ATTACHMENT J

I. LBMP CALCULATION METHOD

The Locational Based Marginal Prices ("LBMPs") for Generators and Loads will be based on the system marginal costs produced by either the Security Constrained Dispatch ("SCD") program for Real-Time Market prices, or the Security Constrained Unit Commitment ("SCUC") program for Day-Ahead Market prices. These will be utilized in an *ex post* computation to produce LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma_i^L + \gamma_i^C$$

Where:

γ_i = LBMP at bus i in $/MWh

λ^R = the system marginal price at the Reference Bus

γ_i^L = Marginal Losses Component of the LBMP at bus i which is the marginal cost of losses at bus i relative to the Reference Bus

g_i^C = Congestion Component of the LBMP at bus i which is the marginal cost of Congestion at bus i relative to the Reference Bus

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The Marginal Losses Component of the LBMP at any bus i within the NYCA is calculated using the equation:

$$\gamma_i^L = (DF_i - 1)\lambda^R$$

Where:

$DF_i =$ delivery factor for bus i to the system Reference Bus
And:

$$DF_i = \left(1 - \frac{\partial L}{\partial P_i}\right)$$

Where:

$L =$ system losses; and

$P_i =$ generation injection at bus I

The Congestion Component of the LBMP at bus i is calculated using the equation:

$$\gamma_i^C = -\left(\sum_{k \in K}^{n} GF_{ik}\mu_k\right)$$

Where:

$K =$ the set of thermal or Interface Constraints;

GF_{ik} = Shift Factor for the Generator at bus i on Constraint k in the pre- or post-Contingency case which limits flows across that Constraint the Shift Factor measures the incremental change in flow on Constraint k, expressed in per unit, for an increment of generation at bus i and a corresponding decrement of generation at the Reference Bus); and

m_k = the reduction in system cost that results from an incremental relaxation of Constraint k expressed in $/MWh.

Substituting the equations for g_i^L and g_i^C into the first equation yields:

$$\gamma_i = \lambda^R + \left(DF_i - 1\right)\lambda^R - \sum_{k \in K} GF_{ik}\mu_k$$

The SCD program execution in a given interval may terminate without observing the limits on all Constraints, usually due to Generator ramp rate limitations on the dispatch. Under these conditions, rules have been developed which the ISO will use to set Generator output levels and to calculate LBMPs. These rules state that the LBMPs are to be calculated from the output of the SCD execution in which Constraints were violated. Prices calculated in this manner closely reflect the marginal cost of Energy on the system. However, the Generator output levels will be set by a second SCD execution in which Generator ramp rate constraints are relaxed. This execution of SCD usually eliminates the Constraint violations and will provide the dispatcher

2000, 90 FERC ¶ 61,352 (2000).

with information to correct the situation. Often Generators will be able to operate at the levels set in the second SCD execution, since they frequently can change their output levels at rates exceeding those included in the Bid data provided to the ISO. Failure to achieve the output levels determined in the second SCD execution will not cause the Generator's performance ratings in the Performance Tracking System to be adversely affected.

LBMPs will be calculated for the Day-Ahead and the Real-Time Markets. In the Day-Ahead Market, the three components of the LBMP at each location will be calculated from the SCUC results and posted for each of the twenty-four (24) hours of the next day. The Real- Time LBMPs will be calculated and posted for each execution of SCD.

Zonal LBMP Calculation Method

The computation described above is at the bus level. This will be suitable for Generator buses because adequate metering is available, or will be provided, to measure Real-Time injections. An eleven (11) zone model will be used for the LBMP billing related to Loads. The LBMP for a zone will be a Load weighted average of the Load bus LBMPs in the zone. The Load weights which will sum to unity will be predetermined by the ISO. Each component of the LBMP for a zone will be calculated as a Load weighted average of the Load bus LBMP components in the zone. The LBMP for a zone j can be written as:

$$\gamma_j^Z = \lambda^R + \gamma_j^{L,Z} + \gamma_j^{C,Z}$$

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where:

γ^{Z}_{j} = LBMP for zone j,

$\gamma^{L,Z}_{j} = \sum_{I=1}^{n} W_i \gamma^{L}_{i}$ is the Marginal Losses Component of the LBMP for zone j;

$\gamma^{C,Z}_{j} = \sum W_i \gamma^{C}_{i}$ is the Congestion Component of the LBMP for zone j;

n = number of Load buses in zone j for which LBMPs are calculated; and

W_i = load weighting factor for bus i.

