new . york . independent . system . operator

nyiso
Day-Ahead Demand Response Program Manual

revised: 05 . ~~18~~21. 2001

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 ~~to purchase Installed Capacity in an Installed Capacity auction~~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 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

For 2001, the program will be administered by the NYISO and host Load Serving Entities (LSEs) only, but will be open to Curtailment Service Providers (CSPs) including non-host LSEs on January 1, 2002. Therefore, the term "LSE/CSP" used below refers to the host LSE for the first year of the program and to an LSE or CSP thereafter.

2.2 Bidding

The NYISO will accept Demand Reduction Bids wherein an LSE/CSP 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.

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 insure that the energy price has been set correctly.~~and subsequently detemine 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 with the day prior to submission of bids~~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 ~~with the day prior to submission of bids~~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

~~An LSE/CSP 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 to allow full recovery of the Curtailment Initiation Cost will be made.~~

~~Additionally, an LSE/CSP 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, but then will receive a rebate from the NYISO as an Incentive (with the exception specified in the Section on Small Generator~~

~~Eligibility below) for the curtailed amount of Load priced at Day-Ahead LBMP. Thus, through this Incentive, they will avoid Day-Ahead Energy charges as a result of the End-User curtailment.~~

1. An LSE/CSP 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 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 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. The portion that will be transferred from the LSE/CSP to the Demand Side Resource is outside the scope of the NYISO, and must be arranged between the LSP/CSP 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

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 an LSE/CSP 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 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 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, 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 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.

3.0 DADRP Registration Procedures

For 2001, 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://wwwnew.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.

If you are an LSE currently registered as a Customer with the NYISO, please complete Attachment A, the LSE 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 ~~pseudo-generator~~Demand Side Resource bid. LSEs must fill out Attachment C for each single or composite ~~pseudo-generator~~Demand Side Resource being modeled.

