Component at each Load Zone and Generator bus. In addition, when certain conditions exist, as defined in the table below, the ISO shall employ the special scarcity pricing rules described in Sections I.A.2.a and 2.b. Procedures governing the calculation of LBMPs at External locations are set forth below in Section E.

		SCR/EDRP NYCA Called and Needed	SCR/EDRP East Called and Needed	Scarcity Pricing Rule to be Used in the West	Scarcity Pricing Rule to be Used in the East
		NO	NO	NONE	NONE
			YES	NONE	B
		YES	NO	A	A
			YES	A	A

Where:	
SCR/EDRP NYCA, Called and Needed	Is “YES” if the ISO has called SCR/EDRP resources and determined that, but for the Expected Load Reduction, the Available Reserves would have been less than the NYCA requirement for total 30-Minute Reserves; or is “NO” otherwise.
SCR/EDRP East, Called and Needed	Is “YES” if the ISO has called SCR/EDRP from resources located East of Central-East and determined that, but for the Expected Load Reduction, the Available Reserves located East of Central-East would have been less than the requirement for 10-Minute Reserves located East of Central-East; or is “NO” otherwise.
Pricing Rule West	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Load Zones located West of Central-East, including the Reference Bus.
Pricing Rule East	Identifies the scarcity pricing rule that will be used, if applicable, to determine the LBMP, the Congestion Component of LBMP, and the Marginal Losses Component of LBMP for all buses and Load Zones located East of Central-East.

1. General Procedures

a. Overview

The ISO shall calculate Real-Time Market LBMPs using the three passes of each Real-Time Dispatch run, except as noted below in Section I.A.1.c. A new Real-Time Dispatch run will begin every five minutes and each run will produce prices and schedules for five points in time. Only the prices and schedules determined for the first point in time of a Real-Time Dispatch run will be binding. Prices and schedules for the other four points in time shall be advisory only.

Each Real-Time Dispatch run shall, depending on when it occurs during the hour, have a bid optimization horizon of fifty, fifty-five, or sixty minutes beyond the first point in time that it addresses. The first and second points of time in each Real-Time Dispatch run will be five minutes apart. The remaining points in time in each run can be either five, ten, or fifteen minutes apart depending on when the run begins within the hour. The points in time in each RTD run are arranged so that they parallel as closely as possible RTC's fifteen minute evaluations.

For example, the RTD run that posts its results at the beginning of an hour ("RTD_0") will initialize at the fifty-fifth minute of the previous hour and produce schedules and prices over a fifty-five minute optimization period. RTD_0 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at the beginning of the hour) and ending at the first time point in its optimization period (i.e., five minutes after the hour). It will produce advisory prices and schedules for its second time point, which is ten minutes after the first time point in its optimization period, and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at five minutes after the beginning of the hour ("RTD_5") will initialize at the beginning of the hour and produce prices over a fifty minute optimization period. RTD_5 will produce binding prices and schedules for the RTD interval beginning when it posts its results (i.e., at five minutes after the hour) and ending at the first time point in its optimization period (i.e., ten minutes after the hour.) It will produce advisory prices and schedules for its second time point (which is five minutes after the first time point), and advisory prices and schedules for its third, fourth and fifth time points, each of which would be fifteen minutes apart. The RTD run that posts its results at ten minutes after the beginning of the hour ("RTD_{10}") will initialize at five minutes after the beginning of the hour and produce prices over a sixty minute optimization period. RTD_{10} will produce binding prices and schedules for the interval beginning when it posts its results (i.e., at ten minutes after the hour) and ending at the first time point in its optimization period (i.e., fifteen minutes after the hour.) It will produce advisory prices and schedules for its second, third, fourth and fifth time points, each of which would be fifteen minutes after the preceding time point.

b. Description of the Real-Time Dispatch Process

(i) The First Pass

The first Real-Time Dispatch pass consists of a least bid cost, multi-period co-optimized dispatch for Energy, Regulation Service and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or are otherwise instructed to remain online by the ISO as if they were blocked on at their UOL_N or UOL_E, whichever is applicable. The first pass establishes "physical base points" (i.e., real-time Energy schedules) and real-time schedules for Regulation

Service and Operating Reserves for the first time point of the run. Physical base points and schedules established for the first time point shall be binding and shall remain in effect until the results of the next run are posted. Physical base points and schedules established for all subsequent time points shall be advisory. The first pass also produces information that is used to calculate the RTD Base Point Signals that the ISO sends to Suppliers.