Until the ISO's software can compute LBMPs at Load buses, the zonal LBMPs will be a weighted average of the Generator bus LBMPs in the zone. The weightings will be pre-determined by the ISO.

LBMP Prices for External Locations

External Generators and Loads can bid into the LBMP Market or participate in Bilateral Transactions. External Generators may arrange Bilateral Transactions with Internal or External Loads and External Loads may arrange Bilateral Transactions with Internal Generators.

The Generator and Load locations for which LBMPs will be calculated will initially be limited to a pre-defined set of buses External to the NYCA. LBMPs will be calculated for each bus within this limited set. The three components of LBMP will be calculated from the results of

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SCD and posted in the Day-Ahead and Real-Time Markets as described above, except that the Marginal Losses Component of LBMP will be calculated differently for Internal locations. The Marginal Losses Component of the LBMP at each bus, as described above, includes the difference between the marginal cost of losses at that bus and the Reference Bus. If this formulation were employed for an External bus, then the Marginal Losses Component would include the difference in the cost of Marginal Losses for a section of the transmission system External to the NYCA. Since the ISO will not charge for losses incurred externally, the formulation will exclude these loss effects. To exclude these External loss effects, the Marginal Losses Component will be calculated from points on the boundary of the NYCA to the Reference Bus.

The Marginal Losses Component of the LBMP at the External bus will be a weighted average of the Marginal Losses Components of the LBMPs at the Interconnection Points. To derive the Marginal Losses Component of the LBMP at an External location, a Transaction will be assumed to be scheduled from the External bus to the Reference Bus. The Shift Factors for this Transaction on the tie lines into these Interconnection buses, which measure the per-unit effect of flows over each of those tie lines that results from the hypothetical transaction, will provide the weights for this calculation. Since all the power from this assumed Transaction crosses the NYCA boundary, the sum of these weights is unity.

The sum of the products of these Shift Factors and the Marginal Losses Component of the LBMP at each of these Interconnection buses yields the Marginal Losses Component of the LBMP that will be used for the External bus. Therefore, the Marginal Losses Component of the LBMP at an External bus E is calculated using the equation:

$$\gamma_E^L = \sum_{b \in I} F_{Eb}\left(DF_b - 1\right)\lambda^R$$

where:

g_E^L =	Marginal Losses Component of the LBMP at an External bus E;
F_{Eb} =	Shift Factor for the tie line going through bus b, computed for a
	hypothetical Bilateral Transaction from bus E to the Reference Bus;
	Marginal Losses Component of the LBMP at bus b; and
$(DF_b - 1)\, l^R$ =	The set of Interconnection buses between the NYCA and adjacent
I =	Control Areas.

II. ACCOUNTING FOR TRANSMISSION LOSSES

1.0 Charges

Subject to Attachment K of this Tariff, the ISO shall charge all Transmission Customers for transmission system losses based on the marginal cost of losses on either a bus or zonal basis, described below.

1.1 Loss Matrix

The ISO's Security Constrained Dispatch ("SCD") program will use a loss matrix (referred to as a B matrix) and penalty factors to estimate and model losses in performing generation dispatch and billing functions for losses.

1.2 Residual Loss Payment

The ISO will determine the difference between the payments by Transmission Customers for losses and the payments to Suppliers for losses associated with all Transactions (LBMP Market or Transmission Service under Parts II, III, and IV of this Tariff) for both the Day-Ahead and Real-Time Markets. The accounting for losses at the margin may result in the collection of more revenue than is required to compensate the Generators for the Energy they produced to supply the actual losses in the system. This over collection is termed residual loss payments. The ISO shall calculate residual loss payments revenue on an hourly basis and will credit them against the ISO's Residual Adjustment (See Rate Schedule 1).

