - \text{MajorHols} \\ \text{WkEnd} &= 1 - \text{WkDay}\end{aligned}$$

The WkDay and WkEnd variables are interacted with weather slope variables to allow weather slopes to be different on weekdays than they are on weekend days and holidays. For example, to allow the slope on average dry bulb temperature (AveDB) to differ between weekdays and weekend days, the following specification can be used:

$$\text{KWh}_d = a + b \times \text{AveDB}_d + c \times (\text{AveDB}_d \times \text{WkEnd}_d)$$

where KWh_d = the estimated kWh for day d,

a = constant term,

b = slope on average temperature on a weekday,

AveDB_d = average dry bulb temperature on day d,

c = slope release for weekend days,

WkEnd_d = weekend day d.

In this way, the slope on average temperature is given by the value b on a weekday and by the value (b+c) on a Saturday, Sunday, or Major holiday. If c is positive, then the weather sensitivity on weekends is larger than on weekdays. If c is negative, then the weather sensitivity on weekends is smaller. As a result, the coefficient c is often called a “slope release,” since it releases the weather slope to be different on specific days.

Season Variables

Two season variables are defined, one for summer months and one for winter months. Effects for remaining months are included in constant terms in the models. The variables are defined as follows:

Summer = 1 for days in June, July, August, and September and 0 otherwise.

Winter = 1 for days in December, January, and February and 0 otherwise.

Season/Day-Type Interactions Variables

Several interaction variables are defined to be used in the hourly fraction models. Each of these variables interacts a season variable with a day-type variable. The variables are:

SummerMon = Summer \times Monday

SummerTWT = Summer \times TWT

SummerFri = Summer \times Friday

SummerSat = Summer \times Saturday

SummerSun = Summer \times Sunday

WinterMon = Winter \times Monday

WinterTWT = Winter \times TWT

WinterFri = Winter \times Friday

WinterSat = Winter \times Saturday

WinterSun = Winter \times Sunday

Weather Variables

Hourly Weather Data

Weather variables that are used in the Baseline Models are:

- Dry Bulb Temperature

These data are available on an hourly basis for all stations listed in Table 1. These data are gathered by WeatherBank each hour through a process that obtains readings during the last 15 minutes of the previous hour. Since different weather providers use different methods to access and download data from the automated stations, the hourly values will show minor variations from one commercial weather data provider to the next.

Hourly data provided by WeatherBank are labeled Hour0 to Hour23. Internally, these are remapped to the integers 1 to 24. This implies that variables labeled as Hour0 in the raw data are used to represent conditions during hour 1 (the hour ending at 1 a.m.), values labeled as Hour1 are used to represent conditions during hour 2 (the hour ending 2 a.m.), and so on. These values are maintained by WeatherBank on standard time throughout the year.

Weather Zones

As part of the ERCOT profile data analysis, an analysis of weather data was conducted. This included analysis of 32 years of daily weather data for 359 stations in Texas, research on the list of stations that have hourly data, correlation analysis using the daily data for pairs of stations, and a cluster analysis to determine which stations should be grouped based on weather similarities. The results were provided to the Profile Working Group (PWG) along with a recommendation for Weather Zone definitions. Adopting some modifications suggested by the PWG, the resulting eight weather zones are defined as indicated in Figure 2. This figure also indicates the location of hourly weather stations used to represent each zone.

Computing Weather Zone Variables

Weather variables are defined for each zone based on multiple stations in that zone. The stations that are used and the weights that are applied are presented in Table 1. The weights in this table are in percent, and sum to 100 for each zone.