When establishing physical base points, the ISO shall assume that each Generator will move toward the physical base point established during the first pass of the prior Real-Time Dispatch run at its specified response rate.

When setting physical base points for a Dispatchable Resource at the first time point, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits. A Resource's dispatch limits shall be determined based on whether it was feasible for it to reach the physical base point calculated by the last RTD run given its: (A) metered output level at the time that the Real-Time Dispatch run was initialized; (B) response rate; (C) minimum generation level; and (D) UOL_N or UOL_E, whichever is applicable. If it was feasible for the Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, and starting from its previous base point. If it was not feasible for the Resource to reach that base point, then its upper and lower dispatch limits shall reflect the highest and lowest output levels it could achieve over the next RTD interval, given its UOL_N or UOL_E, as applicable, but instead starting from the feasible output level closest to its previous base point.

When setting physical base points for a Dispatchable Resource at later time points, the ISO shall ensure that they do not fall outside of the bounds established by the Resource's lower and upper dispatch limits for that time point. A Resource's dispatch limits at later time points shall be based on its: (A) dispatch limits from the first time point; (B) response rate; (C) minimum generation, or, to the extent that the ISO's software can support demand side participation, Demand Reduction level; and (D) UOL_N or UOL_E, whichever is applicable.

The upper dispatch limit for a Dispatchable Resource at later time points shall be determined by increasing the upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for a Dispatchable Resource at later time points shall be determined by decreasing the lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level or, to the extent that the ISO's software can support demand side participation, to a Demand Side Resource's Demand Reduction level.

The RTD Base Point Signals sent to Dispatchable Resources shall be the same as the physical base points determined above.

When setting physical base points for Self-Committed Fixed and ISO-Committed Fixed Generators in any time point, the ISO shall consider the feasibility of the Resource reaching the output levels that it specified in its self-commitment request for each time point in the RTD run given: (A) its metered output at the time that the run was initialized; and (B) its response rate.

The RTD Base Point Signals sent to ISO-Committed Fixed and Self-Committed Fixed Generators shall follow the quarter hour operating schedules that those Generators submitted in their real-time self-commitment requests, regardless of their actual performance. To the extent possible, the ISO shall honor the response rates specified by such Generators when establishing RTD Base Point Signals. If such a Generator's operating schedule is not feasible based on its real-time self-commitment requests then its RTD Base Point Signals shall be determined using a response rate consistent with the operating schedule changes.

(ii) The Second Pass

The second Real-Time Dispatch pass consists of a least bid cost, multi-period, co-optimized dispatch for Energy, Regulation Service, and Operating Reserves that treats all Fixed Block Units that are committed by RTC, or that are otherwise instructed to remain online by the ISO, as flexible (i.e., able to be dispatched anywhere between zero (0) MW and their UOL_N or UOL_E, whichever is applicable), regardless of their minimum run-time status. This pass shall establish “hybrid base points” (i.e., real-time Energy schedules) that are used in the third pass to determine whether minimum run-time constrained Fixed Block Units should be blocked on at their UOL_N or UOL_E, whichever is applicable, or dispatched flexibly. The ISO will not use schedules for Energy, Regulation Service and Operating Reserves established in the second pass to dispatch Resources.

The upper and lower dispatch limits used for ISO-Committed Fixed and Self-Committed Fixed Resources, as well as for Dispatchable Generators scheduled to provide Regulation Service, shall be the same as the physical base points calculated in the first pass.

The upper dispatch limit for the first time point of the second pass for a Dispatchable Resource not scheduled to provide Regulation Service shall be the higher of: (A) its upper dispatch limit from the first pass; or (B) its “pricing base point” from the first time point of the prior RTD interval adjusted down within its Dispatchable range for any possible ramping since that pricing base point was issued.

The lower dispatch limit for the first time point of the second pass for a Dispatchable Resource not scheduled to provide Regulation Service shall be the lower of: (i) its upper dispatch limit from the first pass; or (ii) its pricing base point for the first time point of the prior RTD interval adjusted down within its Dispatchable range to account for any possible ramping since that pricing base point was issued.