2.0 Computation of Residual Loss Payments

2.1 Marginal Losses Component LBMP

The ISO shall utilize the Marginal Losses Component of the LBMP on an internal bus, an external bus, or a zone basis for computing the marginal contribution of each Transaction to the system losses. The computation of these quantities is described in this Attachment.

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2.1.1 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by the ISO's Security Constrained Unit Commitment ("SCUC") program for computing the marginal contributions of each Transaction in the Day-Ahead Market.

2.1.2 Marginal Losses Component Real-Time

The ISO shall utilize the Marginal Losses Component computed by the ISO's Security Constrained Dispatch ("SCD") program for computing the Marginal Losses Component associated with each Transaction scheduled in the Real-Time Market (or deviations from Transactions scheduled in the Day-Ahead Market). The computations will be performed on a SCD interval basis and aggregated to an hourly total.

2.2 Charges

Charges to reflect the impact of Energy consumed by each Load, or transmitted by each Transmission Customer on Marginal Losses Component shall be determined as follows. Each of these charges may be negative.

Day-Ahead Charges

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of: (a) the

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withdrawal scheduled Day-Ahead in each Load Zone by that LSE in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP in that Load Zone, in $/MWh.

As part of the TUC charged to all Transmission Customers whose transmission service has been scheduled Day-Ahead, the ISO shall charge each such Transmission Customer the product of (a) the amount of Energy scheduled Day-Ahead to be injected and withdrawn by that Transmission Customer in each hour, in MWh; and (b) the Marginal Losses Component of the Day-Ahead LBMP at the Point of Delivery (i.e., Load Zone in which Energy is scheduled to be withdrawn or the bus where Energy is scheduled to be withdrawn under if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Day-Ahead LBMP at the Point of Receipt, in $/MWh.

Real-Time Charges

As part of the LBMP charged to all LSEs scheduled Day-Ahead to purchase Energy from the LBMP Market, the ISO shall charge each such LSE the product of (a) the Actual Energy Withdrawals by that LSE in each Load Zone in each hour, minus the Energy withdrawal scheduled Day-Ahead in that Load Zone by that LSE for that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP in that Load Zone, in $/MWh.

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As part of the TUC charged to all Transmission Customers whose transmission service was scheduled after the determination of the Day-Ahead schedule, or who schedule additional transmission service after the determination of the Day-Ahead schedule, the ISO shall charge each such Transmission Customer the product of (a) the amount of Energy scheduled (as of the BME) to be injected and withdrawn by that Transmission Customer in each hour, minus the amount of Energy scheduled Day-Ahead to be injected and withdrawn by that Transmission Customer in that hour, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at the Point of Delivery (i.e., the Load Zone in which Energy is scheduled to be withdrawn or the external bus where Energy is scheduled to be withdrawn if Energy is scheduled to be withdrawn at a location outside the NYCA), minus the Marginal Losses Component of the Real-Time LBMP at the Point of Receipt, in $/MWh.

III. TRANSMISSION SERVICE CURTAILMENT

1.0 ISO's General Responsibilities

The ISO shall evaluate requests for transmission service submitted in the Day- Ahead scheduling process using Security Constrained Unit Commitment ("SCUC"), and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use the Balancing Market Evaluation (BME) to establish schedules for each hour of dispatch in that day.

If required by SCD, the ISO shall Curtail transmission service during dispatch as described in this attachment.

2.0 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under this Tariff to match changing conditions, the ISO shall treat Decremental Bids and Incremental Bids simultaneously and identically as follows: (i) a generating facility selling energy in the LBMP Market may be dispatched downward if the LBMP at the Point of Receipt falls below the generating facility's Incremental Bid; (ii) a Generator serving a transaction scheduled under this Tariff may be dispatched downward if the LBMP at the Generators's Point of Receipt falls below Decremental Bid for the Generator; (iii) a Supplier's Generator may be dispatched upward if the LBMP at the Generator's Point of Receipt rises above the Decremental or Incremental Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a transaction scheduled under this Tariff.

