Recommended FERC Actions to Facilitate Demand Response Resource Programs Within Regional Transmission Organizations & Independent System Operators

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&
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Submitted by:

RETX

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PREFACE

On January 17, 2002, RETX was asked to present recommended Demand Response Resource (DRR) business rules at the FERC-DOE Demand Response Conference on February 14, 2002. We accepted this challenge with the understanding that the rules should show how DRR should participate in the standard market design for Independent System Operators (ISO) and/or Regional Transmission Organizations (RTO).

In order to accomplish this task, RETX sought the assistance from several industry stakeholders. Representatives from (in alphabetical order) Apogee Interactive, Customized Energy Solutions, The E Cubed Company, LLC, EPRI, GoodCents Solutions, PJM, and Summit Blue Consulting agreed to participate. These firms represent a cross section of industry firms that provided commercial demand response services such as consulting services to utilities and energy marketers, technology and implementation solutions, and industry think tanks.

The group recognized that there has been significant work accomplished in various forums to develop demand response operating rules. We borrowed ideas and concepts that have been or are being developed in the PJM, ISONE, and NYISO service territories. It is important to note that a significant amount of the text in the appendix comes from these ISO service territories. We also relied on our professional experiences in other jurisdictions. We also relied on the Peak Load Management Alliance's recently released white paper titled "Demand Response: Principles for Regulatory Guidance" to provide the framework and goals of the enclosed rules.

In light of the short time frame available we decided to utilize email and teleconferences to facilitate our interaction. Over the three-week period we had three formal teleconferences and numerous email exchanges. The process produced at least six (6) document drafts.

We successfully accomplished the assigned task. The enclosed document recommends several policy positions and FERC actions as well as standard business rules. The document provides a strong foundation for the Commission to institutionalize DRR in ISO/RTO standard market designs. However, should the Commission decide to move forward with these rules, we encourage the Commission to allow local markets to improve upon the rules provided that the changes make it easier and/or more beneficial for DRR to participate in the market than prescribed by the following rules.

We recognize that reasonable people disagree with some components of the document. Not all industry segments have had the opportunity to comment on and reach consensus of these issues. If the Commission desires, our group will take their advice and counsel and produce a subsequent document shortly thereafter that addresses these issues.

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INTRODUCTION

The North American electric industry is undergoing a remarkable change. Many wholesale and retail electric markets throughout the United States and Canada are open to free market competition. The development of super regional Independent System Operators (ISO) and Regional Transmission Organizations (RTO) will eliminate transmission expense “pancaking”, improve system planning, and further enable competitive markets. To the extent that the ISO/RTOs develop financial markets with price visibility, they will encourage the industry to develop new ways to use existing resources and provide critical information to promote the development of new resources. In particular, locational pricing will pinpoint where resources should be deployed to manage transmission constraints or supply shortfalls.

Demand Response Resources (DRR) can play a vital role in the new energy marketplace. DRR can and does respond to price signals when given the opportunity and appropriate incentives. Numerous studies have been published over the last few years showing the immense contribution DRR provides in the areas of grid reliability, price spike mitigation, and environmental benefits. For example:

- **“…5 percent reduction in peak demand reduces prices by more than 50 percent.”** *Retail Load Participation in Competitive Wholesale Electricity Markets*, Edison Electric Institute, et al, January 2001.

- **“Some of the same demand responsiveness that results from having consumers pay market prices may also be achieved if utilities either compensate customers for reducing their use or allow customers to resell power to others (in which case, a third party is paying them to reduce their use).”** *Causes and Lessons of the California Energy Crisis*, The Congress of the United States Congressional Budget Office, September 2001.

- **“Building owners and operators should be a more reliable supplier of ancillary services than conventional generators. Because each facility will be supplying a smaller fraction of the total system requirement for each service, the failure of a single resource is less important. Just as a system with 10 100-MW power plants require less contingency reserves than one with a single 1000-MW plant so too a system that utilizes a large aggregation of loads as a resource to supply reserves will require less redundancy in the basic resource than one that carries all of its reserves on a few large generators.”** *How Savvy Building Owners Can Save*, Oak Ridge National Laboratory, Winter 2001-02.

In order for DRR to reach its full potential and for the nation to reap the rewards, the Federal Energy Regulatory Commission (FERC) needs to declare its support for DRR and clarify how DRR should participate in the market. This paper identifies several policy positions that FERC should affirm to facilitate the development of a robust DRR industry.

In addition, the appendix outlines pro-forma demand response business rules designed for an ISO/RTO. FERC should approve these business rules for each ISO/RTO so that industry stakeholders clearly understand how DRR should participate in the market. The pro-forma DRR business rules are intended to be minimum standards provided that the ISO/RTO offers a financial or physical market for the service. Market participants in each region should be allowed to improve upon these minimum standards so that DRR value can be optimized for their marketplace by offering specific tariff proposals to FERC. FERC should resist proposed changes that diminish DRR value or market development.