The upper dispatch limit for the later time points of the second pass for a Dispatchable Resource that was not scheduled to provide Regulation Service in the first pass shall be determined by increasing its upper dispatch limit from the first time point at the Resource's response rate, up to its UOL_N or UOL_E, whichever is applicable. The lower dispatch limit for the later time points of the second pass for such a Resource shall be determined by decreasing its lower dispatch limit from the first time point at the Resource's response rate, down to its minimum generation level.

(iii) The Third Pass

The third Real-Time Dispatch pass is the same as the second pass with three variations. First, the third pass treats Fixed Block Units that received a non-zero physical base point in the first pass, and that received a hybrid base point of zero in the second pass, as blocked on at their UOL_N or UOL_E, whichever is applicable. Second, the third pass produces "pricing base points" (i.e., real-time Energy schedules) instead of hybrid base points. Third, and finally, the third pass calculates real-time Energy prices and real-time Shadow Prices for Regulation Service and Operating Reserves that the ISO shall use for settlement purposes pursuant to Article 4, Rate Schedule 3, and Rate Schedule 4 of this ISO Services Tariff respectively. The ISO shall not use schedules for Energy, Regulation Service and Operating Reserves that are established in the third pass to dispatch Resources.

c. Variations in RTD-CAM

When the ISO activates RTD-CAM, the following variations to the rules specified above in Sections I.A.1.a and 1.b shall apply.

First, if the ISO enters reserve pickup mode: (i) the ISO will produce prices and schedules for a single ten minute interval (not for a multi-point co-optimization period); (ii) the Regulation Service markets will be temporarily suspended as described in Rate Schedule 3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments before executing the three Real-Time Dispatch passes; and (iv) the ISO will have discretion to allow the RTD Base Point Signal of each Dispatchable Generator to be set to the higher of the Generator's physical base point or its actual generation level.

Second, if the ISO enters maximum generation pickup mode: (i) the ISO will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period); (ii) the Regulation Service markets will be temporarily suspended as described in Rate Schedule 3 of this ISO Services Tariff; (iii) the ISO will have discretion to make additional Generator commitments in the affected area before executing the three Real-Time Dispatch passes; and (iv) the ISO will have discretion to either move the RTD Base Point Signal of each Generator within the affected area towards its UOL_E at its emergency response rate or set it at a level equal to its physical base point.

Third, if the ISO enters basepoints ASAP – no commitments mode it will produce prices and schedules for a single five minute interval (not for a multi-point co-optimization period).

Fourth, if the ISO enters basepoints ASAP – commit as needed mode: (i) the ISO will produce price and schedules for a single five minute interval (not for a multi-point co-optimization period); and (ii) the ISO may make additional commitments of Generators that are capable of starting within ten minutes before executing the three Real-Time Dispatch passes.

Fifth, and finally, if the ISO enters re-sequencing mode it will solve for a ten-minute optimization period consisting of two five-minute time points.

d. Calculating the Marginal Losses and Congestion Components

The Marginal Losses Component of the price at each location shall be calculated as the product of the price at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one (1).

The Congestion Component of the price at each location shall be calculated as the price at that location, minus the Marginal Losses Component of the price at that location, minus the price at the Reference Bus.

e. The Real-Time Commitment ("RTC") Process and Automated Mitigation

Attachment H to the Services Tariff shall establish automated market power mitigation measures that may affect the calculation of Real-Time LBMPs. To the extent that these measures are implemented they shall be incorporated into the RTC software through the establishment of a second, parallel, commitment evaluation that will assess the impact of the mitigation measures. The first evaluation, referred to as the "RTC evaluation," will determine the schedules and prices that would result using an original set of offers and Bids before any additional mitigation measures, the necessity for which will be considered in the RTC evaluation, are applied. The second evaluation, referred to as the "RT-AMP" evaluation, will determine the schedules and prices that would result from using the original set of offers and bids as modified by any necessary mitigation measures. Both evaluations will follow the rules governing RTC's operation that are set forth in Article 4 of, and this Attachment B to, the ISO Services Tariff (as well as the corresponding provisions of Attachment J to the ISO OATT).