2.1 Use of Decremental Bids to Dispatch External Generators

When determining the amount of Energy that External Generators taking service under this Tariff are scheduled an hour ahead to produce, the ISO shall treat Decremental Bids and Incremental Bids simultaneously and identically as follows: (i) a generating facility selling

Energy in the LBMP Market will have its hour-ahead schedule reduced if the LBMP forecasted for the next hour by BME at the Point of Receipt falls below the generating facility's Incremental Bid; (ii) a Generator serving a Transaction scheduled under this Tariff will have its schedule reduced if the LBMP forecasted for the next hour by BME at the Generator's Point of Receipt falls below the Decremental Bid for the Generator; (iii) a Supplier's Generator will have its schedule increased if the LBMP forecasted for the next hour by BME at the Generator's Point of Receipt rises above the Decremental or Incremental Bid for the Generator, regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under this Tariff.

3.0 Default Decremental Bids

If an optional Decremental Bid is not provided, the ISO shall assign and post a default Decremental Bid. The default Decremental Bid will be based upon a large, negative value to be applied between 0 MW and the total amount (in MW) of the transmission service. If a Transmission Customer who is using Grandfathered Rights to schedule transmission service in the Day-Ahead Market does not provide a Decremental Bid in association with that transmission service the ISO shall assign a default Decremental Bid equal to the lowest Decremental Bid that can be entered by a unit bidding into SCUC (as constrained by limitations of the bidding software), minus an additional $100/MWh.

4.0 Day-Ahead Schedules

The ISO shall compute all NYCA Interface Transfer Capabilities prior to scheduling Transmission Service Day-Ahead. The ISO shall run the SCUC utilizing the computed Transfer Capabilities, submitted Firm Point-to-Point Transmission Service and Network Integration Transmission service schedules, Load forecasts, and submitted Incremental and Decremental Bids.

In the Day-Ahead schedule, the ISO shall use the SCUC to determine Generator schedules, Transmission Service schedules and DNIs with adjacent Control Areas. The ISO shall not use Decremental Bids submitted by Transmission Customers for Generators associated with Non-Firm Point-to-Point Transmission Service in the determination of the Day-Ahead schedule.

5.0 Reduction and Curtailment

If a Transmission Customer's Finn Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, an Export, or an Import, the ISO shall not Reduce the Transmission Service.

If the Transaction was scheduled in the Day-Ahead Market, and the Day-Ahead Schedule for the Generator designated as the Supplier of Energy for that Bilateral Transaction called for that Generator to produce less Energy than was scheduled Day-Ahead to be consumed in association with that Transaction, the ISO shall supply the Load or Transmission Customer in an Export with Energy from the Day-Ahead LBMP Market. The Transmission Customer shall continue to pay the Day-Ahead TUC based on the Day-Ahead schedule of the Transaction, and in addition, the Transmission Customer, if it takes service under the ISO Services Tariff, shall pay the Day-Ahead LBMP price, at the Point of Receipt for the Transaction, for the replacement amount of Energy in (MWh) purchased in the LBMP Market. If the Transmission Customer does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Day-Ahead LBMP at the Point of Receipt for the Transaction or $100/MWh, for the replacement amount of Energy, as specified in this Tariff. These procedures shall apply regardless of whether the Generator designated to supply Energy in association with the Transaction was located inside or outside the NYCA.

If the Transaction was scheduled following the Day-Ahead Market, or the schedule for the Transaction was revised following the Day-Ahead Market, then the ISO will also supply the Load or Transmission Customer in an Export with Energy from the Real-Time LBMP Market if necessary. If (1) the Generator designated to supply the Transaction is an Internal Generator, and it has been dispatched to produce less than the amount of Energy that is scheduled hour-ahead to be consumed in association with that Transaction; or (2) if the Generator designated to supply the Transaction is an External Generator, and the amount of

