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nyiso
Day-Ahead Demand Response Program Manual

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What's New for 2003?

Following the summer of 2002, a number of changes to the DADRP program were approved by the NYISO Market Participants or implemented by NYISO:

1. Allow Demand Response Providers (DRPs) to offer DADRP to the customers of other LSEs. Originally approved in 2001, this functionality is being implemented for Summer 2003. Deployment is expected to occur July 1, 2003.

2. Exclusion of Local Generation from the program. Local Generation is no longer allowed to participate in DADRP. Diesel generation has always been excluded and other forms of Local Generation have been precluded from receiving the DADRP incentive payment. Since these resources can already utilize equivalent functionality through the use of Price-Capped Load Bidding, Market Participants determined that provision for them in the DADRP was no longer necessary.

3. Elimination of the 110% penalty. Deviations from Day Ahead schedules are now settled at the higher of day ahead or real time LBMP. Previously the penalty was 110% of the higher of day ahead or real time LBMP.

4. New registration requirements. Changes to the DADRP registration forms have been made to accommodate DRPs, as well as to eliminate the option of Local Generators to participate in the program.

5. Revised payment rules. Payment rules have been revised to incorporate the elimination of the 110% penalty, as well as the addition of DRPs to the program.

~~1.0~~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.

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 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 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.~~

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~~ that are not supplied by a Local Generator~~. 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. ~~Prior to January 1, 2002, only Load Serving Entities may qualify as Demand Reduction Providers. On and after January 1, 2002, Curtailment Services Providers may also qualify as Demand Reduction Providers.~~

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 ~~either~~ only by curtailing NYCA Load. ~~or by activating Local Generators, provided, however, for purposes of bidding into the Day-Ahead Market, Demand Side Resources shall not include reduced demand activated by Local Generators that use diesel fuel.~~

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, 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 NYCA, including NYISO 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. Local Generators supply Energy only to the Load they are being operated to serve and do not supply Energy to the distribution system.~~

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 ~~Until modifications are made to the NYISO billing and accounting system (expected in late 2002), the program will be administered by the NYISO and~~ host Load Serving Entities (LSEs) ~~only. The program will be open to~~and ~~Curtailment Service Provider~~Demand Reduction Providers (~~CSPs~~DRPs) including non-host LSEs ~~when the billing and accounting modifications are implemented~~. ~~Therefore, the term "LSE/CSP" used below refers to the host LSE prior to implementing the billing and accounting modifications and to an LSE or CSP thereafter.~~

2.2 Bidding

The NYISO will accept Demand Reduction Bids wherein an LSE/~~CSP~~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/M~~w~~Wh~~r~~ 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 ~~detemine~~ 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. ~~For Local Generation, the CBL is based upon the five lowest generation 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. ~~For Local Generation, the amount of load reduction is equal to the on-site generator MWhr output less its CBL.~~

2.7 Payments

1. An LSE/~~CSP~~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/~~CSP~~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/~~CSP~~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~~ (with certain exceptions specified in the Section on Small Generator Eligibility below)~~.

2.8 Payment Sharing

The payments under the Day-Ahead Demand Reduction Program will be made by the NYISO to the LSE/~~CSP~~DRP. The portion that will be transferred from the LSE/~~CSP~~DRP to the Demand Side Resource is outside the scope of the NYISO, and must be arranged between the LSP/~~CSP~~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%.

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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. ~~The program will be open to small "behind-the-fence" on-site generation (except diesel generators), provided that each generator has a separate interval meter (and other applicable requirements are met). The LSE/CSP in this case will be paid Day-Ahead LBMP and any supplemental payments for Load curtailed through self-supply. However, to the extent that a Demand Side Resource's curtailed Load is self-supplied, its LSE/CSP will not be eligible for the Incentive payment. The LSE/CSP will be charged for the full Day-Ahead Load, and will not receive a rebate from the NYISO as an Incentive payment for the curtailed amount of Load that is self-supplied.~~

2.12 Non-Performance Penalties

~~For Demand Side Resources that are not providing reduction via self-supply, if~~If an LSE/~~CSP~~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/~~CSP~~DRP will be charged ~~110% of~~ 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).

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

~~(a)an actual reduction in consumption (and therefore eligible for the Incentive, but also subject to the 110% Performance Penalty), or~~

~~(b)a self-supplying on-site Generator (and therefore not eligible for the Incentive, and not subject to the 110% Performance Penalty, but simply charged Real-Time LBMP for non-curtailed Load).~~

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, ~~2003~~ 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, ~~2003~~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/~~CSP~~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 ~~Limited~~ 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~~. For the purposes of ICAP and UCAP, the use of statistical verification as approved for this program will be an acceptable alternative to interval metering~~.

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 administrating 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 singe 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 it 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

~~Until modifications are made to the NYISO billing and accounting system (expected in late 2002), only Load Serving Entities (LSEs) can bid Demand Side Resources within the Day-Ahead Demand Reduction Program (DADRP).~~ 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 ~~link entitled Demand Response Programs.~~ 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~~E~~ 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 LSE's 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 LSE's that 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 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.

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, 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 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.

~~http://www.nyiso.com/services/relations/cregistration/pdf/nyiso_reg_1201.pdf~~

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 DRP's that 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 DRP's that are currently registered in the DADRP program, but have never been active or for new DRP's 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% percent 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
Based on the average accepted MWh per month and the average Day-Ahead LBMP the DRP's sales should be approximately $ 12, 982 per month or $51, 928 for a four-month time frame with a run rate of $432.73 per day.

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.

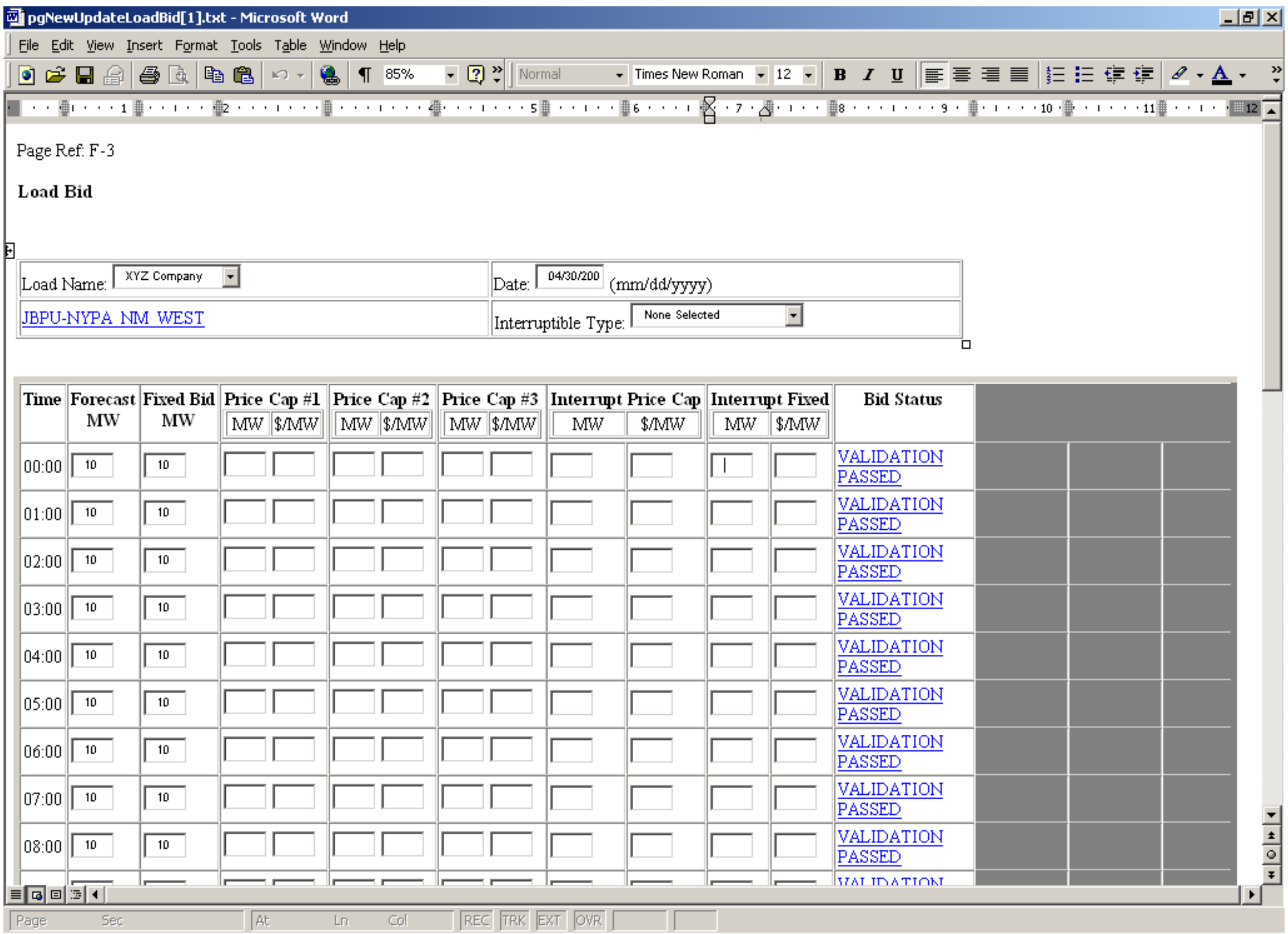
The curtailable load will be modeled as a generator in the ISO's unit commitment software, and uses a generator bid to make the curtailable MW's available to the ISO. ~~This process holds true for both self-supply and curtailable load providers.~~ The bidding instructions on the following pages track the payment examples in Section 8, and will demonstrate different ways to input ~~your~~ 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/~~Mwhr~~ 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/~~Mwhr~~MWh**.** Bids submitted below the floor price will be rejected from the MIS.