POLICY RECOMENDATIONS

The Federal Energy Regulatory Commission (FERC) should immediately order the following:

1. Demand Response Resources (DRR) are viable capacity, energy, ancillary service and transmission congestion resources. Independent System Operators (ISO) and/or Regional Transmission Organizations (RTO) shall allow and facilitate DRR participation in ISO/RTO markets and become a fundamental part of standard market design.

2. Capacity and/or green markets that are currently operational or that may be further defined through FERC's standard market technical conferences and subsequent NOPR should include the participation of DRR as a recognized available resource. These markets may be centralized in the ISO/RTO standard market design, run by a third party, or operate in the bilateral market. DRR must be eligible to participate in all capacity and/or green markets in a manner that is at least comparable to generators.

3. ISO/RTOs should take all necessary steps to ensure that Demand Response Resources support at least 5% of the system wide peak load as direct market participants by April 1, 2004. This may require the enrolled participant level to be significantly greater than 5% of the system wide peak load.

4. Society benefits from DRR by disciplining the markets and reducing market power, making wholesale markets more competitive with less onerous rules, reducing clearing prices, decreasing price volatility, relieving congestion, reducing the need for new transmission and distribution facilities and decreasing emissions. Therefore, ISO/RTOs should not only promote demand response resource participation, but they should also support its development financially and with operational rules

that facilitate market participation and eliminate barriers. Specifically, ISO/RTOs should do the following:

a. Financial support should include, but not be limited to:
    i. Allow DRR to keep the tariff savings of unused energy as well as the market-clearing price for the appropriate service.
    ii. Assist with infrastructure costs for advanced metering and communications (This may be reviewed when Demand Response Resources make up at least 5% of the total resources).
    iii. In the absence of visible locational pricing and markets, DRR should be compensated equivalently to any other market participant that receives above market payments or other consideration for the locational value of the resource.

b. Operational support should include, but not be limited to:
    i. Development of a standardized data exchange format for event notifications and meter data.
    ii. Develop methods that allow aggregation and participation from all market classes including, but not limited to: residential, small and large commercial, and small and large industrial.
    iii. Develop Customer Baseline Load (CBL) methodologies for weather sensitive and non-weather sensitive loads.
    iv. Develop customer baseline methodologies that recognize peak reduction on a daily basis from distributed generation.
    v. A Demand Response Resource Provider (DRRP) does not have to be the energy supplier of the Demand Response Resource (DRR) in order to enroll the DRRP.
    vi. Synchronized and non-synchronized local generation and load shedding capabilities are eligible Demand Response Resources provided that they meet appropriate environmental and interconnection rules.
    vii. Work with environmental agencies to set rules that optimize and stabilize the participation of the extensive fleet of local generators as Demand Response Resources in electricity markets.

RECOMMENDED ACTIONS

1. FERC should immediately affirm the policy recommendations enumerated above.
2. FERC should approve the pro-forma DRR business rules in Appendix A subject to improvements from the local ISO/RTO and conditioned on whether the ISO/RTO operates a financial and/or physical market for the service.

3. FERC should require each ISO/RTO to provide semi-annual status reports on their efforts to promote DRR in their region. In conjunction with this, FERC should hire an independent auditor to provide a prudence audit on the ISO/RTO's progress and program structure.
4. FERC should host at least two industry DRR conferences per year to promote best practices.
5. FERC should work with environmental agencies to set reasonable rules that optimize and stabilize the participation of all local generators as Demand Response Resources in electricity markets.

Appendix A

Standard Market Design for Demand Response Resource Implementation within Regional Transmission Organizations & Independent System Operators

February 14, 2002

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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 or Real Time markets.

Curtailment 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 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 LMP – 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 Response Resource that is bid, produced, purchased and sold over a period of time and measured or calculated in kW hours.

Demand Reduction Wholesale Energy 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 LMP 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 Response Resource Provider (DRRP) - An entity, qualified pursuant to ISO Procedures, which bids Demand Response Resources of at least 100 kW.

Demand Response Resources (DRR) - Resources 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 Response Resources may reduce demand either by curtailing Load or by activating Local Generators.

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 ISO/RTO 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 Reliability Assurance Agreement, which includes 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 ISO/RTO Control Area, including ISO/RTO Direct Customers.

Local Generator - A resource operated by or on behalf of a Load that is either: (i) not synchronized to a local distribution system; or (ii) synchronized to a local distribution system solely in order to support a Load that is equal to or in excess of the resource's Capacity.

Locational Marginal Price (LMP) - The price of energy bought or sold in the LMP 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 LMP – The price (in $/MWh) for in the real-time electricity market calculated on an hourly basis.

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

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

Zone – A geographical area located within the ISO/RTO Control Area. Generally defined as one of the ISO/RTO Transmission Owner boundaries. During the implementation of the LMP Markets, all Loads located within the same Load Zone pay the same Day-Ahead LMP and the same Real-Time LMP for Energy purchased in those markets.