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Energy it has been scheduled an hour ahead to produce (modified for any within-hour changes in DNI, if any) is less than the amount of Energy scheduled hour-ahead to be consumed in association with that Transaction; then the Transmission Customer shall pay the Real-Time TUC for the amount of Energy scheduled in the BME to be transmitted in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be transmitted in association with that Transaction. In addition, to the extent that it has not purchased sufficient replacement Energy in the Day-Ahead Market, the Transmission Customer, if it takes service under the ISO Services Tariff., shall pay the Real-Time LBMP price, at the Point of Injection for the Transaction, for any additional replacement Energy (in MWh) necessary to serve the Load. If the Transmission Customer does not take service under the ISO Services Tariff, it shall pay the greater of 150 percent of the Real-Time LBMP at the Point of Injection for the Transaction or $100/MWh for the replacement amount of Energy, as specified in this Tariff. (In cases where Export Transactions are Curtailed by the actions of operators of other Control Areas, the amount of Energy scheduled Day-Ahead to be consumed in association with such Transactions shall be revised to reflect the effects of any such Curtailments.) These procedures shall apply regardless of whether the Generator designated to supply Energy in association with that Transaction was located inside or outside the NYCA.

If the Transmission Customer was receiving Non-Firm Point-to-Point Transmission Service, and its Transmission Service was Reduced or Curtailed, the replacement Energy may be purchased in the Real-Time LBMP Market by the Internal Load. An Internal Generator supplying Energy for such a Transmission Service that is Reduced or Curtailed may sell its excess Energy in the Real-Time LBMP Market.

The ISO shall not automatically reinstate Non-Firm Point-to-Point Transmission Service that was Reduced or Curtailed. Transmission Customers may submit new schedules to restore the Non-Firm Point-to-Point Transmission Service in the next BME execution.

If a security violation occurs or is anticipated to occur, the ISO shall attempt to relieve the violation using the following procedures:

(i) Reduce Non-Firm Point-to-Point Transmission Service: Partially or fully physically curtail External Non-Firm Transmission Service (Imports, Exports and Wheels-Through) by changing DNI schedules to (1) curtail those in the lowest NERC priority categories first; (2) curtail within each NERC priority category based on Decremental Bids; and (3) prorate Curtailment if Decremental Bids within a priority category are equal.

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(ii) Curtail non-Firm Point-to-Point Transmission Service: Curtail (through changing DNI) unscheduled non-Firm Transactions which contribute to the violation, starting with the lowest NERC priority category.

(iii) Dispatch Internal Generators, based on Incremental and Decremental Bids, including committing additional resources, if necessary;

(iv) Adjust the DNI associated with Transactions supplied by External Resources: Curtail External Firm Transactions until the constraint is relieved by (1) Curtailing based on Decremental Bids, and (2) prorating Curtailment if Decremental Bids are equal;

(v) Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum dispatch able levels. When operating in manual mode, Generators will not be required to adhere to the one percent minimum ramp rate set forth in Section 4.0 of this Tariff, nor will they be required to be respond to SCD Base Point Signals;

(vi) In over generation conditions, decimate Internal Generators based on minimum generation Bid rate in descending order; and

(vii) Invoke other emergency procedures including involuntary load Curtailment, if necessary.

6.0 Scheduling Transmission Service for External Transactions

The amount of Firm Transmission Service scheduled Day-Ahead for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions Day-Ahead. The amount of Firm Transmission Service scheduled in the BME for Bilateral Transactions which designate External Generators to supply Imports or Internal Generators to supply Exports will be equal to the amount of Energy scheduled to be consumed under those Transactions in the BME. The DNI between the NYCA and adjoining Control Areas will be adjusted as necessary to reflect the effects of any Curtailments of Import or Export Transactions resulting from the actions of operators of these Control Areas, but the amount of Transmission Service scheduled for those Transactions will remain unchanged. However, any Curtailment or Reductions of schedules for Export Transactions directed by the ISO will cause both the DNI and the scheduled amount of Transmission Service to change.