4.1 Load Bidding Portion

Using the scenario from Example #1 in Section 8, this bidding example demonstrates how an LSE would bid in their Load into the MIS system. In the example, a 10 MW load is capable of curtailing 3 MW of load at a price cap of $100/Mwh plus $2,000 for "Curtailment Initiation Costs" for a continuous time strip of 6 hours. When the LSE goes into the MIS system to input its load bid it would do so as if the Curtailment portion does not exist. In this example the LSE would put in a fixed load bid of 10 MW.

By bidding in 10 MW as fixed load the LSE purchase 10 MW of load from the Day-Ahead market at the Day-Ahead zonal LBMP price.


pgNewUpdateLoadBid[1].txt - Microsoft Word

Page Ref: F-3

Load Bid

Load Name: XYZ Company | Date: 04/30/200 (mm/dd/yyyy)

JBPU-NYPA NM WEST | Interruptible Type: None Selected

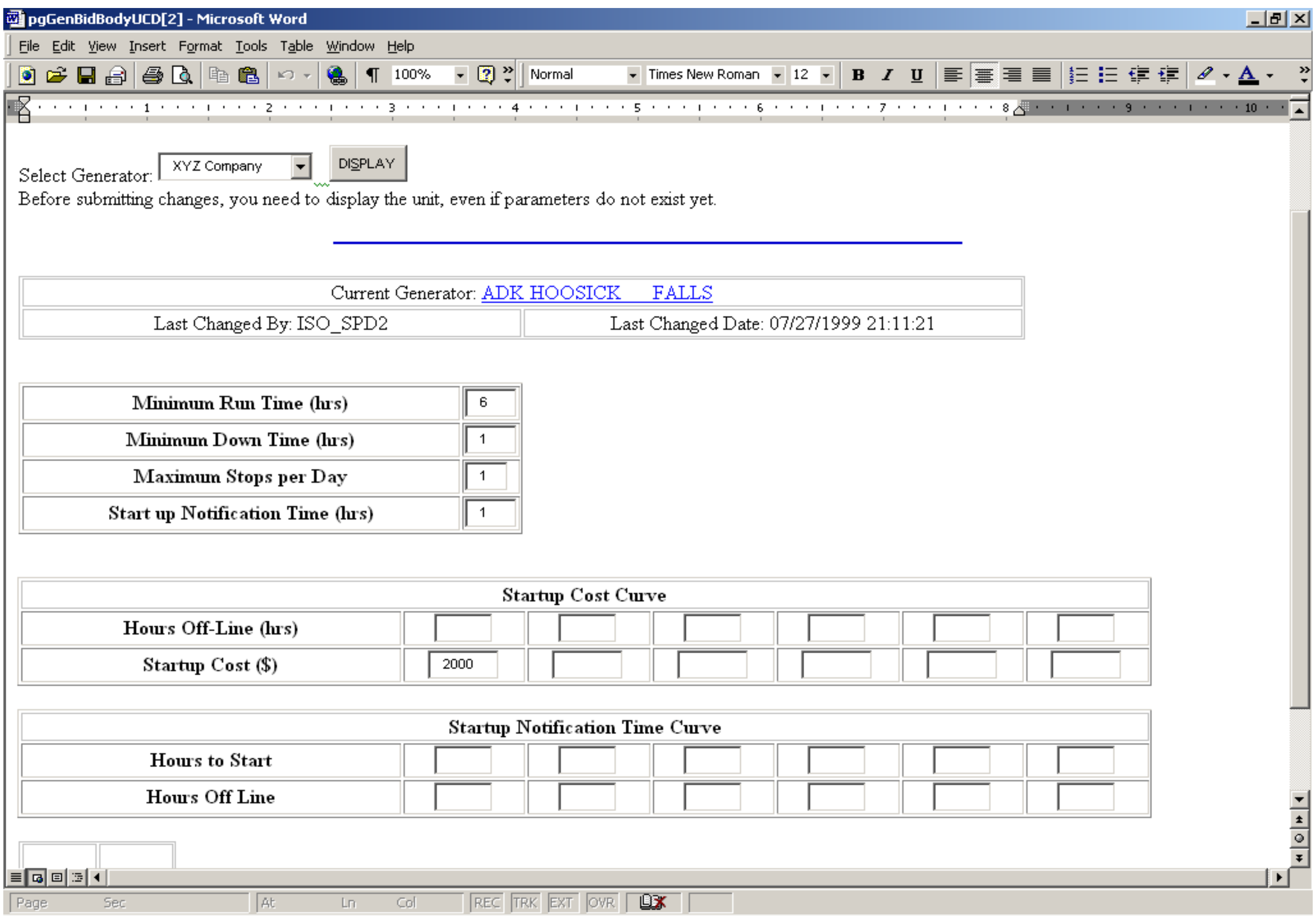
Time	Forecast MW	Fixed Bid MW	Price Cap #1 MW	Price Cap #1 $/MW	Price Cap #2 MW	Price Cap #2 $/MW	Price Cap #3 MW	Price Cap #3 $/MW	Interrupt Price Cap MW	Interrupt Price Cap $/MW	Interrupt Fixed MW	Interrupt Fixed $/MW	Bid Status
00:00	10	10											VALIDATION PASSED
01:00	10	10											VALIDATION PASSED
02:00	10	10											VALIDATION PASSED
03:00	10	10											VALIDATION PASSED
04:00	10	10											VALIDATION PASSED
05:00	10	10											VALIDATION PASSED
06:00	10	10											VALIDATION PASSED
07:00	10	10											VALIDATION PASSED
08:00	10	10											VALIDATION PASSED

4.2 Generator Bid Portion

Once the LSE has bid its load into the MIS system the LSE must also enter a generator bid for the amount of curtailable load being offered. A DRP would enter its curtailable load bid as a generator bid in the same way. First the LSE/DRP must enter data into the Generator Commitment Parameters screen.

4.2.1. Generator Commitment Parameter Screen

The LSE/DRP will enter the generator's Minimum Run Time and startup costs. These values correspond to the Demand Side Resource's minimum shutdown time and curtailment initiation costs, respectively. In this example the ~~units Minimum Run Time~~DSR's minimum shutdown time is 6 hrs. We will assume for this example that the units Minimum Down Time, Maximum Stops per day, and Startup Notification Time are all equal to 1. Please refer to the NYISO Market Participant User's Guide if you have questions regarding the use of these parameters.The only other piece of data that is needed in this screen is the generator startup cost. In this example the startup cost or "curtailment initiation cost" is $2,000. This amount is entered into the startup cost curve as the first and only point on the curve. The user must leave the "hours off line" box empty as well as the Startup Notification Time Curve.