Figure 2: Weather Stations Used in ERCOT System

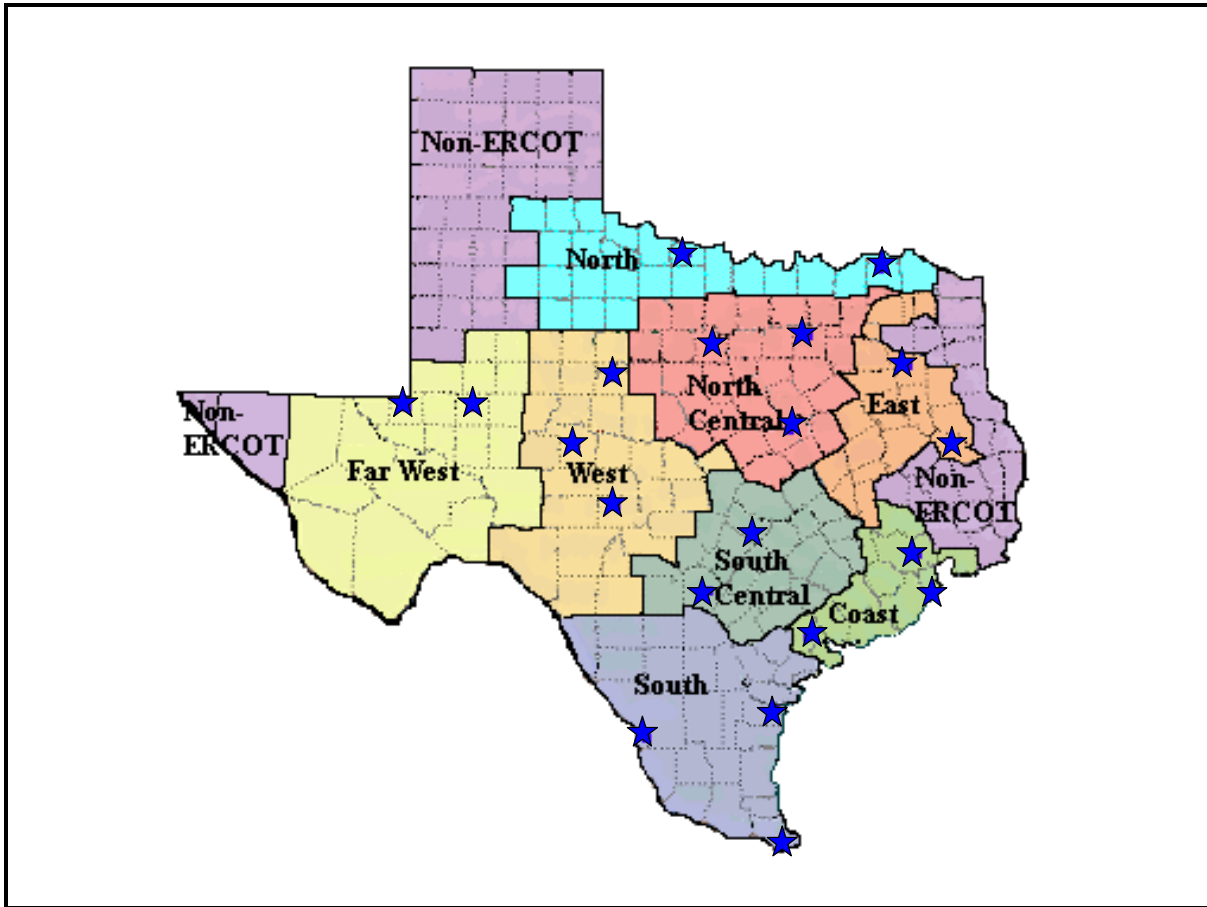


Table 1: Weather Stations and Zone Weights

	Zone Name	Station 1	Wgt	Station 2	Wgt	Station 3	Wgt
1	North	Wichita Falls	50	Paris	50		
2	North Central (NCent)	Dallas	50	Waco	25	Mineral Wells	25
3	East	Tyler	50	Lufkin	50		
4	Far West (FWest)	Wink	50	Midland	50		
5	West	Abilene	40	San Angelo	40	Junction	20
6	South Central (SCent)	Austin	50	San Antonio	50		
7	Coast	Houston	50	Galveston	30	Victoria	20
8	South	Corpus Christi	40	Brownsville	40	Laredo	20

At least two weather stations are used to represent weather conditions in each zone. The main advantage of using multiple stations is that the weather variables are less liable to reflect local conditions that are impacting a specific measurement station at a point in time but that are not impacting the larger geographical area.

The weather variables used in the models are calculated from weighted hourly data which were aggregated within a zone. In the calculations, the values for each station are weighted first and then aggregated across stations. For example, the MornDB variable represents the minimum morning dry bulb temperature. In defining this variable for each zone, the order of calculation is:

1. Compute the weighted average dry bulb temperature for each hour for stations in the zone.
2. Determine the minimum morning dry bulb temperature of the aggregated values for the zone.

The same approach is used for calculating the afternoon and evening maximum values. The daily average values are also computed this way, although the order of the calculations does not matter for computing the daily average values.

Temperature Variables

Dry bulb temperature is the temperature of the air as measured by any standard thermometer. As a result, the terms dry bulb temperature and temperature are used interchangeably. As an example, **Error! Reference source not found.** and **Error! Reference source not found.** show hourly dry bulb temperature values for December and August of 1999 respectively. Data are shown for three stations in the NCent zone (Dallas, Mineral Wells, and Waco).