The ISO shall use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy those Generators are scheduled Day-Ahead to produce in each hour. This in turn will determine the Firm Transmission Service scheduled Day-Ahead to support those Transactions. The ISO shall

2000, 90 FERC ¶ 61,352 (2000).

also use Decremental Bids supplied by Transmission Customers using External Generators to supply Wheels-Through to determine the amount of Energy these Generators are scheduled to produce in the BME, which, in turn, will determine the Transmission Service scheduled in the BME to support those Transactions.

The amount of Transmission Service scheduled hour-ahead in the BME for transactions supplied by one of the following Generators shall retroactively be set equal to that Generator's actual output in each SCD interval:

(i) Generators providing Energy under existing contracts (including PURPA contracts) in which the power purchaser does not control the operation of the supply source but would be responsible for penalties for being off-schedule;

(ii) Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system located in New York City (LBMP Zone J) and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 365 MW of such units; and

(iii) Existing intermittent (i.e., non-schedulable) renewable resource Generators within the NYCA, plus up to an additional 50 MW of such Generators.

This procedure shall not apply at times when the Generator supplying that transaction has been scheduled to provide Regulation or Operating Reserves.

The ISO will not schedule a Bilateral Transaction which crosses an Interface between the NYCA and a neighboring Control Area if doing so would cause the DNI to exceed the Transfer Capability of that Interface.

IV. SCHEDULING

Security Constrained Unit Commitment ("SCUC)

The ISO shall develop an SCUC schedule using a computer algorithm which simultaneously minimizes the total Bid Production cost of: (i) supplying power to satisfy all accepted purchaser's Bids to buy Energy from the Day-Ahead Market; (ii) providing sufficient Ancillary Services to support Energy purchased from the day-ahead Market; (iii) committing sufficient Capacity to meet the ISO's Load forecast and provide associated Ancillary Services;

and (iv) meeting all Transmission Schedules submitted Day-Ahead. The schedule will include commitment of sufficient Generators and/or Interruptible Load to provide for reliable operation of the NYS Transmission System. In addition to all Reliability Rules, the ISO shall consider the following information when developing the SCUC: (i) Load forecasts provided to the ISO and adjusted as required by the ISO; (ii) Ancillary Service requirements as determined by the ISO; (iii) Transmission Service schedules; (iv) price Bids and operating constraints submitted for Generator or Demand Side Resources; (v) price bids for Ancillary Services; (iv) Decremental Bids for Bilateral Transactions; (vii) ancillary Services in support of Bilateral Transactions; and (viii) Bids to purchase energy from the Day-ahead Market. The SCUC schedule shall list the twenty-four (24) hour injections for: (a) each Generator whose Bid the ISO accepts for the following Dispatch Day, and (b) each Bilateral Transaction Scheduled Day-Ahead.

In the development of its SCUC schedule, the ISO may commit and decommit Generators based upon any flexible Bids, including Minimum Generation and Start-Up Costs, Energy, and Incremental and Decremental Bids received by the ISO.

Reliability Forecast

In the SCUC program, system operation shall be optimized over the Dispatch Day. However, to preserve system reliability, the ISO must assure that there will be sufficient Generators available to meet forecasted Load and reserve requirements over the seven-day period that begins with the next Dispatch Day. When SCUC evaluates days two through seven of the commitment cycle and determines that a long start-up time Generator is needed for reliability,

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the ISO shall accept a Bid and the Generator will begin its start-up sequence. During each day of the start sequence, SCUC will determine if the long start-up time Generator will still be needed as previously forecasted. If the Generator is still needed, then it will continue to accrue start-up cost entitlements. If at any time it is determined that the Generator will not be needed as previously forecasted, the ISO shall order the Generator will not be needed as previously forecasted, the ISO shall order the Generator to abort its start sequence, and its start-up payment entitlement beyond the abort time will be discontinued. The ISO may commit to long start-up period Generators, but only as a last resort to preserve reliability (and not for reasons of system economy).