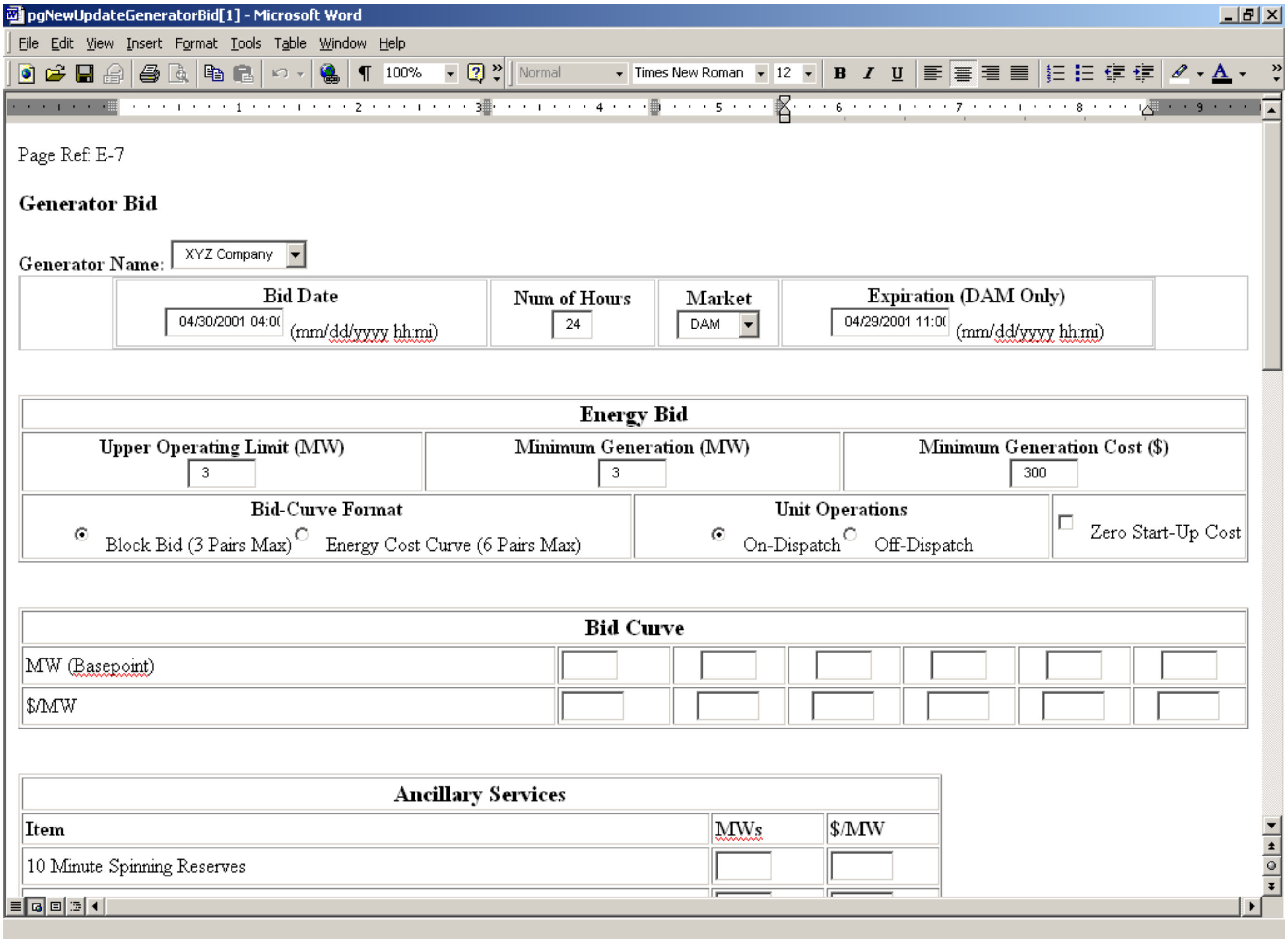


4.2.2 Generator Bid Screen

Second the LSE/DR~~S~~P must enter the specific generator bid data into the MIS system. For illustration purposes, two examples of how to bid the 3 MW curtailable load will be shown. For a more complete understanding of how to bid a generator into the NYISO, an LSE/DR~~S~~P should attend the NYMOC training or contact their Customer Relations Representative.

Example 1:

The first way a user can structure his or her bid is as follows:
The first piece of data that is needed is the Upper Operating Limit (UOL) of the generator. In this example the UOL is 3 MW, which is the maximum amount of curtailable load being offered. Next the User must enter the units Minimum Generation (MW) and Minimum Generation Cost ($). In this case the Minimum Generation is 3 MW and the Minimum Generation Cost is $300. The last piece of data that is needed is the unit's bid curve. For this example the unit's bid curve is left blank, because if the unit's minimum limit and upper limit are the same value the unit is considered a fixed unit and cannot submit a bid curve. DADRP providers are not allowed to bid in the Ancillary Service Market. Also remember that we entered the units startup cost in the previous screen so make sure the box for zero start up cost is not checked. A generator's Min Gen MW level is the only level that is guaranteed commitment for the unit's specified Min Run time.



pgNewUpdateGeneratorBid[1] - Microsoft Word

File Edit View Insert Format Tools Table Window Help

Page Ref: E-7

Generator Bid

Generator Name: XYZ Company

Bid Date	Num of Hours	Market	Expiration (DAM Only)
04/30/2001 04:0((mm/dd/yyyy hh:mi)	24	DAM	04/29/2001 11:0((mm/dd/yyyy hh:mi)

Energy Bid		
Upper Operating Limit (MW)	Minimum Generation (MW)	Minimum Generation Cost ($)
3	3	300
Bid-Curve Format: Block Bid (3 Pairs Max) / Energy Cost Curve (6 Pairs Max)	Unit Operations: On-Dispatch / Off-Dispatch	Zero Start-Up Cost

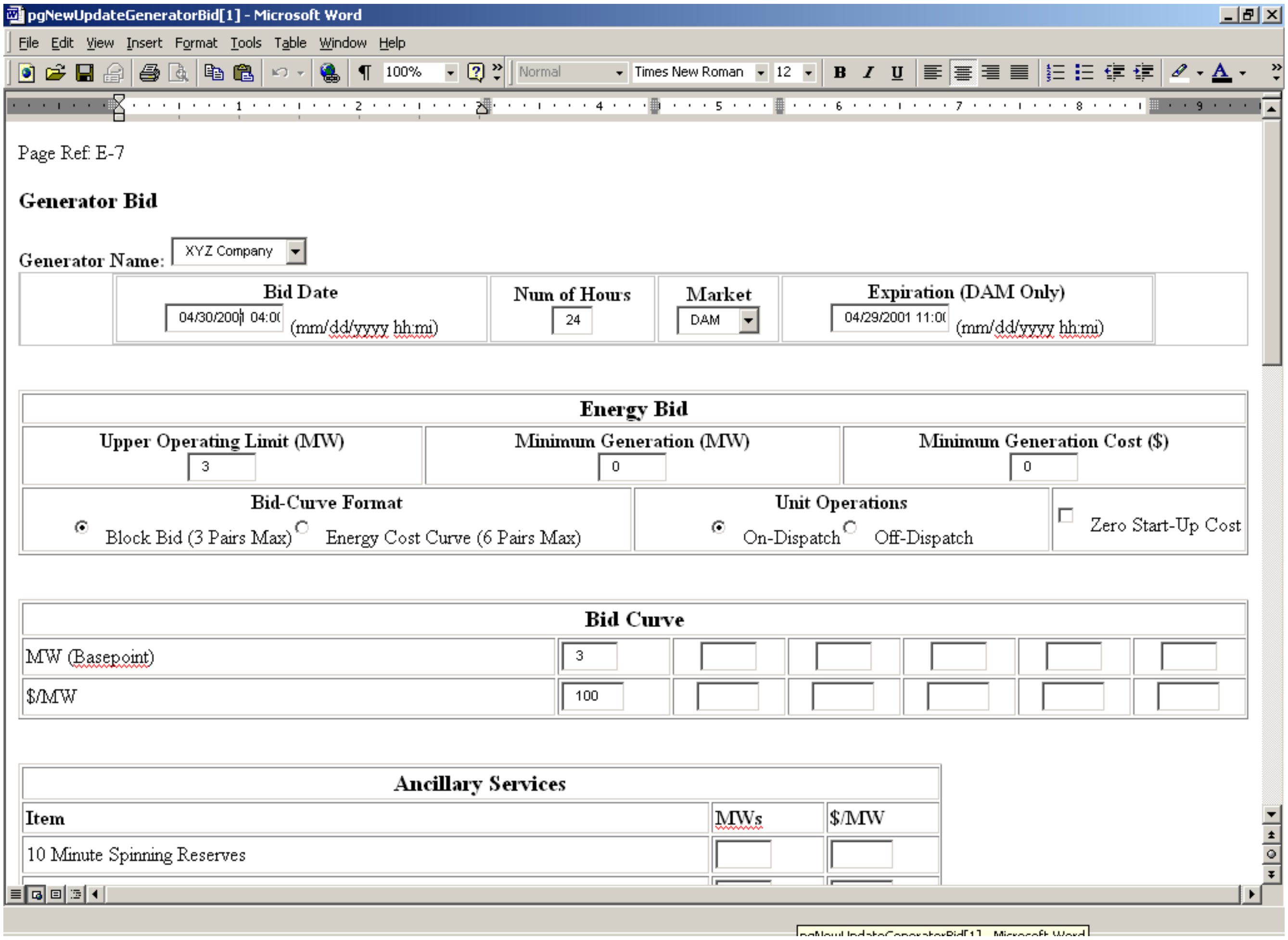
Bid Curve						
MW (Basepoint)						
$/MW						

Ancillary Services		
Item	MWs	$/MW
10 Minute Spinning Reserves		

Under this example, if the bid is accepted it will be scheduled for the six hours of minimum run time. It is important to note that the bid curve cannot be used to submit bid blocks above the first point on the bid curve and assure acceptance of these bids for the entire minimum run time. The higher bid blocks will instead be scheduled by SCUC on hourly basis. For example, if a demand reduction provider wished to enter a bid of an additional 3 MWs at $200/MW for the same six hour period it should not be entered as the second bid point in the above bid curve. In doing so the bid may not be accepted for the entire six hour but only scheduled in the hours where SCUC found the curtailment at this bid price economic.