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

http://wwwnew.nyiso.com/services/relations/cregistration/pdf/nyiso_reg.pdf

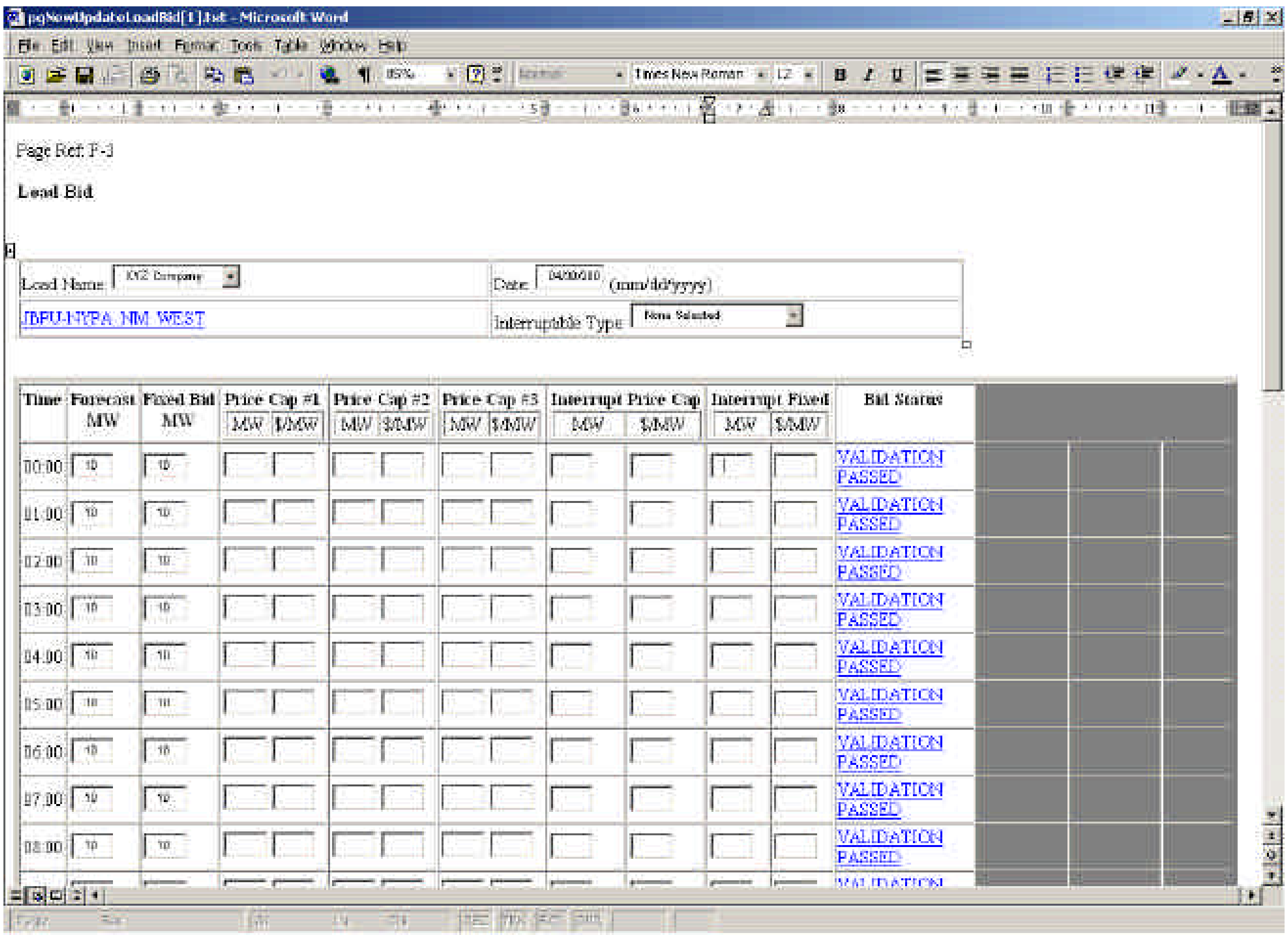
4.0 DADRP Bidding Instructions

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. 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.

~~1.~~14.1 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.