In situations where Attachment H specifies that real-time automated mitigation measures be utilized, the ISO will perform the two parallel RTC evaluations in a manner that enables it to implement mitigation measures one RTC run (i.e., fifteen minutes) in the future. For example, RTC_{15} and $RT\text{-}AMP_{15}$ will perform Resource commitment evaluations simultaneously. $RT\text{-}AMP_{15}$ will then apply the mitigation "impact" test, account for reference bid levels as appropriate and determine which Resources are actually to be mitigated. This information will then be conveyed to RTC_{30} which will make Resource commitments consistent with the application of the mitigation measures (and will thus indirectly be incorporated into future RTD runs).

2.a. Scarcity Pricing Rule “A”

The ISO shall implement the following price calculation procedures for intervals when scarcity pricing rule "A" is applicable.

(i) Except as noted in 2a(ii) below:

- The LBMP at the Reference Bus shall be determined by dividing the lowest offer price at which the quantity of Special Case Resources offered is equal to

$RREQ_{NYCA}$ – ($RACT_{NYCA}$ – ELR_{NYCA}), or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{NYCA}$ – ($RACT_{NYCA}$ – ELR_{NYCA}), by the weighted average of the delivery factors produced by RTD that the ISO uses in its calculation of prices for Load Zone J in that RTD interval,

where:

- $RACT_{NYCA}$ equals the quantity of Available Reserves in the RTD interval;
- $RREQ_{NYCA}$ equals the 30-Minute Reserve requirement set by the ISO for the NYCA; and
- ELR_{NYCA} equals the Expected Load Reduction in the NYCA from the Emergency Demand Response Program and Special Case Resources in that RTD interval. The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one. The LBMP at each location shall be the sum of the Marginal Losses Component of the LBMP at that location, plus the LBMP at the Reference Bus.
- The Congestion Component of the LBMP at each location shall be set to zero.

(ii) However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section I.A.1, above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each location (including the Reference Bus) shall be set to the greater of the LBMP calculated for that location pursuant to Section I.A.1; or the LBMP calculated for that location using the scarcity pricing rule "A" procedures.
- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP at the Reference Bus and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The Congestion Component of the LBMP at each location shall be calculated as the LBMP at that location, minus the LBMP at the Reference Bus, minus the Marginal Losses Component of the LBMP at that location.

2.b. Scarcity Pricing Rule "B"

(i) Except as noted in Pricing Rule 2b(ii) below:

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section I.A.1) and a quantity equal to the delivery factor produced by SCD for that location minus one.
- The Congestion Component of the LBMP at each location shall be equal to the lowest offer price at which the quantity of Special Case Resources offered is equal

to $RREQ_{East}$ – ($RACT_{East}$ – ELR_{East}), or $500/MWh if the total quantity of Special Case Resources offered is less than $RREQ_{East}$ – ($RACT_{East}$– ELR_{East}), minus the LBMP calculated for the Reference Bus (according to Section I.A.1), minus the Marginal Losses Component of the LBMP for Load Zone J,

where:

- $RACT_{East}$ equals the quantity of Available Reserves located East of Central-East in that RTD interval;
- $RREQ_{East}$ equals the 10-Minute Reserve requirement set by the ISO for the portion of the NYCA located East of the Central-East interface; and
- ELR_{East} equals the Expected Load Reduction East of Central-East from the Emergency Demand Response Program and Special Case Resources in that RTD interval.

The LBMP at each location shall be the sum of the LBMP calculated for the Reference Bus (according to Section I.A.1) and the Marginal Loss Component and the Congestion Component for that location.

(ii) However, the ISO shall not use this procedure to set the LBMP for any location lower than the LBMP for that Load Zone or Generator bus calculated pursuant to Section I.A.1, above. In cases in which the procedures described above would cause this rule to be violated:

- The LBMP at each such location shall be set to the LBMP calculated for that location pursuant to Section I.A.1.

- The Marginal Losses Component of the LBMP at each location shall be calculated as the product of the LBMP calculated for the Reference Bus (according to Section I.A.1) and a quantity equal to the delivery factor produced by RTD for that location minus one.
- The Congestion Component of the LBMP at each such location shall be calculated as the LBMP at that location, minus the LBMP calculated for the Reference Bus (according to Section I.A.1), minus the Marginal Losses Component of the LBMP at that location.