As mentioned above, in the ERCOT models, these variables are transformed by computing aggregates and by computing weighted averages of these aggregate measures across weather stations in a zone. The aggregate concepts are:

- **AveDB.** This is the Average Dry Bulb Temperature. It is computed as the arithmetic average of the 24 values for the day.
- **MornDB.** This is the Minimum Dry Bulb Temperature in Morning Hours. In terms of WeatherBank variables, which are labeled from 0 to 23, the minimum is computed over values labeled Hour4 to Hour8. When the 24 values for a day are renumbered from 1 to 24, the minimum is computed over values 5 to 9.
- **AftDB.** This is the Maximum Dry Bulb Temperature in Afternoon Hours. In terms of WeatherBank variables, which are labeled from 0 to 23, the maximum is computed over values labeled Hour11 to Hour16. When the 24 values for a day are renumbered from 1 to 24, the maximum is computed over values 12 to 17.
- **EveDB.** This is the Maximum Dry Bulb Temperature in Evening Hours. In terms of WeatherBank variables, which are labeled from 0 to 23, the maximum is

computed over values labeled Hour18 to Hour21. When the 24 values for a day are renumbered from 1 to 24, the maximum is computed over values from 19 to 22.

Once these aggregate values are computed for each station in a zone, the weighted average of the values is computed. For example, for average temperature:

$$\text{AveDB}_z = \sum_{s \in z} \left(\frac{\text{Wgt}_s}{100} \times \text{AveDB}_s \right)$$

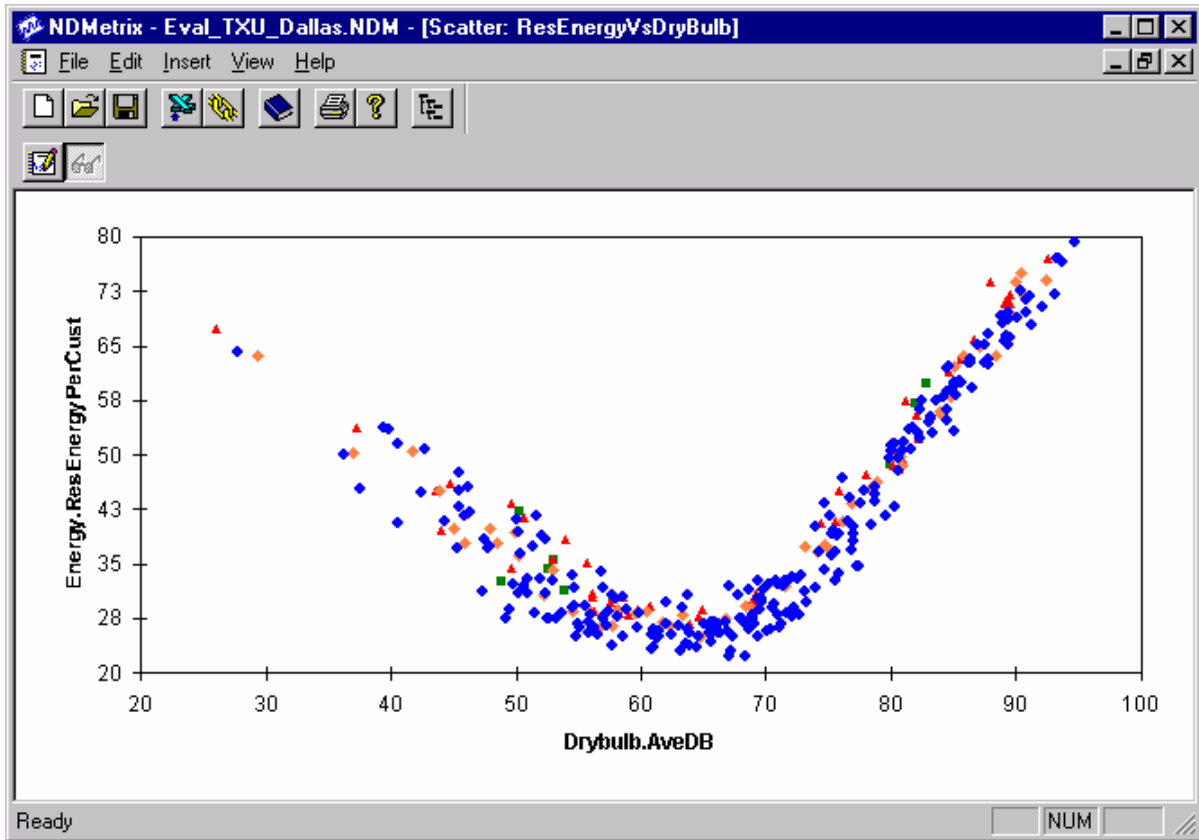
where AveDB_z = the Average Dry Bulb Temperature in zone z,
s ∈ z = the list of stations that are used to represent zone z,
Wgt_s = the weight assigned to station s in zone z,
AveDB_s = the average dry bulb temperature for station s.