Page Ref: P-3

Load Bid

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

JBFU-NYPA NM WEST | Interruptible Type: None Selected

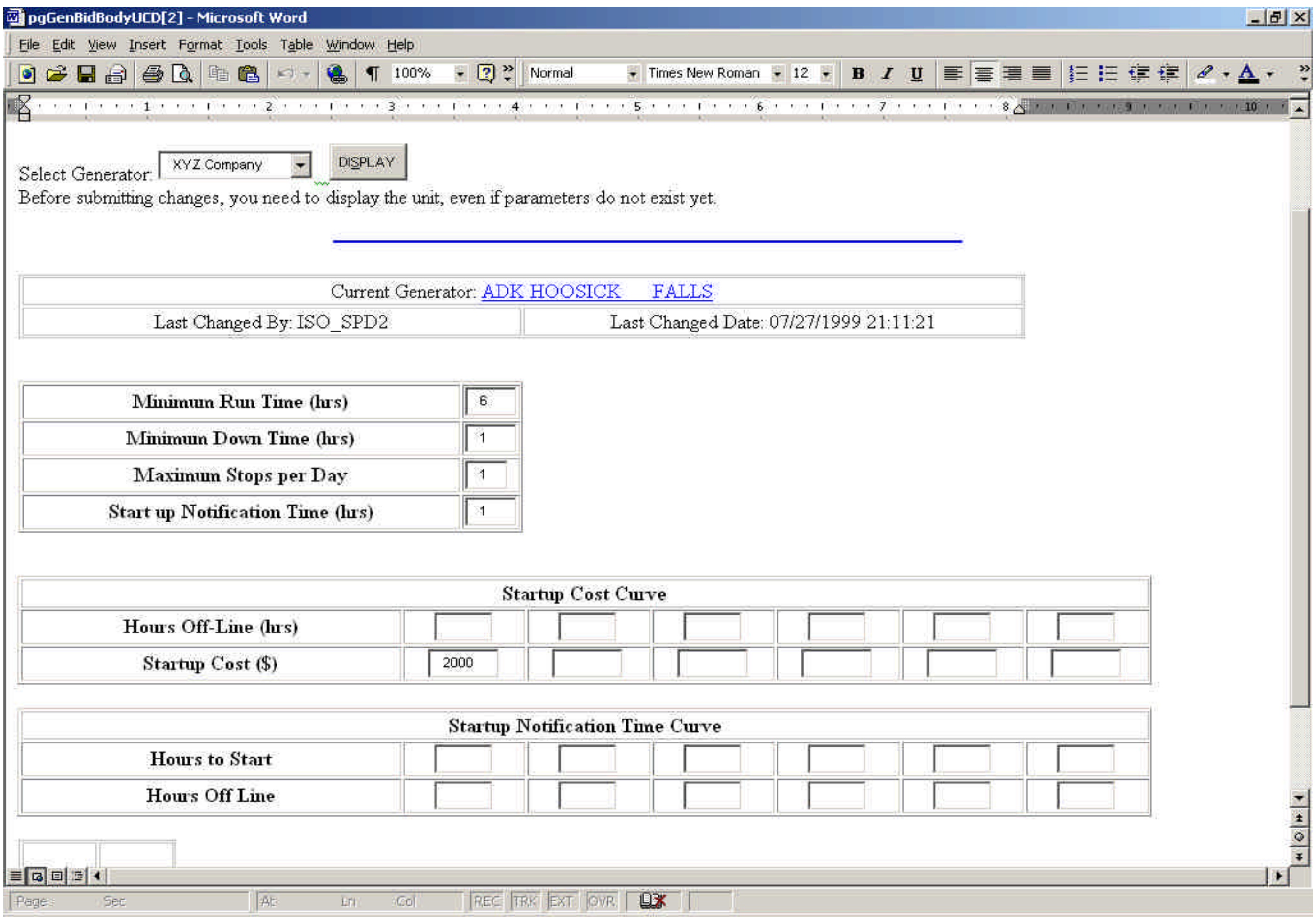
Time	Forecast MW	Fixed Bid MW	Price Cap #1 MW	Price Cap #1 $/MW	Price Cap #2 MW	Price Cap #2 $/MW	Price Cap #3 MW	Price Cap #3 $/MW	Interrupt Price Cap MW	Interrupt Price Cap $/MW	Interrupt Fixed MW	Interrupt Fixed $/MW	Bid Status
00:00	10	10											VALIDATION PASSED
01:00	10	10											VALIDATION 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. First the LSE must enter data into the Generator Commitment Parameters screen.

4.2.1. Generator Commitment Parameter Screen

The LSE will enter the generator's Minimum Run Time and startup costs. In this example the units Minimum Run 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. ~~Please refer to the NYISO Market Participant User's Guide if you have any questions regarding what these parameters are used for.~~ 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.