2.0 Administrative Rules

2.1 Participant Eligibility

a. Demand Response Resource Provider (DRRP)
An end use consumer, or group of consumers, capable of providing at least 100 KW of load reduction or Local on-site generation resource per Zone in a given hour. DRRP resources must participate through a qualified LSE or DRRP (NOTE: some end users may qualify as self supplier LSEs).

b. Load Serving Entities (LSE)
Any LSE in good standing shall be allowed to enroll a DRR resource regardless of whether it is supplying energy to the DRR. They will participate under the terms of their ISO/RTO and OATT contractual relationships.

c. Demand Response Resource Providers (DRRP)
Any DRRP in good standing shall be allowed to enroll a DRR resource regardless of whether it is supplying energy to the DRR. The ISO/RTO will develop a special contract for DSPs with reasonable operational & credit requirements.

2.2 Registration

LSE/DRRPs must complete the ISO/RTO Demand Response Resource Registration Form for each resource it enrolls.

The following general steps will be followed:

1. The participant completes the Demand Load Response Program registration form.
2. ISO/RTO reviews the application and ensures that the qualifications are met, including a determination that appropriate verification procedures are in place metering exists.
3. ISO/RTO informs the requesting participant of the acceptance into the program and notifies the appropriate LSE and EDC of the participant’s acceptance into the program.
4. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must submit to ISO/RTO the applicable environmental permits for running those generators. In the event no environmental permitting has been obtained, written justification for the lack of permits must be provided.

2.3 Term

The following rules shall be effective as of June 1, 2002. The rules shall remain in effect until such time as the commission deems necessary to modify them either by petition from the local ISO/RTO or on its own motion.

3.0 Day-Ahead Demand Response Program (DA DRP)

3.1 Administration

The program will be administered by the ISO/RTO in cooperation with the host Load Serving Entities (LSEs)/ Demand Response Resource Provider (DRRP).

3.2 Bidding

The ISO/RTO will accept Demand Response Resource Provider Bids wherein an LSE/DRRP can bid on behalf of a Demand Response Resource for a specific MW curtailment (in minimum increments of 100 KW by Zone) in contiguous "strips" of one or more hours. The DRRP Bid would include the Day-Ahead LMP above which the Load would not consume, and could also include a Curtailment Initiation Cost.

Bidding is voluntary, however if a bid is submitted and accepted the penalty for non-performance will be a charge to purchase at real time prices any shortfall of energy reduction that had been scheduled. Market Monitoring will be relied on to develop strategies to mitigate and monitor potential gaming.

3.3 Day Ahead Commitment Objective Function

The objective function for day ahead commitment software will accept DRRP 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 DRRP Bid and any bid Curtailment Initiation Costs. Thus, curtailments will not be scheduled unless they reduced total Day-Ahead production costs.

3.4 Setting LMP

DRRP Bids can set Day-Ahead LMP just as a comparably bid Generator.

3.5 Customer Baseline Load

A Demand Response Resource's Customer Baseline Load (CBL) will provide a reference to verify its compliance with a scheduled curtailment. The CBL methodology is described in section 7.0 titled Calculating Customer Baseline Load.

3.6 Determining the Amount of Load Reduction

For DRRPs bidding curtailable load, the amount of actual verified performance will be equal to its CBL less its actual interval data usage as determined by appropriate verification methods during the specified curtailment. For Local Generation, the amount of load reduction is equal to the Local generator MWh output less its CBL.

3.7 Payments

An LSE/DRRP with a Demand Response Resource that curtails Load (as scheduled Day-Ahead by ISO/RTO) will be paid by ISO/RTO the Day-Ahead

LMP. If needed, a supplemental payment will be made to allow full recovery of the Curtailment Initiation Cost. The ISO/RTO will pay the LSE/DRRP for its DRRP performance within 30 days after receiving appropriate verification information for the event. True ups will be done as needed.

3.8 Payment Sharing

The payments for a Day-Ahead Demand Response Resource will be made by ISO/RTO to the LSE/DRRP. The portion that will be transferred from the LSE/DRRP to the Demand Response Resource is outside the scope of ISO/RTO, and must be arranged between the LSP/DRRP and the Demand Response Resource.

3.9 Cost Allocation of Wholesale Energy Payment and Uplift

The ISO shall recover supplemental payments to Demand Reduction Providers from all net purchasers in the Real Time market. Cost recovery will be allocated to all Real Time net purchasers excluding exports and Wheel Through transactions.

3.10 End-User Requirements

All DRRP over 100 kW will be required to have interval metering, and will be responsible for any incremental metering and billing system implementation and administration costs in accordance with applicable retail tariffs. LSE/DRRPs can aggregate customers below 100kW and bid as a Demand Response Resource using accepted statistical procedures where a sample of customers are interval metered to determine curtailed loads for events (See 7.0 Calculating Customer Baseline Loads and 8.0 Reporting and Verifying Customer Baseline Load, Verification of Event Data, and Meter Data).

3.11 Non-Performance Penalties

An LSE/DRRP has a DRR scheduled for a curtailment that would have been eligible for the Wholesale Energy Payment, but that subsequently fails to curtail, the LSE/DRRP will be charged the higher of the Day-Ahead or Real-Time LMP for non-curtailed Load. The premium paid over Real-Time LMP will be applied to reduce uplift costs allocated to Loads purchasing from Real Time.