Temperature Slopes

Figure 0 shows an example of the relationship between daily average temperature and daily energy use (kWh per customer) for the residential sector. This plot shows a strong nonlinear relationship and provides motivation for the temperature variables that are used in the ERCOT models. Specifically, the plot suggests a relatively flat relationship between 60 and 70 degrees, with cooling effects showing on the hot side of the curve (average temperatures above 70) and heating effects showing on the cold side of the curve (average temperatures below 60). To allow further nonlinearities, a second set of cut points are introduced at 50 and 80 degrees. Finally, to allow for “capping” effects that occur when cooling equipment reaches capacity, a final break point is introduced at 85 degrees. The final sets of dry bulb variables included in the models are as follows:

$$\begin{aligned} \text{XColdSlope}_z &= \text{Max}(50 - \text{AveDB}_z, 0) \\ \text{ColdSlope}_z &= \text{Max}(60 - \text{AveDB}_z, 0) \\ \text{MidSlope}_z &= \text{Min}(\text{Max}(\text{AveDB}_z - 60, 0), 10) \\ \text{HotSlope}_z &= \text{Max}(\text{AveDB}_z - 70, 0) \\ \text{XHotSlope}_z &= \text{Max}(\text{AveDB}_z - 80, 0) \\ \text{XXHotSlope}_z &= \text{Max}(\text{AveDB}_z - 85, 0) \end{aligned}$$

Figure 0: Daily Energy vs. Average Temperature



Weekend Slope Release Variables

The two main weather slopes are interacted with indicators of day-type, allowing the temperature sensitivity levels to be different on weekend days than they are on weekdays.

$$\begin{aligned}\text{HotSlopeWkEnd}_z &= \text{HotSlope}_z \times \text{WkEnd} \\ \text{ColdSlopeWkEnd}_z &= \text{ColdSlope}_z \times \text{WkEnd}\end{aligned}$$

Weather-Based Day-Types

In addition to the slope variables, a set of weather-based day-type variables are constructed for each weather zone z . These variables are used as interaction variables to allow remaining weather concepts to have different effects when temperatures are warm than they do when temperatures are cold.

$$\text{HotDay}_z = 1 \text{ if AveDB}_z > 70$$

$$\text{ColdDay}_z = 1 \text{ if AveDB}_z < 60$$

$$\text{MildDay}_z = 1 - \text{HotDay}_z - \text{ColdDay}_z$$

Heat Buildup

In addition to the current day temperature, temperature on preceding days impacts loads through heat buildup effects. The buildup variable is defined as follows.

$$\text{BuildUp}_{z,d} = \sum_{s \in z} \left(\frac{\text{Wgt}_s}{100} \times (0.67 \times \text{AveDB}_{z,d-1} + .33 \times \text{AveDB}_{z,d-2}) \right)$$

where $\text{BuildUp}_{z,d}$ = Weighted average lagged temperature for zone z on day d ,

$s \in z$ = the list of stations that are used to represent zone z ,

Wgt_s = the weight assigned to station s in zone z ,

$\text{AveDB}_{s,d-1}$ = the average temperature for station s on day $d-1$,

$\text{AveDB}_{s,d-2}$ = the average temperature for station s on day $d-2$.

Figure 4 shows a scatter plot of average temperature versus the buildup variable. In modeling loads, we expect a positive sign on the buildup variable on warm days, since heat buildup will increase cooling requirements for a given temperature level. We expect a negative coefficient on cold days, since higher temperatures on preceding days will reduce heating requirements. As a result, three variables are introduced to allow impact of buildup in a zone be different on hot and cold days. In constructing these variables, the mean value of the Buildup variable across all areas (68.4 degrees) is subtracted out, giving the following:

$$\text{HotBuildUp}_z = \text{HotDay}_z \times (\text{BuildUp}_z - 68.4)$$

$$\text{ColdBuildUp}_z = \text{ColdDay}_z \times (\text{BuildUp}_z - 68.4)$$

$$\text{MildBuildUp}_z = \text{MildDay}_z \times (\text{BuildUp}_z - 68.4)$$

By converting this type of variable to deviation-from-the-mean form, it is possible to include the buildup variable interacted with temperature-based day-type variables without including constant releases for the day-type variables, which simplifies the specification.

Temperature Gain Variables

In addition to the average variables, a temperature gain variable provides an indication of the temperature range. It is computed as the afternoon high temperature minus the morning low temperature. On most days this value is positive, and the average temperature gain is about 17.7 degrees. On a small number of days, the gain is negative, indicating that afternoon temperatures are below morning temperatures.