B. Day-Ahead LBMP Calculation Procedures

LBMPs in the Day-Ahead Market are calculated using six passes. The first three passes are commitment and dispatch passes, Passes 4, 5 and 6 are dispatch only passes.

Pass 1 consists of a least cost commitment and ideal dispatch to meet Bid Load that assumes that all Fixed Block Units are dispatchable on a “flexible basis” (they can be dispatched anywhere between zero (0) MW and their maximum Capacity).

meet Bid Load with Fixed Block Units treated as dispatchable on a flexible basis. LBMPs are calculated from this dispatch. Following Step 1A, SCUC tests for automated mitigation procedure ("AMP") activation.

If AMP is activated, Step 1B applies the AMP impact test to determine if the AMP will be triggered by mitigating offer prices subject to mitigation that exceed the conduct threshold to their respective reference prices. These mitigated offer prices together with all originally submitted offer prices not subject to automatic mitigation are then used to commit generation and dispatch energy to meet Bid Load. This step is another iteration of the Security Constrained Unit Commitment process. At the end of Step 1B, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids, and committed non-Fixed Block Units are again dispatched to meet Bid Load using the same mitigated or unmitigated Bids used to determine the commitment to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. LBMPs are calculated from this dispatch. The LBMPs determined at the end of Step 1B are compared to the LBMPs determined at the end of Step 1A to determine the hours and zones in which the impact test is met.

In Step 1C, generation offer prices subject to mitigation that exceed the conduct threshold are mitigated for those hours and zones in which the impact test was met in Step 1B. The mitigated offer prices, together with the original unmitigated offer price of units whose offer prices were not subject to mitigation, or did not trigger the conduct or impact thresholds, are used to commit generation and dispatch energy to meet Bid Load. This step is also a complete iteration of the Security Constrained Unit Commitment process. At the end of Step 1C, Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids, and committed non-Fixed Block Units are again dispatched to meet Bid Load, with Fixed Block Units treated as dispatchable on a flexible basis. LBMPs are calculated from this dispatch.

All non-Fixed Block Units committed in the final step of Pass 1 (which could be either step 1A, 1B, or 1C depending on activation of and the AMP) are blocked on at minimum load in Passes 4 through 6.

Pass 2 consists of a least cost commitment and dispatch of Fixed Block Units, Import offers, Export Bids, and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load that minimizes the cost of incremental Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1, and assumes all Fixed Block Units are dispatchable on a flexible basis.

Pass 3 consists of a least cost commitment and dispatch of Fixed Block Units, Import offers, Export Bids, and non-Fixed Block Units to meet forecast Load requirements in excess of Bid Load that minimizes the cost of Minimum Generation and Start Up Bids, given revenues for Minimum Generation Energy based on LBMPs calculated in Pass 1 and assumes all Fixed Block Units are dispatchable on a flexible basis. Fixed Block Units dispatched in this Pass are not blocked on in Pass 6. Non-Fixed Block Units committed in this step are blocked on at minimum Load in Passes 4 through 6. The difference between Pass 2 and Pass 3 is the inclusion of the In-City reserve and second contingency local reliability criteria. Incremental Import Capacity

Fixed Block Units committed in Pass 3 (the "Day-Ahead committed resources") against forecast Loads.

Pass 5 consists of a least cost dispatch of Fixed Block Units, Import offers, Export Bids, virtual supply and demand Bids and Day-Ahead committed resources to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1. Fixed Block Units are treated as dispatchable on a flexible basis, LBMPs used to settle the Day-Ahead Market are calculated from this dispatch. The Shadow Prices used to compute Day-Ahead Market clearing prices for Regulation Service and for Operating Reserves in Rate Schedules 3 and 4 of this ISO Services Tariff are also calculated from this dispatch.

Pass 6 consists of a least cost dispatch of Day-Ahead committed resources, Import offers, Export Bids, and virtual supply and demand Bids to meet Bid Load, based where appropriate on offer prices as mitigated in Pass 1, with the schedules of all Fixed Block Units dispatched in the final step of Pass 1 or dispatched above zero in Pass 5 blocked on at maximum Capacity. The schedules of dispatchable units and Imports may be backed down, and Export schedules may be increased, to offset the additional Capacity scheduled on these Fixed Block Units. Final schedules for the Day-Ahead Market are calculated from this dispatch.