A bidder must specify whether a Load Curtailment will result from:

- an actual reduction in consumption, or
- a self-supplying Local Generator.

4.0 Real-Time Demand Response Program (RT DRP)

4.1 Administration

The program will be administered by the ISO/RTO in cooperation with the host Load Serving Entities (LSEs)/ Demand Response Resource Provider (DRRP).

4.2 Bidding

ISO/RTO will accept DRRP Bids wherein an LSE/DRRP can expect a load reduction on behalf of a DRR for a specific MW curtailment (in minimum increments of 100 KW by Zone) any time preceding the initiation of a curtailment by the Demand Response Resource.

Bidding is voluntary. Market Monitoring will be relied on to develop strategies to mitigate and monitor potential gaming.

4.3 Real Time Commitment Objective Function

The highest Generation or DRR bid will set the Real Time price in the real time. For the DRRP to set the clearing price 15-minute interval and communication metering technology must be installed. The Objective Function will be to minimize overall costs of Generation and Demand Response Resources.

4.4 Setting LMP

DRRP Bids can set Real Time LMP just as a comparably bid Generator.

4.5 Customer Baseline Load

A Demand Response Resource's Customer Baseline Load (CBL) will provide a reference to verify its compliance with a scheduled curtailment. The CBL methodology is described in section 7.0 titled Calculating Customer Baseline Load.

4.6 Determining the Amount of Load Reduction

For DRRPs bidding curtailable load, the amount of actual verified performance will be equal to its CBL less its actual interval data usage as determined by appropriate verification methods during the specified curtailment. For Local Generation, the amount of load reduction is equal to the Local Generator MWh output less its CBL.

4.7 Payments

An LSE/DRRP with a Demand Response Resource that curtails will be paid by ISO/RTO Real Time LMP. If needed, a supplemental payment will be made to allow full recovery of the Curtailment Initiation Cost. The ISO/RTO will pay the LSE/DRRP for its DRRP performance within 30 days after receiving appropriate verification information for the event. True ups will be done as needed.

4.8 Payment Sharing

The payments for a Real Time Demand Response Resource will be made by ISO/RTO to the LSE/DRRP. The portion that will be transferred from the LSE/DRRP to the Demand Response Resource is outside the scope of ISO/RTO, and must be arranged between the LSP/DRRP and the Demand Response Resource.

4.9 Cost Allocation of Wholesale Energy Payment and Uplift

The ISO shall recover supplemental payments to Demand Reduction Providers from all net purchasers in the Real Time market. Cost recovery will be allocated to all Real Time net purchasers excluding exports and Wheel Through transactions.

4.10 End-User Requirements

All DRRP over 100 kW will be required to have interval metering, and will be responsible for any incremental metering and billing system implementation and administration costs in accordance with applicable retail tariffs. LSE/DRRPs can aggregate customers below 100kW and bid as a Demand Response Resource using accepted statistical procedures where a sample of customers are interval metered to determine curtailed loads for events (See 7.0 Calculating Customer Baseline Loads and 8.0 Reporting and Verifying Customer Baseline Load, Verification of Event Data, and Meter Data).

4.11 Non-Performance Penalties

There will be no performance penalties in the RT DRP.

5.0 Ancillary Service Markets

5.1 Administration
The program will be administered by the ISO/RTO in cooperation with the host Load Serving Entities (LSEs)/ Demand Response Resource Provider (DRRP).

5.2 Bidding
ISO/RTO will accept Demand Reduction Bids wherein an LSE/DRRP can expect a load reduction on behalf of a Demand Response Resource for a specific MW curtailment (in minimum increments of 100 KW by zone) any time preceding the initiation of a curtailment by the Demand Response Resource. DRRP may bid into the following markets: 60 minute operating, 30 minute, 10 minute Non-Spinning Reserves, 10 minute Spinning Reserves, Replacement Reserves, and Regulation provided that the DRRP is capable of supporting the performance requirement for each market and the ISO/RTO offers a financial or physical market for the service.

Bidding is voluntary. Market Monitoring will be relied on to develop strategies to mitigate and monitor potential gaming.

5.3 Real Time Commitment Objective Function
The highest accepted Generation or DRR bid will set the Real Time price in the real time.

5.4 Setting LMP
Demand Reduction Bids can set Real Time LMP just as a comparably bid Generator.

5.5 Customer Baseline Load
A Demand Response Resource's Customer Baseline Load (CBL) will provide a reference to verify its compliance with a scheduled curtailment. The CBL methodology is described in section 8.0 titled Calculating Customer Baseline Load.

5.6 Determining the Amount of Load Reduction
For DRRPs bidding curtailable load, the amount of actual verified performance will be equal to its CBL less its actual interval data usage as determined by appropriate verification methods during the specified curtailment. For Local Generation, the amount of load reduction is equal to the Local Generator MWh output less its CBL.