On each day, the average temperature gain for a zone is computed from the station data as follows:

$$\text{TempGain}_z = \sum_{s \in z} \left(\frac{\text{Wgt}_s}{100} \times (\text{AftDB}_s - \text{MornDB}_s) \right)$$

where TempGain_z = Average temperature gain for a zone,
 $s \in z$ = the list of stations that are used to represent zone z ,
 Wgt_s = the weight assigned to station s in zone z ,
 AftDB_s = the maximum afternoon temperature for station s ,
 MornDB_s = the minimum morning temperature for station s .

When modeling daily energy, a bigger value for the range (given the average temperature) will typically imply a larger value for daily energy. This occurs since a bigger range implies larger extreme values, which imply more heating in the winter and more cooling in the summer. To measure these effects, the temperature gain variable is first reduced by its overall mean value of 17.7 degrees, and the result is then interacted with a set of day-type variables, as follows.

$$\begin{aligned} \text{HotTempGain}_z &= \text{HotDay}_z \times (\text{TempGain}_z - 17.7) \\ \text{ColdTempGain}_z &= \text{ColdDay}_z \times (\text{TempGain}_z - 17.7) \\ \text{MildTempGain}_z &= \text{MildDay}_z \times (\text{TempGain}_z - 17.7) \end{aligned}$$

Time-of-Day Temperature Variables

The hourly fraction models discussed above utilize the time-of-day temperature variables (MornDB, AftDB, and EveDB). By including all of these variables in each equation, it is possible to model fractions that reflect the full weather pattern for each day. For example, for two days with the same average temperature, the baseline on days that have cool mornings and hot afternoons will be different from the baseline on days that have warm mornings and cool afternoons. In the models, these variables are also interacted with the day-type (hot days and cold days) and with the weekend variable, allowing slopes to differ between weekdays and weekend days. The full set of temperature variables used in the hourly fraction equations is as follows.