C. LBMP Calculation Method

System marginal costs will be utilized in an *ex ante* computation to produce Day-Ahead and Real-Time LBMP bus prices using the following equations.

The LBMP at bus i can be written as:

$$\gamma_i = \lambda^R + \gamma^L_i + \gamma^C_i$$

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

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 = 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 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 injection at bus i and a corresponding withdrawal at the Reference Bus); and

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

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

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

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 RTD.

D. Zonal LBMP Calculation Method

The computation described above is at the bus level. 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:

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

where:

γ_j^Z = LBMP for zone j,

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

$\gamma_j^{C,Z} = \sum W_i \gamma_i^C$ 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.

The zonal LBMPs will be a weighted average of the Load bus LBMPs in the zone. The weightings will be predetermined by the ISO.

E. LBMP Calculation Method

1. General Rules

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 RTD, or, in the case of a Proxy Generator Bus, from the results of RTC_{15} during periods in which (1) proposed economic transactions over the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed the Available Transfer Capability for that Interface, (2) proposed interchange schedule changes pertaining to the NYCA as a whole would exceed any Ramp Capacity limits in place for the NYCA as a whole, or (3) proposed interchange schedule changes pertaining to the Interface between the NYCA and the Control Area with which that Proxy Generator Bus is associated would exceed any Ramp

Capacity limit imposed by the ISO for that Interface.

2. Rules for Non-Competitive Proxy Generator Buses

Subject to the condition set forth below, Real-Time LBMPs for a Non-Competitive Proxy Generator Bus shall be determined as follows. When (i) proposed Real-Time Market economic net iImport transactions into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net imports into the NYCA from the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the higher of (i) the RTC-determined price at that Non-Competitive Proxy Generator Bus or (ii) the lower of the LBMP determined by RTD for that Non-Competitive Proxy Generator Bus or zero.

When (i) proposed Real-Time Market economic net Export Transactions from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Available Transfer Capability for the Interface between the NYCA and the Control Area in which the Non-Competitive Proxy Generator Bus is located, or (ii) proposed interchange schedule changes pertaining to increases in Real-Time Market net Exports from the NYCA to the Control Area in which the Non-Competitive Proxy Generator Bus is located would exceed the Ramp Capacity limit imposed by the ISO for the Interface between the NYCA and the Control Area in which that Non-Competitive Proxy Generator Bus is located, the Real-Time LBMP at the Non-Competitive Proxy Generator Bus will be the lower of (i) the RTC-determined price at the Non-Competitive Proxy Generator Bus or (ii) the higher of the LBMP determined by RTD for the Non-Competitive Proxy Generator Bus or the Day-Ahead LBMP determined by SCUC for the Non-Competitive Proxy Generator Bus. The foregoing rule shall be applied when (a) after the determination of Day-Ahead schedules, Energy is scheduled by the NYISO to or from a Non-Competitive Proxy Generator Bus in the subsequent real-time scheduling and dispatch process in order to relieve a transmission or ramping constraint, or (b) the NYISO reduces the MW quantity of a day-ahead

transaction in the real-time scheduling and dispatch process in order to relieve a transmission or ramping constraint. At all other times, the Real-Time LBMP shall be calculated as specified in Section E.1 above.

Under the conditions specified below, the Marginal Losses Component and the Congestion Component of the Real-Time LBMP, calculated pursuant to the preceding paragraph, shall be constructed as follows:

When the Real-Time LBMP is set to zero and that zero price was not the result of using the RTD, RTC or SCUC-determined LBMP;

Marginal Losses Component of the Real-Time LBMP = $\text{Losses}_{\text{RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = $(\text{Energy}_{\text{RTC REF BUS}} + \text{Losses}_{\text{RTC PROXY GENERATOR BUS}})$.