Example 2:

Another way a user can structure his or her bid is as follows:
The Upper Operating Limit can remain the same as the previous example (3 MW). The Minimum Generation (MW) in this example would be $0 and the Minimum generation Cost ($) would be $0 as well. In the Bid Curve section the LSE will enter as a one-point block 3 MW for *MW (Basepoint)* and $100 for *$/MW*. Again no DADRP provider can bid into the Ancillary Service Market, and remember that the zero startup cost box should not be checked.



Within this bid structure SCUC could schedule the generator anywhere between its 0 MW Min Gen and 3 MWs (the last point on the bid curve) to satisfy minimum run time.

In all instances a generator is only guaranteed to be scheduled at its Min Gen MWs for its entire Min Run time.

4.3 Generator Unit Commitment Parameters for Curtailable Load and Self-Supply Generator Types.

Generator commitment table constraints for new generator types:

Generator Unit Commitment Data		
COLUMN_NAME	Required Field	Input Range
MIN_DOWN_TIME	Y	1-24
MIN_RUN_TIME	Y	Maximum of 8 hrs
MAX_STOPS_DAY	Y	1-13
START_UP_NOTIFICATION_TIME	Y	1-37
STRT_UP_COST_CRV1	Y	$0 - $99,999
STRT_UP_COST_CRV2	N	Must be null
STRT_UP_COST_CRV3	N	Must be null
STRT_UP_COST_CRV4	N	Must be null
STRT_UP_COST_CRV5	N	Must be null
STRT_UP_COST_CRV6	N	Must be null
STRT_UP_TIME_CRV1	N	Must be null
STRT_UP_TIME_CRV2	N	Must be null
STRT_UP_TIME_CRV3	N	Must be null
STRT_UP_TIME_CRV4	N	Must be null
STRT_UP_TIME_CRV5	N	Must be null
STRT_UP_TIME_CRV6	N	Must be null
STRT_UP_HOURS_OFF_LINE_CRV1	N	Must be null
STRT_UP_HOURS_OFF_LINE_CRV2	N	Must be null
STRT_UP_HOURS_OFF_LINE_CRV3	N	Must be null
STRT_UP_HOURS_OFF_LINE_CRV4	N	Must be null
STRT_UP_HOURS_OFF_LINE_CRV5	N	Must be null
STRT_UP_HOURS_OFF_LINE_CRV6	N	Must be null
STRT_UP_HOURS_TO_STRT_CRV1	N	Must be null
STRT_UP_HOURS_TO_STRT_CRV2	N	Must be null
STRT_UP_HOURS_TO_STRT_CRV3	N	Must be null
STRT_UP_HOURS_TO_STRT_CRV4	N	Must be null
STRT_UP_HOURS_TO_STRT_CRV5	N	Must be null
STRT_UP_HOURS_TO_STRT_CRV6	N	Must be null

Generator bid data table constraints for new generator types:

Generator Bid Data		
COLUMN_NAME	Required Field	Input Range
DATE_HR	Y	MM/DD/YYYY
DURATION_HR	Y	1-360
MARKET	Y	DAM
UP_OPER_LIM	Y	0 – Proven maximum production capacity
ON_DISPATCH	Y	Y/N
ZERO_START_UP_COST	Y	Y/N
FIXED_MINIMUM_BLOCK_MW	Y	0 – Upper Operating Limit
FIXED_MINIMUM_BLOCK_DOLLARS	Y	0 - $999 * Fixed Min_Block_MW
MIN10_SPIN_RESERVES_MW	N	Must be null
MIN10_SPIN_RESERVES_DOLLAR	N	Must be null
MIN10_NONSYNCH_RESERVES_MW	N	Must be null
MIN10_NONSYNCH_RESERVES_DOLLAR	N	Must be null
MIN30_SPIN_RESERVES_MW	N	Must be null
MIN30_SPIN_RESERVES_DOLLAR	N	Must be null
MIN30_NONSYNCH_RESERVES_MW	N	Must be null
MIN30_NONSYNCH_RESERVES_DOLLAR	N	Must be null
REGULATION_AVAILABILITY_MW	N	Must be null
REGULATION_AVAILABILITY_DOLLAR	N	Must be null
DISPATCH_CURVE_SEGMENTS	Y	CURVE OR BLOCK
DISPATCH_BLOCK_SEGMENTS	Y	CURVE OR BLOCK
DISPATCH_MW1	N	0 – Upper Operating Limit
DISPATCH_MW2	N	MW1 – Upper Operating Limit
DISPATCH_MW3	N	MW2 – Upper Operating Limit
DISPATCH_MW4	N	MW3 – Upper Operating Limit
DISPATCH_MW5	N	MW4 – Upper Operating Limit
DISPATCH_MW6	N	MW6 – Upper Operating LImit
DISPATCH_DOLLAR1	N	$ -1,000 - $1,000 values must be monotonically increasing.
DISPATCH_DOLLAR2	N	Value must be monotonically increasing
DISPATCH_DOLLAR3	N	Value must be monotonically increasing
DISPATCH_DOLLAR4	N	Value must be monotonically increasing
DISPATCH_DOLLAR5	N	Value must be monotonically increasing
DISPATCH_DOLLAR6	N	Value must be monotonically increasing

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

DAMGenScheduleCCYYMMMDD.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 ~~CSP~~DRP, with the NYISO for program participation. The choice of CBL becomes effective when the NYISO accepts the registration.

A.2 At ~~the~~ initial DADRP 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~~DADRP 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.

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 Baseline Calculation Method (On-Site Generation Only)~~

~~For on-site 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 on-site 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 as shown in Section 5.1.I.A .~~

~~2.Select the 5 **lowest** values of kwh(k) and use those days d(I), I = 1...5 to calculate the CBL.~~

~~3.Calculate the CBL for each hour h(i) as the average of the five h(i) values for days d(I), I = 1...5.~~

5.~~3~~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~~s~~ 5.1 ~~and 5.2~~ 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 ~~MWhr~~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 ~~MWhr~~MWh.

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

The composite non-coincident CBL for the aggregated resources would be 4.02 + 7.14 = 11.16 ~~MWhr~~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.

~~Output from DADRP non-diesel on-site generators that are not individually metered will be measured based on the net load revenue meters at the site and billed as a DADRP non-incentivized on-site generator.~~

~~DADRP Demand Side Resources with diesel generators must have separate interval meters on diesels to insure that load curtailment is not self-supplied through the diesels.~~

~~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~~2 Performance (Interruptible Load ~~or On-Site Generation Using Net Metered Load~~)

Performance for interruptible loads ~~or on-site 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 Section 5 of this manual.

Performance for a interruptible load Demand Side 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-xx)h-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 Side Resource/Aggregate was not scheduled for a Demand Reduction.

~~6.4Performance - On-site Generation Only Configuration~~

~~For premises subscribing only on-site 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 On-site 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 on-site generation described in Section 5.2.~~

6.~~5~~3 Data Submission

A Meter Data Service Provider (MDSP) will provide the Demand Side Resource net metered load to the LSE.

The MDSP will receive copies of the Demand Side Resource Registration Form, and the Aggregated Bid Reporting Form, as well as corresponding unique Point Identifiers for each accepted Demand Side Resource/Aggregate from the NYISO.

The MDSP will receive Hourly Interval Meter readings for the net load at each Demand Side Resource. The MDSP will aggregate the meter reads where necessary per the Aggregated Bid Reporting Form, and unique Point Identifier definitions provided by the NYISO.

The MDSP will use the Hourly Interval meter readings for each Demand Side Resource/Aggregate to calculate a Customer Base Load, per the procedure in Section 5 for each Demand Side Resource/Aggregate.

The MDSP will calculate Demand Reduction Performance ($PRL_{meter\ h}$), for hours in which the Demand Side Resource was scheduled for reduction per the formula described in Section 6.3 or 6.4 of this manual, whichever is applicable. The Demand Side Resource/Aggregate metered Load Data and the calculated Customer Base Load should be retained by the MDSP for a period of at least two years.