$$\text{HotMornDB}_z = \text{Hot}_z \times \text{MornDB}_z$$

$$\text{HotAftDB}_z = \text{Hot}_z \times \text{AftDB}_z$$

$$\text{HotEveDB}_z = \text{Hot}_z \times \text{EveDB}_z$$

$$\text{WkEndHotMornDB}_z = \text{WkEnd} \times \text{HotMornDB}_z$$

$$\text{WkEndHotAftDB}_z = \text{WkEnd} \times \text{HotAftDB}_z$$

$$\text{WkEndHotEveDB}_z = \text{WkEnd} \times \text{HotEveDB}_z$$

$$\text{MildMornDB}_z = \text{Mild}_z \times \text{MornDB}_z$$

$$\text{MildAftDB}_z = \text{Mild}_z \times \text{AftDB}_z$$

$$\text{MildEveDB}_z = \text{Mild}_z \times \text{EveDB}_z$$

$$\text{ColdMornDB}_z = \text{Cold}_z \times \text{MornDB}_z$$

$$\text{ColdAftDB}_z = \text{Cold}_z \times \text{AftDB}_z$$

$$\text{ColdEveDB}_z = \text{Cold}_z \times \text{EveDB}_z$$

$$\text{WkEndColdMornDB}_z = \text{WkEnd} \times \text{ColdMornDB}_z$$

$$\text{WkEndColdAftDB}_z = \text{WkEnd} \times \text{ColdAftDB}_z$$

$$\text{WkEndColdEveDB}_z = \text{WkEnd} \times \text{ColdEveDB}_z$$

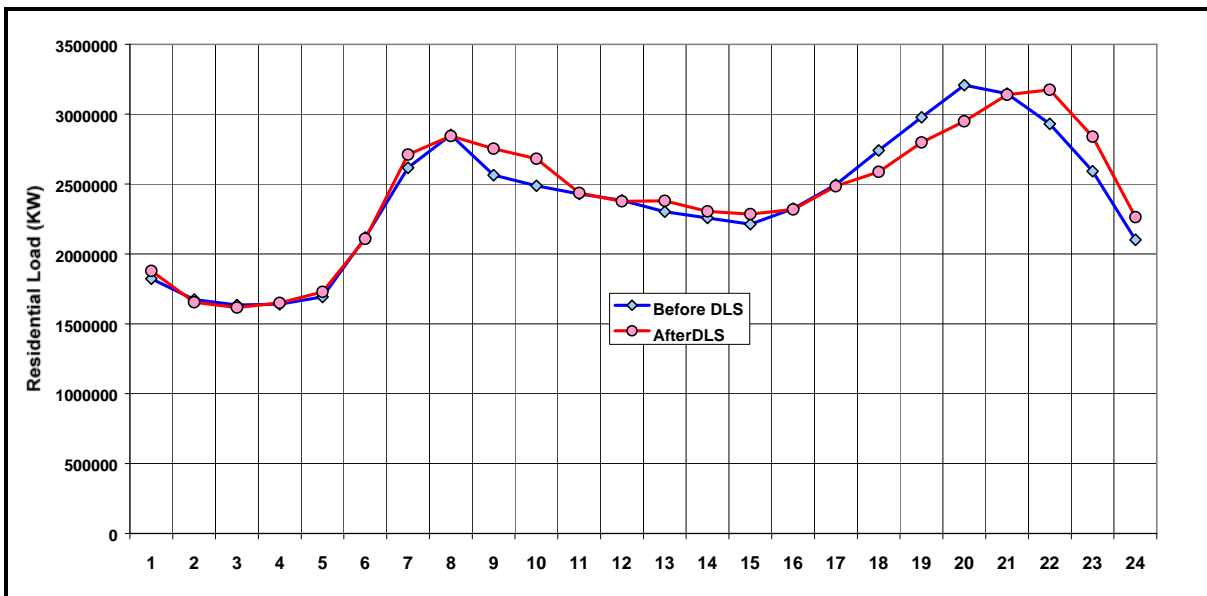
Daylight Variables

Lighting loads have a significant impact on load shapes in the dawn and dusk hours. The timing of these loads is impacted by changes in the time of sunrise and sunset. Although the change is gradual through the annual cycle, there is a one-hour jump at the transitions into and out of Daylight Saving Time.

Data are stored in one of two ways, clock time and standard time. In either case, adjustments can be made for the changes in the solar cycle and for the changes in human behavior associated with Daylight Saving. The baseline models are estimated with data that are on clock time rather than standard time, implying that sunrise and sunset shift one hour to the right in April and one hour to the left in October.

Most load research and system load data are stored in clock time. As a result, there is a missing hour on the first Sunday in April and two reads are averaged on the last Sunday in October. At the same time, the time of sunset jumps from hour 19 (ending 7 p.m.) to hour 20 (ending 8 p.m.) in April and from hour 19 to hour 18 in October. An example of the shift in loads is provided for the total residential class in Figure .

Figure 5: Residential Profiles Before and After Daylight Saving



To track the combination of solar cycles and the incidence of daylight saving, the following variables are included in the daily energy models.

DLSav = 1 for days on Daylight Saving Time, 0 otherwise.

HLight = Sunset – Sunrise (both measured in fractions of hours)

In addition, in the hourly fraction models, a series of variables is defined to quantify the fraction of each of the dawn and dusk hours that is dark.

FracDark7 = Fraction of the hour from 6 a.m. to 7 a.m. that is dark (before sunrise)

FracDark8 = Fraction of the hour from 7 a.m. to 8 a.m. that is dark (before sunrise)

FracDark18 = Fraction of the hour from 5 p.m. to 6 p.m. that is dark (after sunset)

FracDark19 = Fraction of the hour from 6 p.m. to 7 p.m. that is dark (after sunset)

FracDark20 = Fraction of the hour from 7 p.m. to 8 p.m. that is dark (after sunset)

FracDark21 = Fraction of the hour from 8 p.m. to 9 p.m. that is dark (after sunset)

Figure 6 to Figure 11 show examples of these variables plotted over the 1999 calendar. In each chart, the heavy red line is the Fraction Dark variable, and the thin green line represents the number of hours of sunlight. The weighted average values for each zone have been computed and are included in the baseline model spreadsheets.

6.8.1.14 Payments for Capacity for Balancing Energy Up Load Deployed

A QSE that is instructed to deploy Balancing Up Load (BUL) shall be paid a capacity payment for the 15-minute interval the instruction is issued and the three (3) subsequent intervals according to the following formulas. A QSE that is instructed to continue to deploy BUL after the first four (4) 15-minute intervals will be paid a capacity payment for each subsequent interval instruction it is given to deploy BUL. The BUL capacity payment is calculated as follows:

$$\begin{aligned}
 PC_{BULiq} &= -1 * ((MBUL_{iq} * MCPC_{NSi}) / 4) \\
 MBUL_{iq} &= MAX(BUL_{iq-0}, BUL_{iq-1}, BUL_{iq-2}, BUL_{iq-3}) \\
 BULPM_{iq} &= BULETR_{iq} - \sum_{all...zone} (BMRD_{iq} + BMRS_{iq}) \\
 BULETR_{iq} &= [((BRATD_{iq} * AIMLD_{iq}) + (BRATS_{iq} * AIMLS_{iq})) - ((\sum FSBUL_{izq})_z + (\sum DSBUL_{izq})_z)]
 \end{aligned}$$