When the Real-Time LBMP is set to the Day-Ahead LBMP:

Marginal Losses Component of the Real-Time LBMP = Losses $_{\text{RTC PROXY GENERATOR BUS}}$; and

Congestion Component of the Real-Time LBMP = Day-Ahead LBMP $_{\text{PROXY GENERATOR BUS}}$ - (Energy $_{\text{RTC REF BUS}}$ + Losses $_{\text{RTC PROXY GENERATOR BUS}}$).

where:

Energy $_{\text{RTC REF BUS}}$	=	marginal Bid cost of providing Energy at the reference Bus, as calculated by RTC_{15} for the hour;
Losses $_{\text{RTC PROXY GENERATOR BUS}}$	=	Marginal Losses Component of the LBMP as calculated by RTC_{15} at the Non-Competitive Proxy Generator Bus for the hour; and
Day-Ahead LBMP $_{\text{PROXY GENERATOR BUS}}$	=	Day-Ahead LBMP as calculated by SCUC for the Non-Competitive Proxy Generator Bus for the hour.

The Marginal Losses Component of LBMP

The components of LBMP will be 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

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;

$(DF_b - 1)\lambda^R$ = Marginal Losses Component of the LBMP at bus b; and

I = The set of Interconnection buses between the NYCA and adjacent Control Areas.

II. ACCOUNTING FOR TRANSMISSION LOSSES

1.0 Charges

Subject to Attachment K to the ISO OATT, 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 Model

The ISO's RTD software will use a power flow model and penalty factors to estimate losses incurred 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 the ISO OATT) 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 of the ISO OATT).

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.

2.1.1 Marginal Losses Component Day-Ahead

The ISO shall utilize the Marginal Losses Component computed by SCUC for computing the marginal contributions of each Transaction in the Day-Ahead Market.

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 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 if the 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 Payments and Charges

As part of the LBMP paid to all Suppliers providing Energy to the Real-Time LBMP Market, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do not exceed the AGC or RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO Procedures), minus the amount of Energy each of those Generators was scheduled Day-Ahead to inject in that hour, in MWh; and (b) the loss component of the Real-Time LBMP at each of those Generator's buses, in $/MWh.

As part of the LBMP charged to all LSEs that 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.

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) actual Energy Withdrawals scheduled RTD in each hour, minus the amount of Energy scheduled Day-Ahead to be 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.

As part of the LBMP paid to all Suppliers generating an amount of Energy that differs from the amount of Energy those Suppliers were scheduled by RTD to generate in an hour in association with Bilateral Transactions, the ISO shall pay each such Supplier the product of: (a) the amount of Energy actually injected by each of that Supplier's Generators in each hour (to the extent that actual injections do not exceed the AGC or RTD Base Points Signals sent to that Supplier for those Generators plus any Compensable Overgeneration payable pursuant to ISO Procedures) minus the amount of Energy each of those Generators was scheduled by RTD to inject in that hour in association with Bilateral Transactions, in MWh; and (b) the Marginal Losses Component of the Real-Time LBMP at each of those Generators' buses, in $/MWh.

As part of the LBMP charged to all LSEs consuming an amount of Energy that deviates from the amount of Energy those LSEs were scheduled by RTD to consume in an hour in association with Bilateral Transactions, 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 by RTD in

Through at the Proxy Generator Bus designated as the source of the Transaction, shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three; and (b) Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases from the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three. Real-Time Bids submitted for evaluation in $RTC_{15}$for (a) Imports, and Wheels Through at the Proxy Generator Bus designated as the source of the Transaction, shall be priced no lower than the Bid that provides the highest scheduling priority for sales to the LBMP Market plus the product of (i) the Scheduling Differential and (ii) three; and (b) Exports shall be priced no higher than the Bid that provides the highest scheduling priority for purchases to the LBMP Market minus the product of (i) the Scheduling Differential and (ii) three;

(8) For an Internal Generator, whether the Generator is On-Dispatch or Off-Dispatch;

Day. The ISO shall evaluate requests to withdraw Pre-Scheduled Transactions pursuant to ISO Procedures.

Pre-Scheduled Transactions for Wheels Through in the Day-Ahead Market shall be assigned a Decremental Bid at the Proxy Generator Bus designated as the source of the Transaction that provides the highest scheduling priority available for Firm Transmission Service. The ISO shall evaluate requests for Transmission Service submitted in the Day-Ahead scheduling process using SCUC, and will subsequently establish a Day-Ahead schedule. During the Dispatch Day, the ISO shall use RTC_{15} to establish schedules for each hour of dispatch in that day.