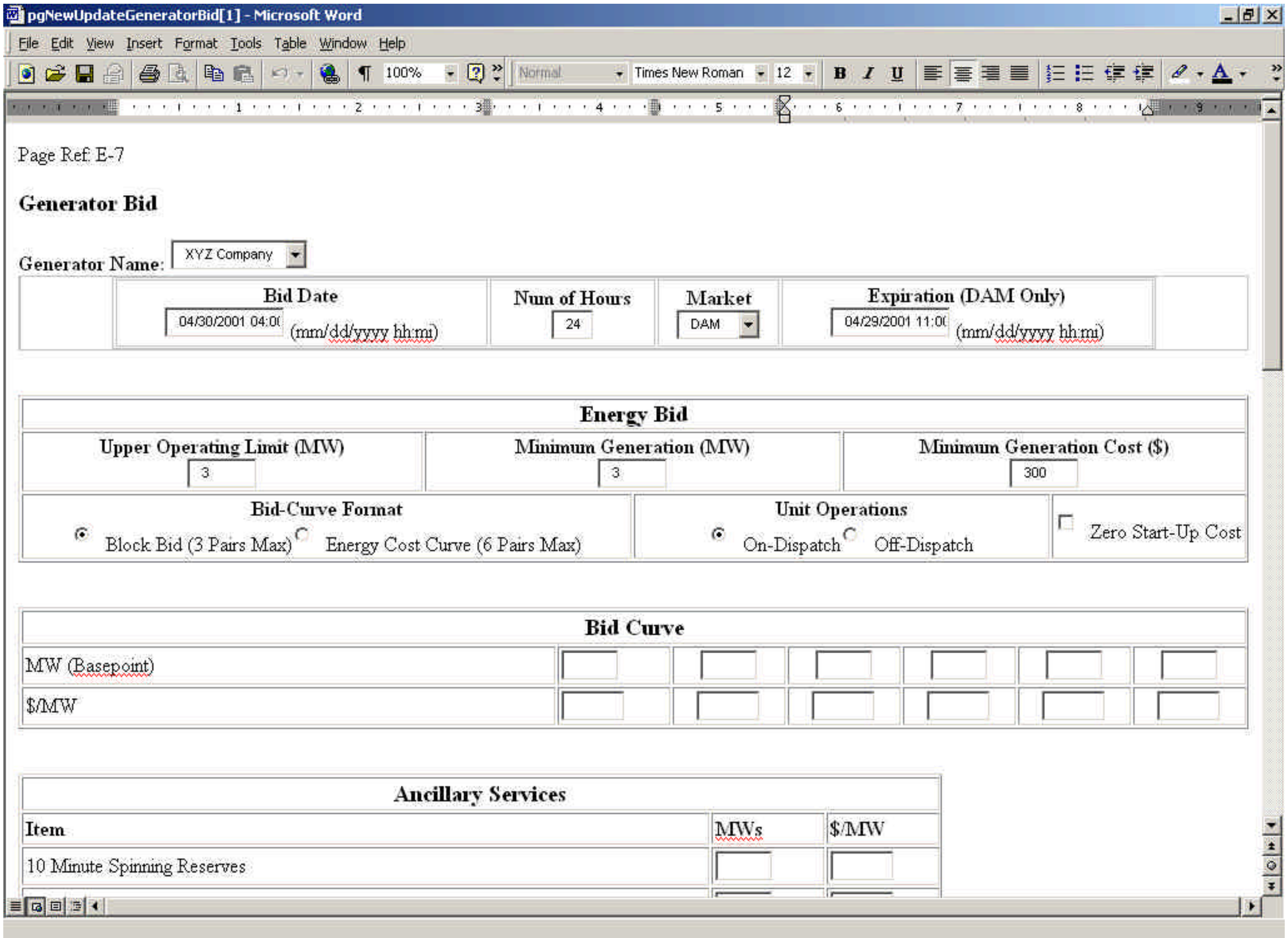


4.2.2 Generator Bid Screen

Second the LSE must enter the specific generator bid data into the MIS system~~. There is flexibility in how an LSE can structure a generation bid to achieve the same desired result~~. 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 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