[PIP112, PRR311, & PRR448: Insert the following when BUL Small Customer Load Management is implemented:]

Given:

IF SMALL CUSTOMER LOAD MANAGEMENT THEN

$$BUL_{iq} = AIMLLM_{iq} - BMRLM_{iq}$$

ELSE:

$$\begin{aligned}
 BUL_{iq} &= MIN[MIN(MAX(0, (\sum DIBUL_{izq})_z), \\
 &\quad MAX(0, ((BRATD_{iq} * AIMLD_{iq}) - BMRD_{iq}))) + \\
 &\quad MAX(0, ((BRATS_{iq} * AIMLS_{iq}) - BMRS_{iq})), (\sum DQ_{izq})_z]
 \end{aligned}$$

$$DIBUL_{izq} = MAX[0, (\sum (MR_{izq} - (DSL_{izq} + INS_{izq} + INS_{ewiq} + SRS_{izq})))_z]$$

$$AIMLD_{iq} = \frac{\sum_{n=1}^x BMRD_{qin} - MAX_{n=1, \dots, x} (BMRD_{qi1}, \dots, BMRD_{qix}) - MIN_{n=1, \dots, x} (BMRD_{qi1}, \dots, BMRD_{qix})}{x-2}$$

$$AIMLS_{iq} = \frac{\sum_{n=1}^x BMRS_{qin} - MAX_{n=1, \dots, x}(BMRS_{qi1}, \dots, BMRS_{qix}) - MIN_{n=1, \dots, x}(BMRS_{qi1}, \dots, BMRS_{qix})}{x - 2}$$

$$AMLDP_{iqn} = \frac{(BMRD_{qi-8n})}{8}$$

$$AMLPS_{iqn} = \frac{(BMRS_{qi-8n})}{8}$$

$$AML PBD_{iq} = \frac{\sum_{n=1}^x AMLPD_{iqn}}{x - 2}$$

$$AML PBS_{iq} = \frac{\sum_{n=1}^x AMLPS_{iqn}}{x - 2}$$

$$BRATD_{iq} = \frac{AML PD_{iq0}}{AML PBD_{iq}}$$

$$BRATS_{iq} = \frac{AML PS_{iq0}}{AML PBS_{iq}}$$

Where:

i	Settlement Interval being calculated
q	QSE
x	count of proxy days
z	zone
AIMLD _{iq}	Representative average interval metered BUL during the last ten (10) proxy days (in the case of weekdays) or six (6) proxy days (if deployment is on a weekend or holiday) for BUL meters that represent dynamic Load. Proxy days cannot be days when BUL was deployed during any interval.

[PIP112, PRR311, & PRR448: Insert the following when BUL Small Customer Load Management is implemented:]

AIMLLM_{iq} QSE aggregate baseline Load for small customers who participate in Load management program assuming the program is not in operation from the appropriate Load Profile.

AIMLS _{iq}	Representative average interval metered BUL during the last ten (10) proxy days (in the case of weekdays) or six (6) proxy days (if deployment is on a weekend or holiday) for BUL meters that represent static Load. Proxy days cannot be days when BUL was deployed during any interval.
AML PBD _{iq}	Average interval metered BUL from the prior ten (10) proxy days (in the case of weekday deployment) or six (6) proxy days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction for BUL meters that represent dynamic Load. Proxy days cannot be days when BUL was deployed during any interval.
AML PBS _{iq}	Average interval metered BUL from the prior ten (10) proxy days (in the case of weekday deployment) or six (6) proxy days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction for BUL meters that represent static Load. Proxy days cannot be days when BUL was deployed during any interval.
AML PD _{iqn}	Average interval metered BUL during the two (2) hours prior to the hour of BUL Notice in the n^{th} prior day for BUL meters that represent dynamic Load. Note, that $n=0$ refers to day of notice.
AML PS _{iqn}	Average interval metered BUL during the two (2) hours prior to the hour of BUL Notice in the n^{th} prior day for BUL meters that represent static Load. Note, that $n=0$ refers to day of notice.
BMRD _{iq}	Aggregate of all actual qualified BUL meter readings per QSE per Settlement Interval per zone for BUL meters that represent dynamic Load.
BMRD _{qimn}	Aggregate of all qualified dynamic BUL meter readings per QSE q during the m^{th} 15-minute time interval after the Settlement Interval i on the n^{th} day prior to the day of settlement, where the n prior days shall be only weekdays excluding ERCOT-defined holidays if the day of settlement is a weekday, and shall be only weekends and ERCOT-defined holidays if the day of settlement is a weekend. Days in which BUL instructions occurred are excluded.