The ISO shall use the information provided by RTC when making Curtailment decisions pursuant to the Curtailment rules described in this Attachment B.

3.2 Use of Decremental Bids to Dispatch Internal Generators

When dispatching Generators taking service under the ISO OATT to match changing conditions, the ISO shall treat Decremental Bids and Incremental Energy 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 Energy Bid; (ii) a Generator serving a Transaction scheduled under the ISO OATT may be dispatched downward if the LBMP at the Generator's Point of Receipt falls below the 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 Energy Bid for the Generator regardless of whether the Generator is supplying Energy to the LBMP Market or supporting a Transaction scheduled under the ISO OATT.

3.3 Scheduling of Bilateral Transactions

Transmission Service for Bilateral Transactions shall be scheduled as follows:

(i) The ISO shall, following evaluation of the Bids submitted, schedule Transmission Service to support Transactions for the hours in which those Transactions may be accommodated.

(ii) The ISO shall treat all Internal Generators as dispatchable and all External Generators as non-dispatchable.

(iii) The ISO will use SCUC and RTD to determine schedules for Internal Generators and schedules for DNI with other Control Areas so that Firm Transmission Service will be provided to any Bilateral Transaction Customer requesting Firm Transmission Service to the extent that is physically feasible.

(iv) The ISO shall not schedule Non-Firm Transmission Service Day-Ahead for a Transaction if Congestion Rents associated with that Transaction are positive, nor will the ISO schedule Non-Firm Transmission Service in the RTC if Congestion Rents associated with that Transaction are expected to be positive. All schedules for Non-Firm Point-to-Point Transmission Service are advisory only and are subject to Reduction if real-time Congestion Rents associated with those Transactions become positive. Transmission Customers receiving Non-Firm Transmission Service will be required to pay Congestion Rents during any delay in the implementation of Reduction (e.g., during the nominal five-minute RTD intervals that elapse before the implementation of Reduction).

3.4 Day-Ahead Bilateral Transaction 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 Energy Bids, Decremental Bids and Sink Price Cap 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.

3.5 Reduction and Curtailment

If a Transmission Customer's Firm Point-to-Point Transmission Service or Network Integration Transmission Service is supporting an Internal Bilateral Transaction, 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.

(modified for 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 withdrawn in real time in association with that Transaction minus the amount of Energy scheduled Day-Ahead to be withdrawn 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 this 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 Energy injections scheduled by RTC_{15} at a Proxy Generator Bus are Curtailed at the request of the ISO then the Supplier or Transmission Customer whose transaction is Curtailed, in addition to paying the charge for replacement Energy necessary to serve the Load and the charge to balance the TUC, as appropriate, shall be paid the product (if positive) of: (a) the Real-Time LBMP at the Proxy Generator Bus minus the higher of the Real-Time Bid price and zero; and (b) the scheduled Energy injection minus the actual Energy injections at that Proxy Generator Bus for the dispatch hour.

If the Transmission Customer does not take service under this 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 the OATT. 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, at the Real-Time LBMP, 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 RTC_{15} 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 Incremental Energy Bids, Decremental Bids, or Sink Price Cap Bids; and (3) prorate Curtailment of equal cost transactions within a priority category.

(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 Energy Bids 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 Incremental Energy Bids, Decremental Bids or Sink Price Cap Bids, and (2) except for External Transactions with minimum run times, prorating Curtailment of equal cost transactions;

(v) Request Internal Generators to voluntarily operate in manual mode below minimum or above maximum dispatchable levels. When operating in manual mode, Generators will not be required to adhere to the one percent minimum ramp rate set forth in Article 4 of the ISO Services Tariff, nor will they be required to respond to RTD Base Point Signals;

(vi) In overgeneration conditions, decommit Internal Generators based on Minimum Generation Bid rate in descending order; and

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

3.6 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 RTC_{15} 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 RTC_{15}. 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. Additionally, any Curtailment or Reductions of schedules for Export Transactions will cause 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 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 RTC_{15}, which, in turn, will determine the Transmission Service scheduled in RTC_{15} to support those Transactions.

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

(i) Generators providing Energy under contracts executed and effective on or before November 18, 1999 (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) in operation on or before November 18, 1999 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