5.7 Payments
An LSE/DRRP with a Demand Response Resource that curtails will be paid by ISO/RTO the day ahead clearing price for the ancillary service based on day ahead bids. For actual calls to provide energy by activating an ancillary service,

the ISO/RTO will pay the Real Time LMP. If needed, a supplemental payment will be made to allow full recovery of the Curtailment Initiation Cost. The ISO/RTO will pay the LSE/DRRP for its DRRP performance within 30 days after receiving appropriate verification information for the event. True ups will be done as needed.

5.8 Payment Sharing

The payments for an Ancillary Service DRR will be made by ISO/RTO to the LSE/DRRP. The portion that will be transferred from the LSE/DRRP to the DRR is outside the scope of ISO/RTO, and must be arranged between the LSP/DRRP and the DRR.

5.9 Cost Allocation of Wholesale Energy Payment and Uplift

The ISO shall recover supplemental payments to Demand Reduction Providers from all net purchasers in the Real Time market. Cost recovery will be allocated to all Real Time net purchasers excluding exports and Wheel Through transactions.

5.10 End-User Requirements

DRRP participating in ancillary service markets must have near real time metering technology that can either be read directly by ISO/RTO or be submitted to ISO/RTO.

5.11 Non-Performance Penalties

There will be no performance penalties in the Real-Time Ancillary Service Markets.

6.0 Emergency Demand Response Program (EDRP)

6.1 Administration

The program will be administered by the ISO/RTO in cooperation with the host Load Serving Entities (LSEs)/ Demand Response Resource Provider (DRRP).

6.2 Emergency Operations

ISO/RTO will initiate the request for load reduction following the declaration of Maximum Emergency Generation (Implementation of the Emergency Load Response Program can be used for regional emergencies). The purpose of Maximum Emergency Generation is to increase the Control Area generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost. ISO/RTO will revise the emergency procedures to reflect the following steps:

1. The ISO/RTO Dispatcher issues Maximum Emergency Generation.
2. The ISO/RTO Dispatcher notifies ISO/RTO Management, ISO/RTO public information personnel, and Local Control Center dispatchers.
3. The ISO/RTO Dispatcher indicates the need for emergency energy and contacts its neighboring control areas.
4. The ISO/RTO Dispatcher recalls off-system sales that are recallable (network resources).
5. The ISO/RTO Dispatcher begins to load Maximum Emergency Generation, requests load reductions from the Emergency Load Response Program participants, and begins to purchase emergency energy from ISO/RTO Members and from neighboring control areas based on economics and availability.
6. The ISO/RTO Dispatcher continues with the remaining emergency procedure steps as stated in the ISO/RTO Manual for Emergency Operations, and cancels them in reverse order when appropriate.
7. The ISO/RTO dispatcher cancels the load reduction request and then cancels Maximum Emergency Generation, when appropriate. The minimum duration of a load reduction request is two hours although the reduction request may be extended if necessary.

6.3 Customer Baseline Load

A Demand Response Resource's Customer Baseline Load (CBL) will provide a reference to verify its compliance with a scheduled curtailment. The CBL methodology is described in section 7.0 titled Calculating Customer Baseline Load.

6.4 Determining the Amount of Load Reduction

For DRRPs bidding curtailable load, the amount of actual verified performance will be equal to its CBL less its actual interval data usage as determined by appropriate verification methods during the specified curtailment. For Local

Generation, the amount of load reduction is equal to the Local Generator MWh output less its CBL.

ISO/RTO requires that the load reduction metering data be submitted to ISO/RTO within 45 days of the event. If the data are not received within 45 days, no payment for participation is provided. Meter readings 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 ISO/RTO via an approved MDSP.

6.5 Payments

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. The magnitude of relief provided could be less than, equal to, or greater than the kW amount declared on the Emergency Demand Response Resource Registration form based on event performance.

ISO/RTO pays the higher of the appropriate zonal Locational Marginal Price (LMP) or economically attractive amounts (i.e. $500/MWh) to the LSE/DRRP that nominates the load. The ISO/RTO will pay the LSE/DRRP for its DRRP performance within 30 days after receiving appropriate verification information for the event. True ups will be done as needed. ISO/RTO will determine and file with the Commission the economically attractive payment levels.

6.6 Payment Sharing

The payments for an Emergency Demand Response Resource will be made by ISO/RTO to the LSE/DRRP. The portion that will be transferred from the LSE/DRRP to the DRR is outside the scope of ISO/RTO, and must be arranged between the LSP/DRRP and the DRR.

6.7 Cost Allocation of Wholesale Energy Payment and Uplift

The ISO shall recover supplemental payments to Demand Reduction Providers from all net purchasers in the Real Time market. Cost recovery will be allocated to all Real Time net purchasers excluding exports and Wheel Through transactions.

6.8 End-User Requirements

Until a statistically acceptable method can be agreed upon for customers under 100 kW, Demand Response 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.

6.9 Non-Performance Penalties

There will be no performance penalties in the EDRP.