[PIP112, PRR311, & PRR448: Insert the following when BUL Small Customer Load Management is implemented:]

BMRLMiq QSE aggregate participating Customer Load during operation of Load management program from the appropriate Load Profile.

BMRS_{iq}	Aggregate of all actual qualified BUL meter readings per QSE per Settlement Interval per zone for BUL meters that represent static Load.
BMRS_{qimn}	Aggregate of all qualified static BUL meter readings per QSE q during the m^{th} 15-minute time interval after the Settlement Interval i on the n^{th} day prior to the day of settlement, where the n prior days shall be only weekdays excluding ERCOT-defined holidays if the day of settlement is a weekday, and shall be only weekends and ERCOT-defined holidays if the day of settlement is a weekend. Days in which BUL instructions occurred are excluded.
BRATD_{iq}	Ratio of average metered dynamic Load for 2 hours prior to BUL instruction to the average interval metered BUL from the prior ten (10) days (in the case of weekday deployment) or six (6) days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction.
BRATS_{iq}	Ratio of average metered static load for two (2) hours prior to BUL instruction to the average interval metered BUL from the prior ten (10) days (in the case of weekday deployment) or six (6) days (for weekend or holiday deployment) for the two (2) hours prior to first BUL instruction.
BUL_{iq}	Quantity in MWhs of BUL deployed per Settlement Interval per QSE.
BULETR_{iq}	Total BUL expected reduction by QSE per interval ERCOT-wide.
BULPM_{iq}	Calculated to determine whether a QSE performed the BUL deployment and should receive a capacity payment.
DIBUL_{izq}	For QSEs with Dynamically Scheduled Loads, the average power delivered to ERCOT per interval per zone as a result of deploying BUL.
DQ_{iqz}	Deployed BUL quantity in MW per zone.
DSBUL_{izq}	For QSEs with Dynamically Scheduled Loads, the integrated signal for the interval that is an estimate in Real Time representing the real power interrupted in response to the deployment of BUL. $DSBUL_{izq} = \text{zero (0)}$ if Load is not dynamically scheduled.
DSL_{izq}	The integral of the Dynamically Scheduled Load telemetered to ERCOT for that QSE per interval per zone.
FSBUL_{izq}	Integrated signal for the interval sent by static scheduling QSEs to ERCOT and is an estimate in Real Time representing the real power interrupted in response to the deployment of BUL.
INS_{ewiq}	ERCOT-wide instructions for that QSE per interval.

INS_{izq}	Zonal Balancing Energy instructions given to that QSE per zone per interval.
$MBUL_{iq}$	Maximum quantity in MWhs of BUL deployed per Settlement Interval per QSE.
$MCPC_{NSi}$	Highest Non-Spinning Reserve Service Market Clearing Price of Capacity costs (\$/MW) for the hour of all procurement processes.
MR_{izq}	Metered Resource value for that QSE per interval per zone.
$PCBUL_{iq}$	Capacity payment for instructed deployment of BUL per Settlement Interval per QSE.
SRS_{izq}	Static Resource schedule per interval per zone of that QSE.

6.8.1.15 Payments for Balancing Energy Provided from Uninstructed Deviation

Resources will be paid the full Market Clearing Price for Energy for up to the amount of all ERCOT instructed schedule deviations on an ERCOT-wide basis.

Resources will be paid a fraction of the market-clearing price for Uninstructed Deviations on an ERCOT-wide basis. An Uninstructed Deviation has occurred whenever the total metered Resources of a QSE for a Settlement Interval are different from the total of the scheduled Resources plus any Resource deployments instructed by ERCOT. An Uninstructed Deviation for a QSE will be equal to the energy that results during a Settlement Interval from the integrated schedule plus Dispatch Instructions minus the sum of the net metered value for the Generation Resources plus Load Resource response to Dispatch Instructions as described in Section 6.10.4, Ancillary Service Deployment Performance Measures.

6.8.1.15.1 Uninstructed Resource Charge Process

Once ERCOT has determined the Congestion Zones in which the Uninstructed Deviations of the QSE have occurred, an uninstructed pricing differential will be applied to a QSE representing Resources whenever one of the following two (2) conditions exists:

- (1) The QSE representing Resources has total metered Resources for any Settlement Interval that are greater than the larger of one hundred one and one-half percent (101.5%) of the QSE's total of schedules plus instructions or five (5) MWh over the total of schedules plus instructions when the integrated amount of ERCOT-wide regulation is less than negative twenty-five (– 25) MWhs in the interval. Upon one-day Notice, ERCOT can reduce the percentage and MWh tolerance to one hundred one percent (101%) and three (3) MWh, respectively, if significant price chasing exists.