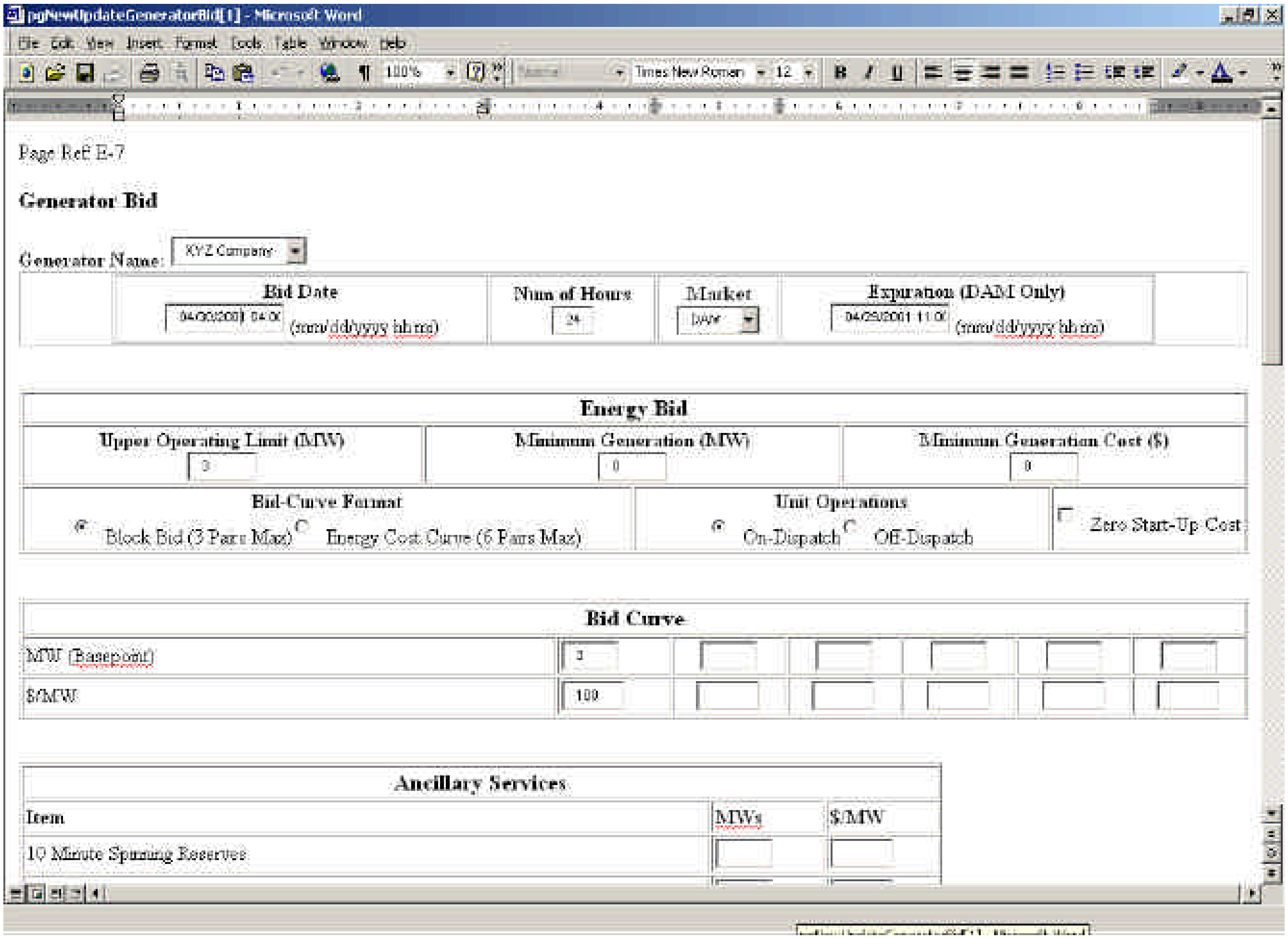
Bid Curve						
MW (Basepoint)						
$/MW						

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)

<u>Calculation Procedure - Weekdays:</u>

Performance in satisfaction of a bid for hours h_i to h_j in day d_n would be assessed against a CBL determined by:

1. Calculating the energy consumption during similar hours over the past 10 weekdays, beginning two days prior to the day in which the scheduled load reduction takes place and excluding days where curtailment due to participation in the EDRP or the Day-Ahead programs occurred.