7.0 Calculating Customer Baseline Load

7.1 The Average Day CBL for DRRP over 100 KW

A. Weekday CBLs

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

A.1.a The *CBL Window* is comprised of the 10 most recent days, not counting the 2 days prior to the event day for which the CBL is being calculated, excluding the following day-types:

A.1.a.1 Holidays, as specified by ISO/RTO

A.1.a.2 Event days which are defined as days on which:

A.1.a.2.a ISO/RTO declared an EDRP event for which the participant was eligible for payment for a curtailment, or

A.1.a.2.b Days on which the participant's DADRP curtailment bid was accepted in the DAM, regardless of whether or not the participant actually curtailed.

A.1.b To define the days that comprise the CBL Window:

A.1.b.1 Begin with the 10-day period defined by the weekday that is 2 days prior to the event through the weekday that is eleven days prior to the event day. This creates a 10-day window.

A.1.b.2 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.

A.1.b.3 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.

A.1.c 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 For each of the 10 days in the CBL 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 CBL is being developed.

A.2.b Create the *average event period usage level* for the 10 days in the CBL Window, which is defined as the simple average of the 10 average daily event period usage values.

A.2.c 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, and return to (Step A.1.a) and add a day to restore the 10-day window and check the elimination criteria and proceed to create a new 10-day CBL window.

A.2.d Order the 10 days in the CBL Window according to their average daily event period usage level, and eliminate the 5 days with the lowest average daily event period usage.

A.2.e The remaining 5 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 5 days that comprise the CBL basis.

B. Average Day CBL formula for weekends

Step 1. Establish the CBL Window

B.1.a The CBL Window is comprised of the most recent 3 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 3 days in the CBL Window.

B.2.b Order the 3 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 2 days that comprise the CBL basis.

7.2 Elective Weather-Sensitive CBL formulation for DRRP over 100 KW

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 2 hour period beginning with the start of the hour that is 4 hours prior to the commencement of the event through the end of the hour 3 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 2 hours in duration, but using the 5 days selected for use in the Average CBL Basis.

2.A.2.b Calculate the average of the 2 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 2 hour adjustment period on the event day.

C. Calculate the gross adjustment factor

2.C.1 The gross adjustment factor is equal to the ratio of the Adjustment Basis CBL and the Adjustment Basis Average Usage.

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.

<u>Step 3.</u> 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.

<u>Sample Similar Day CBL Calculation</u>
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 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 $_{n-11}$
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 appropriate hours each day and select the 5 highest totals:

	Mw hr $_{n-2}$	Mw hr $_{n-3}$	Mwhr $_{n-4}$	Mw hr $_{n-5}$	Mw hr $_{n-6}$	Mw hr $_{n-7}$	Mw hr $_{n-8}$	Mw hr $_{n-9}$	Mw hr $_{n-10}$	Mw hr $_{n-11}$
	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

7.3 Baseline Calculation Method (Local Generation Only)

Local generators that are interval metered can use that meter for event performance purposes provided that the meter conforms with section 8.1 Verification and Meter Requirements. The hourly generation meter data will be used to show actual hourly performance and a CBL adjustment will not be necessary.

Absent independent metering, or if the metering does not conform with section 8.1, the facility meter, or a suitable proxy as described in section 8.1, shall be used to calculate performance using the CBL methodologies described in section 7.1 and 7.2 above.

7.4 Calculating The Average Day CBL for Customers less than 100kW (Mass Market Resources)

Customers less than 100kW can participate without having interval metering installed by participating as part of an aggregated LSE/DRRP mass-market demand response resource where the CBL can reliably be estimated using a statistical process. For a statistical process to work, a reasonable number of customers are needed to allow for effective sampling. Curtailable loads at a customer site as small as 0.5kW can participate if they are using defined technologies that are subject to direct load control devices (including controls on thermostats). These technologies include water heating, air conditioning, pool pumps and lighting. Other technologies can be listed and presented to the RTO/ISO for their approval for use in the mass-market program.

Customers can be residential or commercial loads with curtailable loads of up to 15kW per site. Note that industrial process loads are excluded. The sample sizes outlined below based upon industry experience and are designed such that they should provide a correlation between sampled load (i.e., the interval metered load) and actual load across all sites at a level of accuracy that exceeds a 90% level of confidence and 10% precision. Alternative statistical approaches can be proposed by a mass-market load aggregator, if it can be demonstrated that the alternative will exceed this standard.

This statistical approach has 2 components – stratification and sample size.

Stratification – Within each pricing zone, the sample must be drawn to represent 3 strata with the boundaries determined by the initially estimated curtailable load. The first stratum represents that lowest third of the sites as determined by estimated curtailable load. The second stratum is the middle third of the sites based on curtailable load, and the third stratum is the highest third of the sites as ranked by estimated curtailable load. Equal samples would be drawn from each strata (Note: Proportional sampling can be used if it is reasonably believed that this would increase the precision of the estimated curtailable load; and alternative stratification designs can be proposed if it can be shown to improve upon this base-case design).

Sample Size – The minimum acceptable sample size for each zone is 25 interval-metered sites per pricing zone for up to 100 sites within that zone. If more than 100 sites are present in a given zone, sample sizes are determined as follows:

100 or fewer customers – 25 interval meters on sites that are selected to be representative of all participating sites.