The MDSP will report the Demand Side Resource/Aggregate to the ISO's basftp1.nyiso.com site in the MWH Data Daily file named MWHmmddyyyy.csv. If the metered data can be obtained, and the CBL calculation performed in time for the initial monthly billing, then the actual data should be used. If the metered data cannot be obtained, and/or if the CBL calculation cannot be performed in time for the initial monthly billing, then Demand Reduction Performance (PRLmeter) should be set equal to Scheduled Demand Reduction. Sometime between the Initial Monthly Billing and the First Settlement Adjustment, an updated MWH Data Daily file should be submitted to the ISO based upon actual metered data.

6.~~6~~4 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 it's review of the LSE/~~CSP~~DRP's account determines the LSE/~~CSP~~DRP or one of its customers has committed fraud to extract DADRP payments from the ISO, the ISO will have the right to ban the LSE/~~CSP~~DRP or the LSE/~~CSP~~DRP's customer from the DADRP as well as pursue all of the ISO's legal rights, at its sole discretion.

7.0 Incentive Credits, Demand Reduction Payments and Non-Performance Penalties

7.1 Definition of Terms

PRL_{DA} = DADRP load scheduled

PRL_{RT} = Real-time DADRP load for settlement

PRL_{METER} = Actual DADRP load reduction obtained

$LBMP_{DAZONE}$ = Day-ahead zonal LBMP

$LBMP_{DABUS}$ = Day-ahead bus LBMP

$LBMP_{RTZONE}$ = Time-weighted real-time zonal LBMP

$LBMP_{RTBUS}$ = Time-weighted real-time bus LBMP

7.2 DADRP Interruptible Load Resources

For interruptible loads, credits will be applied for Payment, Uplift and Incentive; debits will be applied for Penalties and Load Balancing.

Determine credit based on accepted schedule and day-ahead LBMP:

Demand Reduction $\text{Payment} = PRL_{DA} * LBMP_{DA_{BUS}}$

For hour(s) committed, determine load reduction bid guarantee (LRGB) revenue requirements based on accepted schedule and actual performance:

$$\text{LRBG} = \overbrace{\frac{\sum_{hr} PRL_{METER}\Big|_0^{PRL_{DA}}}{\sum_{hr} PRL_{DA}}(StartupCost)}^{\text{Startup Cost Allocation}} + \overbrace{\sum_{hr}\left(\left(\frac{PRL_{METER}\Big|_0^{PRL_{DA}}}{MinGenMW}\right)\Bigg|^1 (MinGenCost)\right)}^{\text{Minmum Generation Allocation}} + IncrementalCost_{PRL_{METER}}$$

Determine any uplift credits required based on LRBG and revenue:

$$\text{Uplift} = \left(\text{LRBG} - \sum_{hr}\left(PRL_{METER}\Big|_0^{PRL_{DA}} * LBMP_{DA_{BUS}}\right)\right)\Bigg|_0$$

Determine penalty charge debits for failure to perform:

$$\text{Penalty} = \left(PRL_{METER}\Big|_0^{PRL_{DA}} - PRL_{DA}\right) * 1.1 * \max\left(LBMP_{DA_{BUS}}, LBMP_{RT_{BUS}}\right)$$

Determine amount of overcollection from penalty to offset program costs:

$$\text{Overcollection} = \left(\left(PRL_{METER}\Big|_0^{PRL_{DA}} - PRL_{DA}\right) * LBMP_{RT_{BUS}}\right) - \text{Penalty}$$

Determine incentive payment credit based on actual performance and day-ahead LBMP:

$$\text{Incentive} = PRL_{METER}\Big|_0^{PRL_{DA}} * LBMP_{DA_{BUS}}$$

Determine Load Balance debit to offset credit received by LSE in real-time load settlement:

$$\text{Load Balance} = PRL_{METER}\Big|_0^{PRL_{DA}} * LBMP_{RT_{ZONE}} * (-1.0)$$

The LSE will settle their bid load against the estimated and metered load as currently occurs.

~~7.3 DADRP Non-Diesel Self-Supply Generation Resources~~

~~For self-supply generation resources, credits will be applied for Payment and Uplift; debits will be applied for Penalties and Load Balancing.~~

~~Determine credit based on accepted schedule and day-ahead LBMP:~~

~~Demand Reduction~~ $\text{Payment} = PRL_{DA} * LBMP_{DA_{BUS}}$

~~For hour(s) committed, determine load reduction bid guarantee revenue requirements based on accepted schedule and actual performance:~~

$$\text{LRBG} = \overbrace{\frac{\sum_{hr} PRL_{METER}\Big|_0^{PRL_{DA}}}{\sum_{hr} PRL_{DA}}(StartupCost)}^{\text{Startup Cost Allocation}} + \overbrace{\sum_{hr}\left(\left(\frac{PRL_{METER}\Big|_0^{PRL_{DA}}}{MinGenMW}\right)\Bigg|^{1}(MinGenCost)\right)}^{\text{Minmum Generation Allocation}} + IncrementalCost_{PRL_{METER}}$$

~~Determine any uplift credits required based on LRBG and revenue:~~

$$\text{Uplift} = \left(\text{LRBG} - \sum_{hr}\left(PRL_{METER}\Big|_0^{PRL_{DA}} * LBMP_{DA_{BUS}}\right)\right)\Bigg|_0$$

~~Determine penalty charge debits for failure to perform:~~

$$\text{Penalty} = \left(PRL_{METER}\Big|_0^{PRL_{DA}} - PRL_{DA}\right) * LBMP_{RT_{BUS}}$$

~~Determine Load Balance debit to offset credit received by LSE in real-time load settlement:~~

$$\text{Load Balance} = PRL_{METER}\Big|_0^{PRL_{DA}} * LBMP_{RT_{ZONE}} * (-1.0)$$

~~The LSE will settle their bid load against the estimated and metered load as currently occurs.~~

8.0 Performance and Payment Examples

8.1 Economic "Incentivized" Curtailment of Load – LSE-Sponsored

For Load scheduled to economically curtail Day-Ahead, and that actually does curtail in Real-Time, the LSE would be paid Day-Ahead LBMP and would include a supplement, if needed, to allow full recovery of the "Curtailment Initiation Cost". Also, the LSE would be charged for that curtailed Load, but then would receive a rebate for this charge as the "Incentive".

As an example, assume:

a) A 10 MW Load bids 10 MW fixed Load and bids to curtail 3 MW of Load at a Price Cap 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 LBMP is $250/MWh for those 6 hours.
d) Real-Time LBMP 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/~~CSP~~DRP would be paid $4,500 = $250/MWh LBMP 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 LBMP payment would exceed the $3,800 total curtailment bid.
c) The LSE/~~CSP~~DRP would be charged $15,000 = $250/MWh LBMP x 10 MW x 6 hours for the fixed Load.
d) The LSE/~~CSP~~DRP would then also receive a rebate of $4,500 = $250/MWh LBMP x 3 MW x 6 hours for the curtailed Load as an "Incentive".
e) The LSE/~~CSP~~DRP would be charged $4,950 = $275/MWh * 3 MW * 6 hours for the curtailed load as a Load Balance.
f) The LSE/~~CSP~~DRP would receive a rebate of $4,950 = $275/MWh * 3 MW * 6 hours for the balancing of their Day-Ahead energy purchase.

	Day Ahead	Real Time	
$LBMP_{bus}$	**$250**	**$275**	assumed
$LBMP_{zonal}$	**$250**	**$275**	assumed
Fixed Load (MW)only	**10**	**10**	Net Load + Reduction
Load Reduction (MW)	**3**	**3**	Actual Reduction
Total DAM Load (MW)	**7**	**7**	Real Time Net Load
Shutdown duration (hrs)	**6**	**6**	assumed
Hourly Curtailment Bid	**$100**		
Curtailment Initiation Cost	**$2,000**		
Total Bid Cost	**$3,800**		

	DRP is LSE
Day-Ahead Settlement	**LSE**
LSE DAM Purchase Obligation	($15,000)
LSE DAM Credit (Incentive)	4,500.00
Real-Time Settlement	
Payment for Performance*	4,500.00
Nonperformance Penalty*	0.00
Bid Curtailment Cost Guarantee Payment	$3,800
LSE Load Balance Credit	$4,950
LSE Load Balance Debit	($4,950)
Total Received (Paid) by LSE	($2,200)

~~8.2 Economic Selection of Small Generators for Self-Supply~~

~~For Load scheduled to economically curtail Day-Ahead and which continues to consume, but self-supplies the "curtailed" Load with a "behind-the-fence" small generator, the LSE would be paid Day-Ahead LBMP for the self-supply. This payment would include a supplemental payment, if needed, to allow full recovery of the "Curtailment Initiation Cost" (or "Start-Up and Min Gen Costs" in the case of a self-supplying small Generator). Also, the LSE would be charged for the full amount of Energy that the load consumes (i.e., no rebate would be paid for the "curtailed" Load as an "Incentive").~~