   $kwh_k = sum(h_i \ldots h_j)$ for each day $k = d_{n-2} \ldots d_{n-11}$

2. Selecting the 5 highest values of kwh_k and use those days d_l, $l = 1 \ldots 5$ to calculate the CBL.

3. Calculating the CBL for each hour h_i as the average of the five h_i values for days d_l, $l = 1 \ldots 5$.

4. If more than 5 of the past 10 days have been excluded due to EDRP or DADRP participation, look back beginning with day d_{n-12} until 5 non-excluded days are found. In no cases will the process go back further than day d_{n-31}.

5. If, after looking back 30 days, fewer than 5 days are eligible for the CBL calculation due to exclusions, use only those eligible days.

<u>Calculation Procedure - Weekend Days:</u>

Saturday and Sunday CBLs will be computed separately.

1. Calculate the energy consumption during similar hours over the past 3 Saturdays/Sundays, excluding days where curtailment due to participation in the EDRP or the DADRP occurred.

2. Select the 2 highest values of kwh and use those days to calculate the CBL.

3. Calculate the CBL for each hour h_i as the average of the values for the 2 highest days.

4. Don't look back any more than 3 weekends to select the 2 highest periods (i.e, don't extend the window if exclusions occur).

Sample CBL 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 was:

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

Steps 1 and 2: sum the Mwh for the appropriate hours each day and select the 5 highest totals:

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

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.
   kwh(k) = sum(h(i)...h(j)) for each day k = d(n-2)...d(n-11)

2. Select the 5 **lowest** values of kwh(k) and use those days d(l), l = 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(l), l = 1...5.

4. If more than 5 of the past 10 days have been excluded due to EDRP and/or DADRP participation, look back beginning with day d(n-12) until 5 non-excluded days are found. In no case go back further than day d(n-31).

5. If, after looking back 30 days, fewer than 5 days are eligible for the CBL calculation due to exclusions, use only those eligible days.

5.3 Calculating CBL for Aggregated Load Bids

For aggregated bids involving more than one Demand Side Resource it is necessary to calculate a composite CBL for the bid. The composite CBL will be calculated as the sum of the non-coincident CBLs of the individual DSRs using the procedures defined in Sections 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 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.

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

The composite non-coincident CBL for the aggregated resources would be 4.02 + 7.14 = 11.16 MWhr. 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. For 2001 it is anticipated that the Transmission Owners will be the only Meter Service providers and Meter Data Service providers. 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 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.

6.4 Performance - 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 Data Submission

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

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:

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

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

$$\text{LRBG} = \overbrace{\frac{\sum_{hr} PRL_{METER}\Big|_{0}^{PRL_{DA}}}{\sum_{hr} PRL_{DA}} (StartupCost)}^{\text{Startup Cost Allocation}} + \overbrace{\sum_{hr}\left(\left(\frac{PRL_{METER}\Big|_{0}^{PRL_{DA}}}{MinGenMW} \right)^{1} (MinGenCost) \right)}^{\text{Minmum Generation Allocation}} + IncrementalCost_{PRL_{METER}}$$

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

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 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 would be charged $15,000 = $250/MWh LBMP x 10 MW x 6 hours for the fixed Load.
d) The LSE/CSP 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 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.

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 Uplift Example

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, the payments and charges would be as follows:

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

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

e) 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 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.

8.4 Economic "Incentivized" Curtailment of Load With Non-Performance Penalty for Failure to Reduce Consumption

If an LSE/CSP 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 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 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 $5,940 = 110% x $300/MWh Real-Time LBMP x 3 MW x 6 hours for the Load that failed to curtail.
d) The LSE/CSP also would not receive a rebate as an "Incentive" because it failed to curtail.