500 or fewer customers -- 25 interval meters plus 4 meters for each 100 customers over the initial 100. For example, at 500 customers 41 meters would be required -- 25 initial meters for the first 100 customers, 4 meters for next 100 up to 200, 4 meters for the next 100 sites up to 300, 4 meters for up the next 100 up to 400, and 4 meters the next 100 up to 500 sites. This provides for a total of 41 interval metered sites for a population of 500 participants within that pricing zone.

500 to 1,000 customers – the base would be 41 meters with 3 meters for each 100 additional customers. 600 sites would require 44 meters up to 56 meters for 1,000 sites.

Over 1,000 customers – a minimum of 56 interval meters is required plus 2 for each additional 100 customers. Thus, for 2,000 participating customers, 76 metered sites would be required. At 10,000 sites, 236 interval-metered sites would be required.

Over 10,000 customers – programs this size should be metered based on appropriate stratified sampling protocols using at least 3 strata with these strata addressing residential and commercial customers. A sample size of 236 should be adequate for most any size aggregate Demand Response Resource serving a set of residential and/or small commercial customers with curtailable loads ranging from .5kW up to 20 kW.

The average day CBL and weather-sensitive CBL are calculated as presented in sections 7.1 and 7.2. Or an alternative approach can be used to produce daily load shape estimates using regression procedures, neural network modeling, or other processes that produce an R-Square of .96 or higher on back cast test day results for sites that are within the sample.

7.5 Calculating CBL for Aggregated Load Bids

For aggregated bids involving more than one Demand Response Resource 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 DRRs (including, as one DRR, the aggregated under 100kW mass-market resources as discussed in 8.4 above) using the procedures defined in Sections 7.1 and 7.2 above. The concept of non-coincident CBLs is illustrated with the following example.

Assume that 2 interruptible load Demand Response 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 DRR over the 10 day interval used by the CBL calculation is shown in table 7.1. The 5 days selected for the CBL calculation for each DRR are denoted by the shaded background.

Table 7.1 – 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)
DRR #1	3.2	4.5	3.3	4.2	1.1	1.3	4.5	3.6	3.2	2.3
DRR #2	7.2	7.2	4.5	7.3	7.3	4.9	4.9	6.2	6.3	6.7

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

The CBL for DRR #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.

8.0 Reporting and Verifying Customer Baseline Load and Meter Data

8.1 Verification and Metering Requirements

When a Demand Response Resource registers for participation in the program, whether as a self-supply or interruptible load customer, either an hourly interval meter shall be installed to meter the entire facility or for totalized load at each Demand Response Resource or the statistical process presented in section 7.4 must be followed. An hourly interval meter is required for each participating load unless it qualifies for treatment as a mass-market resource under section 7.4. Any individual DRRP in excess of 1 MW, except DRR only participating in the Emergency Demand Response Program, must have near real time metering technology that can either be read directly by ISO/RTO or be submitted to ISO/RTO.

Whether each customer is metered or a sample is metered (under Section 7.4), the DRRP must have metering equipment that provides integrated hourly kWh values, for market settlement purposes, that either meets the EDC requirements for accuracy or has a maximum error of two percent end-to-end (including PTs and CTs). 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 DRRP that is read electronically by ISO/RTO, or
- Customer-owned meter including one provided by an independent metering service provider or acquired from the DRRP that is read by the customer (or the DRRP), the readings from which are forwarded to ISO/RTO.

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

Note that various Internet applications now exist for transmission of real time metered data. Use of these applications is acceptable provided that ISO/RTO receives metered load reductions in a timely, reliable manner.

The metering requirements can be met using any of the following 3 methods:

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

- Metering that continuously records the load drawn from a specific process or application and is capable of demonstrating that the process or application was halted for the purposes of a load reduction and not due to normal operations.

- Comparing actual metered load to a Customer Baseline Load (CBL) calculated as described above.

8.2 Historical Operating Data

DRRP/ LSEs shall be required to provide historical operating data for each load upon acceptance for participation in the DA DRP and/ or RT DRP. 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 3 month's summary of monthly kWh consumption and demand values, if available.

8.3 Performance

A. Interruptible Load or Local Generation Using Net Metered Load

Performance for interruptible loads or Local generators using net metered 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 the Calculating Customer Baseline Load section.

Performance for an interruptible load Demand Response Resource/Aggregate for each hour shall be calculated as:

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

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

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

NML_h = actual net hourly metered load

If the quantity $(CBL\text{-}xx)h\text{-}NML_h$ is negative in any scheduled hour, then $PRL_{meter\ h}$ should be set equal to zero.
$PRL_{meter\ h}$ should be set equal to zero for all hours in which the Demand Response Resource/Aggregate was not scheduled for a Demand Reduction.

B. Performance - Local Generation Only Configuration
For premises subscribing only Local generation where a separate meter has been installed at the generator, performance for each hour shall be calculated as:

$P_h = OG_h – (GCB\text{-}xx)_h$
Where P_h = performance for the hour

OG_h = Metered Local generator output for the hour

$GCB\text{-}xx_h$ = 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 5.2.