~~Consequently, a Load that "curtails" through self-supply would not be (and specifically is not intended to be) treated exactly the same way as a Load that "curtails" through an actual reduction in consumption. The self-supplied Load is not eligible for the "Incentive". However, this does provide a mechanism for small Generators to bid into the market without the more rigorous requirements of large Generators. For the purposes of billing, a Load and its "behind-the fence" small Generator would be treated as two separate entities under this program.~~

~~As an example, assume:~~

- ~~a)A 10 MW Load bids 10 MW of fixed Load and bids to curtail 3 MW of Load through self-supply via a "behind-the-fence" small generator at a Price Cap of $100/MWh plus $2,000 for "Curtailment Initiation Costs" (or "Start-up and Min Gen 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 LBMP is $250/MWh for those 6 hours.~~
- ~~d)Real-Time LBMP is $275/MWh for those 6 hours.~~
- ~~e)The Load actually consumes 10 MW, but self-supplies 3 MW of that 10 MW over those 6 hours (i.e., it has a net consumption of 7 MW).~~

~~The resulting charges and payments would be as follows:~~

- ~~a)The LSE/CSP would be paid $4,500 = $250/MWh LBMP x 3 MW x 6 hours for the self-supplied "curtailed" Load.~~
- ~~b)No supplemental "Uplift" payment for a "Bid Production Cost Guarantee" would be needed since the $4,500 LBMP payment would exceed the $3,800 total curtailment bid.~~
- ~~c)The LSE/CSP would be charged $15,000 = $250/MWh LBMP x 10 MW x 6 hours for its total consumption even though a portion is self-supplied.~~
- ~~d)The LSE/CSP would not receive a rebate for the curtailed Load (i.e., no "Incentive" payment would be paid for the 3 MW of self-supplied "curtailed" Load).~~
- ~~e)The LSE/CSP would be charged $4,950 = $275/MWh * 3 MW * 6 hours for the curtailed load as a Load Balance.~~
- ~~f)The LSE/CSP would receive a rebate of $4,950 = $275/MWh * 3 MW * 6 hours for the balancing of their Day-Ahead energy purchase.~~

~~The difference, obviously, between "#1" and "#2" above is that under "#1", the LSE would be charged $4,500 less for Energy -- i.e., the "Incentive".~~

8.~~3~~2 Uplift Example – LSE Sponsored

An LSE will be paid Day-Ahead LBMP 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-Cap 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.

~~For a Load without a self-supplying generator, t~~The payments and charges would be as follows:

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

b) The LSE~~/CSP~~DRP 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 LBMP payment (this is based upon the requirement that SCUC determines that the total bid production cost over the 24 hour Dispatch Day will be lower with this Load curtailed).

c) Also, as in the previous example, the LSE~~/CSP~~DRP would be charged $15,000 for the fixed Load ; and then would also receive a rebate of $4,500 as an "Incentive".

d) The LSE~~/CSP~~DRP would be charged $4,950 = $275/MWh * 3 MW * 6 hours for the curtailed load as a Load Balance.

e) The LSE~~/CSP~~DRP would receive a rebate of $4,950 = $275/MWh * 3 MW * 6 hours for the balancing of their Day-Ahead energy purchase.

The same example holds for Load that curtails through self-supply except that the "Incentive" rebate payment is not made.

This example is simplified somewhat because the bids and LBMPs in each hour were the same, but the principle remains that "Uplift" is paid if, over the course of the 24 hour Dispatch Day, bid costs are not fully recovered through LBMP.

	Day Ahead	Real Time	
LBMP bus	**$250**	**$275**	assumed
LBMP zonal	**$250**	**$275**	assumed
Fixed Load (MW)only	**10**	**10**	Net Load + Reduction
Load Reduction (MW)	**3**	**3**	Actual Reduction
Total DAM Load (MW)	**7**	**7**	Real Time Net Load
Shutdown duration (hrs)	**6**	**6**	assumed
Hourly Curtailment Bid	**$150**		
Curtailment Initiation Cost	**$2,000**		
Total Bid Cost	**$4,700**		

	DRP is LSE
Day-Ahead Settlement	**LSE**
LSE DAM Purchase Obligation	($15,000)
LSE DAM Credit (Incentive)	4,500.00
Real-Time Settlement	
Payment for Performance*	4,500.00
Nonperformance Penalty*	0.00
Bid Curtailment Cost Guarantee Payment	$200
LSE Load Balance Credit	$4,950
LSE Load Balance Debit	($4,950)
Total Received (Paid) by LSE	($5,800)

8.~~4~~3 Economic "Incentivized" Curtailment of Load With Non-Performance Penalty for Failure to Reduce Consumption – LSE-Sponsored

If an LSE~~/CSP~~~~DRP~~ has an End-User scheduled for a Price-Cap curtailment that would have been eligible for the "Incentive" payment, and that subsequently fails to curtail, the LSE~~/CSP~~~~DRP~~ will be charged ~~110% of~~ the higher of Day-Ahead or Real-Time LBMP for non-curtailed Load. ~~A self-supplying on-site Generator is not eligible for the "Incentive", and also not subject to the 110% Performance Penalty; it is simply charged Real-Time LBMP for non-curtailed Load.~~

As an example, assume:

a) A 10 MW Load bids 10 MW fixed Load and bids to curtail 3 MW of Load by reducing consumption at a Price Cap 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 LBMP is $250/MWh, and Real-Time LBMP is $300/MWh.
d) Over those six 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~~/CSP~~~~DRP~~ would be paid $4,500 = $250/MWh LBMP x 3 MW x 6 hour for the curtailment.
b) The LSE~~/CSP~~~~DRP~~ would be charged $15,000 = $250/MWh Day-Ahead LBMP x 10 MW x 6 hours for the fixed Load.
c) The LSE~~/CSP~~~~DRP~~ would also be charged $5,~~94~~400 = ~~110% x~~ $300/MWh Real-Time LBMP x 3 MW x 6 hours for the Load that failed to curtail.
d) The LSE~~/CSP~~~~DRP~~ also would not receive a rebate as an "Incentive" because it failed to curtail.

	Day Ahead	Real Time	
$LBMP_{bus}$	**$250**	**$300**	assumed
$LBMP_{zonal}$	**$250**	**$300**	assumed
Fixed Load (MW)only	**10**	10	Net Load + Reduction
Load Reduction (MW)	**3**	**0**	Actual Reduction
Total DAM Load (MW)	7	**10**	Real Time Net Load
Shutdown duration (hrs)	**6**	**6**	assumed
Hourly Curtailment Bid	**$100**		
Curtailment Initiation Cost	**$2,000**		
Total Bid Cost	**$3,800**		

	DRP is LSE
Day-Ahead Settlement	**LSE**
LSE DAM Purchase Obligation	($15,000)
LSE DAM Credit (Incentive)	4,500.00
Real-Time Settlement	
Payment for Performance*	0.00
Nonperformance Penalty*	(5,400.00)
Bid Curtailment Cost Guarantee Payment	$0
LSE Load Balance Credit	$0
LSE Load Balance Debit	$0
Total Received (Paid) by LSE/DRP	($15,900)

8.4 Economic "Incentivized" Curtailment of Load – DRP-Sponsored

For Load scheduled to economically curtail Day-Ahead, and that actually does curtail in Real-Time, the DRP would be paid Day-Ahead LBMP and would include a supplement, if needed, to allow full recovery of the "Curtailment Initiation Cost". Also, the LSE would be charged for that curtailed Load, but then would receive a rebate for this charge as the "Incentive".

As an example, assume:

a. An LSE bids 10 MW fixed Load and a DRP bids to curtail 3 MW of that Load at a Price Cap 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 LBMP is $250/MWh for those 6 hours.=
d. Real-Time LBMP 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 DRP would be paid $4,500 = $250/MWh LBMP 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 LBMP payment would exceed the $3,800 total curtailment bid.
c) The LSE would be charged $15,000 = $250/MWh LBMP x 10 MW x 6 hours for the fixed Load.
d) The LSE would then also receive a rebate of $4,500 = $250/MWh LBMP x 3 MW x 6 hours for the curtailed Load as an "Incentive".
e) The LSE would be charged $4,950 = $275/MWh * 3 MW * 6 hours for the curtailed load as a Load Balance.
f) The LSE would receive a rebate of $4,950 = $275/MWh * 3 MW * 6 hours for the balancing of their Day-Ahead energy purchase.