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 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 2000) 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 2000, 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:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **'no constraints**

$a_2 * (cost_A+\ldots+cost_E) * load_m / (load_A+\ldots+load_E) +$ **'above 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**

$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ **'above CE-LI constraint**

For LSE m in Zones F-I:

$a_1 * (cost_A+\ldots+cost_K) * load_m / (load_A+\ldots+load_K) +$ **'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**

$a_4 * (cost_A+\ldots+cost_J) * load_m / (load_A+\ldots+load_J)$ **'above CE-LI constraint**

For LSE m in Zone J:

$a_1 * (\text{cost}_A+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_K) +$ **'no constraints**
$a_2 * (\text{cost}_F+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_K) +$ **'below Central-East const**
$a_3 * \text{cost}_J * \text{load}_m / \text{load}_J +$ **'below S-D constraint**
$a_4 * (\text{cost}_A+\ldots+\text{cost}_J) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_J)$ **'above CE-LI constraint**

For LSE m in Zone K:

$a_1 * (\text{cost}_A+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_K) +$ **'no constraints**
$a_2 * (\text{cost}_F+\ldots+\text{cost}_K) * \text{load}_m / (\text{load}_F+\ldots+\text{load}_K) +$ **'below Central-East const**
$a_3 * (\text{cost}_A+\ldots+\text{cost}_I+\text{cost}_k) * \text{load}_m / (\text{load}_A+\ldots+\text{load}_I+\text{load}_k) +$ **'above S-D constraint**
$a_4 * \text{cost}_K * \text{load}_m / \text{load}_K$ **'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 Con Ed-Long Island interface is constraining (0.337)
a_4 = fraction of time when Sprainbrook-Dunwoodie interface is constraining (0.061)
$\text{cost}_{A\ldots K}$ = 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
$\text{load}_{A\ldots K}$ = 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 2001, and will be reviewed by the Price-Responsive Load Working Group prior to 2002.

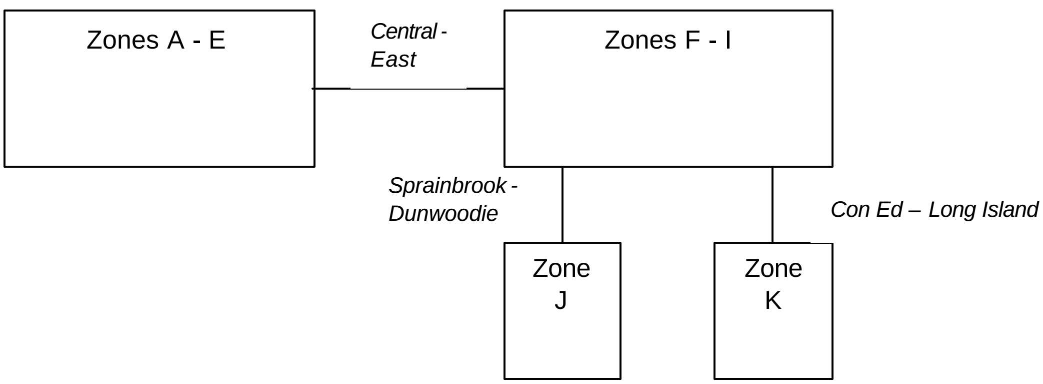


Figure 9.1 – Relationship Between Interface Constraints and Zones

Attachment A – DADRP LSE 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 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 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 **518-356-6208, 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 certifies that the information contained in this form and its attachments is complete and correct.

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

NAME OF Load Serving Entity:________________________________

Name: ________________________________

Title: ________________________________

____
Authorized Representative Signature

Attachment B – DADRP Demand Side Resource Registration

This form must be faxed to **518-356-6208, attention: Manager DADRP or e-mailed to dlawrence@nyiso.com.**

Use one form for each Demand Side Resource Registered by the LSE.

Organization: ____
Address: ____
____
____

Name of Local Distribution Company (LDC): ______________________

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

LBMP Zone of Demand Side Resource: ______________

Capacity 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)

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 2001:

LSE 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 Date

Attachment C – DADRP Aggregated Bid Reporting Form

LSEs 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~~MIN_RUN_TIME~~		~~Max of 8~~
START_UP_NOTIFICATION_TIME~~MAX_STOPS_DAY~~		
STRT_UP_COST_CRV1	Curtailment Initiation Cost	