8.4 Data Submission

A Meter Data Service Provider (MDSP) will provide the Hourly Interval Meter readings for the net load at each Demand Response Resource to the ISO/RTO on behalf of the LSE/ DRRP.

The MDSP will receive copies of the Demand Response Resource Registration Form, and copies of the data submitted for performance compensation.

The ISO/RTO will calculate the Customer Baseline Load and performance compensation for each DRRP. The ISO/RTO will send this information to the MDSP within 5 days after receipt of the hourly interval meter readings.

9.0 Performance and Payment Examples

9.1 Day Ahead Curtailment of Load

For Load scheduled to economically curtail Day-Ahead, and that actually does curtail in Real-Time, the LSE would be paid Day-Ahead LMP and would include a supplement, if needed, to allow full recovery of the "Curtailment Initiation Cost".

As an example, assume:

a) A 10 MW Load bids to curtail 3 MW of Load at a Price of $100/Mwh plus $2,000 for "Curtailment Initiation Costs" for a continuous time strip of 6 hours. This amounts to a total curtailment bid of $3,800 = (3 MW x $100/MWh x 6 hours) plus $2,000.
b) That Load is scheduled Day-Ahead for a 3 MW curtailment for 6 hours.
c) Day-Ahead LMP is $250/MWh for those 6 hours.
d) Real-Time LMP is $275/MWh for those 6 hours.
e) The Load actually consumes 7 MW and curtails 3 MW over those 6 hours.

The resulting payments and charges would be as follows:

a) The LSE/DRRP would be paid $4,500 = $250/MWh LMP x 3 MW x 6 hours for the curtailment.
b) No supplemental "Uplift" payment for a "Bid Curtailment Cost Guarantee" would be needed since the $4,500 LMP payment would exceed the $3,800 total curtailment bid.
c) $4500 would be paid by all net real time energy purchases on a per MWh basis.

9.2 Uplift Example

An LSE will be paid Day-Ahead LMP for the self-supply and would include a supplement, if needed, for "Bid Curtailment Cost Guarantee" to allow full recovery of the "Curtailment Initiation Cost" (in the case of a small self-supplying generator, this would be identical to a "Bid Production Cost Guarantee" to allow full recovery of start-up and min gen costs).

Assume the same example for a curtailable Load Bid above (with and without the self-supplying small generator) except that the Load bids a Price of $150/MWh rather than $100/MWh, and continues to bid $2,000 for "Curtailment Initiation Costs". This amounts to a total curtailment bid of $4,700 = (3 MW x $150/MWh x 6 hours) plus $2,000.

The payments and charges would be as follows:

a) As in the previous example, the LSE/DRRP would be paid $4,500 = $250/MWh LMP x 3 MW x 6 hours for the curtailment.

b) The LSE/DRRP would also be paid $200 = $4,700 - $4,500 as a supplemental payment for a "Bid Curtailment Cost Guarantee" since the total $4,700 curtailment bid exceeded the $4,500 LMP payment (this is based upon the requirement that Day Ahead commitment software determines that the total cost over the 24 hour Dispatch Day will be lower with this Load curtailed).

c) $4700 would be paid by all net real time energy purchases on a per MWh basis.

9.3 DA DRP Curtailment of Load With Non-Performance Penalty for Failure to Reduce Consumption

If an LSE/DRRP has an End-User scheduled for a Price-Cap curtailment that would have been eligible for the "Wholesale Energy Payment" payment, and that subsequently fails to curtail, the LSE/DRRP will be charged 110% of the higher of Day-Ahead or Real-Time LMP for non-curtailed Load.

As an example, assume:

a) A 10 MW Load bids to curtail 3 MW of Load by reducing consumption at a Price of $100/MWh plus $2,000 for "Curtailment Initiation Costs" for a continuous time strip of 6 hours. This amounts to a total curtailment bid of $3,800 = (3 MW x $100/MWh x 6 hours) plus $2,000.
b) That Load is scheduled Day-Ahead for a 3 MW curtailment for 6 hours.
c) For those six hours, Day-Ahead LMP is $250/MWh, and Real-Time LMP is $300/MWh.
d) Over those 6 hours, the Load actually consumes 10 MW; it fails to curtail 3 MW.

The resulting payments and charges would be as follows:

a) The LSE/DRRP would be paid $4,500 = $250/MWh LMP x 3 MW x 6 hour for the accepted curtailment bid.
b) The LSE/DRRP would also be charged $5,940 = 110% x $300/MWh Real-Time LMP x 3 MW x 6 hours for the Load that failed to curtail.
c) Excess penalty of $1,940 would be paid to all net real time energy purchases on a per MWh basis.

9.4 Real Time Bid with Real Time Compliance

Bid into the real time to reduce consumption 1MW at $150 in RT for 3 hours. The RT price was $200 in each of the 3 hours of compliance.

a) The LSE/DRRP will be paid $200 * 3 hours * 1 MW = $600
b) $600 would be paid by all net real time energy purchases on a per MWh basis.