	Day Ahead	Real Time	
$LBMP_{bus}$	**$250**	**$275**	assumed
$LBMP_{zonal}$	**$250**	**$275**	assumed
Fixed Load (MW)only	**10**	**10**	Net Load + Reduction
Load Reduction (MW)	**3**	**3**	Actual Reduction
Total DAM Load (MW)	**7**	**7**	Real Time Net Load
Shutdown duration (hrs)	**6**	**6**	assumed
Hourly Curtailment Bid	**$100**		
Curtailment Initiation Cost	**$2,000**		
Total Bid Cost	**$3,800**		

		DRP is not LSE	
Day-Ahead Settlement		**DRP**	**LSE**
LSE DAM Purchase Obligation			(15,000.00)
LSE DAM Credit (Incentive)			4,500.00
Real-Time Settlement			
Payment for Performance*		4,500.00	
Nonperformance Penalty*		0.00	0.00
Bid Curtailment Cost Guarantee Payment		$0	
LSE Load Balance Credit			$4,950
LSE Load Balance Debit			($4,950)
Total Received (Paid) by LSE		$4,500	($10,500)

8.5 Uplift Example – DRP-Sponsored

The DRP will be paid Day-Ahead LBMP for the load curtailment provided and would also be paid a supplemental payment, if needed, for "Bid Curtailment Cost Guarantee" to allow full recovery of the "Curtailment Initiation Cost"

Assume the same example for a curtailable Load Bid above except that the Load bids a Price-Cap 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 DRP would be paid $4,500 = $250/MWh LBMP x 3 MW x 6 hours for the curtailment.
b) The DRP 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 LBMP payment (this is based upon the requirement that SCUC determines that the total bid production cost over the 24 hour Dispatch Day will be lower with this Load curtailed).
c) As in the previous example, the LSE would be charged $15,000 for the fixed Load
d) The LSE would receive a rebate of $4,500 = $250/MWh LBMP x 3 MW x 6 hour for the curtailment as an “Incentive”.
e) The LSE would be charged $4,950 = $275/MWh * 3 MW * 6 hours for the curtailed load as a Load Balance.
f) The LSE would receive a rebate of $4,950 = $275/MWh * 3 MW * 6 hours for the balancing of their Day-Ahead energy purchase.

	Day Ahead	Real Time	
LBMP $_{bus}$	**$250**	**$275**	assumed
LBMP $_{zonal}$	**$250**	**$275**	assumed
Fixed Load (MW)only	**10**	**10**	Net Load + Reduction
Load Reduction (MW)	**3**	**3**	Actual Reduction
Total DAM Load (MW)	**7**	**7**	Real Time Net Load
Shutdown duration (hrs)	**6**	**6**	assumed
Hourly Curtailment Bid	**$150**		
Curtailment Initiation Cost	**$2,000**		
Total Bid Cost	**$4,700**		

			DRP is not LSE
Day-Ahead Settlement		**DRP**	**LSE**
LSE DAM Purchase Obligation			($15,000.00)
LSE DAM Credit (Incentive)			$4,500.00
Real-Time Settlement			
Payment for Performance*		$4,500.00	
Nonperformance Penalty*		$0.00	$0.00
Bid Curtailment Cost Guarantee Payment		$200.00	
LSE Load Balance Credit			$4,950
LSE Load Balance Debit			($4,950)
Total Received (Paid) by LSE		$4,700	($10,500)

8.6 Economic "Incentivized" Curtailment of Load With Non-Performance Penalty for Failure to Reduce Consumption – DRP-Sponsored

If an LSE/DRP has an End-User scheduled for a Price-Cap curtailment that would have been eligible for the "Incentive" payment, and that subsequently fails to curtail, the LSE/DRP will be charged the higher of Day-Ahead or Real-Time LBMP for non-curtailed Load

As an example, assume:

a. An LSE bids 10 MW fixed Load and a DRP bids to curtail 3 MW of that Load by reducing consumption at a Price Cap 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 LBMP is $250/MWh, and Real-Time LBMP is $300/MWh.
d. Over those six hours, the Load actually consumes 10 MW; it fails to curtail 3 MW.

The resulting payments and charges would be as follows:

a) The DRP would be paid nothing, since the resource did not perform at all in Real Time.
b) The DRP would not have received its total bid production cost of $3,800 = $2000 + ($100/MWh x 3 MW x 6 hours.) However, since it did not perform at all, it is not eligible for a “Bid Curtailment Cost Guarantee Payment”
c) The LSE would be charged $15,000 = $250/MWh Day-Ahead LBMP x 10 MW x 6 hours for the fixed Load.
d) The LSE would receive a rebate of $4,500 = $250/MWh LBMP x 3 MW x 6 hour for the curtailment as an “Incentive”.
e) The LSE and DRP are together responsible for the non-performance penalty of $5,400 = $300/MWh (higher of Day-Aheda or Real-Time Price) x 3 MW x 6 hours for the load that failed to curtail.
f) The LSE would also be charged $4,500 = $250/MWh Day-Ahead LBMP Bus Price x 3 MW x 6 hours for the Load that failed to curtail. This is the LSE’s portion of the non-performance penalty. But it is exactly offset by the amount of its Day-Ahead payment (see (a), above). Thus the LSE is held harmless from the acts of the DRP.
g) The DRP would be charged $900 = $5,400-$4,500, the remainder of the penalty
h) Since Day-Ahead and Real-Time load are the same, the LSE would be neither charged nor credited for Load Balancing.

	Day Ahead	Real Time	
LBMP bus	**$250**	**$300**	assumed
LBMP zonal	**$250**	**$300**	assumed
Fixed Load (MW)only	**10**	**10**	Net Load + Reduction
Load Reduction (MW)	**3**	**0**	Actual Reduction
Total DAM Load (MW)	**7**	**10**	Real Time Net Load
Shutdown duration (hrs)	**6**	**6**	assumed
Hourly Curtailment Bid	**$100**		
Curtailment Initiation Cost	**$2,000**		
Total Bid Cost	**$3,800**		

		DRP	*DRP is not LSE* LSE
Day-Ahead Settlement			
LSE DAM Purchase Obligation			($15,000.00)
LSE DAM Credit (Incentive)			$4,500.00
Real-Time Settlement			
Payment for Performance*		$0.00	
Nonperformance Penalty*		($900.00)	($4,500.00)
Bid Curtailment Cost Guarantee Payment		$0	
LSE Load Balance Credit			$0
LSE Load Balance Debit			$0
Total Received (Paid) by LSE/DRP		($900)	($15,000)

~~8.5 Self-Supply Curtailment of Load With Non-Performance Penalty for Failure to Curtail~~

~~As an example, assume:~~

- ~~a)A 10 MW Load bids 10 MW fixed Load and bids to curtail 3 MW of Load through self-supply at a Price Cap of $100/MWh plus $2,000 for "Start-Up and Min Gen 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 LBMP is $250/MWh, and Real-Time LBMP is $300/MWh.~~
- ~~d)Over those six hours, the Load actually consumes 10 MW; it fails to self-supply 3 MW, and therefore fails to curtail.~~

~~The resulting payments and charges would be as follows:~~

- ~~a)The LSE/CSP would be paid $4,500 = $250/MWh LBMP x 3 MW x 6 hour for the curtailment.~~
- ~~b)The LSE/CSP would be charged $15,000 = $250/MWh Day-Ahead LBMP x 10 MW x 6 hours for the fixed Load.~~
- ~~c)The LSE/CSP would also be charged $5,400 = $300/MWh Real-Time LBMP x 3 MW x 6 hours for the Load that failed to curtail (it is not subject to the 110% penalty since it bid to curtail through self-supply).~~
- ~~d)The LSE/CSP was not eligible for a rebate as an "Incentive" because it bid to self-supply rather than actually reduce consumption.~~

9.0 DADRP Cost Allocation

The DADRP will result in an under-collection of revenue by the NYISO. The revenue deficiency will be the combined result of:

(a) the load reduction bid guarantee, whereby the LBMP revenue will be supplemented to ensure the load reduction recovers their bid costs for the actual real-time MW reduction accomplished, and

(b) the rebate offered to the end-user's LSE/~~CSP~~DRP for the real-time MW reduction accomplished at day-ahead LBMP, and

(c) penalty charges, which offset the revenue deficiency to the extent the non-performance penalties exceed real-time LBMP.