The ISO shall develop a forecast of daily system peak Load for days two through seven in this seven-day period (using LSE forecast data, where appropriate) and add an appropriate reserve margin. The ISO shall then forecast its available Generators for the day in question by summing the Operating Capacities for all Generators currently in operation, the Operating Capacity of all other Generators capable of starting prior to the day in question, and an estimate of the net imports from external Bilateral Transactions. If the forecasted peak Load plus reserves exceeds the ISO's forecast of available Generators for the day in question, then the ISO shall commit additional Generators capable of starting prior to the day in question (e.g., start-up period of two-days when looking at day three) to assure system reliability. In choosing among Generators with comparable start-up periods (e.g., among units with two-day start-up periods), the ISO shall schedule Generators to minimize the bid production cost of meeting forecasted peak load plus reserves for the day in question, including Minimum Generation and Start-Up Bids, and Incremental Bids. This analysis will assume that all Generators in operation on day one are operating at maximum output, as well as any Generators capable of starting up prior to the day in question.

In determining the appropriate reserve margin for days two through seven, the ISO will supplement the normal reserve requirements, to allow for forced outages of the short start-up period units (e.g., gas turbines) assumed to be operating at maximum output in the unit commitment analysis for reliability.

The bidding requirements and the bid tables in Attachment P indicate that Energy Bids are to be provided for days one through seven. Energy bids are binding for day one only for units in operation or with start-up periods less than one day. Energy Bids for Generator with start-up periods greater than one day will be binding only for units that are committed by the ISO and only for the first day in which those units could produce energy given their start-up periods. For example, the Energy Bid for a Generator with a start-up period of two days would be binding only for day three because, if that unit begins to start up at any time during day one, it would begin to produce Energy forty-eight (48) hours later on day three. Similarly, the Energy Bid for a Generator with a start-up period of three (3) days would only be binding for day four.

Balancing Market Evaluation (Hour-Ahead)

After the Day-Ahead schedule is published, and up to ninety (90) minutes prior to each dispatch hour, Direct Customers and Suppliers may: (i) submit additional bids to the ISO for Energy from (a) Generators or other resources that are dispatchable within five (5) minutes and that can be included in and respond to the ISO's SCD program and (b) fixed block Energy (non-dispatchable) Bids available for the next hour; (ii) lower their Bid Price for Energy from Generators committed by the ISO in the Day-Ahead Market; (iii) change their Bid Price for additional Energy from Generators that were committed by the ISO in the Day-Ahead Market; (iv) modify Bilateral Transactions that were accepted by the ISO in the Day-ahead schedule; (v) propose new Bilateral Transactions; and (vi) submit Bids to purchase Energy from the Real-Time Market. The Bids submitted up to ninety (90) minutes before the dispatch hour shall be referred to as Hour-ahead Bids. The ISO shall use the Balancing market Evaluation ("BME") ninety (90) minutes before each dispatch hour to determine schedules for LBMP Market and Bilateral Transactions including Exports, Imports and Wheels Through. In developing these schedules, the

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BME will consider updated Load forecasts and evaluate the impact on reliability of the proposed schedules and commitments. The BME will adjust firm Bilateral Transaction schedules based on Incremental and Decremental Bids and all Generator schedules, based on their Bids, to maintain reliability. The BME will not determine any prices but will schedule on a least total Bid Production Cost basis.

ISO Real-Time Dispatch Using Security Constrained Dispatch ("

The ISO shall dispatch the NYS Power System consistent with the Bids that are submitted by Suppliers and accepted by the ISO, while satisfying the actual system Load. The ISO shall use Day-and Hour-ahead Bids and shall accommodate Bilateral Transaction schedules and schedule changes to the maximum extent possible consisted with reliability, and the Decremental Bids of Bilateral Transaction parties. The ISO shall run a Security Constrained Dispatch ("SCD")
normally every five (5) minutes to minimize the total Bid Production Costs of meeting the system Load and maintaining scheduled interchanges with adjacent Control Areas over the next SCD interval. Bid Production costs, for this purpose, will be calculated using Bids submitted into the Real-Time Market. The dispatch may cause the schedules of Generators providing Energy under Bilateral Transaction Schedules to be modified, depending upon the Decremental Bids submitted (or assigned) in association with these schedules.

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