A static method will be used to allocate costs associated with the under-collective of revenue according to those who benefit from the DADRP:

a) Each Zone (or set of Zones) are allocated the cost of the DADRP based upon its load ratio share on a daily basis using real-time metered daily load data and the static probability: (i) that no constraints existed, (ii) that this Zone(s) was upstream of a constraint and curtailment occurred upstream, and (iii) that this Zone(s) was downstream of a constraint and curtailment occurred downstream.

b) The three most often limiting NYCA interfaces are used, with the total probabilities ~~(for the historical period May-September 2001)~~ of them being limiting or having no constraints normalized to100%. Based upon current data, the three most limiting interfaces historically have been Central-East, Sprainbrook-Dunwoodie, and Con Ed - Long Island. For the purposes of DADRP cost allocation, four composite zones are used: West of Central-East (Zones A,B,C,D,E,), East Upstate Excluding NYC and LI (Zones F,G,H,I), New York City (Zone J), and Long Island (Zone K). For the period May-September ~~2001~~2002, the percentages of time when the specific interfaces were constrained are:

- No constraints: 31.4%
- Central-East: 28.8%
- Con Ed – Long Island: 33.7%
- Sprainbrook – Dunwoodie: 6.1%

The equations used to allocate costs to individual LSEs are as follows:

For LSE m in Zones A-E:

$$\mathbf{a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +} \quad \text{'no constraints}$$
$$\mathbf{a_2 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +} \quad \text{'above Central-East const}$$
$$\mathbf{a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +} \quad \text{'above S-D constraint}$$
$$\mathbf{a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)} \quad \text{'above CE-LI constraint}$$

For LSE m in Zones F-I:

$$\mathbf{a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +} \quad \text{'no constraints}$$
$$\mathbf{a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +} \quad \text{'below Central-East const}$$
$$\mathbf{a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +} \quad \text{'above S-D constraint}$$
$$\mathbf{a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)} \quad \text{'above CE-LI constraint}$$

For LSE m in Zone J:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ 'no constraints
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ 'below Central-East const
$a_3 * cost_J * load_m / load_J +$ 'below S-D constraint
$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ 'above CE-LI constraint

For LSE m in Zone K:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ 'no constraints
$a_2 * (cost_F+\ldots+cost_K) * load_m / (load_F+\ldots+load_K) +$ 'below Central-East const
$a_3 * (cost_A+\ldots+cost_I+cost_k) * load_m / (load_A+\ldots+load_I+load_k) +$ 'above S-D constraint
$a_4 * cost_K * load_m / load_K$ 'below CE-LI constraint

In all cases, the variables are:
a_1 = fraction of time when no constraints exist (0.314)
a_2 = fraction of time when Central-East interface is constraining (0.288)
a_3 = fraction of time when Sprainbrook-Dunwoodie interface is constraining (0.061)
a_4 = fraction of time when Con Ed-Long Island interface is constraining (0.337)
$cost_{A\ldots K}$ = revenue deficiencies due to DADRP load reductions in zones A…K, calculated on a daily basis
$load_m$ = real-time load for LSE m, calculated on a daily basis
$load_{A\ldots K}$ = real-time loads for all LSEs in each zone A…K, calculated on a daily basis

The specific values for $a_1\ldots a_4$ will be used for 2002. The specified values and the overall methodology will be reviewed by the Price-Responsive Load Working Group prior to 2003.

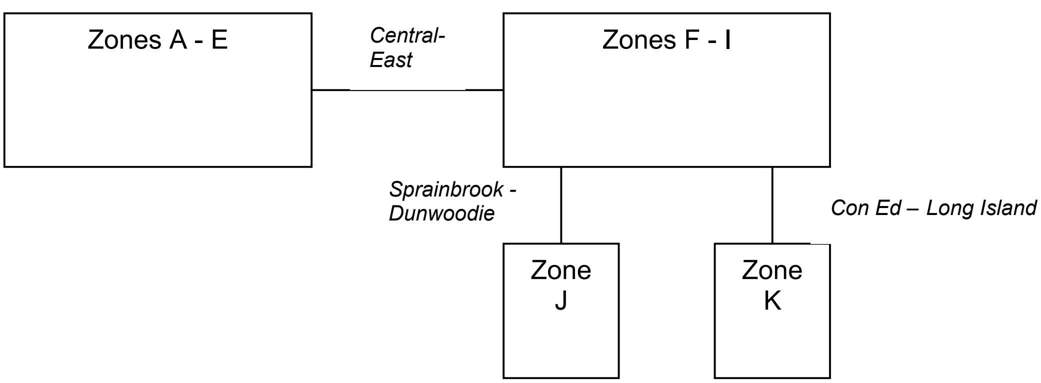


Figure 9.1 – Relationship Between Interface Constraints and Zones

Attachment A – DADRP ~~LSE~~ Demand Response Provider (DRP) Registration

Upon completion of program registration the ISO will model each accepted Demand Side Resource/Aggregate in the Day-Ahead Commitment software. Each accepted Demand Side Resource/Aggregate will be assigned a unique Point Identifier. As a condition of enrollment, the ~~LSE~~ DRP accepts that the NYISO will provide a copy of the Demand Side Resource Registration Form, and the Aggregated Bid Reporting Form to the relevant Meter Data Service Provider (MDSP). Additionally the ~~LSE~~ DRP accepts that the NYISO will provide the relevant MDSP with the unique Point Identifier used to model the Demand Side Resource/Aggregate.

This form must be faxed to **518-356-6146, attention: Manager DADRP or e-mailed to dlawrence@nyiso.com.**

All inquiries, notices and communications by the NYISO will be sent to the address provided below.

Name: ______________________________
Organization: ______________________________
Address: ______________________________
____
____
Phone: ______________________________
Cellphone: ______________________________
Pager: ______________________________
Fax: ______________________________
E-mail: ______________________________

Is your organization a current NYISO Customer? (check one) Yes ❒ No ❒
(If no, you must become a NYISO Customer to participate in this program)

Please check all the LBMP zone(s) in which you plan to submit DADRP bids:

West ❒	Genesee ❒	Central ❒
North ❒	Mohawk Valley ❒	Capital ❒
Hudson Valley ❒	Millwood ❒	Dunwoodie ❒
NYC ❒	Long Island ❒	

The ~~LSE~~ DRP certifies that the information contained in this form and its attachments is complete and correct.

IN WITNESS WHEREOF, this ~~Load Serving Entity's~~Demand Reduction Provider's Day-Ahead Demand Reduction Program Registration has been submitted on this, the ______ day of ________________, 20__.

NAME OF ~~Load Serving Entity~~Demand Reduction Provider:________________________________

Name: ____

Title: ____

____
Authorized Representative Signature

Attachment B – DADRP Demand Side Resource Registration

This form must be faxed to **518-356-6146, attention: Manager DADRP or e-mailed to dlawrence@nyiso.com.**

Use one form for each Demand Side Resource Registered by the ~~LSE~~Demand Reduction Provider (DRP).

Organization: ____

Address: ____

____

____

Name of Local Distribution Company (LDC): ______________________

LDC's Electric Account Number (s) for Demand Side Resource: ______________

LBMP Zone of Demand Side Resource: ______________

Bus or substation name where DSR will be modeled: ______________

~~Capacity~~ Interruptible Load Rating of Demand Side Resource _____.__ MW (rounded to nearest 0.1 MW)

~~*Type of Demand Side Resource (check one) ❒ Interruptible Load*~~

~~*❒ on-Site Generator (diesels not allowed in DADRP)*~~*(Note: as of 2003, only interruptible load resources will be allowed to participate in DADRP)*

Type of metering:

❒ Existing utility interval meter — Meter ID #: ______________

If new meter, date installed or to be installed __________ — Meter ID #: ______________

Attach certification if new meter

Identify dates of any planned Demand Side Resource shutdown periods in ~~2002~~2003:

~~LSE~~ DRP supplying Demand Side Resource: ______________________

I HEREBY CERTIFY that the information contained in this form and its attachments is complete and correct.

Authorized Representative of ~~Load Serving Entity~~Demand Response Provider

Date

Attachment C – DADRP Aggregated Bid Reporting Form

~~LSEs~~ Demand Reduction Providers (DRPs) can aggregate individual Demand Side Resources to allow multiple resources to be combined into one bid. This form allows you to designate which Demand Side Resources will be aggregated. You may have more than one set of aggregated resources, but individual Demand Side Resources can only appear in one aggregated bid.

Please complete one Aggregated Bid Reporting Form for each set of aggregated bids. Only Demand Side Resources located in the same superzone may be aggregated.

Part I – Aggregation Information

Please list all of the Demand Side Resources to be aggregated in this bid (use the Organization and Address information provided on the Demand Side Resource Registration Form).

Organization	Meter ID Number

Part II –Static Data

Item	Description	Value
MAX_WINTER_OPER_LIMIT	Max reduction feasible	
MAX_SUMMER_OPER_LIMIT	Max reduction feasible	
CONTRACTED_SUMMER_INST_CAP	Per ICAP auction	
CONTRACTED_WINTER_INST_CAP	Per ICAP auction	
NORMAL_RESP_RATE		set to large value
PRI_GEN_CONTACT	Principle contact	
GEN_CONTACT_PHONE	Contact phone number	

Part III – Commitment Data

Item	Description	Value
MIN_DOWN_TIME		
MIN_RUN_TIME		Max of 8
MAX_STOPS_DAY		
START_UP_NOTIFICATION_ TIME		
STRT_UP_COST_CRV1	Curtailment Initiation Cost	